No. _____

In the Supreme Court of the United States

MIDWEST OZONE GROUP,
Applicant,

v.

ENVIRONMENTAL PROTECTION AGENCY AND MICHAEL S. REGAN, ET AL.,
ADMINISTRATOR,
Respondents.

EMERGENCY APPLICATION
FOR IMMEDIATE STAY OF FINAL AGENCY ACTION
PENDING DISPOSITION OF PETITION FOR REVIEW

To the Honorable John G. Roberts, Jr.,
Chief Justice of the Supreme Court of the United States and Circuit Justice for the District of Columbia Circuit

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PARTIES TO THIS APPLICATION

The parties to this proceeding are as follows:

i. Applicant is Midwest Ozone Group

ii. Respondents are United States Environmental Protection Agency and Michael S. Regan, Administrator, United States Environmental Protection Agency

PARTIES TO THE PROCEEDINGS

Petitioners Before the D.C. Circuit:

- No. 24-1119: State of North Dakota; State of West Virginia; State of Alaska; State of Arkansas; State of Georgia; State of Idaho; State of Indiana; State of Iowa; State of Kansas; Commonwealth of Kentucky; State of Louisiana; State of Mississippi; State of Missouri; State of Montana; State of Nebraska; State of Oklahoma; State of South Carolina; State of South Dakota; State of Tennessee; State of Texas; State of Utah; Commonwealth of Virginia; State of Wyoming (lead case)
- No. 24-1154: NACCO Natural Resources Corporation
- No. 24-1179: National Rural Electric Cooperative Association; Lignite Energy Council; National Mining Association; Minnkota Power Cooperative, Inc.; East Kentucky Power Cooperative, Inc.; Associated Electric Cooperative, Inc.; Basin Electric Power Cooperative; Rainbow Energy Center, LLC

- No. 24-1184: Oak Grove Management Company, LLC; Luminant Generation Company LLC
- No. 24-1190: Talen Montana, LLC
- No. 24-1194: Westmoreland Mining Holdings LLC
- No. 24-1201: America's Power; Electric Generators MATS Coalition
- No. 24-1217: NorthWestern Corporation, d/b/a NorthWestern Energy
- No. 24-1223: Midwest Ozone Group

Respondents Before the D.C. Circuit:

- Respondents are the United States Environmental Protection Agency and Michael S. Regan, Administrator, United States Environmental Protection Agency.

Intervenors for the Petitioners:

- San Miguel Electric Cooperative, Inc.

Intervenors for the Respondents:

- Air Alliance Houston; Alliance of Nurses for Healthy Environments; American Academy of Pediatrics; American Lung Association; American Public Health Association; Chesapeake Climate Action Network; Citizens for Pennsylvania's Future; City of Baltimore; City of Chicago; City of New York; Clean Air Council; Clean Wisconsin; Commonwealth of Massachusetts; Commonwealth of Pennsylvania; District of Columbia; Downwinders at Risk; Environmental Defense Fund; Environmental

Integrity Project; Montana Environmental Information Center; Natural Resources Council of Maine; Natural Resources Defense Council; Ohio Environmental Council; Physicians for Social Responsibility; Sierra Club; State of Connecticut; State of Illinois; State of Maine; State of Maryland; State of Michigan; State of Minnesota; State of New Jersey; State of New York; State of Oregon; State of Rhode Island; State of Vermont; State of Wisconsin

CORPORATE DISCLOSURE STATEMENT

Pursuant to Rule 29.6, Applicant the Midwest Ozone Group states as follows:

The Midwest Ozone Group is a continuing association of organizations and individual entities operated to promote the general interests of its membership on matters related to air emissions and air quality. Midwest Ozone Group has no parent companies, subsidiaries, or affiliates that have issued shares or debt securities to the public, although specific individuals in the membership of Midwest Ozone Group have done so. Midwest Ozone Group has no outstanding shares or debt securities in the hands of the public. It has no parent company, and no publicly held company has a 10% or greater ownership interest in Midwest Ozone Group.

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CASES

CONSTITUTIONAL PROVISIONS, STATUTES, AND RULES

OTHER AUTHORITIES

GLOSSARY

EGUs	Electric Generating Units
HAP	Hazardous Air Pollutant
MATS	Mercury Air Toxics Standards
MOG	Midwest Ozone Group
Regulatory Impact 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, U.S. Environmental Protection Agency (April 2024).
Rule	National Emission Standards for Hazardous Air Pollutants: Coal - and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed, Reg, 38,508 (May 7, 2024).
States Application	States' Emergency Application for an Immediate Stay of Administrative Action Pending Review in the D.C. Circuit in the State of North Dakota, State of West Virginia, et al. v. EPA to the Honorable John G. Roberts, Jr., Chief Justice of the Unites States and Circuit Justice for the D.C. Circuit, August 16, 2024.

TO THE HONORABLE JOHN G. ROBERTS, JR.,
CHIEF JUSTICE OF THE SUPREME COURT OF THE UNITED STATES AND CIRCUIT JUSTICE FOR THE DISTRICT OF COLUMBIA CIRCUIT:

The Applicant Midwest Ozone Group ("MOG") respectfully requests an immediate stay of the Mercury and Air Toxics Standards ("MATS") rule of the United States Environmental Protection Agency of May 7, 2024, published in the Federal Register 89 Fed. Reg. 38,508, entitled *"National Emission Standards for Hazardous Air Pollutants: Coal - and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review."* (the "Rule").

The Applicant has a petition for review of the Rule pending in the United States Court of Appeals for the District of Columbia Circuit and, due to the immediate harm from the Rule, moved for a stay pending that court's review. A panel of that court denied that motion, forcing the Applicant to seek emergency relief from this Court.

The Applicant agrees with and incorporates the Applications filed by North Dakota, West Virginia and other states "States' Emergency Application for an Immediate Stay of Administrative Action Pending Review in the D.C. Circuit in the State of North Dakota, West Virginia, et al. v. EPA to the Honorable John G. Roberts, Jr., Chief Justice of the Unites States and Circuit Justice for the D.C. Circuit" of August 16, 2024 ("States Application"). The Applicant also agrees with and incorporates the applications of others that have filed with this Court seeking an immediate stay of the Rule in its entirety. The Applicant will not repeat these arguments but will amplify the reasons why the Rule merits this Court's review, is unlawful, and poses immediate and irreparable harm to our nation's electric generation.

INTRODUCTION

This Rule is just one of a series of recent actions announced by EPA in an April 25, 2024, press release titled "Biden-Harris Administration Finalizes Suite of Standards to Reduce Pollution from Fossil Fuel-Fired Power Plants." https://www.epa.gov/newsreleases/biden-harris-administration-finalizes-suite-standards-reduce-pollution-fossil-fuel. This Rule, like other of the rules in EPA's suite that target the fossil fuel-fired power generation industry, will result in irreparable harm to the domestic energy grid (therefore the general public) and the members of the Midwest Ozone Group. EPA has rejected all comments by stakeholders that this Rule will result in grid reliability issues due to an increase in economic pressure on coal and oil-fired electricity generating units ("EGUs"). This Rule forces EGUs to choose between investment in control measures that are not cost-effective and early retirement.

An immediate stay is necessary to stop the Rule from taking effect resulting in immeasurable damage to the electric power industry that will cause a ripple effect impacting on all public consumers of electricity causing economic harm and irreparable injury to many, including Applicant's membership.

DECISION BELOW

The D.C. Circuit's August 6, 2024, order denying the Applicant's and others' motions for a stay is unpublished and may be found at App. 001a. EPA's Rule is published at 89 Fed. Reg. 38,508 (May 7, 2024) and reprinted beginning at App. 003a – 088a.

JURISDICTION

This Court has jurisdiction over this Application pursuant to 28 U.S.C. § 1254(1) and §2101(f) and authority to grant the Applicant relief under the Administrative Procedure Act, 5 U.S.C. § 705, the Clean Air Act, 42 U.S.C. § 7607, and the All Writs Act, 28 U.S.C. § 1651(a).

CONSTITUTIONAL, STATUTORY, AND REGULATORY PROVISIONS

Pertinent constitutional, statutory, and regulatory provisions are reprinted in beginning at App. 089a and are supplemented by the States Application. App. 553a-555a.

REASONS FOR GRANTING THE APPLICATION

Courts traditionally consider four factors to determine whether a stay would be appropriate. The factors are as follows: (1) likelihood of success on the merits; (2) risk of irreparable harm to movant; (3) risk of injury to non-movants; and (4) whether a stay would be in the public interest. *Wash. Metro. Area Transit Comm'n v. Holiday Tours*, 559 F.2d 841, 842-43 (D.C. Cir. 1977). Each of these factors heavily fall in favor of the Applicant. The Rule exceeds EPA's general statutory authority and specifically conflicts with the Clean Air Act. The Rule threatens the n ation's electric generation in the same manner addressed by this Court in *West Virginia v. EPA,* 597 U.S. 697 (2022). Upon reviewing the facts considering the stay factors, the Court should grant a stay pending judicial review of the merits.

I. Applicant Is Likely To Succeed On The Merits.

A court may invalidate actions taken by EPA that are arbitrary, capricious, an abuse of discretion, not in accordance with the law, contrary to a constitutional right, in excess of statutory jurisdiction, or without proper observance of administrative procedure as required by law. 42 U.S.C. § 7607(d)(9) App. 094a.

The Rule here is arbitrary and capricious and in excess of the authority given to EPA pursuant to the Clean Air Act. EPA is required to revise MATS standards "as necessary" and in consideration of "developments in practices, processes, and control technologies." 42 U.S.C. § 7412(d)(6) App. 100a. It has been clearly established that the Clean Air Act only directs EPA to revise a standard if it determines that a revision is necessary to prevent an adverse environmental impact. *See, La. Envtl. Action Network v. EPA*, 955 F.3d 1088, 1097-98 (D.C. Cir. 2020).

Here, EPA identifies minimal environmental benefits from the extremely low reductions in emissions of mercury or non-mercury metal Hazardous Air Pollutants ("HAP"). EPA classifies the reductions as "Non-Monetized Benefits" described as the "[b]enefits from reductions of about 900 to 1000 pounds of Hg annually" and "[b]enefits from reductions about 4 to 7 tons of non-Hg HAP metals annually." *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, U.S. Environmental Protection Agency (April 2024), EPA-HQ-OAR-2018-0794-6966 at (4-63 and 64, App. 256a and 257a. EPA only emphasized the benefits of additional reductions of ozone and particulate matter that far exceed the benefits of mercury and non-mercury metal HAPs) notwithstanding the fact that ozone and particulate matter are not Clean Air Act regulated HAPs, the purported subject of the Rule. *Id*. EPA has departed from the Clean Air Act path and begun a self-guided journey. In a case such as the challenged Rule, when EPA knows that the residual risk of the HAP program it is invoking already provides an ample margin of safety, new standards of miniscule HAP reduction impact, are simply not justifiable. EPA is without authority to revise the HAPs standards in this instance and, therefore, is without authority to promulgate the Rule. *See*, 42 U.S.C. § 7412(d)(6) App. 100a.

As other Petitioner-Emergency Applicants concerning the Rule have demonstrated, the Rule at issue is an unlawful attempt by EPA to exercise its authority in a manner that it has never done before. State Application App. at 33 App. 592a. The Rule is entirely outside the scope of the Clean Air Act or any other delegation of authority by Congress, and therefore it is unlawful. *See, West Virginia v. EPA*, 597 U.S. 697 (2022). Accordingly, it is highly likely that the Applicant will succeed on the merits.

II. Applicant's Membership Will Suffer Irreparable Harm Absent A Stay.

Without a stay, the membership of the Applicant will be unable to maintain existing productivity and operation because of the immediate requirements to budget and modify contracts to install controls that are not cost-effective, resulting in significant and unrecoverable costs and investments. The unrecoverable capital investments combined with the costly substantial operational changes results in irreparable harm which necessitates a stay. *Thunder Basin Coal Co. v. Reich*, 510 U.S. 200, 220-21 (1994) (Scalia, J., concurring) ("[C]omplying with a regulation later held invalid almost *always* produces the irreparable harm of nonrecoverable compliance costs."); *Armour & Co. v. Freeman*, 304 F.2d 404, 406 (D.C. Cir. 1962) (Any "loss of profits which could never be recaptured" is an irreparable harm.); *Sottera, Inc. v. FDA*, 627 F.3d 891, 899 (D.C. Cir. 2010) (injunctive relief appropriate to avoid unrecoverable economic injury).

The Rule requires several harmful actions by the Applicant. It adds new costs of operations, and in turn, will force merchant coal-fired generating plants out of business and put rate-based coal-fired generation at risk. MOG Comments, EPA-HQ-OAR-2018-0794-5923 at 4, App. 372a.

EPA has underestimated the cost to EGUs for the installation and operation of Continuous Emissions Monitoring Systems to address particulate matter. For example, EPA understated the cost of stack testing, and neglected to provide the actual costs. *Id.*

Additionally, because of under-predicting design and operational "rebuild" requirements for electrostatic precipitator control equipment, EPA's estimates of the number of units requiring retrofit or upgrade is only about half the actual impact (20 vs 37). MOG Comments, EPA-HQ-OAR-2018-0794-5923 at 5, App. 373a. Accordingly, EPA's estimate of incurred cost of $12,200-$14,700/ton to comply with an emission rate of 0.010 lb/MMBtu is only one quarter of the $47,371/ton average cost as informed by publicly available data. *Id.*, *See also, "*Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology," Cichanowicz, Marchetti, and Hein, June 19, 2023, Doc. ID EPA-HQ-OAR-2018-0794-5956, beginning at App. 380a.

Before this Rule, periodic stack testing was required to demonstrate compliance. The Rule unjustifiability moves the goalposts for compliance and now requires regulated EGUs to utilize Continuous Emissions Monitoring Systems. MOG Comments EPA-HQ-OAR-2018-0794-5923 at 3, App. 371a. This change resulted in revision to the numerical value, compliance determination technique and the averaging period, which creates compliance uncertainty. Without merit, the Rule targets the sources that have met the conservative health based EGU limit of the MATS Rule (0.015 lb/MMBtu). *Id.* The regulated community has already successfully demonstrated the ability to meet that limit, and further, conduct subsequent three-year testing to ensure ongoing compliance. EPA's rule is unjustifiably harmful and is arbitrary and capricious. The Applicant States have raised the arbitrary and capricious nature of the Rule in the context of cost as well. Citing comments of Applicant States, grid operators, and the regulated community, the Applicant States note that the costs of this Rule. "States' Emergency Application for an Immediate Stay of Administrative Action Pending Review in the D.C. Circuit in the State of

North Dakota, State of West Virginia, et al. v. EPA to the Honorable John G. Roberts, Jr., Chief Justice of the Unites States and Circuit Justice for the D.C. Circuit," August 16, 2024 at 16-20 App 575a-579a. The high cost of compliance will force units to make the decisions now to begin premature retirement. *Id.* Ratepayers and consumers will see a significant increase in costs as EGUs manage demand and availability of electricity. *Id.* A decrease in online units combined with an ever-increasing electricity demand means that there is a high potential grid failure. *Id.*

Grid reliability has largely been ignored by EPA, although the administrative docket and court filings contain numerous statements of concern. For example, the declaration offered by Gavin A. McCollam of Basin Electric Power Cooperative, addresses how lignite powerplants will be impacted by the Rule. McCollam Del. ¶46 App. 450a. McCollam notes that the Rule requires "an immense amount of coordination between different regulated facilities" and it will "likely involve serious risks to the reliability of electric grids providing power to the region while the removal equipment at each of the impacted facilities are taken offline to undergo the additions and upgrades required by the Final Rule." *Id.* Harms to the grid will not be the result of changed operations at lignite powerplants alone. Tawny Bridgeford, General Counsel & Senior Vice President, Regulatory Affairs for the National Mining Association, expressed concern over EPA's "pattern of ignoring the alarms raised by grid experts concerning the threats to grid reliability resulting from rapid early retirement of dispatchable resources" and stated that the Rule will "accelerate the forced retirement of needed coal plants and exacerbate the reliability crisis."

Bridgeford Decl. ¶11. App. 460a. Further, Jerry Purvis, Vice President of Environmental Affairs at East Kentucky Power Cooperative, Inc, emphasized the Rule will result in the interruption of power supply, possible failure of the electric grid, shutdowns, property damage, diminished productivity, economic losses to the private and public sectors and adverse consequences to public health and the environment. Purvis Decl. ¶31. App. 477a-478a. This Court has recently admonished EPA for failing to materially address comments received that are relevant to their rulemaking. *Ohio v. EPA,* 144 S. Ct. 2040 (2024*).* With this Rule, EPA continues to run afoul of its obligations to consider comments and statements to grid reliability. The risk to the grid presents a harmful and irreparable challenge to EGUs that serve it. In the absence of an immediate stay, these impacts are imminent. Economic losses cannot be recovered.

The operational changes required will jeopardize residential and industrial electricity supply. The harm that this Rule causes is widespread across oil and coal electric power providers. "Analysis of Proposed EPA MATS Residual Risk and Technology Review and Potential Effects on Grid Reliability in North Dakota," Vigesaa, North Dakota Transmission Authority, April 3,2024 at 27 App. 509a. A stay of the Rule will ensure that the grid remains intact, allow electric power providers like the Applicant's members to do their job to provide the power generation needed to support the nation.

III. The Balance Of Harms, Risks to Non-Movants And The Public Interest Strongly Favor A Stay.

The consequences that would flow from this Court's decision to grant or deny the request indicate that the balance weighs heavily in favor of a stay. A stay will not injure other parties, to include non-movants, by leaving the EGU industry unregulated. States and regulated powerplants are governed by a myriad of existing regulations of air emissions. The existing HAPs standards have been determined by EPA to protect human health with an adequate margin of safety. 89 Fed. Reg. at 38,517 App. 012a. Should the Court grant the requested stay other regulations will not become invalidated or somehow disappear. Those important environmental laws will remain in effect in the event of a stay and will continue to remain in force while this Rule is reviewed on the merits and likely rejected as unlawful. No environmental harm will come to pass while the Court assesses the legal validity of the Rule. Accordingly, EPA cannot assert that harm will come from a stay pending a careful review of the validity of the challenged Rule.

The economic harm the regulated community will suffer with the Rule far outweighs the benefits EPA asserts. EPA's own analyses demonstrate that the Rule will not deliver any meaningful environmental benefits through regulated reduction in mercury and non-mercury metals. Regulatory Impact Analysis, EPA-HQ-OAR-2018-0794-6966 at 4-64 App. 257a.

For example, EPA dismisses "changes in costs and benefits due to changes in economic welfare of suppliers to the electricity market or to non-electricity consumers from those suppliers. Furthermore, costs due to interactions with preexisting market distortions outside the electricity sector are omitted." Regulatory Impact Analysis at 7-2. App. 315a. EPA's discussion of costs versus benefits is minimal, skirting the issue as much as possible. In its Regulatory Impact Analysis for the Rule, EPA made the following statement:

> [d]ue to current data and modeling limitations, quantified and monetized benefits from reducing Hg and non-Hg HAP metals emissions are not included in the monetized benefits presented here. We are also unable to quantify the potential benefits from the CEMS requirement. Due to data and modeling limitations, there are also still many categories of climate impacts and associated damages that are not reflected yet in the monetized climate benefits from reducing CO2 emissions.

Id. at 7-1 App. 314a.

EPA's lack of interest in grid reliability issues is made clear by its pattern of ignoring comments regarding the same as it proposed its suite of EGU Rules. EPA refuses to acknowledge concerns and statements about the need for a comprehensive, intersectional analysis of the grid's function. Bridgeford Decl. ¶11. App. 460a. Negative impacts to the reliable supply of power to the electric grid will harm the public. Purvis ¶31. App. 477a and 478a. Access to reliable, affordable electricity is a national interest that the public and the regulated community share, and it certainly weighs in favor of a stay. *Texas v. EPA,* 829 F.3d 405, 435 (5th Cir. 2016); *Sierra Club v. Ga. Power Co.*, 180 F.3d 1309, 1311 (11th Cir. 1999); *West Virginia v. EPA*, 90 F.4th 323, 332 (4th Cir. 2024).

EPA has failed to show applicable benefits this Rule will have on HAP air quality, the environment or the public. The regulated community, of which Applicant and its membership are a part, and the public face immediate irreparable harm because of this Rule. Accordingly, a stay of the Rule is necessary.

CONCLUSION

For the foregoing reasons, Applicant respectfully requests an immediate stay of EPA's Rule in its entirety pending judicial review.

Respectfully submitted,

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APPENDIX

Table of Appendices

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 24-1119 **September Term, 2023**

EPA-89FR38508

Filed On: August 6, 2024

State of North Dakota, et al.,

Petitioners

v.

Environmental Protection Agency,

Respondent

San Miguel Electric Cooperative, Inc., et al.,
Intervenors

Consolidated with 24-1154, 24-1179,
24-1184, 24-1190, 24-1194, 24-1201,
24-1217, 24-1223

BEFORE: Henderson, Pan, and Garcia, Circuit Judges

O R D E R

Upon consideration of the motions for stay pending review, the oppositions thereto, the replies, and the Rule 28(j) letter, it is

ORDERED that the motions for stay be denied. Petitioners have not satisfied the stringent requirements for a stay pending court review. See Nken v. Holder, 556 U.S. 418, 434 (2009); D.C. Circuit Handbook of Practice and Internal Procedures 33 (2021). It is

FURTHER ORDERED, on the court's own motion, that the parties submit, within 14 days from the date of this order, proposed formats and schedules for the briefing of these cases. The parties are strongly urged to submit a joint proposal and are reminded that the court looks with extreme disfavor on repetitious submissions and will, where appropriate, require a joint brief of aligned parties with total words not to exceed the standard allotment for a single brief. Whether the parties are aligned or have disparate interests, they must provide detailed justifications for any request to file

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 24-1119 **September Term, 2023**

separate briefs or to exceed in the aggregate the standard word allotment. Requests to exceed the standard word allotment must specify the word allotment necessary for each issue.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

BY: /s/
Selena R. Gancasz
Deputy Clerk

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2018–0794; FRL–6716.3–02–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: Final rule.

SUMMARY: This action finalizes amendments to the national emission standards for hazardous air pollutants (NESHAP) for the Coal- and Oil-Fired Electric Utility Steam Generating Units (EGUs) source category. These final amendments are the result of the EPA's review of the 2020 Residual Risk and Technology Review (RTR). The changes, which were proposed under the technology review in April 2023, include amending the filterable particulate matter (fPM) surrogate emission standard for non-mercury metal hazardous air pollutants (HAP) for existing coal-fired EGUs, the fPM emission standard compliance demonstration requirements, and the mercury (Hg) emission standard for lignite-fired EGUs. Additionally, the EPA is finalizing a change to the definition of ''startup.'' The EPA did not propose, and is not finalizing, any changes to the 2020 Residual Risk Review.

DATES: This final rule is effective on July 8, 2024. The incorporation by reference of certain material listed in the rule was approved by the Director of the Federal Register as of April 16, 2012.

ADDRESSES: The U.S. Environmental Protection Agency (EPA) has established a docket for this action under Docket ID No. EPA–HQ–OAR–2018–0794. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *https://www.regulations.gov,* or in hard copy at the EPA Docket Center, WJC West Building, Room Number 3334, 1301 Constitution Ave. NW, Washington, DC. The Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m. Eastern Standard Time (EST), Monday through Friday. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about this final action contact Sarah Benish, Sector Policies and Programs Division (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, P.O. Box 12055, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5620; and email address: *benish.sarah@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. 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:

APH air preheater
Btu British Thermal Units
CAA Clean Air Act
CEMS continuous emission monitoring system
EGU electric utility steam generating unit
EIA Energy Information Administration
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
Hg^{2+} divalent Hg
$HgCl_2$ mercuric chloride
Hg_p particulate bound Hg
HQ hazard quotient
ICR Information Collection Request
IGCC integrated gasification combined cycle
IPM Integrated Planning Model
IRA Inflation Reduction Act
lb pounds
LEE low emitting EGU
MACT maximum achievable control technology
MATS Mercury and Air Toxics Standards
MMacf million actual cubic feet
MMBtu million British thermal units of heat input
MW megawatt
NAICS North American Industry Classification System
NESHAP national emission standards for hazardous air pollutants
NO_X nitrogen oxides
NRECA National Rural Electric Cooperative Association
OMB Office of Management and Budget
PM particulate matter
$PM_{2.5}$ fine particulate matter
PM CEMS particulate matter continuous emission monitoring systems
REL reference exposure level
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
RIN Regulatory Information Number
RTR residual risk and technology review
SC–CO_2 social cost of carbon
SO_2 sulfur dioxide
TBtu trillion British thermal units of heat input
tpy tons per year
UMRA Unfunded Mandates Reform Act
WebFIRE Web Factor Information Retrieval System

Background information. On April 24, 2023, the EPA proposed revisions to the Coal- and Oil-Fired EGU NESHAP based on our review of the 2020 RTR. In this action, we are finalizing revisions to the rule, commonly known as the Mercury and Air Toxics Standards (MATS). We summarize some of the more significant comments regarding the proposed rule that were received during the public comment period and provide our responses in this preamble. A summary of all other public comments on the proposal and the EPA's responses to those comments is available in *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review Proposed Rule Response to Comments,* Docket ID No. EPA–HQ–OAR–2018–0794. A ''track changes'' version of the regulatory language that incorporates the changes in this action is available in the docket.

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

I. General Information

A. Executive Summary

1. Background and Purpose of the Regulatory Action

Exposure to hazardous air pollutants (''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. These adverse effects can be particularly acute for communities living near sources of HAP. 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 based on maximum achievable control technology (known as ''MACT'' standards) for major sources [1] 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 nonair quality health and environmental impacts and energy requirements, determines is achievable.'' 42 U.S.C. 7412(d)(2). The EPA is further required to ''review, and revise'' those standards every 8 years ''as necessary (taking into account developments in practices, processes, and control technologies).'' *Id.* 7412(d)(6).

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 two parts: (1) a finding that it is not appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112; and (2) the RTR for the 2012 MATS Final Rule.

The EPA reviewed both parts of the 2020 Final Action. The results of the EPA's review of the first part, finding it is appropriate and necessary to regulate EGUs under CAA section 112, 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 HAP emissions, improved methods of operation, and risk-related information to further inform the EPA's review of the second part, the 2020 MATS RTR. The EPA proposed amendments to the RTR on April 24, 2023 (88 FR 24854) (2023 Proposal) and this action finalizes those amendments and presents the final results of the EPA's review of the MATS RTR.

2. Summary of Major Provisions of the Regulatory Action

Coal- and oil-fired EGUs remain one of the largest domestic emitters of Hg and many other HAP, including many of the non-Hg HAP metals—including lead, arsenic, chromium, nickel, and cadmium—and hydrogen chloride (HCl). Exposure to these HAP, at certain levels and duration, is associated with a variety of adverse health effects. In the 2012 MATS Final Rule, the EPA established numerical standards for Hg, non-Hg HAP metals, and acid gas HAP emissions from coal- and oil-fired EGUs. The EPA also established work practice standards for emissions of organic HAP. To address emissions of non-Hg HAP

[1] The term ''major source'' means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants. 42 U.S.C. 7412(a)(1).

metals, the EPA established individual emission limits for each of the 10 non-Hg HAP metals [2] emitted from coal- and oil- fired EGUs. Alternatively, affected sources could meet an emission standard for ''total non-Hg HAP metals'' by summing the emission rates of each of the non-Hg HAP metals or meet a fPM emission standard as a surrogate for the non-Hg HAP metals. For existing coal-fired EGUs, almost every unit has chosen to demonstrate compliance with the non-Hg HAP metals surrogate fPM emission standard of 0.030 pounds (lb) of fPM per million British thermal units of heat input (lb/MMBtu).

Pursuant to CAA section 112(d)(6), the EPA reviewed developments in the costs of control technologies, and the effectiveness of those technologies, as well as the costs of meeting a fPM emission standard that is more stringent than 0.030 lb/MMBtu and the other statutory factors. Based on that review, the EPA is finalizing, as proposed, a revised non-Hg HAP metal surrogate fPM emission standard for all existing coal-fired EGUs of 0.010 lb/MMBtu. This strengthened standard will ensure that the entire fleet of coal-fired EGUs is performing at the fPM pollution control levels currently achieved by the vast majority of regulated units. The EPA further concludes that it is the lowest level currently compatible with the use of PM CEMS for demonstrating compliance.

Relatedly, the EPA is also finalizing a revision to the requirements for demonstrating compliance with the revised fPM emission standard. Currently, affected EGUs that do not qualify for the low emitting EGU (LEE) program for fPM [3] can demonstrate compliance with the fPM standard either by conducting quarterly performance testing (*i.e.,* quarterly stack testing) or by using particulate matter (PM) continuous emission monitoring systems (PM CEMS). PM CEMS confer significant benefits, including increased transparency regarding emissions performance for sources, regulators, and the surrounding communities; and real-time identification of when control technologies are not performing as expected, allowing for quicker repairs. After considering updated information on the costs for quarterly performance testing compared to the costs of PM CEMS and the measurement capabilities of PM CEMS, as well as the many benefits of using PM CEMS, the EPA is finalizing, as proposed, a requirement that all coal- and oil-fired EGUs demonstrate compliance with the revised fPM emission standard by using PM CEMS. As the EPA explained in the 2023 Proposal, by requiring facilities to use PM CEMS, the current compliance method for the LEE program becomes superfluous since LEE is an optional program in which stack testing occurs infrequently, and the revised fPM limit is below the current fPM LEE program limit. Therefore, the EPA is finalizing, as proposed, the removal of the fPM LEE program.

Based on comments received during the public comment period, the EPA is not removing, but instead revising the alternative emission limits for the individual non-Hg HAP metals such as lead, arsenic, chromium, nickel, and cadmium and for the total non-Hg HAP metals proportional to the finalized fPM emission limit of 0.010 lb/MMBtu.[4] Owners and operators of EGUs seeking to use these alternative standards must request and receive approval to use a HAP metal continuous monitoring system (CMS) as an alternative test method under 40 CFR 63.7(f).

The EPA is also finalizing, as proposed, a more protective Hg emission standard for existing lignite-fired EGUs, requiring that such lignite-fired EGUs meet the same Hg emission standard as EGUs firing other types of coal (*i.e.,* bituminous and subbituminous), which is 1.2 lb of Hg per trillion British thermal units of heat input (lb/TBtu) or an alternative output-based standard of 0.013 lb per gigawatt-hour (lb/GWh). Finally, the EPA is finalizing, as proposed, the removal of the second option for defining the startup period for MATS-affected EGUs.

The EPA did not propose and is not finalizing modifications to the HCl emission standard (nor the alternative sulfur dioxide (SO_2) emission standard), which serves as a surrogate for all acid gas HAP (HCl, hydrogen fluoride (HF), selenium dioxide (SeO_2)) for existing coal-fired EGUs. The EPA proposed to require PM CEMS for existing integrated gasification combined cycle (IGCC) EGUs but is not finalizing this requirement due to technical issues calibrating CEMS on these types of EGUs and the related fact that fPM emissions from IGCCs are very low.

In establishing the final standards, as discussed in detail in sections IV., V., VI., and VII. of this preamble, the EPA considered the statutory direction and factors laid out by Congress in CAA section 112. Separately, pursuant to Executive Order 12866 and Executive Order 14904, the EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, *Regulatory Impact Analysis for the Final National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review* (Ref. EPA–452/R–24–005), is available in the docket, and is briefly summarized in sections I.A.3. and IX. of this preamble.

3. Costs and Benefits

In accordance with Executive Order 12866 and 14094, the EPA prepared a Regulatory Impact Analysis (RIA). The RIA presents estimates of the emission, cost, and benefit impacts of this final rulemaking for the 2028 to 2037 period; those estimates are summarized in this section.

The power industry's compliance costs are represented in the RIA as the projected change in electric power generation costs between the baseline and final rule scenarios. The quantified emission estimates presented in the RIA include changes in pollutants directly covered by this rule, such as Hg and non-Hg HAP metals, and changes in other pollutants emitted from the power sector due to the compliance actions projected under this final rule. The cumulative projected national-level emissions reductions over the 2028 to 2037 period under the finalized requirements are presented in table 1. The supporting details for these estimates can be found in the RIA.

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[2] The ten non-Hg HAP metals are antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

[3] In order to qualify for fPM LEE status, an EGU must demonstrate that its fPM emission rate is below 50 percent of standard (or 0.015 lb/MMBtu) from quarterly stack tests for 3 consecutive years. Once a source achieves LEE status for fPM, the source must conduct stack testing every 3 years to demonstrate that its emission rate remains below 50 percent of the standard.

[4] The emission limits for the individual non-Hg HAP metals and the total non-Hg HAP metals have been reduced by two-thirds, consistent with the revision of the fPM emission limit from 0.030 lb/MMBtu to 0.010 lb/MMBtu.

Table 1. Cumulative Projected Emissions Reductions under the Final Rule, 2028 to 2037[a]

Pollutant	Emissions Reductions
Hg (pounds)	9,500
$PM_{2.5}$ (tons)	5,400
SO_2 (tons)	770
NO_x (tons)	220
CO_2 (thousand tons)	650
non-Hg HAP metals (tons)[b]	49

[a] Values rounded to two significant figures.

[b] The non-Hg HAP metals are antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

The EPA expects that emission reductions under the final rulemaking will result in reduced exposure to Hg and non-Hg HAP metals. The EPA also projects health benefits due to improvements in particulate matter with a diameter of 2.5 micrometers or less ($PM_{2.5}$) and ozone and climate benefits from reductions in carbon dioxide (CO_2) emissions. The EPA also anticipates benefits from the increased transparency to the public, the assurance that standards are being met continuously, and the accelerated identification of anomalous emissions due to requiring PM CEMS in this final rule.

The EPA estimates negative net monetized benefits of this rule (see table 2 below). However, the benefit estimates informing this result represent only a partial accounting of the potential benefits of this final rule. Several categories of human welfare and climate benefits are unmonetized and are thus not directly reflected in the quantified net benefit estimates (see section IX.B. in this preamble and section 4 of the RIA for more details). In particular, estimating the economic benefits of reduced exposure to HAP generally has proven difficult for a number of reasons: it is difficult to undertake epidemiologic studies that have sufficient power to quantify the risks associated with HAP exposures experienced by U.S. populations on a daily basis; data used to estimate exposures in critical microenvironments are limited; and there remains insufficient economic research to support valuation of HAP benefits made even more challenging by the wide array of HAP and possible HAP effects.[5] In addition, due to data limitations, the EPA is also unable to quantify potential emissions impacts or monetize potential benefits from continuous monitoring requirements.

The present value (PV) and equivalent annual value (EAV) of costs, benefits, and net benefits of this rulemaking over the 2028 to 2037 period in 2019 dollars are shown in table 2. In this table, results are presented using a 2 percent discount rate. Results under other discount rates and supporting details for the estimates can be found in the RIA.

[5] See section II.B.2. for discussion of the public health and environmental hazards associated with HAP emissions from coal- and oil-fired EGUs and discussion on the limitations to monetizing and quantifying benefits from HAP reductions. See also *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration and Affirmation of the Appropriate and Necessary Supplemental Finding,* 88 FR 13956, 13970–73 (March 6, 2023).

Table 2. Projected Benefits, Costs, and Net Benefits under the Final Rule, 2028 to 2037 (millions of 2019 dollars, discounted to 2023)[a]

	2% Discount Rate	
	PV	EAV
Ozone- and $PM_{2.5}$-related Health Benefits	300	33
Climate Benefits[b]	130	14
Compliance Costs	860	96
Net Benefits[c]	-440	-49
Non-Monetized Benefits	Benefits from reductions of about 900 to 1000 pounds of Hg annually	
	Benefits from reductions of about 4 to 7 tons of non-Hg HAP metals annually	
	Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS	

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

[b] Climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the SC-CO_2 (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate.

[c] Several categories of benefits remain unmonetized and are thus not reflected in the table.

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The EPA notes that analysis of such impacts is distinct from the determinations finalized in this action under CAA section 112, which are based on the statutory factors the EPA discusses in section II.A. and sections IV. through VII. below.

B. Does this action apply to me?

Regulated entities. The source category that is the subject of this action is coal- and oil-fired EGUs regulated by NESHAP under 40 CFR part 63, subpart UUUUU, commonly known as MATS. The North American Industry Classification System (NAICS) codes for the coal- and oil-fired EGU source category are 221112, 221122, and 921150. This list of NAICS codes is not intended to be exhaustive, but rather to provide a guide for readers regarding entities likely to be affected by the final action for the source category listed. To determine whether your facility is affected, you should examine the applicability criteria in the appropriate NESHAP. If you have any questions regarding the applicability of any aspect of this NESHAP, please contact the appropriate person listed in the preceding FOR FURTHER INFORMATION CONTACT section of this preamble.

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

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

Additional information is available on the RTR website at *https://www.epa.gov/stationary-sources-air-pollution/risk-and-technology-review-national-emissions-standards-hazardous.* This information includes an overview of the RTR program and links to project websites for the RTR source categories.

D. Judicial Review and Administrative Reconsideration

Under CAA section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit (the Court) by July 8, 2024. Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

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

General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

II. Background

A. What is the statutory authority for this action?

1. Statutory Language

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 major sources control HAP emissions at the level achieved by the best-performing sources, referred to as the 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 the emission standards should be revised 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 primary subject of this final rule. 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 nonair quality health and environmental impacts and energy requirements, determines is achievable.'' (emphasis added). These standards are commonly referred to as MACT standards. CAA section 112(d)(3) establishes a minimum control level for MACT standards, known as the MACT ''floor.'' [6] 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.[7]

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). The residual risk review and the technology review are distinct requirements and are both mandatory.

In this action, the EPA is finalizing amendments to the MACT standards based on two independent sources of authority: (1) its review of the 2020 Final Action's risk and technology review pursuant to the EPA's statutory authority under CAA section 112, and (2) 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. Statutory Structure and Legislative History

In addition to the text of the specific subsections of CAA section 112 discussed above, the statutory structure and legislative history of CAA section 112 further support the EPA's authority to take this action. Throughout CAA section 112 and its legislative history, Congress made clear its intent to quickly secure large reductions in the volume of HAP emissions from stationary sources based on technological developments in control technologies because of its recognition of the hazards to public health and the environment that result from exposure to such emissions. CAA section 112 and its legislative history also reveal Congress's understanding that fully characterizing the risks posed by HAP emissions was exceedingly difficult. Thus, Congress purposefully replaced a regime that required the EPA to make an assessment of risk in the first instance, with one in which Congress determined risk existed and directed the EPA to make swift and substantial reductions based upon the most stringent standards technology could achieve.

Specifically, in 1990, Congress radically transformed section 112 of the CAA and its treatment of HAP through the Clean Air Act Amendments, by

[6] 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. 42 U.S.C. 7412(d)(3). For new sources MACT shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source. *Id.*

[7] 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.

amending CAA section 112 to be a technology-driven standard setting provision as opposed to the risk-based one that Congress initially promulgated in the 1970 CAA. The legislative history of the 1990 Amendments indicates Congress's dissatisfaction with the EPA's slow pace addressing HAP under the 1970 CAA: ''In theory, [hazardous air pollutants] were to be stringently controlled under the existing Clean Air Act section 112. However, . . . only 7 of the hundreds of potentially hazardous air pollutants have been regulated by EPA since section 112 was enacted in 1970.'' H.R. Rep. No. 101–490, at 315 (1990); see also *id.* at 151 (noting that in 20 years, the EPA's establishment of standards for only seven HAP covered ''a small fraction of the many substances associated . . . with cancer, birth defects, neurological damage, or other serious health impacts.'').

In enacting the 1990 Amendments with respect to the control of HAP, Congress noted that ''[p]ollutants controlled under [section 112] tend to be less widespread than those regulated [under other sections of the CAA], but are often associated with more serious health impacts, such as cancer, neurological disorders, and reproductive dysfunctions.'' *Id.* at 315. In its substantial 1990 Amendments, Congress itself listed 189 HAP (CAA section 112(b)) and set forth a statutory structure that would ensure swift regulation of a significant majority of these HAP emissions from stationary sources. Specifically, after defining major and area sources and requiring the EPA to list all major sources and many area sources of the listed pollutants (CAA section 112(c)), the new CAA section 112 required the EPA to establish technology-based emission standards for listed source categories on a prompt schedule and to revisit those technology-based standards every 8 years on an ongoing basis (CAA section 112(d) (emission standards); CAA section 112(e) (schedule for standards and review)). The 1990 Amendments also obligated the EPA to conduct a one-time evaluation of the residual risk within 8 years of promulgation of technology-based standards. CAA section 112(f)(2).

In setting the standards, CAA section 112(d) requires the EPA to establish technology-based standards that achieve the ''maximum degree of reduction,'' ''including a prohibition on such emissions where achievable.'' CAA section 112(d)(2). Congress specified that the maximum degree of reduction must be at least as stringent as the average level of control achieved in practice by the best performing sources in the category or subcategory based on emissions data available to the EPA at the time of promulgation. This technology-based approach enabled the EPA to swiftly set standards for source categories without determining the risk or cost in each specific case, as the EPA had done prior to the 1990 Amendments. In other words, this approach to regulation quickly required that all major sources and many area sources of HAP meet an emission standard consistent with the top performers in each category, which had the effect of obtaining immediate reductions in the volume of HAP emissions from stationary sources. The statutory requirement that sources obtain levels of emission limitation that have actually been achieved by existing sources, instead of levels that could theoretically be achieved, inherently reflects a built-in cost consideration.[8]

Further, after determining the minimum stringency level of control, or MACT floor, CAA section 112(d)(2) directs the EPA to ''require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section (including a prohibition on such emissions, where achievable)'' that the EPA determines are achievable after considering the cost of achieving such standards and any non-air-quality health and environmental impacts and energy requirements of additional control. In doing so, the statute further specifies in CAA section 112(d)(2) that the EPA should consider requiring sources to apply measures that, among other things, ''reduce the volume of, or eliminate emissions of, such pollutants . . . '' (CAA section 112(d)(2)(A)), ''enclose systems or processes to eliminate emissions'' (CAA section 112(d)(2)(B)), and ''collect, capture, or treat such pollutants when released . . . '' (CAA section 112(d)(2)(C)). The 1990 Amendments also built in a regular review of new technologies and a one-time review of risks that remain after imposition of MACT standards. CAA section 112(d)(6) requires the EPA to evaluate every NESHAP no less often than every 8 years to determine whether additional control is necessary after taking into consideration ''developments in practices, processes, and control technologies,'' separate from its obligation to review residual risk. CAA section 112(f) requires the EPA to ensure within 8 years of promulgating a NESHAP that the risks are acceptable and that the MACT standards provide an ample margin of safety.

The statutory requirement to establish technology-based standards under CAA section 112 eliminated the requirement for the EPA to identify hazards to public health and the environment in order to justify regulation of HAP emissions from stationary sources, reflecting Congress's judgment that such emissions are inherently dangerous. See S. Rep. No. 101–228, at 148 (''The MACT standards are based on the performance of technology, and not on the health and environmental effects of the [HAP].''). The technology review required in CAA section 112(d)(6) further mandates that the EPA continually reassess standards to determine if additional reductions can be obtained, without evaluating the specific risk associated with the HAP emissions that would be reduced. Notably, Congress required the EPA to conduct the CAA section 112(d)(6) review of what additional reductions may be obtained based on new technology even after the EPA has conducted the one-time CAA section 112(f)(2) risk review and determined that the existing standard will protect the public with an ample margin of safety. The two requirements are distinct, and both are mandatory.

B. What is the Coal- and Oil-Fired EGU source category and how does the NESHAP regulate HAP emissions from the source category?

1. Summary of Coal- and Oil-Fired EGU Source Category and NESHAP Regulations

The EPA promulgated the Coal- and Oil-Fired EGU NESHAP (commonly referred to as MATS) on February 16, 2012 (77 FR 9304) (2012 MATS Final Rule). The standards are codified at 40 CFR part 63, subpart UUUUU. The coal- and oil-fired electric utility industry consists of facilities that burn coal or oil 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

[8] Congress recognized as much: ''The Administrator may take the cost of achieving the maximum emission reduction and any non-air quality health and environmental impacts and energy requirements into account when determining the emissions limitation which is achievable for the sources in the category or subcategory. Cost considerations are reflected in the selection of emissions limitations which have been achieved in practice (rather than those which are merely theoretical) by sources of a similar type or character.'' A Legislative History of the Clean Air Act Amendments of 1990 (CAA Legislative History), Vol 5, pp. 8508–8509 (CAA Amendments of 1989; p. 168–169; Report of the Committee on Environment and Public Works S. 1630).

after May 3, 2011. An EGU is a 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 electric output to any utility power distribution system for sale is also considered an EGU. The 2012 MATS Final 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.'' In 2028, the EPA expects the source category covered by this MACT standard to include 314 coal-fired steam generating units (140 GW at 157 facilities), 58 oil-fired steam generating units (23 GW at 35 facilities), and 5 IGCC units (0.8 GW at 2 facilities).

For coal-fired EGUs, the 2012 MATS Final 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 flue gas desulfurization (FGD) systems and SO_2 CEMS installed and operational. Standards for fPM serve as a surrogate for the non-Hg HAP metals. Work practice standards limit formation and emissions of organic HAP.

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

MATS includes standards for existing and new EGUs for eight subcategories: three 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 seven of the subcategories are subject to numeric emission limits for all the pollutants described above except for organic HAP (limited-use liquid oil-fired EGUs are not subject to numeric emission limits). 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 and additional information of the history and other requirements of the 2012 MATS Final Rule are available in the 2023 Proposal preamble (88 FR 24854).

2. Public Health and Environmental Hazards Associated With Emissions From Coal- and Oil-Fired EGUs

Coal- and oil-fired EGUs are a significant source of numerous HAP that are associated with adverse effects to human health and the environment, including Hg, HF, HCl, selenium, arsenic, chromium, cobalt, nickel, hydrogen cyanide, beryllium, and cadmium emissions. Hg is a persistent and bioaccumulative toxic metal that, once released from power plants into the ambient air, can be readily transported and deposited to soil and aquatic environments where it is transformed by microbial action into methylmercury.[9] Methylmercury bioaccumulates in the aquatic food web eventually resulting in highly concentrated levels of methylmercury within the larger and longer-living fish (*e.g.,* carp, catfish, trout, and perch), which can then be consumed by humans.

Of particular concern is chronic prenatal exposure via maternal consumption of foods containing methylmercury. Elevated exposure has been associated with developmental neurotoxicity and manifests as poor performance on neurobehavioral tests, particularly on tests of attention, fine motor function, language, verbal memory, and visual-spatial ability. Evidence also suggests potential for adverse effects on the cardiovascular system, adult nervous system, and immune system, as well as potential for causing cancer. Because the impacts of the neurodevelopmental effects of methylmercury are greatest during periods of rapid brain development, developing fetuses, infants, and young children are particularly vulnerable. Children born to populations with high fish consumption (*e.g.,* people consuming fish as a dietary staple) or impaired nutritional status may be especially susceptible to adverse neurodevelopmental outcomes. These dietary and nutritional risk factors are often particularly pronounced in vulnerable communities with people of color and low-income populations that have historically faced economic and environmental injustice and are overburdened by cumulative levels of pollution. In addition to adverse neurodevelopmental effects, there is evidence that exposure to methylmercury in humans and animals can have adverse effects on both the developing and adult cardiovascular system.

Along with the human health hazards associated with methylmercury, it is well-established that birds and mammals are also exposed to methylmercury through fish consumption (Mercury Study). At higher levels of exposure, the harmful effects of methylmercury include slower growth and development, reduced reproduction, and premature mortality. The effects of methylmercury on wildlife are variable across species but have been observed in the environment for numerous avian species and mammals including polar bears, river otters, and panthers.

EGUs are also the largest source of HCl, HF, and selenium emissions, and are a major source of metallic HAP emissions including arsenic, chromium, nickel, cobalt, and others. Exposure to these HAP, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. These adverse health effects may include chronic health disorders (*e.g.,* pneumonitis, decreased pulmonary function, pneumonia, or lung damage; detrimental effects on the central nervous system; damage to the kidneys) and alimentary effects (such as nausea and vomiting). As of 2021, three of the key metal HAP emitted by EGUs (arsenic, chromium, and nickel) have been classified as human carcinogens, while three others (cadmium, selenium, and lead) are classified as probable human carcinogens. Overall (metal and nonmetal), the EPA has classified four of the HAP emitted by EGUs as human carcinogens and five as probable human carcinogens.

While exposure to HAP is associated with a variety of adverse effects, quantifying the economic value of these impacts remains challenging. Epidemiologic studies, which report a central estimate of population-level risk, are generally used in an air pollution benefits assessment to estimate the number of attributable cases of events. Exposure to HAP is typically more uneven and more highly concentrated among a smaller number of individuals than exposure to criteria pollutants.

[9] U.S. EPA. 1997, Mercury Study Report to Congress, EPA–452/R–97–003 (December 1997); *see also* 76 FR 24976 (May 3, 2011); 80 FR 75029 (December 1, 2015).

Hence, conducting an epidemiologic study for HAP is inherently more challenging; for starters, the small population size means such studies often lack sufficient statistical power to detect effects (particularly outcomes like cancer, for which there can exist a multi-year time lag between exposure and the onset of the disease). By contrast, sufficient power generally exists to detect effects for criteria pollutants because exposures are ubiquitous and a variety of methods exist to characterize this exposure over space and time.

For the reasons noted above, epidemiologic studies do not generally exist for HAP. Instead, the EPA tends to rely on experimental animal studies to identify the range of effects which may be associated with a particular HAP exposure. Human controlled clinical studies are often limited due to ethical barriers (*e.g.,* knowingly exposing someone to a carcinogen). Generally, robust data are needed to quantify the magnitude of expected adverse impacts from varying exposures to a HAP. These data are necessary to provide a foundation for quantitative benefits analyses but are often lacking for HAP, made even more challenging by the wide array of HAP and possible noncancer HAP effects.

Finally, estimating the economic value of HAP is made challenging by the human health endpoints affected. For example, though EPA can quantify the number and economic value of HAP-attributable deaths resulting from cancer, it is difficult to monetize the value of reducing an individual's potential cancer risk attributable to a lifetime of HAP exposure. An alternative approach of conducting willingness to pay studies specifically on risk reduction may be possible, but such studies have not yet been pursued.

C. Summary of the 2020 Residual Risk Review

As required by CAA section 112(f)(2), the EPA conducted the residual risk review (2020 Residual Risk Review) in 2020, 8 years after promulgating the 2012 MATS Final Rule, and presented the results of the 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 3 of this document, 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 (Document ID No. EPA–HQ–OAR–2018–0794–4553). The EPA summarized the results and findings of the 2020 Residual Risk Review in the preamble of the 2023 Proposal (88 FR 24854), and additional information concerning the residual risk review can be found in our *National-Scale Mercury Risk Estimates for Cardiovascular and Neurodevelopmental Outcomes for the National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration, and Affirmation of the Appropriate and Necessary Finding; Notice of Proposed Rulemaking* memorandum (Document ID No. EPA–HQ–OAR–2018–0794–4605).

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Table 3. 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 Noncancer HQ[4]
	Based on . . .		Based on . . .		Based on . . .		Based on . . .		Based on Actual Emissions Level
	Actual Emissions Level	Allowable Emissions Level	Actual Emissions Level	Allowable Emissions Level	Actual Emissions Level	Allowable Emissions Level	Actual Emissions Level	Allowable Emissions Level	
322	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.

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D. 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 2012 MATS Final Rule was promulgated. Control technologies typically used to minimize emissions of pollutants that have numeric emission limits under the 2012 MATS Final Rule include electrostatic precipitators (ESPs) and fabric filters (FFs) for control of fPM as a surrogate for non-Hg HAP metals; wet scrubbers, dry scrubbers, and dry sorbent injection for control of acid gases (SO_2, HCl, and HF); and activated carbon injection (ACI) and other Hg-specific technologies for control of Hg. The EPA determined that the 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 2012 MATS Final 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 2012 MATS Final 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 any 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 (Document 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).

E. Summary of the EPA's Review of the 2020 RTR and the 2023 Proposed Revisions to the NESHAP

Pursuant to CAA section 112(d)(6), the EPA conducted a review of the 2020 Technology Review and presented the results of this review, along with our proposed decisions, in the 2023 Proposal. The results of the technology review are presented briefly below in this preamble. More detail on the proposed technology review is in the memorandum *2023 Technology Review for the Coal- and Oil-Fired EGU Source Category* (''2023 Technical Memo'') (Document ID No. EPA–HQ–OAR–2018–0794–5789).

Based on the results of the technology review, the EPA proposed to lower the fPM standard, the surrogate for non-Hg HAP metals, for coal-fired EGUs from 0.030 lb/MMBtu to 0.010 lb/MMBtu. The Agency solicited comment on the control technology effectiveness and cost assumptions used in the proposed rule, as well as on a more stringent fPM limit of 0.006 lb/MMBtu or lower. Additionally, the Agency proposed to require the use of PM CEMS for all coal-fired, oil-fired, and IGCC EGUs for demonstrating compliance with the fPM standard. As the Agency proposed to require PM CEMS for compliance demonstration, we also proposed to remove the LEE option, a program based on infrequent stack testing, for fPM and non-Hg HAP metals. As EGUs would be required to demonstrate compliance with PM CEMS, the Agency also proposed to remove the alternate emission standards for non-Hg HAP metals and total HAP metals, 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 solicited comment on prorated metal limits (adjusted proportionally according to the level of the final fPM standard), should the Agency not finalize the removal of the non-Hg HAP metals limits.

The Agency also proposed to lower the Hg emission standard for lignite-fired EGUs from 4.0 lb/TBtu to 1.2 lb/TBtu and solicited comment on the performance of Hg controls and on cost and effectiveness of control strategies to meet more stringent Hg standards. Lastly, the EPA did not identify new developments in control technologies or improved methods of operation that would warrant revisions to the Hg emission standards for non-lignite EGUs, for the organic HAP work practice standards, for the acid gas standards, or for standards for oil-fired EGUs. Therefore, the Agency did not propose changes to these standards in the 2023 Proposal but did solicit comment on the EPA's proposed findings that no revisions were warranted and on the appropriateness of the existing standards.

Additionally, the EPA proposed to remove one of the two options for defining the startup period for MATS-affected EGUs.

In the 2023 Proposal, the EPA determined not to reopen the 2020 Residual Risk Review, and accordingly did not propose any revisions to that review. As the EPA explained in the proposal, the EPA found in the 2020 RTR that risks from the Coal- and Oil-Fired EGU source category due to emissions of air toxics are acceptable and that the existing NESHAP provides an ample margin of safety to protect public health. As noted in the proposal, 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. The EPA granted in part the environmental organizations' petition which sought the EPA's review of startup and shutdown provisions in the 2023 Proposal, 88 FR 24885, and the EPA continues to review and will respond to other aspects of the petition in a separate action.[10]

III. What is included in this final rule?

This action finalizes the EPA's determinations pursuant to the RTR provisions of CAA section 112 for the Coal- and Oil-Fired EGU source category and amends the Coal- and Oil-Fired EGU NESHAP based on those determinations. This action also finalizes changes to the definition of startup for this rule. This final rule includes changes to the 2023 Proposal after consideration of comments received during the public comment period described in sections IV., V., VI., and VII. of this preamble.

A. What are the final rule amendments based on the technology review for the Coal- and Oil-Fired EGU source category?

We determined that there are developments in practices, processes, and control technologies that warrant revisions to the MACT standards for this source category. Therefore, to satisfy the requirements of CAA section 112(d)(6), we are revising the MACT standards by revising the fPM limit for existing coal-fired EGUs from 0.030 lb/MMBtu to 0.010 lb/MMBtu and requiring the use of PM CEMS for coal and oil-fired EGUs to demonstrate compliance with the revised fPM standard, as proposed. We are also finalizing, as proposed, a Hg limit for lignite-fired EGUs of 1.2 lb/TBtu, which aligns with the existing Hg limit that has been in effect for other coal-fired EGUs since 2012. This revised Hg limit for lignite-fired EGUs is more stringent than the limit of 4.0 lb/TBtu that was finalized for such units in the 2012 MATS Final Rule. The rationale for these changes is discussed in more detail in sections IV. and V. below.

Based on comments received during the public comment period, the EPA is not finalizing the proposed removal of the non-Hg HAP metals limits for existing coal-fired EGUs (see section V.). Additionally, this final rule is requiring the use of PM CEMS for compliance demonstration for coal- and oil-fired EGUs (excluding EGUs in the limited-use liquid oil-fired subcategory), but not for IGCC EGUs (see section VI.).

Because this final rule includes revisions to the emissions standards for fPM as a surrogate for non-Hg HAP metals for existing coal-fired EGUs, the fPM emission standard compliance demonstration requirements, the Hg emission standard for lignite-fired EGUs, and the definition of ''startup,'' the EPA intends each portion of this rule to be severable from each other as it is multifaceted and addresses several distinct aspects of MATS for independent reasons. This includes the revised emission standard for fPM as a surrogate for non-Hg HAP metals and the fPM compliance demonstration requirement to utilize PM CEMS. While the EPA considered the technical feasibility of PM CEMS in establishing the revised fPM standard, the EPA finds there are independent reasons for adopting each revision to the standards, and that each would continue to be workable without the other in the place.

[10] See Document ID No. EPA–HQ–OAR–2018–0794–4565 at *https://www.regulations.gov*.

The EPA intends that the various pieces of this package be considered independent of each other. For example, the EPA notes that our judgments regarding developments in fPM control technology for the revised fPM standard as a surrogate for non-Hg HAP metals largely reflect that the fleet was reporting fPM emission rates well below the current standard and with lower costs than estimated during promulgation of the 2012 MATS Final Rule; while our judgments regarding the ability for lignite-fired EGUs to meet the same standard for Hg emissions as other coal- and oil-fired EGUs rest on a separate analysis specific to lignite-fired units. Thus, the revised fPM surrogate emissions standard is feasible and appropriate even absent the revised Hg standard for lignite-fired units, and vice versa. Similarly, the EPA is finalizing changes to the fPM compliance demonstration requirement based on the technology's ability to provide increased transparency for owners and operators, regulators, and the public; and the EPA is finalizing changes to the startup definition based on considerations raised by environmental groups in petitions for reconsideration. Both of these actions are independent from the EPA's revisions to the fPM surrogate standard, and the Hg standard for lignite-fired units. Accordingly, the EPA finds that each set of standards is severable from each other set of standards.

Finally, the EPA finds that implementation of each set of standards, compliance demonstration requirements, and revisions to the startup definition are independent. That is, a source can abide by any one of these individual requirements without abiding by any others. Thus, the EPA's overall approach to this source category continues to be fully implementable even in the absence of any one or more of the elements included in this final rule.

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

B. What other changes have been made to the NESHAP?

The EPA is finalizing, as proposed, the removal of the work practice standards of paragraph (2) of the definition of ''startup'' in 40 CFR 63.10042. 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). 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 final rule requires that all EGUs use the work practice standards in paragraph (1) of the definition of ''startup,'' which is already being used by the majority of EGUs.

C. What are the effective and compliance dates of the standards?

The revisions to the MACT standards being promulgated in this action are effective on July 8, 2024. The compliance date for affected coal-fired sources to comply with the revised fPM limit of 0.010 lb/MMBtu and for lignite-fired sources to meet the lower Hg limit of 1.2 lb/TBtu is 3 years after the effective date of the final rule. The Agency believes this timeline is as expeditious as practicable considering the potential need for some sources to upgrade or replace pollution controls. As discussed elsewhere in this preamble, we are adding a requirement that compliance with the fPM limit be demonstrated using PM CEMS. Based on comments received during the comment period and our understanding of suppliers of PM CEMS, the EPA is finalizing the requirement that affected sources use PM CEMS for compliance demonstration by 3 years after the effective date of the final rule. The compliance date for existing affected sources to comply with amendments pertaining to the startup definition is 180 days after the effective date of the final rule, as few EGUs are affected, and changes needed to comply with paragraph (1) of startup are achievable by all EGUs at little to no additional expenditures. All affected facilities remain subject to the current requirements of 40 CFR part 63, subpart UUUUU, until the applicable compliance date of the amended rule.

The EPA has considered the concerns raised by commenters that these compliance deadlines could affect electric reliability and concluded that given the flexibilities detailed further in this section, the requirements of the final rule for existing sources can be met without adversely impacting electric reliability. In particular, the EPA notes the flexibility of permitting authorities to allow, if warranted, a fourth year for compliance under CAA section 112(i)(3)(B). This flexibility, if needed, would address many of the concerns that commenters raised. Furthermore, in the event that an isolated, localized concern were to emerge that could not be addressed solely through the 1-year extension under CAA section 112(i)(3), the CAA provides additional flexibilities to bring sources into compliance while maintaining reliability.

The EPA notes that similar concerns regarding reliability were raised about the 2012 MATS Final Rule—a rule that projected the need for significantly greater installation of controls and other capital investments than this current revision. In the 2012 MATS Final Rule, the EPA emphasized that most units should be able to comply with the requirements of the final rule within 3 years. However, the EPA also made it clear that permitting authorities have the authority to grant a 1-year compliance extension where necessary, in a range of situations described in the 2012 MATS Final Rule preamble.[11] The EPA's Office of Enforcement and Compliance Assurance (OECA) also issued the MATS Enforcement Response policy (Dec. 16, 2011)[12] which described the approach regarding the issue of CAA section 113(a) administrative orders with respect to the sources that must operate in noncompliance with the MATS rule for up to 1 year to address specific documented reliability concerns. While several affected EGUs requested and were granted a 1-year CAA section 112(i)(3)(B) compliance extension by their permitting authority, OECA only issued five administrative orders in connection with the Enforcement Response policy. The 2012 MATS Final Rule was ultimately implemented over the 2015—2016 timeframe without challenges to grid reliability.

[11] 77 FR 9406.

[12] *https://www.epa.gov/enforcement/enforcement-response-policy-mercury-and-air-toxics-standard-mats.*

IV. What is the rationale for our final decisions and amendments to the filterable PM (as a surrogate for non-Hg HAP metals) standard and compliance options from the 2020 Technology Review?

In this section, the EPA provides descriptions of what we proposed, what we are finalizing, our rationale for the final decisions and amendments, and a summary of key comments and responses related to the emission standard for fPM, non-Hg HAP metals, and the compliance demonstration options. For all comments not discussed in this preamble, comment summaries and the EPA's responses can be found in the comment summary and response document *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review Proposed Rule Response to Comments,* available in the docket.

Based on its review, the EPA is finalizing a revised non-Hg HAP metal surrogate fPM emission standard for all existing coal-fired EGUs of 0.010 lb/MMBtu and is requiring that all coal- and oil-fired EGUs demonstrate compliance with the revised fPM emission standard by using PM CEMS. The revised fPM standard will ensure that the entire fleet of coal-fired EGUs achieves performance levels that are consistent with those of the vast majority of regulated units operating today—*i.e.,* that the small minority of units that currently emit significantly higher levels of HAP than their peers use proven technologies to reduce their HAP to the levels achieved by the rest of the fleet. Further, the EPA finds that a 0.010 lb/MMBtu fPM emission standard is the lowest level currently compatible with PM CEMS for demonstrating compliance, which the EPA finds provides significant benefits including increased transparency regarding emissions performance for sources, regulators, and the surrounding communities; and real-time identification of when control technologies are not performing as expected, allowing for quicker repairs. In addition, the rule's current requirement to shift electronic reporting of PM CEMS data to the Emissions Collection and Monitoring Plan System (ECMPS) will enable regulatory authorities, nearby citizens, and others, including members of the public and media, to quickly and easily locate, review, and download fPM emissions using simple, user-directed inquiries. An enhanced, web-based version of ECMPS (ECMPS 2.0) is currently being prepared that will ease data editing, importing, and exporting and is expected to be available prior to the date by which EGUs are required to use PM CEMS.

A. What did we propose pursuant to CAA section 112(d)(6) for the Coal- and Oil-Fired EGU source category?

1. Proposed Changes to the Filterable PM Standard

The EPA proposed to lower the fPM limit, a surrogate for total non-Hg HAP metals, for coal-fired EGUs from 0.030 lb/MMBtu to 0.010 lb/MMBtu. The EPA further solicited comment on an emission standard of 0.006 lb/MMBtu or lower. The EPA did not propose any changes to the fPM emission standard for oil-fired EGUs or for IGCC units. The EPA also proposed to remove the total and individual non-Hg HAP metals emission limits. The EPA also solicited comment on adjusting the total and individual non-Hg HAP metals emission limits proportionally to the revised fPM limit rather than eliminating the limits altogether.

2. Proposed Changes to the Requirements for Compliance Demonstration

The EPA proposed to require that all coal- and oil-fired EGUs (IGCC units are discussed in section VI.) use PM CEMS to demonstrate compliance with the fPM emission limit. The EPA also proposed to remove the option of demonstrating compliance using infrequent stack testing and the LEE program (where stack testing occurs quarterly for 3 years, then every third year thereafter) for both PM and non-Hg HAP metals.

B. How did the technology review change for the Coal- and Oil-Fired EGU source category?

1. Filterable PM Emission Standard

Commenters provided both supportive and opposing arguments for issues regarding the fPM limit that were presented in the proposed review of the 2020 Technology Review. Comments received on the proposed fPM limit for coal-fired EGUs, along with additional analyses, did not change the Agency's conclusions that were presented in the 2023 Proposal, and, therefore, the Agency is finalizing the 0.010 lb/MMBtu fPM emission limit for existing coal-fired EGUs, as proposed.

Additionally, commenters urged the Agency to retain the option of complying with individual non-Hg HAP metal (*e.g.,* lead, arsenic, chromium, nickel, and cadmium) emission rates or with a total non-Hg HAP metal emission rate. After consideration of public comments, the Agency is finalizing updated limits for non-Hg HAP metals and total non-Hg HAP metals that have been reduced proportional to the reduction of the fPM emission limit from 0.030 lb/MMBtu to the new final fPM emission limit of 0.010 lb/MMBtu. EGU owners or operators who would choose to comply with the non-Hg HAP metals emission limits instead of the fPM limit must request and receive approval of a non-Hg HAP metal CMS as an alternative test method (*e.g.,* multi-metal CMS) under the provisions of 40 CFR 63.7(f).

2. Compliance Demonstration Options

Comments received on the compliance demonstration options for coal- and oil-fired EGUs also did not change the results of the technology review, therefore the Agency is finalizing the use of PM CEMS for compliance demonstration purposes and removing the fPM and non-Hg HAP metals LEE options for all coal-fired EGUs and for oil-fired EGUs (except those in the limited use liquid oil-fired EGU subcategory). The Agency received comments that some PM CEMS that are currently correlated for the 0.030 lb/MMBtu fPM emission limit may experience some difficulties should re-correlation be necessary at a lower fPM standard. Based on these comments and on additional review of PM CEMS test reports, as mentioned in sections IV.C.2. and IV.D.2., the Agency has made minor technical revisions to shift the basis of correlation testing from sampling a minimum volume per run to collecting a minimum mass or minimum sample volume per run and has adjusted the quality assurance (QA) criterion otherwise associated with the new emission limit. These changes will enable PM CEMS to be properly certified for use in demonstrating compliance with the lower fPM standard with a high degree of accuracy and reliability.

C. What key comments did we receive on the filterable PM and compliance options, and what are our responses?

1. Comments on the Filterable PM Emission Standard

Comment: Some commenters supported the proposed fPM limit of 0.010 lb/MMBtu as reasonable and achievable, noting that this limit is slightly greater than the fPM emission limit required for new and reconstructed units. Additionally, commenters stated CAA section 112 was intended to improve the performance of lagging industrial sources and that a standard that falls far behind what the vast majority of sources have already achieved, as the current standard does, is inadequate. Other commenters opposed the proposed fPM limit of 0.010 lb/MMBtu as too stringent. For instance, some commenters stated that the EPA did not provide adequate support for the proposed limit. Other commenters stated that the fact that the vast majority of units are achieving emission rates below the current limit does not constitute ''developments in practices, processes, and control technologies.''

Response: The EPA disagrees that the Agency has not adequately supported the proposed fPM limit. As described in the proposal preamble, the Agency conducted a review of the 2020 Technology Review pursuant to CAA section 112(d)(6), which focused on identifying and evaluating developments in practices, processes, and control technologies for the emission sources in the source category that occurred since promulgation of the 2012 MATS Final Rule. Based on that review, the EPA found that a majority of sources were not only reporting fPM emissions significantly below the current emission limit, but also that the fleet achieved lower fPM rates at lower costs than the EPA estimated when it promulgated the 2012 MATS Final Rule. The EPA explains these findings in more detail in section IV.D.1. of this preamble and elsewhere in the record. Further, the EPA finds that there are technological developments and improvements in PM control technology, which also controls non-Hg HAP metals, since the 2012 MATS Final Rule that informed the 2023 Proposal and this action, as discussed further in section IV.D.1. below. For example, industry has implemented ''best practices'' for monitoring ESP operation more carefully, and more durable materials have been adopted for FFs since the 2012 MATS Final Rule. The EPA also finds that these are cognizable developments for purposes of CAA section 112(d)(6). As other commenters noted, in *National Association for Surface Finishing* v. *EPA,* 795 F.3d 1, 11 (D.C. Cir. 2015), the D.C. Circuit found that the EPA ''permissibly identified and took into account cognizable developments'' based on the EPA's interpretation of the term as ''not only wholly new methods, but also technological improvements.'' Similarly, here the EPA identified a clear trend in control efficiency, costs, and technological improvements, which the EPA is accounting for in this action. Further, as discussed elsewhere in this section and in section IV.D.1. of this preamble, the EPA finds case law and substantial administrative precedent support the EPA's decision to update the fPM limit based upon these developments.

Comment: Many commenters recommended that the EPA add a compliance margin in its achievability assumptions. These commenters conveyed that most EGUs typically operate well below the limit to allow for a compliance margin in the event of an equipment malfunction or failure, which they encouraged the EPA to consider when setting new limits. These commenters claimed that with a proposed fPM limit of 0.010 lb/MMBtu, an appropriate design margin of 20 percent necessitates that control technologies must be able to achieve a limit of 0.008 lb/MMBtu or lower in practice. They also expressed concerns that the EPA did not take design margin into consideration in the cost analysis. They stated that by not including the need for a design margin, which the EPA has acknowledged the need for in at least two of the Agency's publications (*NESHAP Analysis of Control Technology Needs for Revised Proposed Emission Standards for New Source Coal-fired EGUs,* Document ID No. EPA–HQ–OAR–2009–0234–20223 and *PM CEMS Capabilities Summary for Performance Specification 11, NSPS, and MACT Rules,* Document ID No. EPA–HQ–OAR–2018–0794–5828), the EPA underpredicted the number of units that would require retrofits. These commenters stated that the combination of a very low fPM limit and having to account for the measurement uncertainty and correlation methodology of PM CEMS would likely necessitate an ''operational target limit'' of 50 percent of the applicable limit. Some commenters referenced the National Rural Electric Cooperative Association (NRECA) technical evaluation for the 2023 Proposal titled *Technical Comments on National Emissions Standard for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology.*[13] They said that, even using the EPA's unrealistic ''baseline fPM rates'' and the lowest possible compliance margin of 20 percent, the NRECA technical evaluation estimated that 37 units—almost twice as many as the EPA's estimate—would be required to take substantial action to comply with the proposed limit.

Response: The EPA agrees that most facility operators normally target an emission level below the emission limit by incorporating a compliance margin or margin of error in case of equipment malfunctions or failures. As the commenters noted, the Agency has previously recognized that some operators target an emission level 20 to 50 percent below the limit. However, no commenters provided data to suggest that ESPs or FF are unable to achieve a lower fPM limit. Furthermore, the Agency does not prescribe specifically how an EGU controls its emissions or how the unit operates. The choice to target a lower-level emission rate for a compliance margin is the sole decision of owners and operators. For facilities with more than one EGU in the same subcategory, owners or operators may find emissions averaging (40 CFR 63.10009), coupled with or without a compliance margin, could help the facility attain and maintain emission limits as an effective, low-cost approach. Additionally, no commenters provided data to indicate that every owner or operator aims to comply with the fPM limit with the same compliance margin. Because some operators might aim for a larger compliance margin than others, it would be difficult to select a particular assumption about compliance margin for the cost analysis. Every operator plans for compliance differently and the EPA cannot know every operator's plans for a compliance margin. Even if the EPA were to assume a 20 percent compliance margin in its evaluation of PM controls, the results of the analysis would not change the EPA's decision to adopt a lower fPM limit. Specifically, a 20 percent compliance margin assumption to a fPM limit of 0.010 lb/MMBtu would increase the number of affected EGUs from 33 to 53 (14.1 to 23.9 GW affected capacity) and the annual compliance costs from $87.2M to $147.7M. The number of EGUs that demonstrated an ability to meet the lower fPM limit, but do not do so on average and therefore would require O&M, would increase from 17 to 27 (including the compliance margin). Similarly, the number of ESP upgrades (previously 11) and bag upgrades (previously 3) would also increase (to 20 and 4, respectively). There would be no change in the number of new FF installs. Therefore, cost-effectiveness values for fPM and individual and total non-Hg HAP metals would only increase slightly. Moreover, the 30-boiler operating day averaging period using PM CEMS for compliance

[13] *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology.* Cichanowicz, *et al.* June 19, 2023. Attachment A to Document ID No. EPA–HQ–OAR–2018–0794–5994.

demonstration provides flexibility for owners and operators to account for equipment malfunctions, operational variability, and other issues. Lastly, as described in the 2023 Proposal, and updated here, the vast majority of coal-fired EGUs are reporting fPM emissions well below the revised fPM limit. For instance, the median fPM rate of the 296 coal-fired EGUs assessed in the 2024 Technical Memo is 0.004 lb/MMBtu,[14] or 60 percent below the revised fPM limit of 0.010 lb/MMBtu. The median fPM rate of a quarter of the best performing sources (N=74) is 0.002 lb/MMBtu, about 80 percent below the revised fPM limit of 0.010 lb/MMBtu. Therefore, for these reasons, the EPA disagrees with commenters that a compliance margin needs to be considered in the cost analysis.

The updated PM analysis, detailed in the memorandum *2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category* (''2024 Technical Memo'') available in the docket, estimates that the number of EGUs that will need to improve their fPM emission rate to achieve a 0.010 lb/MMBtu limit has increased from the 20 EGUs assumed in the 2023 Proposal to 33 EGUs, which is more consistent with the NRECA technical evaluation estimate of 37 EGUs. This increase is a result of updated methodology that utilizes both the lowest achieved fPM rate (*i.e.,* the lowest quarter's 99th percentile) and the average fPM rate across all quarterly data when assessing PM upgrade and costs assumptions for the evaluated limits. The Agency disagrees with the commenters, however, that the 37 EGUs in the NRECA technical evaluation would require ''substantial action to comply with the proposed standard.'' In the Agency's revised analysis, only 13 EGUs would require capital investments to meet a fPM limit of 0.010 lb/MMBtu. Of these, only two EGUs at one facility (Colstrip) currently without the most effective PM controls are projected to require installation of a FF, the costliest PM control upgrade option, to meet 0.010 lb/MMBtu. The remaining nine EGUs projected by the EPA to require capital investments are estimated to require various levels of ESP upgrades. The EPA estimates that more than half (20 EGUs) would be able to comply without any capital investments and would instead require improvements to their existing FF or ESP as they have already demonstrated the ability to meet the limit, but do not do so on average.

Comment: Some commenters stated that cost effectiveness is an important consideration in technology reviews under CAA section 112(d)(6) and acknowledged that the EPA undertook cost-effectiveness analyses for the three fPM standards on which the Agency sought comment. However, the commenters stated, the NRECA technical evaluation found meaningful errors in the EPA's cost analysis, including unreasonably low capital cost estimates for ESP rebuilds and a failure to consider the variability of fPM due to changes in operation or facility design, by not utilizing a compliance margin. They asserted that these errors resulted in sizeable cost-effectiveness underestimates that eroded the EPA's overall determination that the proposed fPM limit is cost-effective. These commenters also asserted that the EPA's rationale was arbitrary on its face because it reversed, without explanation, the EPA's prior acknowledgements that a cost-effectiveness analysis should account for the cost effectiveness of controls at each affected facility and not simply on an aggregate nationwide basis. They stated that facility-specific costs should factor into the EPA's assessment of what is ''necessary'' pursuant to the provisions of CAA section 112(d)(6) and CAA section 112(f)(2).

Some commenters asserted that, even using the EPA's cost-effectiveness figures, the proposed 0.010 lb/MMBtu limit is not cost-effective. These commenters stated that the EPA's proposal to revise the fPM standard to 0.010 lb/MMBtu based on a cost-effectiveness estimate of up to $14.7 million per ton of total non-Hg HAP metals removed (equivalent to $44,900 per ton of fPM removed) is inconsistent with the EPA's prior actions because the cost-effectiveness estimate is substantially higher than estimates the Agency has previously found to be not cost-effective. They further said that, in the past, the EPA has decided against revising fPM standards based on cost-effectiveness estimates substantially lower than the cost-effectiveness estimates here. They said that the EPA should follow these precedents and acknowledge that $12.2 to $14.7 million per ton of non-Hg HAP metals reduced is not cost-effective. They argued that the Agency should not finalize the proposed standard of 0.010 lb/MMBtu for that reason. Further, these commenters argued that the alternative, more stringent limit of 0.006 lb/MMBtu is even less cost-effective at $25.6 million per ton of non-Hg HAP metals reduced, so it should not be considered either.

The commenters provided the following examples of previous rulemakings where EPA found controls to not be cost-effective:

• In the Petroleum Refinery Sector technology review,[15] the EPA declined to revise the fPM emission limit for existing fluid catalytic cracking units after finding that it would cost $10 million per ton of total non-Hg HAP metals reduced (in that case, equivalent to $23,000 per ton of fPM reduced), which was not cost-effective.

• In the Iron Ore Processing technology review,[16] the EPA declined to revise the non-Hg HAP metals limit after finding that installing wet scrubbers would cost $16 million per ton of non-Hg HAP metals reduced, which was not cost-effective.

• In the Integrated Iron and Steel Manufacturing Facilities technology review,[17] the EPA declined to revise the non-Hg HAP metals limit after finding that upgrading all fume/flame suppressants at blast furnaces to baghouses would cost $7 million per ton of non-Hg HAP metals reduced, which was not cost-effective. The Agency made a similar finding for a proposed limit that would have cost $14,000 per ton of volatile HAP reduced.

• In the Portland Cement Manufacturing beyond-the-floor analysis,[18] the EPA declined to impose a more stringent non-Hg HAP metals limit because it resulted in ''significantly higher cost effectiveness for PM than EPA has accepted in other NESHAP.'' The EPA noted in that rulemaking that it had previously ''reject[ed] $48,501 per ton of PM as not cost-effective for PM,'' and noted prior EPA statements in a subsequent rulemaking providing that $268,000 per ton of HAP removed was a higher cost-effectiveness estimate than the EPA had accepted in other NESHAP rulemakings.

In contrast, other commenters focused on the EPA's estimated cost-effective estimates for fPM (which is a surrogate for non-Hg HAP metals) and argued that

[14] For the revised fPM analysis, the EPA uses two methods to assess the performance of the fleet: average and the 99th percentile of the lowest quarter of data. Values reported here use the average fPM rate for each EGU.

[15] *Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards,* 80 FR 75178, 75201 (December 1, 2015).

[16] *National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing Residual Risk and Technology Review,* 85 FR 45476, 45483 (July 28, 2020).

[17] *National Emission Standards for Hazardous Air Pollutants: Integrated Iron and Steel Manufacturing Facilities Residual Risk and Technology Review,* 85 FR 42074, 42088 (July 13, 2020).

[18] *National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants,* 78 FR 10006, 10021 (February 12, 2013).

those estimates were substantially lower than estimates that the EPA has considered to be cost-effective in other technology reviews. Therefore, these commenters concluded that the EPA should strengthen the limit to at least 0.010 lb/MMBtu. These commenters also pointed to a 2023 report by Andover Technology Partners [19] that found that the cost to comply with an emission limit of 0.006 lb/MMBtu on a fleetwide basis was significantly less than the costs estimated by the EPA. Andover Technology Partners attributed this difference ''to the assumptions EPA made regarding the potential emission reductions from ESP upgrades, which result in a much higher estimate of baghouse retrofits in EPA's analysis for an emission rate of 0.006 lb/MMBtu.'' These commenters stated that meeting the lower emission limit of 0.006 lb/MMBtu is technologically feasible using currently available controls, and they urged the EPA to adopt this limit. They stated that although cost effectiveness is less relevant in the CAA section 112 context than for other CAA provisions, the $103,000 per ton of fPM and $209,000 per ton of filterable fine $PM_{2.5}$ estimates that the EPA calculated for the 0.006 lb/MMBtu limit were reasonable and comparable to past practice in technology reviews under CAA section 112(d)(6). They noted that the EPA has previously found a control measure that resulted in an inflation-adjusted cost of $185,000 per ton of $PM_{2.5}$ reduced to be cost-effective for the ferroalloys production source category [20] and proposed a limit for secondary lead smelting sources that cost an inflation-adjusted $114,000 per ton of fPM reduced.[21] They argued that, using the Andover Technology Partners cost estimates, the 0.006 lb/MMBtu limit has even better cost-effectiveness estimates at about $72,000 per ton of fPM reduced and $146,000 per ton of filterable $PM_{2.5}$ reduced. These commenters noted that the EPA also calculated cost effectiveness based on allowable emissions (*i.e.,* assuming emission reductions achieved if all evaluated EGUs emit at the maximum allowable amount of fPM, or 0.030 lb/MMBtu) at $1,610,000 per ton, showing that a limit of 0.006 lb/MMBtu allows far less pollution at low cost to the power sector. They concluded that all these metrics and approaches to considering costs show that a fPM limit of 0.006 lb/MMBtu would require cost-effective reductions and can be achieved at a reasonable cost that would not jeopardize the power sector's function.

Additionally, some commenters cited *Sierra Club* v. *Costle,* 657 F.2d 298, 330 (D.C. Cir. 1981), and said the case supports the EPA's discretion to weigh cost, energy, and environmental impacts, recognizing the Agency's authority to take these factors into account ''in the broadest sense at the national and regional levels and over time as opposed to simply at the plant level in the immediate present.'' These commenters said that the EPA has the authority to require costs that are reasonable for the industry even if they are not reasonable for every facility. These commenters acknowledged that the EPA has discretion to consider cost effectiveness under CAA section 112(d)(2), citing *NRDC* v. *EPA,* 749 F.3d 1055, 1060–61 (D.C. Cir. 2014), but argued that the dollar-per-ton cost-effectiveness metric is less relevant under CAA section 112 than under other CAA provisions because the Agency is not charged with equitably distributing the costs of emission reductions through a uniform compliance strategy, as the EPA has done in its transport rules. The commenters concluded that the Agency should require maximum reductions of HAP emissions from each regulated source category and has no authority to balance cost effectiveness across industries.

Response: In this action, the EPA is acting under its authority in CAA section 112(d)(6) to ''review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards'' promulgated under CAA section 112. As the EPA explained in the 2023 Proposal, this technology review is separate and distinct from other standard-setting provisions under CAA section 112, such as establishing MACT floors, conducting the beyond-the-floor analysis, and reviewing residual risk.

Regarding the comments that the EPA underestimated costs to an extent that undermines the EPA's overall cost-effectiveness assumptions, the EPA disagrees that the Agency underestimated the typical costs of ESP rebuilds. The commenters provided cost examples from only two facilities to support their assertions regarding the costs of ESP rebuilds. The costs provided for one of those facilities, Labadie, were not the costs associated with an ESP rebuild, but instead were the costs associated with the full replacement of an ESP. The commenter stated that, ''Ameren retrofitted the entire ESP trains on two units in 2014/2015. On each of these units two of the three original existing ESPs had to be abandoned and one of the existing ESPs was retrofitted with new power supplies and flue gas flow modifications. A new state-of-the-art ESP was added to each unit to supplement the retrofitted ESPs.'' An ESP replacement is different from an ESP rebuild, and therefore the costs of an ESP replacement do not inform the costs of an ESP rebuild. The ESP rebuild cost provided for the other facility, Petersburg, was less than the EPA's final assumption regarding the typical cost of an ESP rebuild on a capacity-weighted average basis. Neither of these examples provided by the commenter demonstrate that the EPA underestimated costs. For these reasons, the EPA disagrees with these commenters. Additionally, the EPA disagrees with these commenters that the Agency must add a compliance margin in its cost assumptions. As described above, the Agency does not prescribe specifically how an EGU must be controlled or how it must be operated, and the choice of overcompliance is at the sole discretion of the owners and operators.

Generally, the EPA agrees with commenters that cost effectiveness, *i.e.,* the costs per unit of emissions reduction, is a metric that the EPA consistently considers, often alongside other cost metrics, in CAA section 112 rulemakings where it can consider costs, *e.g.,* beyond-the-floor analyses and technology reviews, and agrees with commenters who recognize that the Agency has discretion in how it considers statutory factors under CAA section 112(d)(6), including costs. *See e.g., Association of Battery Recyclers, Inc.* v. *EPA,* 716 F.3d 667, 673–74 (D.C. Cir. 2013) (allowing that the EPA may consider costs in conducting technology reviews under CAA section 112(d)(6)); *see also Nat'l Ass'n for Surface Finishing* v. *EPA,* 795 F.3d 1, 11 (D.C. Cir. 2015). The EPA acknowledges that the cost-effectiveness values for these standards are higher than cost-effectiveness values that the EPA concluded were not cost-effective and weighed against implementing more stringent standards for some prior rules. The EPA disagrees, however, that there is any particular threshold that renders

[19] Assessment of Potential Revisions to the Mercury and Air Toxics Standards. Andover Technology Partners. June 15, 2023. Docket ID No. EPA–HQ–OAR–2018–0794. Also available at *https://www.andovertechnology.com/wp-content/uploads/2023/06/C_23_CAELP_Final.pdf.*

[20] *National Emission Standards for Hazardous Air Pollutants: Ferroalloys Production,* 80 FR 37381 (June 30, 2015).

[21] *National Emission Standards for Hazardous Air Pollutants: Secondary Lead Smelting,* 76 FR 29032 (May 19, 2011).

a rule cost-effective or not.[22] The EPA's prior findings about cost effectiveness in other rules were specific to those rulemakings and the industries at issue in those rules. As commenters have pointed out, in considering cost effectiveness, the EPA will often consider what estimates it has deemed cost-effective in prior rulemakings. However, the EPA routinely views cost effectiveness in light of other factors, such as other relevant costs metrics (*e.g.,* total costs, annual costs, and costs compared to revenues), impacts to the regulated industry, and industry-specific dynamics to determine whether there are ''developments in practices, processes, and control technologies'' that warrant updates to emissions standards pursuant to CAA section 112(d)(6). Some commenters, pointing to prior CAA section 112 rulemakings where the EPA chose not to adopt more stringent controls, mischaracterized cost effectiveness as the sole criterion in those decisions. These commenters omitted any discussion of other relevant factors from those rulemakings that, in addition to cost effectiveness, counseled the EPA against adopting more stringent standards. For example, in the 2014 Ferroalloys rulemaking that commenters cited to, the EPA rejected a potential control option due to questions about technical feasibility and significant economic impacts the option would create for the industry, including potential facility closures that would impact significant portions of industry production.[23] In contrast here, the controls at issue are technically feasible (they are used at facilities throughout the country) and will not have significant effects on the industry. Indeed, the EPA does not project that the final revisions to MATS will result in incremental changes in operational coal-fired capacity.

Similarly, in the other rulemakings these commenters pointed to, where the EPA found similar cost-effectiveness values to those that the EPA identified for the revised fPM standard here, there are distinct aspects of those rulemakings and industries that distinguish those prior actions from this rulemaking. In the 2015 Petroleum Refineries rulemaking, the EPA considered the cost effectiveness of developments at only two facilities to decide whether to deploy a standard across the much wider industry.[24] Here in contrast, the EPA is basing updates to fPM standards for coal-fired EGUs on developments across the majority of the industry and the performance of the fleet as a whole, which has demonstrated the achievability of a more stringent standard. Additionally, there are inherent differences between the power sector and other industries that similarly distinguish prior actions from this rulemaking. For example, because of the size of the power sector (314 coal-fired EGUs at 157 facilities), and because this source category is one of the largest stationary source emitters of Hg, arsenic, and HCl and is one of the largest regulated stationary source emitters of total HAP,[25] even considering that this rule affects only a fraction of the sector, the estimated HAP reductions in this final rule (8.3 tpy) are higher than those in the prior rulemakings cited by the commenters (as are the estimated PM reductions (2,537 tpy) used as a surrogate for non-Hg HAP metals). In contrast, in the 2020 Integrated Iron and Steel Manufacturing rulemaking, the source category covered included only 11 facilities, and the estimated reductions the EPA considered would have removed 3 tpy of HAP and 120 tpy of PM.[26] Likewise, in the 2013 Portland Cement rulemaking, the EPA determined not to pursue more stringent controls for the sector after finding the standard would only result in 138 tpy of nationwide PM reductions and that there was a high cost for such modest reductions.[27] Here, the EPA estimates significantly greater HAP emission reductions, and fPM emission reductions that are orders of magnitude greater than both prior rulemakings.[28]

There are also unique attributes of the power sector that the EPA finds support the finalization of revised standards for fPM and non-Hg HAP metals despite the relatively high cost-effectiveness values of this rulemaking as compared to other CAA section 112 rulemakings. As the EPA has demonstrated throughout this record, there are hundreds of EGUs regulated under MATS with well-performing control equipment that are already reporting emission rates below the revised standards, whereas only a handful of facilities with largely outdated or underperforming controls are emitting significantly more than their peers. That means that the communities located near these handful of facilities may experience exposure to higher levels of toxic metal emissions than communities located near similarly sized well-controlled plants. This is what the revised standards seek to remedy, and as discussed throughout this record, this goal is consistent with the EPA's authority under CAA section 112(d)(6) and the purpose of CAA section 112 more generally.

U.S. EGUs are a major source of HAP metals emissions including arsenic, beryllium, cadmium, chromium, cobalt, lead, nickel, manganese, and selenium. Some HAP metals emitted by U.S. EGUs are known to be persistent and bioaccumulative and others have the potential to cause cancer. Exposure to these HAP metals, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. These adverse health effects may include chronic health disorders (*e.g.,* irritation of the lung, skin, and mucus membranes; decreased pulmonary function, pneumonia, or lung damage; detrimental effects on the central nervous system; damage to the kidneys; and alimentary effects such as nausea and vomiting). The emissions reductions projected under this final rule from the use of PM controls are expected to reduce exposure of individuals residing near these facilities to non-Hg HAP metals, including carcinogenic HAP.

EGUs projected to be impacted by the revised fPM standards represent a small fraction of the total number of the coal-fired EGUs (11 percent for the 0.010 lb/MMBtu fPM limit). In addition, many regulated facilities are electing to retire

[22] See *e.g., National Emissions Standards for Hazardous Air Pollutants: Ferroalloys Production,* 80 FR 37366, 37381 (June 30, 2015) (''[I]t is important to note that there is no bright line for determining acceptable cost effectiveness for HAP metals. Each rulemaking is different and various factors must be considered.'').

[23] *National Emission Standards for Hazardous Air Pollutants: Ferroalloys Production,* 79 FR 60238, 60273 (October 6, 2014).

[24] *Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards,* 80 FR 75178, 75201 (December 1, 2015).

[25] 2020 National Emissions Inventory (NEI) Data; *https://www.epa.gov/air-emissions-inventories/2020-national-emissions-inventory-nei-data.*

[26] *National Emission Standards for Hazardous Air Pollutants: Integrated Iron and Steel Manufacturing Facilities Residual Risk and Technology Review,* 85 FR 42074, 42088 (July 13, 2020).

[27] *National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants,* 78 FR 10006, 10020–10021 (February 12, 2013).

[28] In addition, while commenters are correct that the EPA determined not to adopt more stringent controls under the iron ore processing technology review, the aspects of the rulemaking that the commenters cite to concerned whether additional controls were necessary to provide an ample margin of safety under a residual risk review. In that instance, the EPA determined not to implement more stringent standards under the risk review based on the installation of wet ESPs in addition to wet scrubbers, based on the EPA's determination that such improvements were not necessary to provide an ample margin of safety to protect public health. See *National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing Residual Risk and Technology Review,* 84 FR 45476, 45483 (July 28, 2020).

due to factors independent of the EPA's regulations, and the EPA typically has more information on plant retirements for this sector than other sectors regulated under CAA section 112. Both of these factors contribute to relatively higher cost-effectiveness estimates in this rulemaking as compared to other sectors where the EPA is not able to account for facility retirements and factor in shorter amortization periods for the price of controls.

While some commenters stated that meeting an even lower emission limit of 0.006 lb/MMBtu is technologically feasible using currently available controls, the Agency declines to finalize this limit primarily due to the technological limitations of PM CEMS at this lower emission limit (as discussed in more detail in sections IV.C.2. and IV.D.2. below). Additionally, the EPA considered the higher costs associated with a more stringent standard as compared to the final standard presented in section IV.D.1.

Finally, as mentioned in the Response to Comments document, the EPA finds that use of PM CEMS, which provide continuous feedback with respect to fPM variability, in lieu of quarterly fPM emissions testing, will render moot the commenter's suggestion that margin of compliance has not been taken into account.

Comment: Some commenters argued that the low residual risks the EPA found in its review of the 2020 Residual Risk Review obviate the need for the EPA to revise the standards under the separate technology review, and that residual risk should be a relevant aspect of the EPA's technology review of coal- and oil-fired EGUs. These commenters argued that it is arbitrary and capricious for the EPA to impose high costs on facilities, which they claimed will only result in marginal emission reductions, when the EPA determined there is not an unreasonable risk to the environment or public health.

Other commenters agreed with the EPA's ''two-pronged'' interpretation that CAA section 112(d)(6) provides authorities to the EPA that are distinct from the EPA's risk-based authorities under CAA section 112(f)(2). These commenters said that if the criteria under CAA section 112(d)(6) are met, the EPA must update the standards to reflect new developments independent of the risk assessment process under CAA section 112(f)(2). They said the technology-based review conducted under CAA section 112(d)(6) need not account for any information learned during the residual risk review under CAA section 112(f)(2) unless that information pertains to statutory factors under CAA section 112(d)(6), such as costs. They concluded that CAA section 112(d)(6) requires the EPA to promulgate the maximum HAP reductions possible where achievable at reasonable cost and is separate from the EPA's residual risk analysis.

Response: The EPA has an independent statutory authority and obligation to conduct the technology review separate from the EPA's authority to conduct a residual risk review, and the Agency agrees with commenters that recognized that the EPA is not required to account for information obtained during a residual risk review in conducting a technology review. The EPA's finding that there is an ample margin of safety under the residual risk review in no way interferes with the EPA's obligation to require more stringent standards under the technology review where developments warrant such standards. The D.C. Circuit has recognized the CAA section 112(d)(6) technology review and 112(f)(2) residual review are ''distinct, parallel analyses'' that the EPA undertakes ''[s]eparately.'' *Nat'l Ass'n for Surface Finishing* v. *EPA,* 795 F.3d 1, 5 (D.C. Cir. 2015). In other recent residual risk and technology reviews, the EPA determined additional controls were warranted under technology reviews pursuant to CAA section 112(d)(6) although the Agency determined additional standards were not necessary to maintain an ample margin of safety under CAA section 112(f)(2).[29] The EPA has also made clear that the Agency ''disagree[s] with the view that a determination under CAA section 112(f) of an ample margin of safety and no adverse environmental effects alone will, in all cases, cause us to determine that a revision is not necessary under CAA section 112(d)(6).''[30] While the EPA has considered risks as a factor in some previous technology reviews,[31] that does not compel the Agency to do so in this rulemaking. Indeed, in other instances, the EPA has adopted the same standards under both CAA sections 112(f)(2) and 112(d)(6) based on independent rationales where necessary to provide an ample margin of safety and because it is technically appropriate and necessary to do so, emphasizing the independent authority of the two statutory provisions.[32]

The language and structure of CAA section 112, along with its legislative history, further underscores the independent nature of these two provisions.[33] While the EPA is only required to undertake the risk review once (8 years after promulgation of the original MACT standards), it is required to undertake the technology review multiple times (at least every 8 years after promulgation of the original MACT standard). That Congress charged the EPA to ensure an ample margin of safety through the risk review, yet still required the technology review to be conducted on a periodic basis, demonstrates that Congress anticipated that the EPA would strengthen standards based on technological developments even after it had concluded there was an ample margin of safety. CAA section 112's overarching charge to the EPA to ''require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section (including a prohibition on such emissions)'' further demonstrates that Congress sought to minimize the emission of hazardous air pollution wherever feasible independent of a finding of risk. Moreover, as discussed *supra,* in enacting the 1990 CAA Amendments, Congress purposefully replaced the previous risk-based approach to establishing standards for HAP with a technology-driven approach. This technology-driven

[29] See, *e.g., National Emission Standards for Hazardous Air Pollutants: Refractory Products Manufacturing Residual Risk and Technology Review,* 86 FR 66045 (November 19, 2021); *National Emission Standards for Hazardous Air Pollutants: Site Remediation Residual Risk and Technology Review,* 85 FR 41680 (July 10, 2020); *National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline) Residual Risk and Technology Review,* 85 FR 40740, 40745 (July 7, 2020); *National Emission Standards for Hazardous Air Pollutants: Generic Maximum Achievable Control Technology Standards Residual Risk and Technology Review for Ethylene Production,* 85 FR 40386, 40389 (July 6, 2020); *National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills,* 82 FR 47328 (October 11, 2017); *National Emission Standards for Hazardous Air Pollutants: Generic Maximum Achievable Control Technology Standards; and Manufacture of Amino/Phenolic Resins,* 79 FR 60898, 60901 (October 8, 2014).

[30] *National Emission Standards for Hazardous Air Pollutant Emissions: Group I Polymers and Resins; Marine Tank Vessel Loading Operations; Pharmaceuticals Production; and the Printing and Publishing Industry,* 76 FR 22566, 22577 (April 21, 2011).

[31] See, *e.g., National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry,* 71 FR 76603, 76606 (December 21, 2006); *see also Proposed Rules: National Emission Standards for Halogenated Solvent Cleaning,* 73 FR 62384, 62404 (October 20, 2008).

[32] *National Emissions Standards for Hazardous Air Pollutants: Secondary Lead Smelting,* 77 FR 556, 564 (January 5, 2012).

[33] See section II.A.2. above for further discussion of the statutory structure and legislative history of CAA section 112.

approach recognizes the ability for the EPA to achieve substantial reductions in HAP based on technological improvements without the inherent difficulty in quantifying risk associated with HAP emission exposure given the complexities of the pathways through which HAP cause harm and insufficient availability of data to quantify their effects discussed in section II.B.2. Independent of risks, it would be inconsistent with the text, structure, and legislative history for the EPA to conclude that Congress intended the statute's technology-based approach to be sidelined after the EPA had concluded the risk review.

Comment: Some commenters expressed concern that some portion of affected units could simply retire instead of coming into compliance with new requirements, potentially occurring before new generation could be built to replace the lost generation. During this period, a lack of dispatchable generation could significantly increase the likelihood of outages, particularly during periods of severe weather. In addition, some commenters argued that revising the fPM limit was unnecessary as there is a continuing downward trend in HAP emissions from early retirements of coal-fired EGUs, whereas accelerating this trend could have potential adverse effects on reliability. Some commenters also stated that as more capacity and generation is shifted away from coal-fired EGUs due to the Inflation Reduction Act (IRA) and other regulatory and economic factors, the total annual fPM and HAP emissions from industry will decline, regardless of whether the fPM limit is made more stringent.

Response: The EPA disagrees that this rule would threaten resource adequacy or otherwise degrade electric system reliability. Commenters provided no credible information supporting the argument that this final rule would result in a significant number of retirements or a larger amount of capacity needing controls. The Agency estimates that this rule will require additional fPM control at less than 12 GW of operable capacity in 2028, which is about 11 percent of the total coal-fired EGU capacity projected to operate in that year. The units requiring additional fPM controls are projected to generate less than 1.5 percent of total generation in 2028. Moreover, the EPA does not project that any EGUs will retire in response to the standards promulgated in this final rule. Because the EPA projects no incremental changes in existing operational capacity to occur in response to the final rule, the EPA does not anticipate this rule will have any implications for resource adequacy.

Nevertheless, it is possible that some EGU owners may conclude that retiring a particular EGU and replacing it with new capacity is a more economic option from the perspective of the unit's customers and/or owners than making investments in new emissions controls at the unit. The EPA understands that before implementing such a retirement decision, the unit's owner will follow the processes put in place by the relevant regional transmission organization (RTO), balancing authority, or state regulator to protect electric system reliability. These processes typically include analysis of the potential impacts of the proposed EGU retirement on electrical system reliability, identification of options for mitigating any identified adverse impacts, and, in some cases, temporary provision of additional revenues to support the EGU's continued operation until longer-term mitigation measures can be put in place. No commenter stated that this rule would somehow authorize any EGU owner to unilaterally retire a unit without following these processes, yet some commenters nevertheless assume without any rationale that is how multiple EGU owners would proceed, in violation of their obligations to RTOs, balancing authorities, or state regulators relating to the provision of reliable electric service.

In addition, the Agency has granted the maximum time allowed for compliance under CAA section 112(i)(3) of 3 years, and individual facilities may seek, if warranted, an additional 1-year extension of the compliance date from their permitting authority pursuant to CAA section 112(i)(3)(B). The construction of any additional pollution control technology that EGUs might install for compliance with this rule can be completed within this time and will not require significant outages beyond what is regularly scheduled for typical maintenance. Facilities may also obtain, if warranted, an emergency order from the Department of Energy pursuant to section 202(c) of the Federal Power Act (16 U.S.C. 824a(c)) that would allow the facility to temporarily operate notwithstanding environmental limits when the Secretary of Energy determines doing so is necessary to address a shortage of electric energy or other electric reliability emergency.

Further, despite the comments asserting concerns over electric system reliability, no commenter cited a single instance where implementation of an EPA program caused an adverse reliability impact. Indeed, similar claims made in the context of the EPA's prior CAA rulemakings have not been borne out in reality. For example, in the stay litigation over the Cross-State Air Pollution Rule (CSAPR), claims were made that allowing the rule to go into effect would compromise reliability. Yet in the 2012 ozone season starting just over 4 months after the rule was stayed, EGUs covered by CSAPR collectively emitted below the overall program budgets that the rule would have imposed in that year if the rule had been allowed to take effect, with most individual states emitting below their respective state budgets. Similarly, in the litigation over the 2015 Clean Power Plan, assertions that the rule would threaten electric system reliability were made by some utilities or their representatives, yet even though the Supreme Court stayed the rule in 2016, the industry achieved the rule's emission reduction targets years ahead of schedule without the rule ever going into effect. *See West Virginia* v. *EPA,* 142 S. Ct. 2587, 2638 (2022) (Kagan, J., dissenting) (''[T]he industry didn't fall short of the [Clean Power] Plan's goal; rather, the industry exceeded that target, all on its own . . . . At the time of the repeal . . . 'there [was] likely to be no difference between a world where the [Clean Power Plan was] implemented and one where it [was] not.' '') (quoting 84 FR 32561). In other words, the claims that these rules would have had adverse reliability impacts proved to be groundless.

The EPA notes that similar concerns regarding reliability were raised about the 2012 MATS Final Rule—a rule that projected the need for significantly greater installation of controls and other capital investments than this current revision.[34] As with the current rule, the flexibility of permitting authorities to allow a fourth year for compliance was available in a broad range of situations, and in the event that an isolated, localized concern were to emerge that could not be addressed solely through the 1-year extension under CAA section 112(i)(3), the CAA provides flexibilities to bring sources into compliance while maintaining reliability. We have seen no evidence in the last decade to suggest

[34] The EPA projected that the 2012 MATS Final Rule would drive the installation of an additional 20 GW of dry FGD (dry scrubbers), 44 GW of DSI, 99 GW of additional ACI, 102 GW of additional FFs, 63 GW of scrubber upgrades, and 34 GW of ESP upgrades. While a subsequent analysis found that the industry ultimately installed fewer controls than was projected, the control installations that occurred following the promulgation of the 2012 MATS Final Rule were still significantly greater than the installations that are estimated to occur as a result of this final rule (where, for example, the EPA estimates that less than 2 GW of capacity would install FF technology for compliance).

that the implementation of MATS caused power sector adequacy and reliability problems, and only a handful of sources obtained administrative orders under the enforcement policy issued with MATS to provide relief to reliability critical units that could not comply with the rule by 2016.

Comment: Commenters suggested that the EPA use its authority to create subcategories of affected facilities that elect to permanently retire by the compliance date as the Agency has taken in similar proposed rulemakings affecting coal- and oil-fired EGUs. Commenters stated the EPA should subcategorize those sources that have adopted enforceable retirement dates and not subject those sources to any final rule requirements. They indicated that the EPA is fully authorized to subcategorize these units under CAA section 112(d)(1). Commenters asked that the EPA consider other simultaneous rulemakings, such as the proposed Greenhouse Gas Standards and Guidelines for Fossil Fuel Power Plants,[35] where the EPA proposed that EGUs that elect to shut down by January 1, 2032, must maintain their recent historical carbon dioxide (CO_2) emission rate via routine maintenance and operating procedures (*i.e.,* no degradation of performance). Commenters also referenced the retirement date of December 31, 2032, in the EPA Office of Water's proposed Effluent Limitation Guidelines.[36]

Commenters claimed that creating a subcategory for units facing near-term retirements that harmonizes the retirement dates with other rulemakings would greatly assist companies with moving forward on retirement plans without running the risk of being forced to retire early, which could create reliability concerns or, in the alternative, forced to deliberate whether to install controls and delaying retirement to recoup investments in the controls. Commenters also suggested that EGUs with limited continued operation be allowed to continue to perform quarterly stack testing to demonstrate compliance with the fPM limitations (rather than having to install PM CEMS). Commenters suggested that imposing different standards on these subcategories should continue the status quo for these units until retirement. Commenters claimed that it would make no sense for the EPA to require an EGU slated to retire in the near term to expend substantial resources on controls in the interim since these sources are very unlikely to find it viable to construct significant control upgrades for a revised standard that would become effective in mid-2027, only 5 years before the unit's permanent retirement. Commenters further noted if the EPA does not establish such a subcategory or take other action to ensure these units are not negatively impacted by the rulemaking, the retirement of some units could be accelerated due to the costs of installing a PM CEMS and the need to rebuild or upgrade an existing ESP or install a FF to supplement an existing ESP. Commenters stated that the EPA cannot ignore the need for a coordinated retirement of thermal generating capacity while new generation sources come online to avoid detrimental impacts to grid reliability.

Commenters suggested that if the EPA decides to proceed with finalizing the revised standards in the 2023 Proposal, the Agency should create a subcategory for coal-fired EGUs that elect by the compliance date of the revised standards (*i.e.,* mid-2027) to retire the units by December 31, 2032, or January 1, 2032, if the EPA prefers to tie the 2023 Proposal to the proposed Emission Guidelines instead of the Effluent Limitation Guidelines, and maintain the current MATS standards for this subcategory of units. Commenters requested that the EPA coordinate the required retirement date for the 2023 Proposal with other rules so that all retirement dates align. Commenters reiterated that the EPA has multiple authorities with overlapping statutory timelines that affect commenters' plans regarding the orderly retirement of coal-fired EGUs and their ability to continue the industry's clean energy transformation while providing the reliability and affordability that their customers demand. Commenters suggested that EGUs that plan to retire by 2032 should have the opportunity to seek a waiver from PM CEMS installation altogether and continue quarterly stack testing during the remaining life of the unit. They also suggested that if a unit does not retire by the specified date, it should be required to immediately cease operation or meet the standards of the rule. Commenters stated that under this recommendation an EGU's failure to comply would then be a violation of the 2023 Proposal's final rule subject to enforcement.

Response: In response to commenters' concerns, the EPA evaluated the feasibility of creating a subcategory for facilities with near-term retirements but disagrees with commenters that such a subcategory is appropriate for this rulemaking. In particular, the EPA found that, based on its own assessment and that of commenters, only a few facilities would likely be eligible for a near-term retirement subcategory and that it would not significantly reduce the costs of the revised standards. According to the EPA's assessment, 67 of the 296 EGUs assessed[37] have announced retirements between 2029 and 2032—less than one-quarter of the fleet—and all but three of those EGUs (at two facilities) have already demonstrated the ability to comply with the 0.010 lb/MMBtu fPM standard on average. Additionally, these three EGUs already use PM CEMS to demonstrate compliance, therefore the comment requesting a waiver of PM CEMS installations for EGUs with near-term retirements is not relevant. Because the EPA's analysis led the Agency to conclude that there would be little utility to a near-term retirement subcategory and it would not change the costs of the rule in a meaningful way, the EPA determined not to create a retirement subcategory for the fPM standard. In addition, the EPA notes that allowing units to operate without the best performing controls for an additional number of years would lead to higher levels of non-Hg HAP metals emissions and continued exposure to those emissions in the communities around these units during that timeframe. Regarding a fPM compliance requirement subcategory for EGUs with near-term retirements, the Agency estimates 26 of 67 EGUs are already using PM CEMS for compliance demonstration and finds that the costs to install PM CEMS for facilities with near-term retirements are reasonable. The Agency finds that the transparency provided by PM CEMS and the increased ability to quickly detect and correct potential control or operational problems using PM CEMS furthers Congress's goal to ensure that emission reductions are consistently maintained and makes PM CEMS the best choice for this rule's compliance monitoring for all EGUs.

2. Comments on the Proposed Changes to the Compliance Demonstration Options

Comment: The Agency received both supportive and opposing comments requiring the use of PM CEMS for compliance demonstration. Supportive commenters stated the EPA must require the use of PM CEMS to monitor their emissions of non-Hg HAP metals

[35] 88 FR 33245 (May 23, 2023).

[36] 88 FR 18824, 18837 (March 29, 2023).

[37] In this final rule, the EPA reviewed fPM compliance data for 296 coal-fired EGUs expected to be operational on January 1, 2029. This review is explained in detail in the 2024 Technical Memo.

as PM CEMS are now more widely deployed than when MATS was first promulgated, and experience with PM CEMS has enabled operators to more promptly detect and correct problems with pollution controls as compared to other monitoring and testing options allowed under MATS (*i.e.,* periodic stack testing and parametric monitoring for PM), thereby lowering HAP emissions. They said that the fact that PM CEMS have been used to demonstrate compliance in a majority of units in the eight best performing deciles [38] provides strong evidence that PM CEMS can be used effectively to measure low levels of PM emissions.

Opposing commenters urged the EPA to retain all current options for demonstrating compliance with non-Hg HAP metal standards, including quarterly PM and metals testing, LEE, and PM CPMS. These commenters said removing these compliance flexibility options goes beyond the scope of the RTR and does not address why the reasons these options were originally included in MATS are no longer valid. Commenters said they have previously raised concerns about PM CEMS that the EPA has avoided by stating that CEMS are not the only compliance method for PM. They stated that previously, the EPA has determined these compliance methods were both adequate and frequent enough to demonstrate compliance.

Response: The Agency disagrees with commenters who suggests that the rule should retain all previous options for demonstrating compliance with either the individual metals, total metals, or fPM limits. Congress intended for CAA section 112 to achieve significant reductions of HAP, and the EPA agrees with other commenters that the use of CEMS in general and PM CEMS in particular enables owners or operators to detect and quickly correct control device or process issues in many cases before the issues become compliance problems. Consistent with the discussion contained in the 2023 Proposal (88 FR 24872), the Agency finds the transparency and ability to quickly detect and correct potential control or operational problems furthers Congress's goal to ensure that emission reductions are consistently maintained and makes PM CEMS the best choice for this rule's compliance monitoring.

Comment: Some commenters objected to the EPA's proposal to require the use of PM CEMS for purposes of demonstrating compliance with the revised fPM standard, stating that the requirements of Performance Specification 11 of 40 CFR part 60, appendix B (PS–11) will become extremely hard to satisfy at the low emission limits proposed. For PS–11, relative correlation audit (RCA), and relative response audit (RRA), the tolerance interval and confidence interval requirements are expressed in terms of the emission standard that applies to the source. The commenters reviewed test data from operating units and found significantly higher PS–11 failure (>80 percent), RCA failure (>80 percent), and RRA failure (60 percent) rates at the more stringent proposed emission limits. They stated that the cost, complexity, and failure rate of equipment calibration remains one of the biggest challenges with the use of PM CEMS and therefore other compliance demonstration methods should be retained. Commenters also noted that repeated tests due to failure could result in higher total emissions from the units.

Response: The Agency is aware of concerns by some commenters that PM CEMS currently correlated for the 0.030 lb/MMBtu fPM emission limit may experience difficulties should re-correlation be necessary; and those concerns are also ascribed to yet-to-be installed PM CEMS. In response to those concerns, the Agency has shifted the basis of correlation testing from requiring only the collection of a minimum volume per run to also allowing the collection of a minimum mass per run and has adjusted the QA criterion otherwise associated with the new emission limit. These changes will ease the transition for coal- and oil-fired EGUs using only PM CEMS for compliance demonstration purposes. The first change, allowing the facility to choose either the collection of a minimum mass per run or a minimum volume per run, should reduce high-level correlation testing duration, addressing other concerns about extended runtimes with degraded emissions control or increased emissions, and should reduce correlation testing costs. The second change, adjusting the QA criteria, is consistent with other approaches the Agency has used when lower ranges of instrumentation or methods are employed. For example, in section 13.2 of Performance Specification 2 (40 CFR part 60, appendix B) the QA criteria for the relative accuracy test audit for SO_2 and Nitrogen Oxide CEMS are relaxed as the emission limit decreases. This is accomplished at lower emissions by allowing a larger criterion or by modifying the calculation and allowing a less stringent number in the denominator. With these changes to the QA criteria and correlation procedures, the EPA believes EGUs will be able to use PM CEMS to demonstrate compliance at the revised level of the fPM standard.

Comment: Some commenters asserted that if the EPA finalizes the requirement to demonstrate compliance using PM CEMS, EGUs will not be able to comply with a lower fPM limit on a continuous basis and that accompanying a lower limit with more restrictive monitoring requirements adds to the regulatory burden of affected sources and permitting authorities.

Response: The EPA disagrees with commenters' claim that that EGUs will not be able to demonstrate compliance continuously with a fPM limit of 0.010 lb/MMBtu. The EPA believes that CEMS in general and PM CEMS in particular enable owners and operators to detect and quickly correct control device or process issues in many cases before the issues become compliance problems. Contrary to the commenter's assertion that EGUs will not be able to comply with a lower fPM limit on a continuous basis, as mentioned in the June 2023 Andover Technology Partners analysis,[39] over 80 percent of EGUs using PM CEMS for compliance purposes have already been able to achieve and are reporting and certifying consistent achievement of fPM rates below 0.010 lb/MMBtu.[40] The EPA is unaware of any additional burden experienced by those EGU owners or operators or their regulatory authorities with regard to PM CEMS use at these lower emission levels, and does not expect additional burden to be placed on EGU owners or operators with regard to PM CEMS from application of the revised emission limit. However, this final rule incorporates approaches, such as switching from a minimum sample volume per run to collection of a

[38] Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants. Andover Technology Partners. August 19, 2021. Document ID No. EPA–HQ–OAR–2018–0794–4583.

[39] Assessment of Potential Revisions to the Mercury and Air Toxics Standards. Andover Technology Partners. June 15, 2023. Docket ID No. EPA–HQ–OAR–2018–0794. June 2023. Also available at *https://www.andovertechnology.com/wp-content/uploads/2023/06/C_23_CAELP_Final.pdf.*

[40] See for example the PM CEMS Thirty Boiler Operating Day Rolling Average Reports for Duke's Roxboro Steam Electric Plant in North Carolina and at Minnesota Power's Boswell Energy Center in Minnesota. These reports and those from other EGUs reporting emission levels at or lower than 0.010 lb/MMBtu are available electronically by searching in the EPA's Web Factor Information Retrieval System (WebFIRE) Report Search and Retrieval portion of the Agency's WebFIRE internet website at *https://cfpub.epa.gov/webfire/reports/esearch.cfm.*

minimum mass sample or mass volume per run and adjusting the PM CEMS QA acceptability criteria, to reduce the challenges with using PM CEMS. Moreover, the 30-boiler-operating-day averaging period of the limit provides flexibility for owners and operators to account for equipment malfunctions and other issues. Consistent with the discussion in the 2023 Proposal,[41] the Agency finds that PM CEMS are the best choice for this rule's compliance monitoring as they provide increased emissions transparency, ability for EGU owner/operators to quickly detect and correct potential control or operational problems, and greater assurance of continuous compliance. While PM CEMS can produce values at lower levels provided correlations are developed appropriately, the Agency established the final fPM limit of 0.010 lb/MMBtu after considering factors such as run times necessary to develop correlations, potential random error effects, and costs.

Comment: Commenters stated that the EPA's cost estimates contradict the Agency's suggestion that the use of PM CEMS is a more cost-effective monitoring approach than quarterly testing, especially for units that qualify as LEE. They said that the EPA used estimates from the Institute of Clean Air Companies (ICAC) or Envea/Altech which do not include numerous costs associated with PM CEMS that make them not cost-effective, such as the cost of intermittent stack testing associated with the PS–11 correlations and the ongoing costs of RCAs and RRA, which are a large part of the costs associated with PM CEMS and would rise substantially in conjunction with the proposed new PM limits. The commenters said that the ICAC estimated range of PM CEMS installation costs are particularly understated and outdated and should be ignored by the Agency. They said that the EPA estimates may also understate PM CEMS cost by assuming the most commonly used light scattering based PM CEMS will be used for all applications. The commenters said that while more expensive, a significant number of beta gauge PM CEMS are used for MATS compliance, especially where PM spiking is used for PS–11 correlation and RCA testing and that this higher degree of accuracy from beta gauge PM CEMS may be needed for sources without a margin of compliance under the new, more stringent emission limit.

Response: The EPA disagrees with the commenters' suggestion that the Agency is required to select the most cost-effective approach for compliance monitoring. Rather, the Agency selects the approach that best provides assurance that emission limits are met. PM CEMS annual costs represent a very small fraction of a typical coal-fired EGU's operating costs and revenues. As described in the *Ratio of Revised Estimated Non-Beta Gauge PM CEMS EUAC to 2022 Average Coal-Fired EGU Gross Profit* memorandum, available in the docket, if all coal-fired EGUs were to purchase and install new PM CEMS, the Equivalent Uniform Annual Cost (EUAC) would represent less than four hundredths of a percent of the average annual operating expenses from coal-fired EGUs.

Further, as described in the *Revised Estimated Non-Beta Gauge PM CEMS and Filterable PM Testing Costs* technical memorandum, available in the rulemaking docket, the EPA calculated average costs for PM CEMS and quarterly testing from values submitted by commenters in response to the proposal's solicitation, which are discussed in section IV.D. of the preamble. Based on the commenters' suggestions, these revised costs include the costs of intermittent stack testing associated with the PS–11 correlations and ongoing costs of RCAs and RRAs. While the average EUAC for PM CEMS exceeds the average annual cost of quarterly stack emission testing, the cost for PM CEMS does not include important additional benefits associated with providing continuous emissions data to EGU owners or operators, regulators, nearby community members, or the general public. As a reminder, the EPA is not obligated to choose the most inexpensive approach for compliance demonstrations, particularly when all benefits are not monetized, even though costs can be an important consideration. Consistent with the discussion contained in the 2023 Proposal at 88 FR 24872, the Agency finds the increased transparency of EGU fPM emissions and the ability to quickly detect and correct potential control or operational problems, along with greater assurance of continuous compliance makes PM CEMS the best choice for this rule's compliance monitoring.

The Agency acknowledges the commenters' suggestions that EGU owners or operators may find that using beta gauge PM CEMS is most appropriate for the lower fPM emission limit in the rule; such suggestions are consistent with the Agency's view, as expressed in 88 FR 24872. However, the Agency believes other approaches, including spiking, can also ease correlation testing for PM CEMS. Moreover, the Agency anticipates that the new fPM limit will increase demand for, and perhaps spur increased production of, beta gauge PM CEMS.

D. What is the rationale for our final approach and decisions for the filterable PM (as a surrogate for non-Hg HAP metals) standard and compliance demonstration options?

The EPA is finalizing a lower fPM emission standard of 0.010 lb/MMBtu for coal-fired EGUs, as a surrogate for non-Hg HAP metals, and the use of PM CEMS for compliance demonstration purposes for coal- and oil-fired EGUs (with the exception of limited-use liquid oil-fired EGUs) based on developments in the performance of sources within the category since the EPA finalized MATS and the advantages conferred by using CEMS for compliance. As described in the 2023 Proposal, non-Hg HAP metals are predominately a component of fPM, and control of fPM results in concomitant reduction of non-Hg HAP metals (with the exception of Se, which may be present in the filterable fraction or in the condensable fraction as the acid gas, SeO_2). The EPA observes that since MATS was finalized, the vast majority of covered units have significantly outperformed the standard, with a small number of units lagging behind and emitting significantly higher levels of these HAP in communities surrounding those units. The EPA deems it appropriate to require these lagging units to bring their pollutant control performance up to that of their peers. Moreover, the EPA concludes that requiring use of PM CEMS for compliance yields manifold benefits, including increased emissions transparency and data availability for owners and operators and for nearby communities.

The EPA's conclusions with regard to the fPM standard and requirement to use PM CEMS for compliance demonstration are closely related, both in terms of CAA section 112(d)(6)'s direction for the EPA to reduce HAP emissions based on developments in practices, processes, and control technologies, and in terms of technical compatibility.[42] The EPA finds that the manifold benefits of PM CEMS render it appropriate to promulgate an updated fPM emission standard as a surrogate for non-Hg HAP metals for which PM CEMS can be used to monitor

[41] See 88 FR 24872.

[42] As noted in section III.A. above, there are nonetheless independent reasons for adopting both the revision to the fPM standard and the PM CEMS compliance demonstration requirement and each of these changes would continue to be workable without the other in effect, such that the EPA finds the two revisions are severable from each other.

compliance. However, as the fPM limit is lowered, operators may encounter difficulties establishing and maintaining existing correlations for the PM CEMS and may therefore be unable to provide accurate values necessary for compliance. The EPA has determined, based on comments and on the additional analysis described below, that the lowest possible fPM limit considering these challenges at this time is 0.010 lb/MMBtu with adjusted QA criteria. Therefore, the EPA determined that this two-pronged approach—requiring PM CEMS in addition to a lower fPM limit—is the most stringent option that balances the benefits of using PM CEMS with the emission reductions associated with the tightened fPM emission standard. Further, the EPA finds that the more stringent limit of 0.006 lb/MMBtu fPM cannot be adequately monitored with PM CEMS at this time, because the random error component of measurement uncertainty from correlation stack testing is too large and the QA criteria passing rate for PM CEMS is too small to provide accurate (and therefore enforceable) compliance values. Below, we further describe our rationale for each change.

1. Rationale for the Final Filterable PM Emission Standard

In the 2023 Proposal, the Agency proposed a lower fPM emission standard for coal-fired EGUs as a surrogate for non-Hg HAP metals based on developments in practices, processes, and control technologies pursuant to CAA section 112(d)(6), including the EPA's assessment of the differing performance of sources within the category and updated information about the cost of controls. As described in the 2023 Proposal, non-Hg HAP metals are predominately a component of fPM, and control of fPM results in reduction of non-Hg HAP metals (with the exception of Se, which may be present in the filterable fraction or in the condensable fraction as the acid gas, SeO_2).

In conducting this technology review, the EPA found important developments that informed its proposal. First, from reviewing historical information contained in WebFIRE,[43] the EPA observed that most EGUs were reporting fPM emission rates well below the 0.030 lb/MMBtu standard. The fleet was achieving these performance levels at lower costs than estimated during promulgation of the 2012 MATS Final Rule. Second, there are technical developments and improvements in PM control technology since the 2012 MATS Final Rule that informed the 2023 Proposal.[44] For example, while ESP technology has not undergone fundamental changes since 2011, industry has learned and adopted ''best practices'' associated with monitoring ESP operation more carefully since the 2012 MATS Final Rule. For FFs, more durable materials have been developed since the 2012 MATS Final Rule, which are less likely to fail due to chemical, thermal, or abrasion failure and create risks of high PM emissions. For instance, fiberglass (once the most widely used material) has largely been replaced by more reliable and easier to clean materials, which are more costly. Coated fabrics, such as Teflon or P84 felt, also clean easier than other fabrics, which can result in less frequent cleaning, reducing the wear that could damage filter bags and reduce the effectiveness of PM capture.

To examine potential revisions, the EPA evaluated fPM compliance data for the coal-fired fleet and evaluated the control efficiency and costs of PM controls to achieve a lower fPM standard. Based on comments received on the 2023 Proposal, the EPA reviewed additional fPM compliance data for 62 EGUs at 33 facilities (see 2024 Technical Memo and attachments for detailed information). The review of additional fPM compliance data showed that more EGUs had previously demonstrated an ability to meet a lower fPM rate, as shown in figure 4 of the 2024 Technical Memo. Compared to the 2023 Proposal where 91 percent of existing capacity demonstrated an ability to meet 0.010 lb/MMBtu, the updated analysis showed that 93 percent are demonstrating the ability to meet 0.010 lb/MMBtu with existing controls. The EPA received comments on the cost assumptions for upgrading PM controls and found that the costs estimated at proposal were not only too high, but that the cost effectiveness of PM upgrades was also underestimated (*i.e.,* the standard is more cost-effective than the EPA believed at proposal).

The EPA is finalizing the fPM emission limit of 0.010 lb/MMBtu with adjusted QA criteria, based on developments since 2012, for the reasons described in this final rule and in the 2023 Proposal as the lowest achievable fPM limit that allows for the use of PM CEMS for compliance demonstration purposes. First, this level of control ensures that the highest emitters bring their performance to a level where the vast majority of the fleet is already performing. For example, as described above, the majority of the existing coal-fired fleet subject to this final rule has previously demonstrated an ability to comply with the lower 0.010 lb/MMBtu fPM limit at least 99 percent of the time during one quarter, in addition to meeting the lower fPM limit on average across all quarters assessed. The Agency estimates that only 33 EGUs are currently operating above this revised limit. Compared to some of the best performing EGUs, the 33 EGUs requiring additional PM control upgrades or maintenance are more likely to have an ESP instead of a FF and to demonstrate compliance using intermittent stack testing. In addition, most of these EGUs have operated at a higher level of utilization than the coal-fired fleet on average.

Second, as discussed in section II.A.2. above, Congress updated CAA section 112 in the 1990 Clean Air Act Amendments to achieve significant reductions in HAP emissions, which it recognized are particularly harmful pollutants, and implemented a regime under which Congress directed the EPA to make swift and substantial reductions to HAP based upon the most stringent standards technology could achieve. This is evidenced by Congress's charge to the EPA to ''require the maximum degree of reduction in emissions of hazardous air pollutants (including a prohibition on such emissions),'' that is achievable accounting for ''the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements. . . .'' CAA section 112(d)(2). Further, by creating separate and distinct requirements for the EPA to consider updates to CAA section 112 pursuant to both technology review under CAA section 112(d)(6) and residual risk review under CAA section 112(f)(2), Congress anticipated that the EPA would strengthen standards pursuant to technology reviews ''as necessary (taking into account developments in practices, processes, and control technologies),'' CAA section 112(d)(6), even after the EPA concluded there was an ample margin of safety based on the risks that the EPA can quantify.[45] As the EPA explained in the

[43] WebFIRE includes data submitted to the EPA from the Electronic Reporting Tool (ERT) and is searchable at *https://cfpub.epa.gov/webfire/reports/esearch.cfm.*

[44] Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants. Andover Technology Partners. August 19, 2021. Document ID No. EPA–HQ–OAR–2018–0794–4583.

[45] EPA's CAA section 112(f)(2) quantitative risk assessments evaluate cancer risk associated with a lifetime of exposure to HAP emissions from each source in the source category, the potential for HAP exposure to cause adverse chronic (or long-term) noncancer health effects, and the potential for HAP

proposal, the EPA does consider costs, technical feasibility, and other factors when evaluating whether it is necessary to revise existing emission standards under CAA section 112(d)(6) to ensure the standards ''require the maximum degree of emissions reductions . . . achievable.'' CAA section 112(d)(2). The text, structure, and history of this provision demonstrate Congress's direction to the EPA to require reduction in HAP where technology is available to do so and the EPA accounts for the other statutory factors.

Accordingly, the EPA finds that bringing this small number of units to the performance levels of the rest of the fleet serves Congress's mandate to the EPA in CAA section 112(d)(6) to continually consider developments ''that create opportunities to do even better.'' *See LEAN,* 955 F.3d at 1093. As such, the EPA has a number of times in the past updated its MACT standards to reflect developments where the majority of sources were already outperforming the original MACT standards.[46] Indeed, this final rule 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). 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, and those controls are of reasonable cost, sources should be required to use them.

The fleet has been able to ''over comply'' with the existing fPM standard due to the very high PM control effectiveness of well-performing ESPs and FFs, often exceeding 99.9 percent. But the performance of a minority of units lags well behind the vast majority of the fleet. As indicated by the two highest fPM rates,[47] EGUs without the most effective PM controls have not been able to demonstrate fPM rates comparable to the rest of the fleet. Specifically, the Colstrip facility, a 1,500 MW subbituminous-fired power plant located in Colstrip, Montana, operates the only two coal-fired EGUs in the country without the most modern PM controls (*i.e.,* ESP or FF). Instead, this facility utilizes venturi wet scrubbers as its primary PM control technology and has struggled to meet the original 0.030 lb/MMBtu fPM limit, even while employing emissions averaging across the operating EGUs at the facility. Colstrip is also the only facility where the EPA estimates the current controls would be unable to meet a lower fPM limit. Specifically, the 2018 second quarter compliance stack tests showed average fPM emission rates above the 0.030 lb/MMBtu fPM limit, in violation of its Air Permit. Talen Energy, one of the owners of the facility, agreed to pay $450,000 to settle these air quality violations.[48] As a result, the plant was offline for approximately 2.5 months while the plant's operator worked to correct the problem. Comments from Colstrip's majority owners discuss the efforts this facility has undergone to improve their wet PM scrubbers, which they state remove 99.7 percent of the fly ash particulate but agree with the EPA that additional controls would be needed to meet a 0.010 lb/MMBtu limit. However, as stated in *NorthWestern Energy's Annual PCCAM Filing and Application of Tariff Changes*,[49] ''Colstrip has a history of operating very close to the upper end limit: for 43 percent of the 651 days of compliance preceding the forced outage its [Weighted Average Emission Rate or] WAER was within 0.03 lb/dekatherm [50] of the limit [. . . to comply with the Air Permit and MATS, Colstrip's WAER must be equal to or less than 0.03 lb/dekatherm].''

The Northern Cheyenne Reservation is 20 miles from the Colstrip facility and the Tribe exercised its authority in 1977 to require additional air pollution controls on the new Colstrip units (Colstrip 3 and 4, the same EGUs still operating today), recognizing the area as a Class I airshed under the CAA. According to comments submitted by the Northern Cheyenne Tribe, their tribal members—both those living on the Reservation and those living in the nearby community of Colstrip—have been disproportionally impacted by exposure to HAP emissions from the Colstrip facility.[51]

The EPA believes a fPM emission limit of 0.010 lb/MMBtu appropriately takes into consideration the costs of controls. 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. Costs of PM upgrades are much lower than the EPA estimated in 2012, and the Agency revised its costs assumptions as described in the 2024 Technical Memo, available in the docket. Table 4 of this document summarizes the updated cost effectiveness of the three fPM emission limits considered in the 2023 Proposal for the existing coal-fired fleet. For the purpose of estimating cost effectiveness, the analysis presented in this table, described in detail in the 2023 and 2024 Technical Memos, is based on the observed emission rates of all existing coal-fired EGUs except for those that have announced plans to retire by the end of 2028. The analysis presented in table 4 estimated the costs associated for each unit to upgrade their existing PM controls to meet a lower fPM standard. In the cases where existing PM controls would not achieve the necessary reductions, unit-specific FF install costs were estimated. Unlike the cost and benefit projections presented in the RIA, 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 IRA, future regulatory actions, or changes in economic conditions. For example, of the more than 14 GW of coal-fired capacity that the EPA estimates would require control improvements to achieve the final fPM rate, less than 12 GW is projected to be

exposure to cause adverse acute (or short-term) noncancer health effects.

[46] See, *e.g., National Emission Standards for Hazardous Air Pollutants: Site Remediation Residual Risk and Technology Review,* 85 FR 41680, 41698 (July 10, 2020) (proposed 84 FR 46138, 46161; September 3, 2019)) (requiring compliance with more stringent equipment leak definitions under a technology review, which were widely adopted by industry); *National Emissions Standards for Mineral Wool Production and Fiberglass Manufacturing,* 80 FR 45280, 45307 (July 29, 2015) (adopting more stringent limits for glass-melting furnaces under a technology review where the EPA found that ''all glass-melting furnaces were achieving emission reductions that were well below the existing MACT standards regardless of the control technology in use''); *National Emissions Standards for Hazardous Air Pollutants From Secondary Lead Smelting,* 77 FR 556, 564 (January 5, 2012) (adopting more stringent stack lead emission limit under a technology review ''based on emissions data collected from industry, which indicated that well-performing baghouses currently used by much of the industry are capable of achieving outlet lead concentrations significantly lower than the [current] limit.'').

[47] See figure 4 of the 2024 Technical Memo.

[48] See Document CLT–1T Testimony, CLT–11, and CL–12 in Docket 190882 at *https://www.utc.wa.gov/documents-and-proceedings/dockets.*

[49] See NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes, Docket No. 2019.09.058, Final Order 7708f paragraph 21 (November 18, 2020) (noting that ''Colstrip has a history of operating very close to the upper end limit''), available at *https://reddi.mt.gov/prweb.*

[50] For reference, a dekatherm is equivalent to one million Btus (MMBtu).

[51] See Document ID No. EPA–HQ–OAR–2018–5984 at *https://www.regulations.gov.*

operational in 2028 (see section 3 of the RIA for this final rule).

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Table 4. Summary of the Updated Cost Effectiveness Analysis for Three Potential fPM Limits[1]

	Potential fPM emission limit (lb/MMBtu)		
	0.015	0.010	0.006
Affected Units (Capacity, GW)	11 (4.7)	33 (14.1)	94 (41.3)
Annual Cost ($M, 2019 dollars)	38.8	87.2	398.8
fPM Reductions (tpy)	1,258	2,526	5,849
Total Non-Hg HAP Metals Reductions (tpy)	3.0	8.3	22.7
Total Non-Hg HAP Metals Cost Effectiveness ($k/ton)	13,050	10,500	17,500
Total Non-Hg HAP Metals Cost Effectiveness ($/lb)	6,500	5,280	8,790

[1] This analysis used reported fPM compliance data for 296 coal-fired EGUs to develop unit-specific average and lowest achieved fPM rate values to determine if the unit, with existing PM controls, could achieve a lower fPM limit. Using the compliance data, the EPA evaluated costs to upgrade existing PM controls, or if necessary, install new controls in order to meet a lower fPM limit.

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The EPA has updated its costs analyses for this final rule based on comments received and additional data review, which is described in more detail in the 2024 Technical Memo available in the docket. In response to commenters stating that the use of the lowest quarter's 99th percentile, or the lowest achievable fPM rate, is not indicative of overall EGU operation and emission performance, the EPA added a review of average fPM rates. In these updated analyses, both the lowest quarter's 99th percentile and the average fPM rate must be below the potential fPM limit for the EPA to assume no additional upgrades are needed to meet a revised limit. If an EGU has previously demonstrated an ability to meet a potential lower fPM limit, but the average fPM rate is greater than the potential limit, the analysis for the final rule has been updated to assume increased bag replacement frequency (for units with FFs) or operation and maintenance costing $100,000/year (2022$). This additional cost represents increased vigilance in maintaining ESP performance and includes technician labor to monitor performance of the ESP and to periodically make typical repairs (*e.g.,* replacement of failed insulators, damaged electrodes or other internals that may fail, repairing leaks in the ESP casing, ductwork, or expansion joints, and periodic testing of ESP flow balance and any needed adjustments).

Additionally, the Agency received comments that the PM upgrade costs estimated at proposal were too high on a dollar per ton basis and these costs have been updated and are provided in the 2024 Technical Memo. Specifically, commenters demonstrated that the observed percent reductions in fPM attributable to ESP upgrades were significantly greater than the percent reductions that the EPA had assumed for the proposed rule. Additionally, commenters demonstrated that ESP performance guarantees for coal-fired utility boilers were much lower than the EPA was aware of at proposal. These updates, as well as improving our methodology which increases the number of EGUs estimated to need PM upgrades, slightly lower the dollar per ton estimates from what was presented in the 2023 Proposal.

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).[52] As much of the

[52] See, *e.g., National Emission Standards for Hazardous Air Pollutants: Mercury Cell Chlor-Alkali Plants Residual Risk and Technology Review,* 87 FR 27002, 27008 (May 6, 2022) (considered annual costs and average capital costs per facility in technology review and beyond-the-floor analysis); *National Emission Standards for Hazardous Air Pollutants: Primary Copper Smelting Residual Risk and Technology Review and Primary Copper Smelting Area Source Technology Review,*

fleet is already reporting fPM emission rates below 0.010 lb/MMBtu, both the total costs and non-Hg HAP metal reductions of the revised limit are modest in context of total PM upgrade control costs and emissions of the coal fleet. The cost-effectiveness estimate for EGUs reporting average fPM rates above the final fPM emission limit of 0.010 lb/MMBtu is $10,500,000/ton of non-Hg HAP metals, slightly lower than the range presented in the 2023 Proposal.

Further, the EPA finds that costs for facilities to meet the revised fPM emission limit represent a 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 Final Rule relative to the typical annual revenues, capital expenditures, and total (capital and production) expenditures.[53] 87 FR 7648–7659 (February 9, 2022); 80 FR 37381 (June 30, 2015). Using electricity sales data from the U.S. Energy Information Administration (EIA), the EPA updated the analysis presented in the 2022 Proposal. We find revenues from retail electricity sales increased from $333.5 billion in 2000 to a peak of $429.6 billion in 2008 (an increase of about 29 percent during this period) and slowly declined since to a post-2011 low of $388.6 billion in 2020 (a decrease of about 10 percent from its peak during this period) in 2019 dollars.[54] Revenues increased in 2022 to nearly the same amount as the 2008 peak ($427.8 billion). The annual control cost estimate for the final fPM standard based on the cost-effectiveness analysis in table 4 (see section 1c of the 2024 Technical Memo) of this document is a very small share of total power sector sales (about 0.03 percent of the lowest year 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 estimates. Therefore, as in previous CAA section 112 rulemakings, the EPA considered costs in many ways, including cost effectiveness, the total capital costs of proposed measures, annual costs, and costs compared to total revenues to determine the appropriateness of the revised fPM standard under the CAA section 112(d)(6) technology review, and determined the costs are reasonable.

In this final rule, the EPA finds that costs of the final fPM standard are reasonable, and that the revised fPM standard appropriately balances the EPA's obligation under CAA section 112 to achieve the maximum degree of emission reductions considering statutory factors, including costs. Further, the EPA finds that its consideration of costs is consistent with D.C. Circuit precedent, which has found that CAA section 112(d)(2) expressly authorizes cost consideration in other aspects of the standard-setting process, such as CAA section 112(d)(6), *see Association of Battery Recyclers, Inc.* v. *EPA,* 716 F.3d 667, 673–74 (D.C. Cir. 2013), and that CAA section 112 does not mandate a specific method of cost analysis in an analogous situation when considering the beyond-the-floor review. *See NACWA* v. *EPA,* 734 F.3d 1115, 1157 (D.C. Cir. 2013) (finding the statute did not ''mandate a specific method of cost analysis''); *see also NRDC* v. *EPA,* 749 F.3d 1055, 1060–61 (D.C. Cir. 2014).

As discussed in section IV.C.1. in response to comments regarding the relatively higher dollar per ton cost effectiveness of the final fPM standard, the EPA finds that in the context of this industry and this rulemaking, the updated standards are an appropriate exercise of the EPA's standard setting authority pursuant to the CAA section 112(d)(6) technology review. As commenters rightly note, the EPA routinely considers the cost effectiveness of potential standards where it can consider costs under CAA section 112, *e.g.,* in conducting beyond-the-floor analyses and technology reviews, to determine the achievability of a potential control option. And the D.C. Circuit recognized that the EPA's interpretation of costs as ''allowing consideration of cost effectiveness was reasonable.'' *NRDC* v. *EPA,* 749 F.3d 1055, 1060–61 (D.C. Cir. 2014) (discussing the EPA's consideration of cost effectiveness pursuant to a CAA section 112(d)(2) beyond-the-floor analysis). However, cost effectiveness is not the sole factor that the EPA considers when determining the achievability of a potential standard in conducting a technology review, nor is cost effectiveness the only value that the EPA considers with respect to costs.[55] Some commenters pointed to other rulemakings (which are discussed in section IV.C.1. above) where the EPA determined not to pursue potential control options with relatively higher cost-effectiveness estimates as compared to prior CAA section 112 rulemakings. However, there were other factors that the EPA considered, in addition to cost effectiveness, that counseled against pursuing such updates. In this rulemaking, the EPA finds that several factors discussed throughout this record make promulgation of the new fPM standard appropriate under CAA section 112(d)(6). First, a wide majority of units have invested in the most-effective PM controls and are already demonstrating compliance with the new fPM standard and at lower costs than assumed during promulgation of the original MATS fPM emission limit. Of the 33 EGUs that the EPA estimated would require control improvements to meet a 0.010 lb/MMBtu fPM standard, only two are not using the most effective PM control technologies available. The EPA assumed that these two units would need to install FFs to achieve the 0.010 lb/MMBtu emission standard, and the cost of those FF retrofits accounts for 42 percent of the total annualized costs presented in table 4. Further, 11 EGUs that the EPA assumed would require different levels of ESP upgrades to meet the 0.010 lb/MMBtu emission standard (all of which have announced retirement dates between 2031 and 2042 resulting in shorter assumed amortization periods) account for about 57 percent of the total annualized costs. The remaining 1 percent of the total annualized costs are associated with 10 EGUs with existing FFs that the EPA

87 FR 1616, 1635 (proposed January 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 RTR and Standards of Performance for Phosphate Processing,* 80 FR 50386, 50398 (August 19, 2015) (considered total annual costs and capital costs compliance costs and annualized costs for technology review and beyond the floor analysis); *National Emissions Standards for Hazardous Air Pollutants: 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); *National Emission Standards for Hazardous Air Pollutants: Off-Site Waste and Recovery Operations,* 80 FR 14248, 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); *National Emission Standards for Hazardous Air Pollutant Emissions: Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks; and Steel Pickling-HCl Process Facilities and Hydrochloric Acid Regeneration Plants,* 77 FR 58220, 58226 (September 19, 2012) (considered total annual costs and capital costs in technology review); *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews,* 77 FR 49490, 49523 (August 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).

[53] See Cost TSD for 2022 Proposal at Document ID No. EPA–HQ–OAR–2018–0794–4620 at *https://www.regulations.gov.*

[54] 2019 dollars were used for consistency with the 2023 Proposal.

[55] See note 50, above, for examples of other costs metrics the EPA has considered in prior CAA section 112 rulemakings.

assumes will require bag upgrades or increased bag changeouts and 10 EGUs that are assumed to need additional operation and maintenance of existing ESPs, which is further explained in the 2024 Technical Memo. Since only a small handful of units emit significantly more than peer facilities, the Agency finds these upgrades appropriate. Additionally, the size and unique nature of the coal-fired power sector, and the emission reductions that will be achieved by the new standard, in addition to the costs, make promulgation of the new standard appropriate under CAA section 112(d)(6).

The power sector also operates differently than other industries regulated under CAA section 112.[56] For example, the power sector is publicly regulated, with long-term decision-making and reliability considerations made available to the public; it is a data-rich sector, which generally allows the EPA access to better information to inform its regulation; and the sector is in the midst of an energy generation transition leading to plant retirements that are independent of EPA regulation. Because of the relative size of the power sector, while cost effectiveness of the final standard is relatively high as compared to prior CAA section 112 rulemakings involving other industries, costs represent a much smaller fraction of industry revenue. In the likely case that the power sector's transition to lower-emitting generation is accelerated by the IRA, for example, the total costs and emission reductions achieved by each final fPM standard in table 4 of this document would also be an overestimate.

As demonstrated in the proposal, the power sector, as a whole, is achieving fPM emission rates that are well below the 0.030 lb/MMBtu standard from the 2012 Final MATS Rule, with the exception of a few outlier facilities. The EPA estimates that only one facility (out of the 151 evaluated coal-fired facilities), which does not have the most modern PM pollution controls and has been unable to demonstrate an ability to meet a lower fPM limit, will be required to install the most-costly upgrade to meet the revised standards, which significantly drives up the cost of this final rule. However, the higher costs for one facility to install demonstrated improvements to its control technology should not prevent the EPA from establishing achievable standards for the sector under the EPA's CAA section 112(d)(6) authority. Instead, the EPA finds that it is consistent with its CAA section 112(d)(6) authority to consider the performance of the industry at large. The average fPM emissions of the industry demonstrate the technical feasibility of higher emitting facilities to meet the new standard and shows there are proven technologies that if installed at these units will allow them to significantly lower fPM and non-Hg HAP metals emissions.

In this rulemaking, the EPA also determined not to finalize a more stringent standard for fPM emissions, such as a limit of 0.006 lb/MMBtu or lower, which the EPA took comment on in the 2023 Proposal. The EPA declines to finalize an emission standard of 0.006 lb/MMBtu or lower primarily due to technical limitations in using PM CEMS for compliance demonstration purposes described in the next section. The EPA has determined that a fPM emission standard of 0.010 lb/MMBtu is the lowest that would also allow the use of PM CEMS for compliance demonstration. Additionally, the EPA also considered the overall higher costs associated with a more stringent standard as compared to the final standard, which the EPA considered under the technology review.

Additionally, compliance with a fPM emission limit of 0.006 lb/MMBtu could only be demonstrated using periodic stack testing that would require test run durations longer than 4 hours[57] and would not provide the source, the public, and regulatory authorities with continuous, transparent data for all periods of operation. Establishing a fPM limit of 0.006 lb/MMBtu while maintaining the current compliance demonstration flexibilities of quarterly ''snapshot'' stack testing would, theoretically, result in greater emission reductions; however, the measured emission rates are only representative of rates achieved at optimized conditions at full load. While coal-fired EGUs have historically provided baseload generation, they are being dispatched much more as load following generating sources due to the shift to more available and cheaper natural gas and renewable generation. As such, traditional generation assets—such as coal-fired EGUs—will likely continue to have more startup and shutdown periods, more periods of transient operation as load following units, and increased operation at minimum levels, all of which can produce higher PM emission rates. Maintaining the status quo with quarterly stack testing will likely mischaracterize emissions during these changing operating conditions. Thus, while a fPM emission limit of 0.006 lb/MMBtu paired with use of quarterly stack testing may appear to be more stringent than the 0.010 lb/MMBtu standard paired with use of PM CEMS that the EPA is finalizing in this rule, there is no way to confirm emission reductions during periods in between quarterly tests when emission rates may be higher. Therefore, the Agency is finalizing a fPM limit of 0.010 lb/MMBtu with the use of PM CEMS as the only means of compliance demonstration. The EPA has determined that this combination of fPM limit and compliance demonstration represents the most stringent available option taking into account the statutory considerations.

The EPA also determined not to finalize a fPM standard of 0.015 lb/MMBtu, which the EPA took comment on in the 2023 Proposal, because the EPA determined that a standard of 0.010 lb/MMBtu is appropriate for the reasons discussed above.

In this rule, the EPA is also reaching a different conclusion from the 2020 Technology Review with respect to the fPM emission standard and requirements to utilize PM CEMS. As discussed in section II.D. above, the 2020 Technology Review did not consider developments in the cost and effectiveness of proven technologies to control fPM as a surrogate for non-Hg HAP metals emissions, nor did the EPA evaluate the current performance of emission reduction control equipment and strategies at existing MATS-affected EGUs. In this rulemaking, in which the EPA reviewed the findings of the 2020 Technology Review, the Agency determined there are important developments regarding the emissions performance of the coal-fired EGU fleet, and the costs of achieving that performance that are appropriate for the EPA to consider under its CAA section 112(d)(6) authority, and which are the basis for the revised emissions standards the EPA is promulgating through this final rule.

The 2012 MATS Final Rule contains emission limits for both individual and total non-Hg HAP metals (*e.g.,* lead, arsenic, chromium, nickel, and cadmium), as well as emission limits for fPM. Those non-Hg HAP metals

[56] This is a fact which Congress recognized in requiring the EPA to first determine whether regulation of coal-fired EGUs was ''appropriate and necessary'' under CAA section 112(n)(1)(A) before proceeding to regulate such facilities under CAA section 112's regulatory scheme.

[57] Run durations greater than 4 hours would ensure adequate sample collection and lower random error contributions to measurement uncertainty for a limit of 0.006 lb/MMBtu. The EPA aims to keep run durations as short as possible, generally at least one but no more than 4 hours in length, in order to minimize impacts to the facility (*e.g.,* overall testing campaign testing costs, employee focused attention and safety).

emission limits serve as alternative emission limits because fPM was found to be a surrogate for either individual or total non-Hg HAP metals emissions. While EGU owners or operators may choose to demonstrate compliance with either the individual or total non-Hg HAP metals emission limits, the EPA is aware of just one owner or operator who has provided non-Hg HAP metals data—both individual and total—along with fPM data, for compliance demonstration purposes. This is for a coal refuse-fired EGU with a generating capacity of 46.1 MW. Given that owners or operators of all the other EGUs that are subject to the requirements in MATS have chosen to demonstrate compliance with only the fPM emission limit, the EPA proposed to remove the total and individual non-Hg HAP metals emission limits from all existing MATS-affected EGUs and solicited comment on our proposal. In the alternative, the EPA took comment on whether to retain total and/or individual non-Hg HAP metals emission limits that have been lowered proportionally to the revised fPM limit (*i.e.,* revised lower by two-thirds to be consistent with the revision of the fPM standard from 0.030 lb/MMBtu to 0.010 lb/MMBtu).

Commenters urged the EPA to retain the non-Hg HAP metals limits, arguing it is incongruous for the EPA to eliminate the measure for the pollutants that are the subject of regulation under CAA section 112(d)(6), notwithstanding the fact that the fPM limit serves as a more easily measurable surrogate for these HAP metals. Additionally, some commenters stated that the inability to monitor HAP metals directly will significantly impair the EPA's ability to revise emission standards in the future.

After considering comments, the EPA determined to promulgate revised total and individual non-Hg HAP metals emission limits for coal-fired EGUs that are lowered proportionally to the revised fPM standard. Just as this rule requires owners or operators to demonstrate continuous compliance with fPM limits, owners or operators who choose to demonstrate compliance with these alternative limits will need to utilize approaches that can measure non-Hg HAP metals on a continuous basis—meaning that intermittent emissions testing using Reference Method 29 will not be a suitable approach. Owners or operators may petition the Administrator to utilize an alternative test method that relies on continuous monitoring (*e.g.,* multi-metal CMS) under the provisions of 40 CFR 63.7(f). The EPA disagrees with the suggestion that failure to monitor HAP metals directly could impair the ability to revise those standards in the future.

2. Rationale for the Final Compliance Demonstration Options

In the 2023 Proposal, the EPA proposed to require that coal- and oil-fired EGUs utilize PM CEMS to demonstrate compliance with the fPM standard used as a surrogate for non-Hg HAP metals. The EPA proposed the requirement for PM CEMS based on its assessment of costs of PM CEMS versus stack testing, and the many other benefits of using PM CEMS including increased transparency and accelerated identification of anomalous emissions. In particular, the EPA noted the ability for PM CEMS to provide continuous feedback on control device and plant operations and to provide EGU owners and operators, regulatory authorities, and members of nearby communities with continuous assurance of compliance with emissions limits as an important benefit. Further, the EPA explained in the 2023 Proposal that PM CEMS are currently in use by approximately one-third of the coal-fired fleet, and that PM CEMS can provide low-level measurements of fPM from existing EGUs.

After considering comments and conducting further analysis,[58] the EPA is finalizing the use of PM CEMS for compliance demonstration purposes for coal- and oil-fired EGUs pursuant to its CAA section 112(d)(6) authority. As discussed in section IV.D.1. above, Congress intended for CAA section 112 to achieve significant reductions in HAP, which it recognized as particularly harmful pollutants. The EPA finds that the benefits of PM CEMS to provide real-time information to owners and operators (who can promptly address any problems with emissions control equipment), to regulators, to adjacent communities, and to the general public, further Congress's goal to ensure that emission reductions are consistently maintained. The EPA determined not to require PM CEMS for existing IGCC EGUs, described in section VI.D., due to technical issues calibrating CEMS on these types of EGUs due to the difficulty in preparing a correlation range because these EGUs are unable to de-tune their fPM controls and their existing emissions are less than one-tenth of the final emission limit. Further, the EPA finds additional authority to require the use of PM CEMS under CAA section 114(a)(1)(C), which allows that the EPA may require a facility that ''may have information necessary for the purposes set forth in this subsection, or who is subject to any requirement of this chapter'' to ''install, use, and maintain such monitoring equipment'' on a ''on a one-time, periodic or continuous basis.'' 114(a)(1)(C).

From the EPA's review of PM CEMS, the Agency determined that a fPM standard of 0.010 lb/MMBtu with adjusted QA criteria—used to verify consistent correlation of CEMS data initially and over time—is the lowest fPM emission limit possible at this time with use of PM CEMS.[59] PM CEMS correlated using these values will ensure accurate measurements—either above, at, or below this emission limit. As discussed in section IV.D.1. above, one of the reasons the EPA determined not to finalize a more stringent standard for fPM is because it would prove challenging to verify accurate measurement of fPM using PM CEMS. Specifically, as mentioned in the *Suitability of PM CEMS Use for Compliance Determination for Various Emission Levels,* memorandum, available in the docket, no fPM standard more stringent than 0.010 lb/MMBtu with adjusted QA criteria is expected to have acceptable passing rates for the QA checks or acceptable random error for reference method testing.

At proposal, the EPA estimated that the EUAC of PM CEMS was $60,100 (88 FR 24873). Based on comments the EPA received on the costs and capabilities of PM CEMS and additional analysis the EPA conducted, the EPA determined that the revised EUAC of PM CEMS is higher than estimated at proposal. The EPA now estimates that the EUAC of non-beta gauge PM CEMS is $72,325, which is 17 percent less than what was estimated for the 2012 MATS Final Rule. That amount is somewhat greater than the revised estimated costs of infrequent emission testing (generally quarterly)—the revised average estimated costs of such infrequent emissions testing using EPA Method 5I[60] is $60,270.[61]

In choosing a compliance demonstration requirement, the EPA considers multiple factors, including

[58] The EPA explains additional analyses of PM CEMS in the memos titled *Suitability of PM CEMS Use for Compliance Determination for Various Emissions Levels* and *Summary of Review of 36 PM CEMS Performance Test Reports versus PS11 and Procedure 2 of 40 CFR part 60, appendices B and F, respectively,* which are available in the docket.

[59] The EPA notes that the fPM standard [0.010 lb/MMBtu] is based on hourly averages obtained from PM CEMS over 30 boiler operating days [see 40 CFR 63.10021(b)].

[60] Method 5I is one of the EPA's reference test methods for PM. See 40 CFR part 60, appendix A.

[61] See *Revised Estimated Non-Beta Gauge PM CEMS and Filterable PM Testing Costs* memorandum, available in the docket.

costs, benefits of the compliance technique, technical feasibility and commercial availability of the compliance method, ability of personnel to conduct the compliance method, and continuity of data used to assure compliance. PM CEMS are readily available and in widespread use by the electric utility industry, as evidenced by the fact that over 100 EGUs already utilize PM CEMS for compliance demonstration purposes. Moreover, the electric utility industry and its personnel have demonstrated the ability to install, operate, and maintain numerous types of CEMS—including PM CEMS. As mentioned earlier, EGU owners and/or operators who chose PM CEMS for compliance demonstration have attested in their submitted reports to the suitability of their PM CEMS to measure at low emission levels, certifying fPM emissions lower than 0.010 lb/MMBtu with their existing correlations developed using emission levels at 0.030 lb/MMBtu. The EPA conducted a review of eight EGUs with varying fPM control devices that rely on PM CEMS that showed certified emissions ranging from approximately 0.002 lb/MMBtu to approximately 0.007 lb/MMBtu. The EPA's review analyzed 30 boiler operating day rolling averages obtained from reports posted to WebFIRE for the third quarter of 2023 from these eight EGUs.[62]

As described in the *Summary of Review of 36 PM CEMS Performance Test Reports versus PS11 and Procedure 2 of 40 CFR part 60, Appendices B and F* memorandum, available in the docket, the EPA investigated how well a sample of EGUs using PM CEMS for compliance purposes would meet initial and ongoing QA requirements at various emission limit levels, even though no change in actual EGU operation occurred. As described in the aforementioned *Suitability of PM CEMS Use for Compliance Determination for Various Emission Levels* memorandum, as the emission limit is lowered, the ability to meet both components necessary to correlate PM CEMS—acceptable random error and QA passing rate percentages—becomes more difficult. Based on this additional analysis and review, the EPA determined to finalize requirements to use PM CEMS with adjusted QA criteria and a 0.010 lb/MMBtu fPM emission limit as the most stringent limit possible with PM CEMS.

Use of PM CEMS can provide EGU owners or operators with an increased ability to detect and correct potential problems before degradation of emission control equipment, reduction or cessation of electricity production, or exceedances of regulatory emission standards. As mentioned in the *Ratio of Revised Estimated Non-Beta Gauge PM CEMS EUAC to 2022 Average Coal-Fired EGU Gross Profit* memorandum, using PM CEMS can be advantageous, particularly since their EUAC is offset if their use allows owners or operators to avoid 3 or more hours of generating downtime per year.

In deciding whether to finalize the proposal to use PM CEMS as the only compliance demonstration method for non-IGCC coal- and oil-fired EGUs, the Agency assessed the costs and benefits afforded by requiring use of only PM CEMS as compared to continuing the current compliance demonstration flexibilities (*i.e.,* allowing use of either PM CEMS or infrequent PM emissions stack testing). As mentioned above, the average annual cost for quarterly stack testing provided by commenters is about $12,000 less than the EUAC for PM CEMS. While no estimate of quantified benefits was provided by commenters, the EPA recognizes that the 35,040 15-minute values provided by a PM CEMS used at an EGU operating during a 1-year period is over 243 times as much information as is provided by quarterly testing with three 3-hour run durations. This additional, timely information provided by PM CEMS affords the adjacent communities, the general public, and regulatory authorities with assurances that emission limits and operational processes remain in compliance with the rule requirements. It also provides EGU owners or operators with the ability to quickly detect, identify, and correct potential control device or operational problems before those problems become compliance issues. When establishing emission standards under CAA section 112, the EPA must select an approach to compliance demonstration that best assures compliance is being achieved.

The continuous monitoring of fPM required in this rule provides several benefits which are not quantified in this rule, including greater certainty, accuracy, transparency, and granularity in fPM emissions information than exists today. Continuous measurement of emissions accounts for changes to processes and fuels, fluctuations in load, operations of pollution controls, and equipment malfunctions. By measuring emissions across all operations, power plant operators and regulators can use the data to ensure controls are operating properly and to assess compliance with relevant standards. Because CEMS enable power plant operators to quickly identify and correct problems with pollution control devices, it is possible that continuous monitoring could lead to lower fPM emissions for periods of time between otherwise required intermittent testing, currently up to 3 years for some units.

To illustrate the potentially substantial differences in fPM emissions between intermittent and continuous monitoring, the EPA analyzed emissions at several EGUs for which both intermittent and continuous monitoring data are available. This analysis is provided in the 2024 Technical Memo, available in the rulemaking docket. For example, one 585-MW bituminous-fired EGU, with a cold-side ESP for PM control, has achieved LEE status for fPM and is currently required to demonstrate compliance with an emission standard of 0.015 lb/MMBtu using intermittent stack testing every 3 years. In the most recent LEE compliance report, submitted on February 25, 2021, the unit submitted the result of an intermittent stack test with an emission rate of 0.0017 lb/MMBtu. In the subsequent 36 months over which this unit is currently not subject to any further compliance testing, continuous monitoring demonstrates that the fPM emission rate increased substantially. At one point, the continuously monitored 30-day rolling average emissions rate[63] was nine times higher than the intermittent stack test average, reaching the fPM LEE limit of 0.015 lb/MMBtu. In this example, the actual continuously monitored daily average emissions rate over the February 2021 to April 2023 period ranged from near-zero to 0.100 lb/MMBtu. Emissions using either the stack test average or hourly PM CEMS data were calculated for 2022 for this unit. Both approaches indicate fPM emissions well below the allowable levels for a fPM limit of 0.010 lb/MMBtu, while estimates using PM CEMS are about 2.5 times higher than the stack test estimate. Additional examples of differences between intermittent stack testing and continuous monitoring are provided in the 2024 Technical Memo, including for periods when PM CEMS data is lower

[62] See Third Quarter 2023 p.m. CEMS Thirty Boiler Operating Day Rolling Average Reports for Iatan Generating Station units 1 and 2, Missouri; Marshall Steam Station units 1 and 3, North Carolina; Kyger Creek Station unit 3, Ohio; Virginia City Hybrid Energy Center units 1 and 2, Virginia; and Ghent Generating Station unit 1, Kentucky. These reports are available electronically by searching in the WebFIRE Report Search and Retrieval portion of the Agency's WebFIRE internet website at *https://cfpub.epa.gov/webfire/reports/esearch.cfm.*

[63] The 30-day rolling average emission rate was calculated by taking daily fPM rate averages over a 30-day operating period while filtering out hourly fPM data during periods of startup and shutdown.

than the stack test averages,[64] which further illustrate real-life scenarios in which fPM emissions for compliance methods may be substantially different.

The potential reduction in fPM and non-Hg HAP metals emission resulting from the information provided by continuous monitoring coupled with corrective actions by plant operators could be sizeable over the total capacity that the EPA estimates would install PM CEMS under this rule (nearly 82 GW). Furthermore, the potential reduction in non-Hg HAP metal emissions would likely reduce exposures to people living in proximity to the coal-fired EGUs potentially impacted by the amended fPM standards. The EPA has found that populations living near coal-fired EGUs have a higher percentage of people living below two times the poverty level than the national average.

In addition to significant value of further pollution abatement, the CEMS data are transparent and accessible to regulators, stakeholders, and the public, fostering greater accountability. 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. This transparency is facilitated by a requirement for electronic reporting of fPM emissions data by the source to the EPA. This emissions data, once submitted, becomes accessible and downloadable—along with other operational and emissions data (*e.g.,* for SO_2, CO_2, NO_X, Hg, *etc.*) for each covered source.

On balance, the Agency finds that the benefits of emissions transparency and the continuous information stream provided by PM CEMS coupled with the ability to quickly detect and correct problems outweigh the minor annual cost differential from quarterly stack testing. The EPA is finalizing, as proposed, the use of PM CEMS to demonstrate compliance with the fPM emission standards for coal- and oil-fired EGUs (excluding IGCC units and limited-use liquid-oil-fired EGUs).

More information on the proposed technology review can be found in the 2023 Technical Memo (Document ID No. EPA–HQ–OAR–2018–0794–5789), in the preamble for the 2023 Proposal (88 FR 24854), and the 2024 Technical Memo, available in the docket. For the reasons discussed above, pursuant to CAA section 112(d)(6), the EPA is finalizing, as proposed, the use of PM CEMS (with adjusted QA criteria as a result of review of comments) for the compliance demonstration of the fPM emission standard (as a surrogate for non-Hg HAP metal) for coal- and oil-fired EGUs, and the removal of the fPM and non-Hg HAP metals LEE provisions.

V. What is the rationale for our final decisions and amendments to the Hg emission standard for lignite-fired EGUs from review of the 2020 Technology Review?

A. What did we propose pursuant to CAA section 112(d)(6) for the lignite-fired EGU subcategory?

In the 2012 MATS Final Rule, the EPA finalized a Hg emission standard of 4.0E-06 lb/MMBtu (4.0 lb/TBtu) for a subcategory of existing lignite-fired EGUs.[65] The EPA also finalized a Hg emission standard of 1.2E-06 lb/MMBtu (1.2 lb/TBtu) for coal-fired EGUs not firing lignite (*i.e.,* for EGUs firing anthracite, bituminous coal, subbituminous coal, or coal refuse); and the EPA finalized a Hg emission output-based standard for new lignite-fired EGUs of 0.040 lb/GWh and a Hg emission output-based standard for new non-lignite-fired EGUs of 2.0E-04 lb/GWh. In 2013, the EPA reconsidered the Hg emission standard for new non-lignite-fired EGUs and revised the output-based standard to 0.003 lb/GWh (see 78 FR 24075).

As explained in the 2023 Proposal, Hg emissions from the power sector have declined since promulgation of the 2012 MATS Final Rule with the installation of Hg-specific and other control technologies and 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). However, units burning lignite (or permitted to burn lignite) accounted for a disproportionate amount of the total Hg emissions in 2021. As shown in table 5 in the 2023 Proposal (88 FR 24876), 16 of the top 20 Hg-emitting EGUs in 2021 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.

Prior to the 2023 Proposal, the EPA assembled information on developments in Hg emission rates and installed controls at lignite-fired EGUs from operational and emissions information that is provided routinely to the EPA for demonstration of compliance with MATS and from information provided to the EIA. In addition, the EPA's final decisions were informed by information that was submitted as part of a CAA section 114 information survey (2022 ICR). The EPA also revisited information that was used in establishing the emission standards in the 2012 Final MATS Rule and considered information that was submitted during the public comment period for the 2023 Proposal. From that information, the EPA determined, as explained in the 2023 Proposal, that there are available cost-effective control technologies and improved methods of operation that would allow existing lignite-fired EGUs to achieve a more stringent Hg emission standard. As such, the EPA proposed a revised Hg emission standard for existing EGUs firing lignite (*i.e.,* for those in the ''units designed for low rank virgin coal'' subcategory). Specifically, the EPA proposed that such lignite-fired units must meet the same emission standard as existing EGUs firing other types of coal (*e.g.,* anthracite, bituminous coal, subbituminous coal, and coal refuse), which is 1.2 lb/TBtu (or an alternative output-based standard of 0.013 lb/GWh). The EPA did not propose to revise the Hg emission standards either for existing EGUs firing non-lignite coal or for new non-lignite coal-fired EGUs.[66]

B. How did the technology review change for the lignite-fired EGU subcategory?

The outcome of the technology review for the Hg standard for existing lignite-fired EGUs has not changed since the 2023 Proposal. However, in response to comments, the EPA expanded its review to consider additional coal compositional data and the impact of sulfur trioxide (SO_3) in the flue gas.

[64] See Case Study 2 in the 2024 Technical Memo, which shows long time periods of PM CEMS data below the most recent RRA. Note this unit uses PM CEMS for compliance with the fPM standard, so the RRA is used as an indicator of stack test results.

[65] The EPA referred to this subcategory in the final rule as ''units designed for low rank virgin coal.'' The EPA went on to specify that such a unit is designed to burn and 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) and that is constructed and operates at or near the mine that produces such coal. The EPA also finalized an alternative output-based emission standard of 0.040 lb/GWh. Currently, the approximately 22 units that are permitted as lignite-fired EGUs are located exclusively in North Dakota, Texas, and Mississippi.

[66] As stated in the 2023 Proposal, when proposed revisions to existing source emission standards are more stringent than the corresponding new source emission standard, the EPA proposes to revise the corresponding new source standard to be at least as stringent as the proposed revision to the existing source standard. This is the case with the Hg emission standard for new lignite-fired sources, which will be adjusted to be as stringent as the existing source standard.

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

The Agency received both supportive and critical comments on the proposed revision to the Hg emission standard for existing lignite-fired EGUs. Some commenters agreed with the EPA's decision to not propose revisions to the Hg emission standards for non-lignite-fired EGUs, while others disagreed. Significant comments are summarized below, and the Agency's responses are provided.

Comment: Several commenters stated that industry experience confirms that stringent limits on power plant Hg emissions can be readily achieved at lower-than-predicted costs and thus should be adopted nationally through CAA section 112(d)(6). They said that at least 14 states have, for years, enforced state-based limits on power plant Hg emissions, and nearly every one of those states has imposed more stringent emission limits than those proposed in this rulemaking or in the final 2012 MATS Final Rule. The commenters said that these lower emissions limits have resulted in significant and meaningful Hg emission reductions, which have proven to be both achievable and cost-effective.

Some commenters recommended that the EPA revise the Hg limits to levels that are much more stringent than existing or proposed standards for both EGUs firing non-lignite coals and those firing lignite. They claimed that more stringent Hg emission standards are supported by developments in practices, processes, and control technologies. They pointed to a 2021 report by Andover Technology Partners, which details advances in control technologies that support more stringent Hg standards for all coal-fired EGUs.[67] These advances include advanced activated carbon sorbents with higher capture capacity at lower injection rates and carbon sorbents that are tolerant of flue gas species.

Response: The EPA has taken these comments and the referenced information into consideration when establishing the final emission standards. The EPA disagrees that the Agency should, in this final rule, revise the Hg limits for all coal-fired EGUs to levels more stringent than the current or proposed standards. The Agency did not propose in the 2023 Proposal to revise the Hg emission standard for ''not-low-rank coal units'' (*i.e.,* those EGUs that are firing on coals other than lignite) and did not suggest an emission standard for lignite-fired EGUs more stringent than the 1.2 lb/TBtu emission standard that was proposed. However, the EPA will continue to review emission standards and other rule requirements as part of routine CAA section 112(d)(6) technology reviews, which are required by statute to be conducted at least every 8 years. If we determine in subsequent CAA section 112(d)(6) technology reviews that further revisions to Hg emission standards (or to standards for other HAP or surrogate pollutants) are warranted, then we will propose revisions at that time. We discuss the rationale for the final emission standards in section V.D. of this preamble and in more detail in the 2024 Technical Memo.

Comment: Several commenters challenged the data that the EPA used in the CAA 112(d)(6) technology review. Commenters stated that the information collected by the EPA via the CAA section 114 request consisted of 17 units each submitting two 1-week periods of data and associated operational data preselected by the EPA, and that only a limited number of the EGUs reported burning only lignite. Other EGUs reported burning primarily refined coal, co-firing with natural gas, and firing or co-firing with large amounts of subbituminous coal (referencing table 7 in the 2023 Proposal). Commenters stated that if the EPA's intent was to assess the Hg control performance of lignite-fired EGUs, then the EGUs evaluated should have burned only lignite, not refined coal, subbituminous coal, or natural gas.

Response: The EPA disagrees with the commenters' argument that the Agency should have only considered emissions and operational data from EGUs that were firing only lignite. The EPA's intent was to evaluate the Hg emission control performance of units that are permitted to burn lignite and are thus subject to a Hg emission standard of 4.0 lb/TBtu. According to fuel use information supplied to EIA on form 923,[68] 13 of 22 EGUs that were designed to burn lignite utilized ''refined coal'' to some extent in 2021, as summarized in table 7 in the 2023 Proposal preamble (88 FR 24878). EIA form 923 does not specify the type of coal that is ''refined'' when reporting boiler or generator fuel use. For the technology review, the EPA assumed that the facilities utilized ''refined lignite,'' as reported in fuel receipts on EIA form 923. In any case, firing of refined lignite or subbituminous coal or co-firing with natural gas or fuel oil are considered to be Hg emission reduction strategies for a unit that is subject to an emission standard of 4.0 lb/TBtu, which was based on the use of lignite as its fuel.

In a related context, in *U.S. Sugar Corp.* v. *EPA,* the D.C. Circuit held that the EPA could not exclude unusually high performing units within a subcategory from the Agency's determination of MACT floor standards for a subcategory pursuant to CAA section 112(d)(3). 830 F.3d 579, 631–32 (D.C. Cir. 2016) (finding ''an unusually high-performing source should be considered[,]'' in determining MACT floors for a subcategory, and that ''its performance suggests that a more stringent MACT standard is appropriate.''). While the technology review at issue here is a separate and distinct analysis from the MACT floor setting requirements at issue in *U.S. Sugar* v. *EPA,* similarly here the EPA finds it is appropriate to consider emissions from all units that are permitted to burn lignite and are therefore subject to the prior Hg emission standard of 4.0 lb/TBtu and are part of the lignite-fired EGU subcategory, for the purposes of determining whether more stringent standards are appropriate under a technology review. However, while the EPA has considered the emissions performance of all units within the lignite-fired EGU subcategory, it is not the performance of units that are firing or co-firing with other non-lignite fuels that provide the strongest basis for the more stringent standard. Rather, the most convincing evidence to support the more stringent standard is that there are EGUs that are permitted to fire lignite—and are only firing lignite—that have demonstrated an ability to meet the more stringent standard of 1.2 lb/TBtu.

Comment: Several commenters claimed that, rather than using actual measured Hg concentrations in lignite that had been provided in the CAA section 114 request responses (and elsewhere), the EPA used Integrated Planning Model (IPM) data to assign inlet Hg concentrations to various lignite-fired EGUs. Some commenters asserted that the actual concentration of Hg in lignite is higher than those assumed by the EPA and that there is considerable variability in the concentration of Hg in the lignite used in these plants. As a result, the commenters claimed, the percent Hg capture needed to achieve the proposed 1.2 lb/TBtu emission standard would be higher than that assumed by the EPA in the 2023 Proposal.

[67] Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants. Andover Technology Partners. August 19, 2021. Document ID No. EPA–HQ–OAR–2018–0794–4583.

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

Response: In the 2023 Proposal, the EPA assumed a Hg inlet concentration (*i.e.,* concentration of Hg in the fuel) that reflected the maximum Hg content of the range of feedstock coals that the EPA assumes is available to each of the plants in the IPM. In response to comments received on the proposal, the EPA has modified the Hg inlet concentration assumptions for each unit to reflect measured Hg concentrations in lignite using information provided by commenters and other sources, including measured Hg concentrations in fuel samples from the Agency's 1998 Information Collection Request (1998 ICR). This is explained in additional detail below in section V.D.1. and in a supporting technical memorandum titled *1998 ICR Coal Data Analysis Summary of Findings.* However, this adjustment in the assumed concentration of Hg in the various fuels did not change the EPA's overall conclusion that there are available controls and improved methods of operation that will allow lignite-fired EGUs to meet a more stringent Hg emission standard of 1.2 lb/TBtu.

Comment: Some commenters claimed that the Agency failed to account for compositional differences in lignite as compared to those of other types of coal—especially in comparison to subbituminous coal.

Response: The EPA disagrees with these commenters. In the 2023 Proposal, the EPA emphasized the similarities between lignite and subbituminous coal—especially regarding the fuel properties that most impact the control of Hg. The EPA noted that lignite and subbituminous coal are both low rank coals with low halogen content and explained that the halogen content of the coal—especially chlorine—strongly influences the oxidation state of Hg in the flue gas stream and, thereby, directly influences the ability to capture and contain the Hg before it is emitted into the atmosphere. The EPA further noted that the fly ashes from lignite and subbituminous coals tend to be more alkaline (relative to that from bituminous coal) due to the lower amounts of sulfur and halogen and to the presence of a more alkaline and reactive (non-glassy) form of calcium in the ash. Due to the natural alkalinity, subbituminous and lignite fly ashes can effectively neutralize the limited free halogen in the flue gas and prevent oxidation of gaseous elemental Hg vapor (Hg^0). This lack of free halogen in the flue gas challenges the control of Hg from both subbituminous coal-fired EGUs and lignite-fired EGUs as compared to the Hg control of EGUs firing bituminous coal. The EPA noted in the 2023 Proposal, however, that control strategies and control technologies have been developed and utilized to introduce halogens to the flue gas stream, and that EGUs firing subbituminous coals have been able to meet (and oftentimes emit at emission rates that are considerably lower than) the 1.2 lb/TBtu emission standard in the 2012 MATS Final Rule. Therefore, while the EPA acknowledges that there are differences in the composition of the various coal types, there are available control technologies that allow EGUs firing any of those coal types to achieve an emission standard of 1.2 lb/TBtu. The EPA further notes that North Dakota and Texas lignites are much more similar in composition and in other properties to Wyoming subbituminous coal than either coal type is to eastern bituminous coal. Both lignite and subbituminous coal are lower heating value fuels with high alkaline content and low natural halogen. In contrast, eastern bituminous coals are higher heating value fuels with high natural halogen content and low alkalinity. But while Wyoming subbituminous coal is much more similar to lignite than it is to eastern bituminous coals, EGUs firing subbituminous coal must meet the same Hg emission standard (1.2 lb/TBtu) as EGUs firing bituminous coal. The EPA further acknowledges the differences in sulfur content between subbituminous coal and lignite and its impact is discussed in the following comment summary and response.

Comment: Some commenters claimed that the EPA did not account for the impacts of the higher sulfur content of lignite as compared to that of subbituminous coal, and that such higher sulfur content leads to the presence of additional SO_3 in the flue gas stream. The commenters noted that the presence of SO_3 is known to negatively impact the effectiveness of activated carbon for Hg control.

Response: The EPA agrees with the commenters that the Agency did not fully address the potential impacts of SO_3 on the control of Hg from lignite-fired EGUs in the 2023 Proposal. However, in response to these comments, the EPA conducted a more robust evaluation of the impact of SO_3 in the flue gas of lignite-fired EGU and determined that it does not affect our previous determination that there are control technologies and methods of operation that are available to EGUs firing lignite that would allow them to meet a Hg emission standard of 1.2 lb/TBtu—the same emission standard that must be met by EGUs firing all other types of coal. As discussed in more detail below, the EPA determined that there are commercially available advanced ''SO_3 tolerant'' Hg sorbents and other technologies that are specifically designed for Hg capture in high SO_3 flue gas environments. These advanced sorbents allow for capture of Hg in the presence of SO_3 and other challenging flue gas environments at costs that are consistent with the use of conventional pre-treated activated carbon sorbents.[69] The EPA has considered the additional information regarding the role of flue gas SO_3 on Hg control and the information on the availability of advanced ''SO_3 tolerant'' Hg sorbents and other control technologies and finds that this new information does not change the Agency's determination that a Hg emission standard of 1.2 lb/TBtu is achievable for lignite-fired EGUs.

Comment: Several commenters noted the EPA made improper assumptions to reach the conclusion that the revised Hg emissions limit is achievable and claimed that none of the 22 lignite-fired EGUs are currently in compliance with the proposed 1.2 lb/TBtu Hg emission standard and that the EPA has not shown that any EGU that is firing lignite has demonstrated that it can meet the proposed Hg emission standard.

Response: The EPA disagrees with commenters' assertion and maintains that the Agency properly determined that the proposed, more stringent Hg emission standard can be achieved, cost-effectively, using available control technologies and improved methods of operation. Further, the EPA notes that, contrary to commenters' claim, there are, in fact, EGUs firing lignite that have demonstrated an ability to meet the more stringent 1.2 lb/TBtu Hg emission standard. Twin Oaks units 1 and 2 are lignite-fired EGUs operated by Major Oak Power, LLC, and located in Robertson County, Texas. In the 2023 Proposal (see 88 FR 24879 table 8), we showed that 2021 average Hg emission rates for Twin Oaks 1 and 2 (listed in the table as Major Oak #1 and Major Oak #2) were 1.24 lb/TBtu and 1.31 lb/TBtu, respectively, which are emission rates that are just slightly above the final emission limit. Both units at Major Oak have qualified for LEE status for Hg. To demonstrate LEE status for Hg an EGU owner/operator must conduct an initial EPA Method 30B test over 30 days and follow the calculation procedures in the final rule to document a potential to emit (PTE) that is less than 10 percent of the applicable Hg emissions limit (for

[69] See Tables 8 and 9 from ''Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants'', Andover Technology Partners (August 2021); available in the rulemaking docket at Docket ID: EPA–HQ–OAR–2018–4583.

lignite-fired EGUs this would be a rate of 0.40 lb/TBtu) *or* less than 29 lb of Hg per year. If an EGU qualifies as a LEE for Hg, then the owner/operator must conduct subsequent performance tests on an annual basis to demonstrate that the unit continues to qualify. In their most recent compliance reports [70] (dated November 14, 2023), Major Oak Power, LLC, summarized the performance testing. Between August 1 and September 19, 2023, Major Oak Power, LLC, personnel performed a series of performance tests for Hg on Twin Oaks units 1 and 2. The average Hg emissions rate for the 30-boiler operating day performance tests was 1.1 lb/TBtu for unit 1 and 0.91 lb/TBtu for unit 2. The EGUs demonstrated LEE status by showing that each of the units has a Hg PTE of less than 29 lb per year. Further, in LEE demonstration testing for the previous year (2022), Major Oak Power, LLC, found that the average Hg emissions rate for the 30-boiler operating day performance test was 0.86 lb/TBtu for unit 1 and 0.63 lb/TBtu for unit 2.

In the 2023 LEE demonstration compliance report, Twin Oaks unit 1 was described as a fluidized bed boiler that combusts lignite and is equipped with fluidized bed limestone (FBL) injection for SO_2 control, selective non-catalytic reduction (SNCR) for control of nitrogen oxides (NO_X), and a baghouse (FF) for PM control. In addition, unit 1 has an untreated activated carbon injection (UPAC) system as well as a brominated powdered activated carbon (BPAC) injection system for absorbing vapor phase Hg in the effluent upstream of the baghouse. Twin Oaks unit 2 is described in the same way.

Similarly, Red Hills units 1 and 2, located in Choctaw County, Mississippi,[71] also demonstrated 2021 annual emission rates while firing lignite from an adjacent mine of 1.33 lb/TBtu and 1.35 lb/TBtu, which are reasonably close to the proposed Hg emission standard of 1.2 lb/TBtu to demonstrate achievability. In 2022, average Hg emission rates for Red Hills unit 1 and unit 2, again while firing Mississippi lignite, were 1.73 lb/TBtu and 1.75 lb/TBtu, respectively. The EPA also notes that, as shown below in table 5, lignite mined in Mississippi has the highest average Hg content—as compared to lignites mined in Texas and North Dakota.

The performance of Twin Oaks units 1 and 2 and Red Hills Generating Facility units 1 and 2 clearly demonstrate the achievability of the proposed 1.2 lb/TBtu emission standard by lignite-fired EGUs. However, even if there were no lignite-fired EGUs that are meeting (or have demonstrated an ability to meet) the more stringent Hg emission standard, that would not mean that the more stringent emission standard was not achievable. Most Hg control technologies are ''dial up'' technologies—for example, sorbents or chemical additives have injection rates that can be ''dialed'' up or down to achieve a desired Hg emission rate. In response to the EPA's 2022 CAA section 114 information request, some responding owners/operators indicated that sorbent injection rates were set to maintain a Hg emission rate below the 4.0 lb/TBtu emission limit. In some instances, operators of EGUs reported that they were not injecting any Hg sorbent and were able to meet the less stringent emission standard. Most units that are permitted to meet a Hg emission standard of 4.0 lb/TBtu have no reason to ''over control'' since doing so by injecting more sorbent would increase their operating costs. So, it is unsurprising that many units that are permitted to fire lignite have reported Hg emission rates between 3.0 and 4.0 lb/TBtu.

While most lignite-fired EGUs have no reason to ''over control'' beyond their permitted emission standard of 4.0 lb/TBtu, Twin Oaks units 1 and 2 do have such motivation. As mentioned earlier, those sources have achieved LEE status for Hg (by demonstrating a Hg PTE of less than 29 lb/yr) and they must conduct annual performance tests to show that the units continue to qualify. According to calculations provided in their annual LEE certification, to maintain LEE status, the units could emit no more than 1.79 lb/TBtu and maintain a PTE of less than 29 lb/TBtu. So, the facilities are motivated to over control beyond 1.79 lb/TBtu (which, as described earlier in this preamble, they have consistently done).

Comment: To highlight the difference in the ability of lignite-fired and subbituminous-fired EGUs to control Hg, one commenter created a table to show a comparison between the Big Stone Plant (an EGU located in South Dakota firing subbituminous coal) and Coyote Station (an EGU located in North Dakota firing lignite). Additionally, the commenter included figures showing rolling 30-boiler operating day average Hg emission rates and the daily average ACI feed rates for Big Stone and Coyote EGUs for years 2021–2022. Their table showed that Big Stone and Coyote are similarly configured plants that utilize the same halogenated ACI for Hg control. The commenters said, however, that Coyote Station's average sorbent feed rate on a lb per million actual cubic feet (lb/MMacf) basis is more than three times higher than that for Big Stone, yet Coyote Station's average Hg emissions on a lb/TBtu basis are more than five times higher than Big Stone.

Response: The EPA agrees that the Big Stone and Coyote Station units referenced by the commenter are similarly sized and configured EGUs, with the Big Stone unit in South Dakota firing subbituminous coal and the Coyote Station unit in North Dakota firing lignite. However, there are several features of the respective units that can have an impact on the control of Hg. First, and perhaps the most significant, the Big Stone unit has a selective catalytic reduction (SCR) system installed for control of NOx. The presence of an SCR is known to enhance the control of Hg—especially in the presence of chemical additives. The Coyote Station EGU does not have an installed SCR. Further, both EGUs have a dry FGD scrubber and FF baghouse installed for SO_2/acid gas and fPM control. The average sulfur content of North Dakota lignite is approximately 2.5 times greater than that of Wyoming subbituminous coal. However, the average SO_2 emissions from the Coyote Station EGU (0.89 lb/MMBtu) were approximately 10 times higher than the SO_2 emissions from the Big Stone EGU (0.09 lb/MMBtu). The Big Stone dry scrubber/FF was installed in 2015; while the dry scrubber/FF at Coyote Station was installed in 1981—approximately 31 years earlier. So, considering the presence of an SCR—which is known to enhance Hg control—and newer and better performing downstream controls, it is unsurprising that there are differences in the control of Hg at the two EGUs. In addition, since the Coyote Station has been subject to a Hg emission standard of 4.0 lb/TBtu, there would be no reason for the operators to further optimize its control system to achieve a lower emission rate. And, as numerous commenters noted, the Hg content of North Dakota is higher than that of Wyoming subbituminous coal.

Comment: Some commenters claimed that the EPA has not adequately justified a reversal in the previous policy to establish a separate subcategory for lignite-fired EGUs.

[70] See page 1–1 of the 2023 Compliance Reports for Twin Oaks 1 and 2 available in the rulemaking docket at EPA–HQ–OAR–2018–0794.

[71] Choctaw Generation LP leases and operates the Red Hills Power Plant. The plant supplies electricity to the Tennessee Valley Authority (TVA) under a 30-year power purchase agreement. The lignite output from the adjacent mine is 100 percent dedicated to the power plant. *https://www.purenergyllc.com/projects/choctaw-generation-lp-red-hills-power-plant/#page-content.*

Response: In developing the 2012 Final MATS Rule, the EPA examined the EGUs in the top performing 12 percent of sources for which the Agency had Hg emissions data. In examining that data, the EPA observed that there were no lignite-fired EGUs among the top performing 12 percent of sources for Hg emissions. The EPA then determined that this indicated that there is a difference in the Hg emissions from lignite-fired EGUs when compared to the Hg emissions from EGUs firing other coal types (that were represented among the top performing 12 percent). That determination was not based on any unique property or characteristic of lignite—only on the observation that there were no lignite-fired EGUs among the best performing 12 percent of sources (for which the EPA had Hg emissions data). In fact, as noted in the preamble for the 2012 Final MATS Rule, the EPA ''believed at proposal that the boiler size was the cause of the different Hg emissions characteristics.'' See 77 FR 9378.

The EPA ultimately concluded that it is appropriate to continue to base the subcategory definition, at least in part, on whether the EGUs were ''designed to burn and, in fact, did burn low rank-virgin coal'' (*i.e.,* lignite), but that it is not appropriate to continue to use the boiler size criteria (*i.e.,* the height-to-depth ratio). However, the EPA ultimately finalized the ''unit designed for low rank virgin coal'' subcategory based on the characteristics of the EGU—not on the properties of the fuel. ''We are finalizing that the EGU is considered to be in the ''unit designed for low rank virgin coal'' subcategory if the EGU: (1) meets the final definitions of ''fossil fuel-fired'' and ''coal-fired electric utility steam generating unit;'' and (2) is designed to burn and 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) and that is constructed and operates at or near the mine that produces such coal.'' See 77 FR 9369.

While, in the 2012 MATS Final Rule, the EPA based the lignite-fired EGU subcategory on the design and operation of the EGUs, the EPA did not attribute the observed differences in Hg emissions to any unique characteristic(s) of lignite. As the EPA clearly noted in the 2023 Proposal, there are, in fact, characteristics of lignite that make the control of Hg more challenging. These include the low natural halogen content, the high alkalinity of the fly ash, the sulfur content, the relatively higher Hg content, and the relatively higher variability of Hg content. However, as the EPA has explained, these characteristics that make the control of Hg more challenging are also found in non-lignite fuels. Subbituminous coals also have low natural halogen content and high fly ash alkalinity. Eastern and central bituminous coals also have high sulfur content. Bituminous and anthracitic waste coals (coal refuse) have very high and variable Hg content. EGUs firing any of these non-lignite coals have been subject to—and have demonstrated compliance with—the more stringent Hg emission standard of 1.2 lb/TBtu.

The EPA has found it appropriate to reverse the previous policy because the decision to subcategorize ''units designed for low rank virgin coal'' in the 2012 MATS Final Rule was based a determination that there were differences in Hg emissions from lignite-fired EGUs as compared to EGUs firing non-lignite coals. That perceived difference was based on an observation that there were no lignite-fired EGUs in the top performing 12 percent of EGUs for which the Agency had Hg emissions data and on an assumption that the perceived difference in emissions was somehow related to the design and operation of the EGU. The EPA is unaware of any distinguishing features of EGUs that were designed to burn lignite that would impact the emissions of Hg. Further, the EPA does not now view the fact that there were no lignite-fired EGUs in the population of the best-performing 12 percent of EGUs for which the Agency had Hg emissions data to represent a ''difference in emissions.''

But, on re-examination of the data, the EPA has concluded that the Hg emissions from the 2010 ICR for the lignite-fired EGUs were not clearly distinctive from the Hg emissions from EGUs firing non-lignite coal. In setting the emission standards for the 2012 MATS Final Rule, the EPA had available and useable Hg emissions data from nearly 400 coal-fired EGUs (out of the 1,091 total coal-fired EGUs operating at that time). However, the EPA only had available and useable data from nine lignite-fired EGUs with reported floor Hg emissions ranging from 1.0 to 10.9 lb/TBtu. But these were not outlier emission rates. EGUs firing bituminous coal reported Hg emissions as high as 30.0 lb/TBtu; and those firing subbituminous coal reported Hg emissions as high as 9.2 lb/TBtu.

D. What is the rationale for our final approach and decisions for the lignite-fired EGU Hg standard?

In the 2023 Proposal, the EPA proposed to determine that there are developments in available control technologies and methods of operation that would allow lignite-fired EGUs to meet a more stringent Hg emission standard of 1.2 lb/TBtu—the same Hg emission standard that must be met by coal-fired EGUs firing non-lignite coals (*e.g.,* anthracite, bituminous coal, subbituminous coal, coal refuse, *etc.*). After consideration of public comments received on the proposed revision of the Hg emission standard, the EPA continues to find that the evidence supports that there are commercially available control technologies and improved methods of operation that allow lignite-fired EGUs to meet the more stringent Hg emission standard that the EPA proposed. As noted above, lignite-fired EGUs also comprise some of the largest sources of Hg emissions within this source category and are responsible for a disproportionate share of Hg emissions relative to their generation. While previous EPA assessments have shown that current modeled exposures [of Hg] are well below the reference dose (RfD), we conclude that further reductions of Hg emissions from lignite-fired EGUs covered in this final action should further reduce exposures including for the subsistence fisher sub-population. This anticipated exposure is of particular importance to children, infants, and the developing fetus given the developmental neurotoxicity of Hg. Therefore, in this final action, the EPA is revising the Hg emission standard for lignite-fired EGUs from the 4.0 lb/TBtu standard that was finalized in the 2012 MATS Final Rule to the more stringent emission standard of 1.2 lb/TBtu, as proposed. The rationale for the Agency's final determination is provided below.

In this final rule, the EPA is also reaching a different conclusion from the 2020 Technology Review with respect to the Hg emission standard for lignite-fired EGUs. As discussed in section II.D. above, the 2020 Technology Review did not evaluate the current performance of emission reduction control equipment and strategies at existing lignite-fired EGUs. Nor did the 2020 Technology Review specifically address the discrepancy between Hg emitted from lignite-fired EGUs and non-lignite coal-fired EGUs or consider the improved performance of injected sorbents or chemical additives, or the development of SO_3-tolerant sorbents. Based on the EPA's review in this rulemaking which considered such information, the Agency determined that there are available control technologies that allow EGUs firing lignite to achieve an emission standard of 1.2 lb/TBtu, consistent with the Hg emission standard required for non-lignite coal-fired EGUs, which the EPA is finalizing pursuant to its CAA section 112(d)(6) authority.

1. Mercury Content of Lignite

For analyses supporting the proposal, the EPA assumed ''Hg Inlet'' levels (*i.e.,* Hg concentration in inlet fuel) that are consistent with those assumed in the Agency's power sector model (IPM) and then adjusted accordingly to reflect the 2021 fuel blend for each unit. Several commenters indicated that the Hg content of lignite fuels is much higher and has greater variability than the EPA assumed.

To support the development of the NESHAP for the Coal- and Oil-Fired EGU source category, the Agency conducted a 2-year data collection effort which was initiated in 1998 and completed in 2000 (1998 ICR). The ICR had three main components: (1) identifying all coal-fired units owned and operated by publicly owned utility companies, federal power agencies, rural electric cooperatives, and investor-owned utility generating companies; (2) obtaining accurate information on the amount of Hg contained in the as-fired coal used by each electric utility steam generating unit with a capacity greater than 25 MW electric, as well as accurate information on the total amount of coal burned by each such unit; and (3) obtaining data by coal sampling and stack testing at selected units to characterize Hg reductions from representative unit configurations.

The ICR captured the origin of the coal burned, and thus provided a pathway for linking emission properties to coal basins. The 1998–2000 ICR resulted in more than 40,000 data points indicating the coal type, sulfur content, Hg content, ash content, chlorine content, and other characteristics of coal burned at coal-fired utility boilers greater than 25 MW.

Annual fuel characteristics and delivery data reported on EIA form 923 also provide continual data points on coal heat content, sulfur content, and geographic origin, which are used as a check against characteristics initially identified through the 1998 ICR.

For this final rule, the EPA re-evaluated the 1998 ICR data.[72] Specifically, the EPA evaluated the coal Hg data to characterize the Hg content of lignite, which is mined in North Dakota, Texas, and Mississippi, and to characterize by seam and by coal delivered to a specific plant.[73] The results are presented as a range of Hg content of the lignites as well as the mean and median Hg content. The EPA also compared the fuel characteristics of lignites mined in North Dakota, Texas, and Mississippi against coals mined in Wyoming (subbituminous coal), Pennsylvania (mostly upper Appalachian bituminous coal), and Kentucky (mostly lower Appalachian bituminous coal). The Agency also included in the re-evaluation, coal analyses that were submitted in public comments by North American Coal (NA Coal). In addition to the Hg content, the analysis included the heating value and the sulfur, chlorine, and ash content for each coal that is characterized.

The analysis showed that lignite mined in North Dakota had a mean Hg content of 9.7 lb/TBtu, a median Hg content of 8.5 lb/TBtu, and a Hg content range of 2.2 to 62.1 lb/TBtu. Other characteristics of North Dakota lignite include an average heating value (dry basis) of 10,573 Btu/lb, an average sulfur content of 1.19 percent, an average ash content of 13.5 percent, and an average chlorine content of 133 parts per million (ppm). In response to comments on the 2023 Proposal, for analyses supporting this final action, the EPA has revised the assumed Hg content of lignite mined in North Dakota to 9.7 lb/TBtu versus the 7.81 lb/TBtu assumed in the 2023 Proposal.

Similarly, the analysis showed that lignite mined in Texas had a mean and median Hg content of 25.0 lb/TBtu and 23.8 lb/TBtu, respectively, and a Hg content range from 0.7 to 92.0 lb/TBtu. Other characteristics include an average heating value (dry basis) of 9,487 Btu/lb, an average sulfur content of 1.42 percent, an average ash content of 24.6 percent, and an average chlorine content of 233 ppm. In response to comments on the 2023 Proposal, for analyses supporting this final action, the EPA has revised the assumed Hg content of lignite mined in Texas to 25.0 lb/TBtu versus the range of 14.65 to 14.88 lb/TBtu that was assumed for the 2023 Proposal.

Lignite mined in Mississippi had the highest mean Hg content at 34.3 lb/TBtu and the second highest median Hg emissions rate, 30.1 lb/TBtu. The Hg content ranged from 3.6 to 91.2 lb/TBtu. Lignite from Mississippi had an average heating value (dry basis) of 5,049 Btu/lb and a sulfur content of 0.58 percent. In response to comments submitted on the 2023 Proposal, for analyses supporting this final action, the EPA assumed a Hg content of 34.3 lb/TBtu for lignite mined in Mississippi versus the 12.44 lb/TBtu assumed for the proposal.

The EPA 1998 ICR dataset did not contain information on lignite from Mississippi, which resulted in a smaller number of available data points (227 in Mississippi lignite versus 864 for North Dakota lignite and 943 for Texas lignite). Table 5 of this document more fully presents the characteristics of lignite from North Dakota, Texas, and Mississippi.

[72] Technical Support Document ''*1998 ICR Coal Data Analysis Summary of Findings*'' available in the rulemaking docket at EPA–HQ–OAR–2018–0794.

[73] In 2022, over 99 percent of all lignite was mined in North Dakota (56.2 percent), Texas (35.9 percent), and Mississippi (7.1 percent). Small amounts (less than 1 percent) of lignite were also mined in Louisiana and Montana. See Table 6. ''Coal Production and Number of Mines by State and Coal Rank'' from EIA Annual Coal Report, available at *https://www.eia.gov/coal/annual/.*

Table 5. Characteristics of Lignite mined in North Dakota, Texas, and Mississippi from the EPA 1998 ICR Dataset

	North Dakota	Texas	Mississippi
Number of data points	864	943	227
Range of Hg content (lb/TBtu)	2.2 – 62.1	0.7 – 92.0	3.6 – 91.2
Mean Hg content (lb/TBtu)	9.7	25.0	34.3
Median Hg content (lb/TBtu)	8.5	23.8	30.1
Heating value average (Btu/lb, dry)	10,573	9,486	5,049
Sulfur content average (%, dry)	1.12	1.42	0.58
Ash content average (%, dry)	13.54	24.60	N/A
Chlorine content average (ppm, dry)	133	232	N/A

Coals mined in Kentucky, Pennsylvania, and Wyoming were also analyzed for comparison. The types of coal (all non-lignite) included bituminous, bituminous-high sulfur, bituminous-low sulfur, subbituminous, anthracite, waste anthracite, waste bituminous, and petroleum coke. Bituminous coal accounted for 92 percent of the data points from Kentucky and 75 percent of the data points from Pennsylvania. Subbituminous coal accounted for 96 percent of the data points from Wyoming.

Bituminous coals from Kentucky had a mean Hg emissions content of 7.2 lb/TBtu (ranging from 0.7 to 47.4 lb/TBtu), an average heating value (dry basis) of 13,216 Btu/lb, an average sulfur content of 1.43 percent, an average ash content of 10.69 percent, and an average chlorine content of 1,086 ppm.

Bituminous coals from Pennsylvania had a mean Hg emissions rate of 14.5 lb/TBtu (ranging from 0.1 to 86.7 lb/TBtu), an average heating value (dry basis) of 13,635 Btu/lb, an average sulfur content of 1.88 percent, an average ash content of 10.56 percent, and an average chlorine content of 1,050 ppm.

Subbituminous coals from Wyoming had a mean Hg rate of 5.8 lb/TBtu, an average heating value (dry basis) of 12,008 Btu/lb, an average sulfur content of 0.44 percent, an average ash content of 7.19 percent, and an average chlorine content of 127 ppm. Table 6 of this document shows the characteristics of bituminous coal from Kentucky and Pennsylvania and subbituminous coal from Wyoming.

Table 6. Characteristics of Bituminous and Subbituminous Coals mined in Kentucky, Pennsylvania, and Wyoming from the EPA 1998 ICR Dataset

	Kentucky (Bituminous)	Pennsylvania (Bituminous)	Wyoming (Subbituminous)
Number of data points	5,340	3,072	6,467
Range of Hg content (lb/TBtu)	0.7 – 47.4	0.1 – 86.7	0.7 – 40.7
Mean Hg content (lb/TBtu)	7.2	14.5	5.8
Median Hg content (lb/TBtu)	6.7	9.7	2.4
Heating value average (Btu/lb, dry)	13,216	13,635	12,008
Sulfur content average (%, dry)	1.43	1.88	0.44
Ash content average (%, dry)	10.69	10.56	7.19
Chlorine content average (ppm, dry)	1,086	1,050	127

Several commenters claimed that one of the factors that contributes to the challenge of controlling Hg emissions from EGUs firing lignite is the variability of the Hg content in lignite. However, as can be seen in table 5 and table 6 of this document, all coal types examined by the EPA contain a variable content of Hg. The compliance demonstration requirements in the 2012 MATS Final Rule were designed to accommodate the variability of Hg in coal by requiring compliance with the respective Hg emission standards over a 30-operating-day rolling average period. When examining the Hg emissions for EGUs firing on the various coal types (including those firing Wyoming subbituminous coal, which has the lowest mean and median Hg content and the narrowest range of Hg content), daily emissions often exceed the applicable emission standard (sometimes considerably). However, averaging emissions over a rolling 30-operating-day period effectively dampens the impacts of fuel Hg content variability. For example, in figure 1 (a graph) of this document, the 2022 Hg emissions from Dave Johnston unit BW41, a unit firing subbituminous coal, are shown. The graph shows both the daily Hg emissions and the 30-operating-day rolling average Hg emissions. As can be seen in the graph, the daily Hg emissions very often exceed the 1.2 lb/TBtu emission rate; however, the 30-operating-day rolling average is consistently below the emission limit (the annual average emission rate is 0.9 lb/TBtu).

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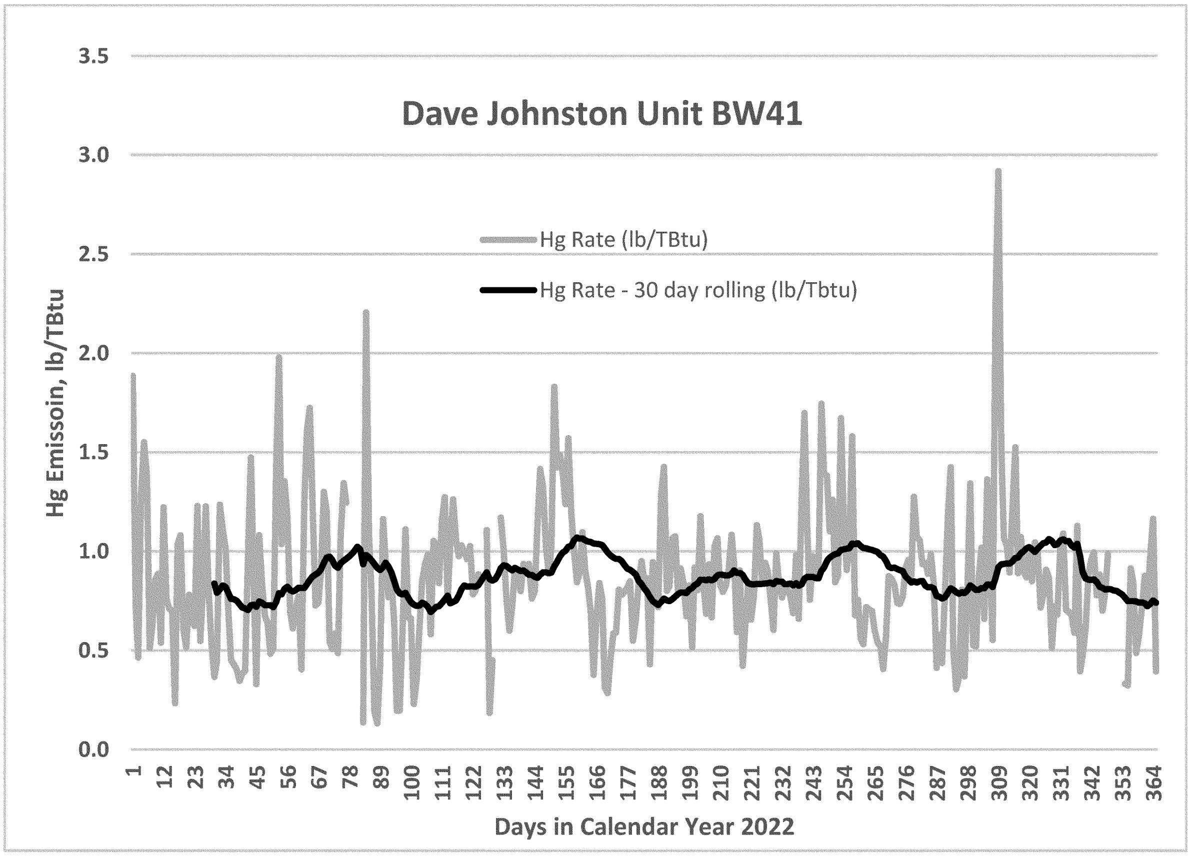

Figure 1. 2022 Daily and 30-Day Rolling Average Hg Emission Rates (lb/TBtu)

From Dave Johnston Unit BW41, a subbituminous-fired EGU in Wyoming.

A similar effect can be seen with the 2022 daily and 30-operating-day rolling average Hg emissions from Leland Olds unit 1, an EGU firing North Dakota lignite, shown in figure 2 of this document.

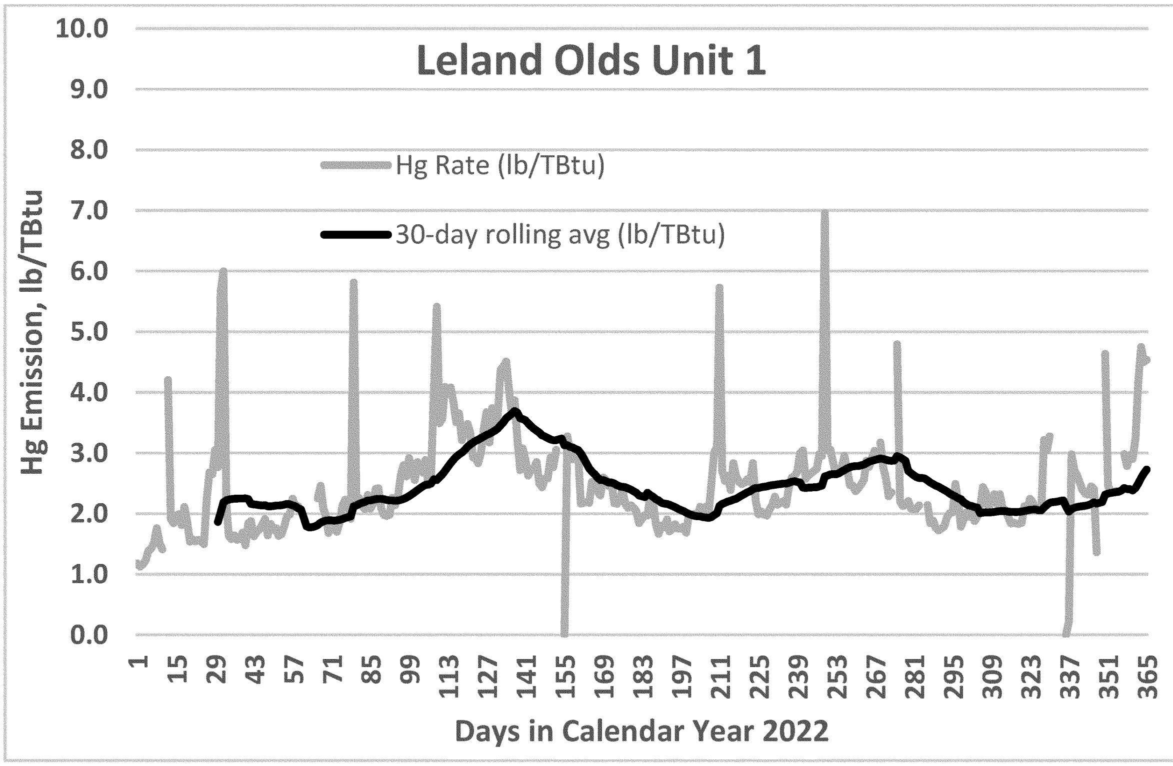

Figure 2. Daily and 30-Day Rolling Average Hg Emission Rates (lb/TBtu) from Leland Olds Unit 1, lignite-fired EGU in North Dakota.

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As with the EGU firing subbituminous coal, the daily Hg emissions very often exceed the emission limit (in this case 4.0 lb/TBtu); however, the 30-operating-day rolling average is consistently below the applicable emission limit (the 2022 annual average emission rate for Leland Olds unit 1 is 2.3 lb/TBtu).

2. The Impact of Halogen Content of Lignite on Hg Control

In the 2023 Proposal, the EPA explained that during combustion of coal, the Hg contained in the coal is volatilized and converted to Hg^0 vapor 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, injected sorbents) in the flue gas stream, often referred to as ''particulate bound Hg'' (Hg_p) and be removed in a downstream PM control device. Certain oxidized Hg compounds that are water soluble may be further removed in a downstream 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 may enter 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 tables 5 and 6 of this document, the chlorine content of bituminous coals mined in Kentucky and Pennsylvania averaged 1,086 ppm and 1,050 ppm, respectively. In comparison, the average chlorine content of Wyoming subbituminous coal is 127 ppm; while the chlorine contents of lignite mined in North Dakota and Texas are 133 ppm and 232 ppm, respectively. 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 natural 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.

While some bituminous coal-fired EGUs require the 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 described above, the Hg in the flue gas for EGUs firing subbituminous coal or lignite tends to be in the nonreactive Hg^0 vapor phase due to lack of available free halogen to promote the oxidation reaction. To alleviate this challenge, activated carbon and other sorbent providers and control technology vendors have developed methods to introduce halogen into the flue gas to improve the control of Hg emissions from EGUs firing subbituminous coal and lignite. This is 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. In the

2022 CAA section 114 information collection, almost all the lignite-fired units reported use of some sort of halogen additive or injection as part of their Hg control strategy by using refined coal (which typically has added halogen), bromide or chloride chemical additives, pre-halogenated sorbents, and/or oxidizing agents. Again, low chlorine content in the fuel is a challenge that is faced by EGUs firing either subbituminous coals or lignite, and EGUs firing subbituminous coal have been subject to a Hg emission standard of 1.2 lb/TBtu since the MATS rule was finalized in 2012.

3. The Impact of SO_3 on Hg Control

Some commenters noted that the EPA did not account for the impacts of the higher sulfur content of lignite as compared to that of subbituminous coal, and that such higher sulfur content leads to the presence of additional SO_3 in the flue gas stream. As shown in table 5 and table 6 of this document, while the halogen content of subbituminous coal and lignite is similar, the average sulfur content of lignite is more like that of bituminous coal mined in Kentucky and Pennsylvania.

During combustion, most of the sulfur in coal is oxidized into SO_2, and only a small portion is further oxidized to SO_3 in the boiler. In response to environmental requirements, many EGUs have installed SCR systems for NO_X control and FGD systems for SO_2 control. One potential consequence of an SCR retrofit is an increase in the amount of SO_3 in the flue gas downstream of the SCR due to catalytic oxidation of SO_2. Fly ash and condensed SO_3 are the major components of flue gas that contribute to the opacity of a coal plant's stack emissions and the potential to create a visible sulfuric acid ''blue plume.'' In addition, higher SO_3 levels can adversely affect many aspects of plant operation and performance, including corrosion of downstream equipment and fouling of the air preheater (APH). This is primarily an issue faced by EGUs firing bituminous coal. EGUs fueled by subbituminous coal and lignite do not typically have the same problem with blue plume formation. Of the EGUs that are designed to fire lignite, only Oak Grove units 1 and 2, located in Texas, have an installed SCR for NO_X control. Several lignite-fired EGUs utilize SNCR systems for NO_X control, which are less effective for NO_X control as compared to SCR systems. Several commenters claimed that SCR is not a viable NO_X control technology for EGUs firing North Dakota lignite because of catalyst fouling from the high sodium content of the fuel and resulting fly ash.

Coal 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 coals and lignite 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—and, as noted by commenters—the presence of sodium compounds in the ash. The natural alkalinity of the subbituminous and lignite fly ash may effectively neutralize the limited free halogen in the flue gas and prevent oxidation of the Hg^0. However, the natural alkalinity also helps to minimize the impact of SO_3, because a common control strategy for SO_3 is the injection of alkaline sorbents (dry sorbent injection, DSI).

Still, as commenters correctly noted, the presence of SO_3 in the flue gas stream is also known to negatively impact the effectiveness of sorbent injection for Hg control. This impact has been known for some time, and control technology researchers and vendors have developed effective controls and strategies to minimize the impact of SO_3.[74] As noted above, coal-fired EGUs utilizing bituminous coal—which also experience significant rates of SO_3 formation in the flue gas stream—have also successfully demonstrated the application of Hg control technologies to meet a standard of 1.2 lb/TBtu.

The AECOM patented SBS Injection™ (''sodium-based solution'') technology has been developed for control of SO_3, and co-control of Hg has also been demonstrated. A sodium-based solution is injected into the flue gas, typically ahead of the APH or, if present, the SCR. By removing SO_3 prior to these devices, many of the adverse effects of SO_3 can be successfully mitigated. AECOM has more recently introduced their patented HBS Injection™ technology for effective Hg oxidation and control.[75] This new process injects halogen salt solutions into the flue gas, which react in-situ to form halogen species that effectively oxidize Hg. The HBS Injection™ can be co-injected with the SBS Injection™ for effective SO_3 control and Hg oxidation/control.

Other vendors also offer technologies to mitigate the impact of SO_3 on Hg control from coal combustion flue gas streams. For example, Calgon Carbon offers their ''sulfur tolerant'' Fluepac ST, which is a brominated powdered activated carbon specially formulated to enhance Hg capture in flue gas treatment applications with elevated levels of SO_3.[76] In testing in a bituminous coal combustion flue gas stream containing greater than 10 ppm SO_3, the Fluepac ST was able to achieve greater than 90 percent Hg control at injection rates of a third or less as compared to injection rates using the standard brominated sorbent.

Babcock & Wilcox (B&W) offers dry sorbent injection systems that remove SO_3 before the point of activated carbon sorbent injection to mitigate the impact of SO_3.[77] Midwest Energy Emissions Corporation (ME_2C) offers ''high-grade sorbent enhancement additives—injected into the boiler in minimal amounts'' that work in conjunction with proprietary sorbent products to ensure maximum Hg capture. ME_2C claims that their Hg control additives and proprietary sorbent products are ''high-sulfur-tolerant and SO_3-tolerant sorbents.'' [78]

Cabot Norit Activated Carbon is the largest producer of powdered activated carbon worldwide.[79] Cabot Norit offers different grades of their DARCO® powdered activated carbon (PAC) for Hg removal at power plants. These grades include non-impregnated PAC which are ideal when most of the Hg is in the oxidized state; impregnated PAC for removing oxidized and Hg^0 from flue gas; special impregnated PAC used in conjunction with DSI systems (for control of acid gases); and special impregnated ''sulfur resistant'' PAC for flue gases that contains higher concentrations of acidic gases like SO_3.

[74] The mention of specific products by name does not imply endorsement by the EPA. The EPA does not endorse or promote any particular control technology. The EPA mentions specific product names here to emphasize the broad range of products and vendors offering sulfur tolerant Hg control technologies.

[75] *https://www.aecom.com/wp-content/uploads/2019/07/10_EUEC_P_PT_Brochure_HBS_InjectionTechnology_20160226_singles.pdf.*

[76] *https://www.calgoncarbon.com/app/uploads/DS-FLUEST15-EIN-E1.pdf.*

[77] *https://www.babcock.com/assets/PDF-Downloads/Emissions-Control/E101-3200-Mercury-and-HAPs-Emissions-Control-Brochure-Babcock-Wilcox.pdf.*

[78] ME2C 2016 Corporate Brochure, available in the rulemaking docket at EPA–HQ–OAR–2018–0794.

[79] *https://norit.com/application/power-steel-cement/power-plants.*

Similarly, ADA–ES offers FastPAC™ Platinum 80,[80] an activated carbon sorbent that was specifically engineered for SO_3 tolerance and for use in applications where SO_3 levels are high. So, owner/operators of lignite-fired EGUs can choose from a range of technologies and technology providers that offer Hg control options in the presence of SO_3. The EPA also notes that SO_3 is more often an issue with EGUs firing eastern bituminous coal—as those coals typically have higher sulfur content and lower ash alkalinity. Those bituminous coal-fired EGUs are subject to—and have demonstrated compliance with—an emission standard of 1.2 lb/TBtu.

[80] *https://www.advancedemissionssolutions.com/ADES-Investors/ada-products-and-services/default.aspx.*

4. Cost Considerations for the More Stringent Hg Emission Standard

From the 2022 CAA section 114 information survey, most lignite-fired EGUs utilized a control strategy that included sorbent injection coupled with chemical additives (usually halogens). In the beyond-the-floor analysis in the 2012 MATS Final Rule, we noted that the results from various demonstration projects suggested that greater than 90 percent Hg control can be achieved at lignite-fired units using brominated activated carbon sorbents at an injection rate of 2.0 lb/MMacf (*i.e.,* 2.0 pounds of sorbent injected per million actual cubic feet of flue gas) 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 7 of this document, all units (in 2022) would have needed to control their Hg emissions to 95 percent or less to meet an emission standard of 1.2 lb/TBtu. Based on this, we expect that the units could meet the final, more stringent, emission standard of 1.2 lb/TBtu by utilizing brominated activated carbon at the injection rates suggested in the beyond-the-floor memorandum from the 2012 MATS Final Rule.

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Table 7. Measured Hg Emissions and Estimated Control Performance of Lignite-Fired EGUs in 2022

EGU	Estimated 2022 Hg Inlet[81] (lb/TBtu)	Estimated Hg Control (%) at 4.0 lb/TBtu	Estimated Hg Control (%) at 1.2 lb/TBtu	2022 Measured Hg Emissions (lb/TBtu)	Estimated 2022 Hg Control (%)
North Dakota EGUs					
Antelope Valley 1	11.2	64.4	89.3	3.03	73.0
Antelope Valley 2	11.2	64.4	89.3	3.00	73.3
Coal Creek 1	9.7	58.7	87.6	3.43	64.6
Coal Creek 2	9.7	58.7	87.6	3.87	60.1
Coyote 1	9.7	58.6	87.6	2.28	76.4
Leland Olds 1	11.3	64.5	87.6	2.34	79.3
Leland Olds 2	11.3	64.5	87.6	3.10	72.5
Milton R Young 1	9.7	58.6	87.6	3.02	68.8
Milton R Young 2	9.7	58.6	87.6	3.00	69.0
Spiritwood Station 1	9.2	56.5	87.0	2.14	76.8
Texas and Mississippi EGUs					
Limestone 1*	5.8	30.7	79.2	0.78	86.5
Limestone 2*	5.8	30.7	79.2	0.85	85.3
Major Oak Power 1	24.9	84.0	95.2	0.86	96.5
Major Oak Power 2	24.9	84.0	95.2	0.63	97.5
Martin Lake 1*	5.8	31.0	79.3	1.53	73.6
Martin Lake 2*	5.8	31.0	79.3	2.50	56.9
Martin Lake 3*	5.8	31.0	79.3	2.36	59.3
Oak Grove 1	24.8	83.9	95.2	2.53	89.8
Oak Grove 2	24.8	83.9	95.2	2.23	91.0
San Miguel 1	28.9	86.2	95.9	3.03	89.5
Red Hills 1	22.9	82.6	94.8	1.73	92.5
Red Hills 2	22.9	82.6	94.8	1.75	92.4

* These units, which are permitted to fire lignite, utilized primarily subbituminous coal in 2022.

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To determinethe cost effectiveness of that strategy, we calculated the cost per lb of Hg controlled for a model 800 MW lignite-fired EGU, as described in the 2024 Technical Memo. We calculated the cost of injecting brominated activated carbon sorbent at injection rates suggested in the beyond-the-floor memorandum from the 2012 MATS Final Rule (*i.e.,* 2.0 lb/MMacf and 3.0 lb/MMacf) and at a larger injection rate of 5.0 lb/MMacf to achieve an emission rate of 1.2 lb/TBtu. We also calculated the incremental cost to meet the more stringent 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 cost effectiveness of using the brominated carbon sorbent at an injection rate of 3.0 lb/MMacf was $3,050 per lb of Hg removed while the incremental cost effectiveness was $10,895 per incremental lb of Hg removed at a brominated activated carbon injection rate of 3.0 lb/MMacf. The cost effectiveness of using the brominated carbon sorbent at an injection rate of 5.0 lb/MMacf was $5,083 per lb of Hg removed while the incremental cost effectiveness was $28,176 per incremental lb of Hg removed. The actual cost effectiveness is likely lower than either of these estimates as it is unlikely that sources will need to inject brominated activated carbon sorbent at rates as high as 5.0 lb/MMacf (from the 2022 CAA section 114 information collection, the Oak Grove units were injecting less than 0.5 lb/MMacf) and is either well below or reasonably consistent with the cost effectiveness that the EPA has found to

[81] Estimated Hg inlet values are based on fuel use data from EIA Form 923 and assumed Hg content of coals as shown in Table 5 and Table 6 in this preamble.

be acceptable in previous rulemakings for Hg controls.[82]

In addition to cost effectiveness, the EPA finds that the revised Hg emission standard for lignite-fired units appropriately considers the costs of controls, both total costs and as a fraction of total revenues, along with other factors that the EPA analyzed pursuant to its CAA section 112(d)(6) authority. Similar to the revised fPM emission standard (as a surrogate for non-Hg HAP metals) discussed in section IV. of this preamble, the EPA anticipates that the total costs of controls (which consists of small annual incremental operating costs) to comply with the revised Hg emission standard will be a small fraction of the total revenues for the impacted lignite-fired units. The EPA expects that sources will be able to meet the revised emission standard using existing controls (*e.g.,* using existing sorbent injection equipment), and that significant additional capital investment is unlikely. If site-specific conditions necessitate minor capital improvements to the ACI control technology, it is important to note that any incremental capital would be small relative to ongoing sorbent costs accounted for in this analysis. Further, in addition to the EPA finding that costs are reasonable for the revised Hg standard for lignite-fired EGUs, the revised standard will also bring these higher emitting sources of Hg emission in line with Hg emission rates that are achieved by non-lignite-fired EGUs. As mentioned earlier in this preamble, in 2021, lignite-fired EGUs were responsible for almost 30 percent of all Hg emitted from coal-fired EGUs while generating about 7 percent of total megawatt-hours.

Despite the known differences in the quality and composition of the various coal types, the EPA can find no compelling reasons why EGUs that are firing lignite cannot meet the same emission limit as EGUs that are firing other types of coal (*e.g.,* eastern and western bituminous coal, subbituminous coal, and anthracitic and bituminous waste coal). Each of the coal types/ranks has unique compositions and properties. Low halogen content in coal is known to make Hg capture more challenging. But, both lignites and subbituminous coals have low halogen content with higher alkaline content. Lignites tend to have average higher Hg content than subbituminous and bituminous coals—especially lignites mined in Mississippi and Texas. However, waste coals (anthracitic and bituminous coal refuse) tend to have the highest average Hg content. Lignites tend to have higher sulfur content than that of subbituminous coals and the sulfur in the coal can form SO_3 in the flue gas. This SO_3 is known to make Hg capture using sorbent injection more challenging. However, bituminous coals and waste coals have similar or higher levels of sulfur. The formation of SO_3 is more significant with these coals. Despite all the obstacles and challenges presented to EGUs firing non-lignite coals, all of those EGUs have been subject to the more stringent Hg emission limit of 1.2 lb/TBtu—and emit at or below that emission limit since the rule was fully implemented. Advanced, better performing Hg controls—including ''SO_3 tolerant'' sorbents—are available to allow lignite-fired EGUs to also emit at or below the more stringent Hg emission limit of 1.2 lb/TBtu. As mentioned earlier in this preamble, in 2021, lignite-fired EGUs were responsible for almost 30 percent of all Hg emitted from coal-fired EGUs while generating about 7 percent of total megawatt-hours.

VI. What is the rationale for our other final decisions and amendments from review of the 2020 Technology Review?

A. What did we propose pursuant to CAA section 112(d)(6) for the other NESHAP requirements?

The EPA did not propose any changes to the organic HAP work practice standards, acid gas standards, continental liquid oil-fired EGU standards, non-continental liquid oil-fired EGUs, limited-use oil-fired EGU standards, or standards for IGCC EGUs. The EPA proposed to require that IGCC EGUs use PM CEMS for compliance demonstration with their fPM standard.

The EPA did note in the 2023 Proposal that 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. As such, the EPA solicited 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 solicited 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.

B. How did the technology review change for the other NESHAP requirements?

The technology review for the organic HAP work practice standards, acid gas standards, and standards for oil-fired EGUs has not changed from the proposal.

The proposed technology review with respect to the use of PM CEMS for compliance demonstration by IGCC EGUs has changed due to comments received on the very low fPM emission rates and on technical challenges with certifying PM CEMS on IGCC EGUs. Therefore, the Agency is not finalizing the required use of PM CEMS for compliance demonstration with the fPM emission standard at IGCC EGUs.

C. What key comments did we receive on the other NESHAP requirements, and what are our responses?

Comment: Commenters urged the EPA to retain the current definition of the limited-use liquid oil-fired subcategory and not to impose new HAP standards on EGUs in this subcategory, given that there are already limits on the amount of fuel oil that can be burned. Commenters noted that the Agency has not identified any justification for the costs required for implementation and compliance with new HAP standards for limited-use liquid oil-fired EGUs. Some commenters alleged that any changes to the existing HAP standards for EGUs in the limited-use liquid oil-fired subcategory may complicate reliability management during cold winter spells or other extreme weather events.

Response: The Agency did not propose changes to the limited-use liquid oil-fired EGU subcategory or to the requirements for such units. To evaluate the potential HAP emission impact of liquid oil-fired EGUs[83] during extreme weather events, the Agency reviewed the 2022 fPM emissions of 11 liquid oil-fired EGUs in the Northeast U.S. that were operated during December 2022 Winter Storm Elliot, as described in the 2024 Technical Memo. The review found that total non-Hg HAP metal emissions during 2022 from the 11 oil-fired EGUs in New England were very small—approximately 70 times lower than the non-Hg HAP metal emissions estimated from oil-fired units

[82] For example, the EPA proposed that $27,500 per lb of Hg removed was cost-effective for the Primary Copper RTR (87 FR 1616); and approximately $27,000 per lb of Hg ($2021) was found to be cost-effective in the beyond-the-floor analysis supporting the 2012 MATS Final Rule.

[83] Oil-fired EGUs burning residual fuel oil have generally higher emission rates of HAP compared to that from the use of other types of fuel.

in Puerto Rico, which were among the facilities with the highest (but acceptable) residual risk in the 2020 Residual Risk Review.[84] The EPA will continue to monitor the emissions from the dispatch of limited-use liquid oil-fired EGUs—especially during extreme weather events.

In addition, the Agency reviewed the performance of PM CEMS for compliance demonstration at oil-fired EGUs. Given the higher emission rates and limits from this subcategory of EGUs, the Agency did not find any of the correlation issues with the use of PM CEMS with oil-fired EGUs similar to those that were discussed earlier for coal-fired EGUs. Moreover, the benefits of PM CEMS use that were described earlier (*i.e.,* emissions transparency, operational feedback, *etc.*) translate well to oil-fired EGUs; therefore, the EPA is finalizing the requirement for oil-fired EGUs (excluding limited-use liquid oil-fired EGUs) to use PM CEMS for compliance demonstration, as proposed.

Comment: One commenter recommended that units involved with carbon capture and sequestration (CCS) projects retain the option to use stack testing for compliance demonstration. They said that PM emissions would be measured from the stack downstream of the carbon capture system (they specifically mentioned the carbon capture system being contemplated to be built to capture CO_2 emission from the Milton R. Young Station facility in North Dakota). The commenters said that PM CEMS correlation testing will cause operational impacts on the CCS operations due to operational changes or reduced control efficiencies that temporarily increase PM emissions for long time periods, resulting in CCS operations being adversely affected or even shut down for long periods.

Response: The Agency disagrees with the commenter's recommendation that units utilizing a carbon capture system should be able to continue to use periodic stack testing for compliance demonstration. At the present time, the many ways that CCS can be employed and deployed at coal-fired EGUs supports the use of PM CEMS for compliance purposes. For example, measures (such as a bypass stack) are available that would minimize the operational impacts on the carbon capture system and would allow for proper PM CEMS correlations. Furthermore, the Agency finds that the increased transparency and the improved ability to detect and correct potential control or operational problems offered by PM CEMS, as well as the greater assurance of continuous compliance, outweigh the minor operational impacts potentially experienced. To the extent that a specific coal- or oil-fired EGU utilizing CCS wishes to use an alternative test method for compliance demonstration purposes, its owner or operator may submit a request to the Administrator under the provisions of 40 CFR 63.7(f).

D. What is the rationale for our final approach and decisions regarding the other NESHAP requirements?

The Agency did not receive comments that led to any changes in the outcome of the technology review for other NESHAP requirements as presented in the 2023 Proposal. The Agency did not propose any changes for the current requirements for organic HAP work practice standards, acid gas standards, or standards for oil-fired EGUs and therefore no changes are being finalized.

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. These EGUs have LEE qualification for PM, with most current test results of 0.0007 and 0.0003 lb/MMBtu, respectively. 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 (*i.e.,* operating essentially as a natural gas combined cycle turbine EGU). Before this EGU switched to pipeline quality natural gas as a fuel, it qualified for PM LEE status in 2018; to the extent that the EGU again operates as an IGCC, it could continue to claim PM LEE status. While this subcategory has a less stringent fPM standard of 0.040 lb/MMBtu (as compared to that of coal-fired EGUs), recent compliance data indicate fPM emissions well below the most stringent standard option of 0.006 lb/MMBtu that was evaluated for coal-fired EGUs.

The EPA is not finalizing the required use of PM CEMS for compliance demonstration for IGCC EGUs due to technical limitations expressed by commenters. For example, commenters noted that due to differences in stack design, the only possible installation space for a PM CEMS on an IGCC facility is on a stack with elevated grating, exposing the instrument to the elements, which would impact the sensitivity and accuracy of a PM CEMS. Additionally, there are no PM control devices at an IGCC unit available for de-tuning, which is necessary for establishing a correlation curve under PS–11. The EPA has considered these comments and agrees with these noted challenges to the use of PM CEMS at IGCC EGUs and, for those reasons, the EPA is not finalizing the proposed requirement for IGCCs to use PM CEMS for compliance demonstration, thus IGCCs will continue to demonstrate compliance via fPM emissions testing. As a result of comments we received on coal-fired run durations and our consideration on those comments, along with the low levels of reported emissions, the EPA determined that owners or operators of IGCCs will need to ensure each run has a minimum sample volume of 2 dscm or a minimum mass collection of 3 milligrams. In addition, IGCC EGUs will continue to be able to obtain and maintain PM LEE status.

VII. Startup Definition for the Coal- and Oil-Fired EGU Source Category

A. What did we propose for the Coal- and Oil-Fired EGU source category?

In the 2023 Proposal, the EPA proposed to remove the alternative work practice standards, *i.e.,* those contained in paragraph (2) of the definition of ''startup'' in 40 CFR 63.10042 from the rule based on a petition for reconsideration from environmental groups that was remanded to the EPA in *Chesapeake Climate Action Network* v. *EPA,* 952 F.3d 310 (D.C. Cir. 2020), and responding in part to a separate petition for reconsideration from environmental groups, that sought the EPA's reconsideration of certain aspects of the 2020 Residual Risk Review.[85] The first option under paragraph (1) defines 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. 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 onsite 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

[84] See *Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2019 Risk and Technology Review Proposed Rule* (Docket ID No. EPA–HQ–OAR–2018–0794–0014).

[85] See Document ID No. EPA–HQ–OAR–2018–0794–4565 at *https://www.regulations.gov.*

event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any purpose (including onsite use), or 4 hours after the EGU makes useful thermal energy for industrial, commercial, heating, or cooling purposes, whichever is earlier.

As described in the 2023 Proposal, the Agency proposed to remove paragraph (2) of the definition of ''startup'' as part of our obligation to address the remand on this issue. In addition, as the majority of EGUs currently rely on work practice standards under paragraph (1) of the definition of ''startup,'' we believe this change is achievable by all EGUs and would result in little to no additional expenditures, especially since the additional reporting and recordkeeping requirements associated with use of paragraph (2) would no longer apply. Lastly, the time period for engaging PM or non-Hg HAP metal controls after non-clean fuel use, as well as for full operation of PM or non-Hg HAP metal controls, is expected to be reduced when transitioning to paragraph (1), therefore increasing the duration in which pollution controls are employed and lowering emissions.

B. How did the startup provisions change for the Coal- and Oil-Fired EGU source category?

The EPA is finalizing the amendment to remove paragraph (2) from the definition of ''startup'' as proposed.

C. What key comments did we receive on the startup provisions, and what are our responses?

We received both supportive and adverse comments on the proposed removal of paragraph (2) of the definition of ''startup.'' The summarized comments and the EPA's responses are provided in the *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review Proposed Rule Response to Comments* document. The most significant adverse comments and the EPA's responses are provided below.

Comment: Commenters recommended that the 4-hour startup definition should continue to be allowed as removing it for simplicity is not an adequate justification. They said the EPA is conflating the MACT standard-setting process with this RTR process. Although the EPA notes that the best performing 12 percent of sources do not need this alternative startup definition, commenters stated that this change is beyond the scope of the technology review. Commenters asserted that the EPA's determination that only eight EGUs are currently using that option is insufficient justification for eliminating the definition. Given that the 2023 Proposal did not identify any flaws with the current definition, the commenters stated that the EPA should explain why elimination of the 4-hour definition from MATS is appropriate when there are units currently relying on it. Commenters also stated that the EPA should consider providing reasonable exemptions for the EGUs that currently use that definition, thus gradually phasing out the definition without imposing any additional compliance burdens. The commenters also argued that with potentially lower fPM standards, more facilities may need the additional flexibility allowed by this definition of startup as their margin of compliance is reduced. They noted that startup or non-steady state operation is not conducive to CEMS accuracy and that it may create false reporting of emissions data biased either high or low depending on the actual conditions.

Commenters stated that several facilities are currently required to use the 4-hour startup definition per federal consent decrees or state agreements. They said such a scenario provides clear justification for a limited exemption, as MATS compliance should not result in an EGU violating its consent decree. Commenters noted other scenarios where state permits have special conditions with exemptions from emission limits during ramp-up or ramp-down periods. They said many facilities alleviate high initial emissions by using alternate fuels to begin the combustion process, which has been demonstrated as a Best Management Practice and to lower emissions. Commenters noted that the permit modification process, let alone any physical or operational modifications to the facility, could take significantly longer than the 180-day compliance deadline, depending on public comments, meetings, or contested hearing requests made during the permit process.

Commenters stated the startup definition paragraph (2) has seen limited use due to the additional reporting requirements that the EPA imposed on sources that chose to use the definition, which they believe are unnecessary and should be removed from the rule. The commenters said that the analysis the EPA conducted during the startup/shutdown reconsideration in response to *Chesapeake Climate Action Network* v. *EPA,* 952 F.3d 310 (D.C. Cir. 2020) showed that the definition was reasonable, and they argued that the definition may be needed if the EPA further reduces the limits, given the transitory nature of unit and control operation during these periods. Commenters also stated that the startup definition paragraph (2) is beneficial to units that require extended startups. They said including allowances for cold startup conditions could allow some EGUs to continue operation until more compliant generation is built, which would help facilitate a smooth transition to newer plants that meet the requirements without risking the reliability of the electric grid. Commenters also noted that some control devices, such as ESPs, may not be operating fully even when the plant begins producing electricity.

Commenters stated that the EPA should consider allowing the use of diluent cap values from 40 CFR part 75. As these are limited under MATS, commenters noted that startup and shutdown variations are more pronounced than if diluent caps were to be allowed. They said that with a lower emissions limitation, the diluent cap would mathematically correct for calculation inaccuracies inherent in emission rate calculation immediately following startup. Commenters stated that relative accuracy test audits (RATA) must be conducted at greater than 50 percent load under 40 CFR part 60 and at normal operating load under 40 CFR part 75. They said that it is not reasonable to require facilities to certify their CEMS, including PM CEMS, at greater than 50 percent capacity and use it for compliance at less than 50 percent capacity. Commenters stated that startups have constantly changing flow and temperatures that do not allow compliance tests to be conducted during these periods.

Response: The Agency disagrees with the commenters who suggest that the 4-hour startup duration should be retained. As mentioned in the 2023 Proposal (88 FR 24885), 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 and/or better design structure, or a combination of factors, to be able to meet the requirements of paragraph (1) of the startup definition. This ability points out an improvement in operation that all EGUs should be able to meet at little to no additional expenditure, since the additional recordkeeping and reporting provisions associated with the work practice standards of paragraph (2) of the startup definition were more expensive than the requirements of paragraph (1) of the definition. As mentioned with respect to gathering experience with PM CEMS, the Agency believes owners or operators of the 8 EGUs relying on the 4-hour startup period can build on their startup experience gained since finalization of the 2012 MATS Final Rule, along with the experience shared by some of the other EGUs that have been able to conform with startup definition paragraph (1), as well as the experience to be obtained in the period yet remaining before compliance is required; such experience could prove key to aiding source owners or operators in their shift from reliance on startup definition paragraph (2) to startup definition paragraph (1). Should EGU owners or operators find that their attempts to rely on startup definition (1) are unsuccessful after application of that experience, they may request of the Administrator the ability to use an alternate non-opacity standard, as described in the NESHAP general provisions at 40 CFR 63.6(g). Before the Administrator's approval can be granted, the EGU owner or operator's request must appear in the **Federal Register** for the opportunity for notice and comment by the public, as required in 40 CFR 63.6(g)(1).

Regarding consent decrees or state agreements for requirements other than those contained in this rule, while the rule lacks the ability to revise such agreements, the EPA recommends that EGU owners or operators contact the other parties to see what, if any, revisions could be made. Nonetheless, the Agency expects EGU source owners or operators to comply with the revised startup definition by the date specified in this rule. Given the concern expressed by the commenters for some sources, the Agency expects such source owners or operators to begin negotiations with other parties for other non-rule obligations to begin early enough to be completed prior to the compliance date specified in this rule.

The Agency disagrees with the commenters' suggestions that startup definition paragraph (2)'s reporting requirements were too strict to be used. That suggestion is not consistent with the number of commenters who claimed to need to use paragraph (2) of the startup definition, even though only 2.5 percent of EGUs currently rely on this startup definition. The Agency's experience is that almost all EGU source owners or operators have been able to adjust their unit operation such that adherence to startup definition paragraph (1) reduced, if not eliminated, the concern by some about use of startup definition paragraph (1). As mentioned earlier in this document, the better performers in the coal-fired EGU source category no longer need to have, or use, paragraph (2) of the startup definition after gaining experience with using paragraph (1).

The Agency disagrees with the commenter's suggestion that the diluent cap values allowed for use by 40 CFR part 75 be included in the rule, because diluent cap values are already allowed for use during startup and shutdown periods per 40 CFR 63.10007(f)(1). Note that while emission values are to be recorded and reported during startup and shutdown periods, they are not to be used in compliance calculations per 40 CFR 63.10020(e). In addition to diluent cap use during startup and shutdown periods, section 6.2.2.3 of appendix C to 40 CFR part 63, subpart UUUUU allows diluent cap use for PM CEMS during any periods when oxygen or CO_2 values exceed or dip below, respectively, the cap levels. Diluent cap use for other periods from other regulations are not necessary for MATS. The Agency does not understand the commenter's suggestion concerning the load requirement for a RATA. The Agency believes the commenter may have mistaken HCl CEMS requirements, which use RATAs but were not proposed to be changed, with PM CEMS requirements, which do not use RATAs. Since PM CEMS are not subject to RATAs and the Agency did not propose changes to requirements for HCl CEMS, the comment on RATAs being conducted at greater than 50 percent load is moot. The EPA is finalizing the removal of startup definition paragraph (2), as proposed.

D. What is the rationale for our final approach and final decisions for the startup provisions?

The EPA is finalizing the removal of paragraph (2) of the definition of "startup" in 40 CFR 63.10042 consistent with reasons described in the 2023 Proposal. As the majority of EGUs are already relying on the work practice standards in paragraph (1) of the startup definition, the EPA finds that such a change is achievable within the 180-day compliance timeline by all EGUs at little to no additional expenditure since the additional reporting and recordkeeping provisions under paragraph (2) were more expensive than paragraph (1). Additionally, the time period for engaging pollution controls for PM or non-Hg HAP metals is expected to be reduced when transitioning to paragraph (1), therefore increasing the duration in which pollution controls are employed and lowering emissions.

VIII. What other key comments did we receive on the proposal?

Comment: Some commenters argued that it is well-established that cost is a major consideration in rulemakings reviewing existing NESHAP under CAA section 112(d)(6). In particular, commenters cited to *Michigan* v. *EPA,* 576 U.S. 743, 759 (2015), to support the argument that the EPA must consider the costs of the regulation in relation to the benefits intended by the statutory requirement mandating this regulation, that is, the benefits of the HAP reductions. Commenters stated that the EPA should not seek to impose the excessive costs associated with this action as there would be no benefit associated with reducing HAP. The commenters said that the EPA certainly should not do so for an industry that is rapidly reducing its emissions because it is on the way to retiring most, if not all, units in the source category in little over a decade. The commenters also claimed that as *Michigan* held that cost and benefits must be considered in determining whether it is "appropriate" to regulate EGUs under CAA section 112 in the first place, it necessarily follows that the same threshold must also apply when the EPA subsequently reviews the standards.

Response: The EPA agrees that it is appropriate to take costs into consideration in deciding whether it is necessary to revise an existing NESHAP under CAA section 112(d)(6). As explained in the 2023 Proposal and this document, the EPA has carefully considered the costs of compliance and the effects of those costs on the industry. Although the commenters seem to suggest that the EPA should weigh the costs and benefits of the revisions to the standard, we do not interpret the comments as arguing that the EPA should undertake a formal benefit cost analysis but rather the commenters believe that the EPA should instead limit its analysis supporting the standard to HAP emission reductions. Our consideration of costs in this rulemaking is consistent with the Supreme Court's direction in *Michigan* where the Court noted that "[i]t will be up to the Agency to decide (as always, within the limits of reasonable interpretation) how to account for cost," 576 U.S. 743, 759 (2015), and with comments arguing that the EPA should focus its decision-making on the standard on the anticipated reductions in HAP.

In *Michigan,* the Supreme Court concluded that the EPA erred when it concluded it could not consider costs when deciding as a threshold matter whether it is ''appropriate and necessary'' under CAA section 112(n)(1)(A) to regulate HAP from EGUs, despite the relevant statutory provision containing no specific reference to cost. 576 U.S. at 751. In doing so, the Court held that the EPA ''must consider cost—including, most importantly, cost of compliance—before deciding whether regulation is appropriate and necessary'' under CAA section 112. *Id.* at 759. In examining the language of CAA section 112(n)(1)(A), the Court concluded that the phrase ''appropriate and necessary'' was ''capacious'' and held that ''[r]ead naturally in the present context, the phrase 'appropriate and necessary' requires at least some attention to cost.'' *Id.* at 752. As is clear from the record for this rulemaking, the EPA has carefully considered cost in reaching its decision to revise the NESHAP in this action.

The EPA has also taken into account the numerous HAP-related benefits of the final rule in deciding to take this action. These benefits include not only the reduced exposure to Hg and non-Hg HAP metals, but also the additional transparency provided by PM CEMS for communities that live near sources of HAP, and the assurance PM CEMS will provide that the standards are being met on a continuous basis. As discussed in section II.B.2., and section IX.E. many of these important benefits are not able to be monetized. Although this rule will result in the reduction of HAP, including Hg, lead, arsenic, chromium, nickel, and cadmium, data limitations prevent the EPA from assigning monetary value to those reductions. In addition, there are several benefits associated with the use of PM CEMS which are not quantified in this rule.

While the Court's examination of CAA section 112(n)(a)(1) in *Michigan* considered a different statutory provision than CAA section 112(d)(6) under which the EPA is promulgating this rulemaking, the EPA has nonetheless satisfied the Court's directive to consider costs, both in the context of the individual revisions to MATS (as directed by the language of the statute) and in the context of the rulemaking as a whole. Moreover, while the EPA is not required to undertake a ''formal cost benefit analysis in which each advantage and disadvantage [of a regulation] is assigned a monetary value,'' *Michigan,* 576 U.S. at 759, the EPA has contemplated and carefully considered both the advantages and disadvantages of the revisions it is finalizing here, including qualitative and quantitative benefits of the regulation and the costs of compliance.

IX. Summary of Cost, Environmental, and Economic Impacts and Additional Analyses Conducted

The following analyses of costs and benefits, and environmental, economic, and environmental justice impacts are presented for the purpose of providing the public with an understanding of the potential consequences of this final action. The EPA notes that analysis of such impacts is distinct from the determinations finalized in this action under CAA section 112, which are based on the statutory factors the EPA discussed in section II.A. and sections IV. through VII.

The EPA's obligation to conduct an analysis of the potential costs and benefits under Executive Order 12866, discussed in this section and section X.A., is distinct from its obligation in setting standards under CAA section 112 to take costs into account. As explained above, the EPA considered costs in multiple ways in choosing appropriate standards consistent with the requirements of CAA section 112. The benefit-cost analysis is performed to comply with Executive Order 12866. The EPA, however, did not rely on that analysis in choosing the appropriate standard here, consistent with the Agency's longstanding interpretation of the statute. As discussed at length in section II.B.2. above and in the EPA's 2023 final rulemaking finalizing the appropriate and necessary finding (88 FR 13956), historically there have been significant challenges in monetizing the benefits of HAP reduction. Important categories of benefits from reducing HAP cannot be monetized, making benefit-cost analysis ill-suited to the EPA's decision making on regulating HAP emissions under CAA section 112. Further, there are also unquantified emission reductions anticipated from installing PM CEMS, as discussed in section IX.E. For this reason, combined with Congress's recognition of the particular dangers posed by HAP and consequent direction to the EPA to reduce emissions of these pollutants to the ''maximum degree,'' the EPA does not at this time believe it is appropriate to rely on the results of the monetized benefit-cost analysis when setting the standards.

As noted in section X.A. below, the EPA projects that the net monetized benefits of this rule are negative. Many of the benefits of this rule discussed at length in this section and elsewhere in this record, however, were not monetized. This rule will result in the reduction of HAP, including Hg, lead, arsenic, chromium, nickel, and cadmium,[86] consistent with Congress's direction in CAA section 112 discussed in section II.A. of this final rule. At this time, data limitations prevent the EPA from assigning monetary value to those reductions, as discussed in section II.B.2. above.[87] In addition, the benefits of the additional transparency provided by the requirement to use PM CEMS for communities that live near sources of HAP, and the assurance PM CEMS provide that the standards are being met on a continuous basis were not monetized due to data limitations. While the EPA does not believe benefit-cost analysis is the right way to determine the appropriateness of a standard under CAA section 112, the EPA notes that when all of the costs and benefits are considered (including non-monetized benefits), this final rule is a worthwhile exercise of the EPA's CAA section 112(d)(6) authority.

A. What are the affected facilities?

The EPA estimates that there are 314 coal-fired EGUs[88] and 58 oil-fired EGUs that will be subject to this final rule by the compliance date.

B. What are the air quality impacts?

The EPA estimated emission reductions under the final rule for the years 2028, 2030, and 2035 based upon IPM projections. The quantified emissions estimates were developed with the EPA's Power Sector Modeling Platform 2023 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

[86] As of 2023, three of the HAP metals or their compounds emitted by EGUs (arsenic, chromium, and nickel) are classified as carcinogenic to humans. More details are available in section II.B.2. and Chapter 4.2.2 of the RIA.

[87] *See also National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration and Affirmation of the Appropriate and Necessary Supplemental Finding,* 88 FR 13956, 13970–73 (March 6, 2023) (for additional discussion regarding the limitations to monetizing and quantifying most benefits from HAP reductions in the 2023 rulemaking finalizing the appropriate and necessary finding).

[88] The number of coal-fired affected EGUs is larger than the 296 coal-fired EGUs assessed for the fPM standard in section IV. because it includes four EGUs that burn petroleum coke (which are a separate subcategory for MATS) and 14 EGUs without fPM compliance data available on the EPA's Compliance and Emissions Data Reporting Interface (CEDRI), *https://www.epa.gov/electronic-reporting-air-emissions/cedri.*

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.

The quantified emission reduction estimates presented in the RIA include reductions in pollutants directly covered 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 final rule. Table 8 of this document presents the projected emissions under the final rule. Note that, unlike the cost-effectiveness analysis presented in sections IV. and V. of this preamble, the projections presented in table 8 are incremental to a projected baseline which reflects future changes in the composition of the operational coal-fired EGU fleet that are projected to occur by 2035 as a result of factors affecting the power sector, such as the IRA, promulgated regulatory actions, or changes in economic conditions.

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Table 8. Projected EGU Emissions in the Baseline and Under the Final Rule: 2028, 2030, and 2035[a]

		Total Emissions			
	Year	Baseline	Final Rule	Change from Baseline	% Change
Hg (lb)	2028	6,129	5,129	-999	-16%
	2030	5,863	4,850	-1,013	-17%
	2035	4,962	4,055	-907	-18%
$PM_{2.5}$ (thousand tons)	2028	70.5	69.7	-0.8	-1.1%
	2030	66.3	65.8	-0.5	-0.8%
	2035	50.7	50.2	-0.5	-0.9%
PM_{10} (thousand tons)	2028	79.5	77.4	-2.1	-2.6%
	2030	74.5	73.1	-1.3	-1.8%
	2035	56.0	54.8	-1.2	-2.1%
SO_2 (thousand tons)	2028	454.3	454.0	-0.3	-0.1%
	2030	333.5	333.5	0.0	0.0%
	2035	239.9	239.9	0.0	0.0%
Ozone-season NO_x (thousand tons)	2028	189.0	188.8	-0.165	-0.09%
	2030	174.9	175.4	0.488	0.28%
	2035	116.9	119.1	2.282	1.95%
Annual NO_x (thousand tons)	2028	460.5	460.3	-0.283	-0.06%
	2030	392.8	392.7	-0.022	-0.01%
	2035	253.4	253.5	0.066	0.03%
HCl (thousand tons)	2028	2.5	2.5	0.0	0.0%
	2030	2.2	2.2	0.0	0.0%
	2035	1.5	1.5	0.0	0.1%
CO_2 (million metric tons)	2028	1,158.8	1,158.7	-0.1	0.0%
	2030	1,098.3	1,098.3	0.0	0.0%
	2035	724.2	724.1	-0.1	0.0%

[a] This analysis is limited to the geographically contiguous lower 48 states.

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In addition to the projected emissions impacts presented in table 8, we also estimate that the final rule will reduce at least 7 tons of non-Hg HAP metals in 2028, 5 tons of non-Hg HAP metals in 2030, and 4 tons of non-Hg HAP metals in 2035. These reductions are composed of reductions in emissions of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.[89]

Importantly, the continuous monitoring of fPM required in this rule will likely induce additional emissions reductions that we are unable to quantify. Continuous measurements of emissions accounts for changes to processes and fuels, fluctuations in load, operations of pollution controls, and equipment malfunctions. By measuring emissions across all operations, power plant operators and regulators can use the data to ensure controls are operating properly and to assess compliance with relevant standards. Because CEMS enable power plant operators to quickly identify and correct problems with pollution control devices, it is possible that fPM emissions could be lower than they otherwise would have been for up to 3 months—or up to 3 years if testing less frequently under the LEE program—at a time. This potential reduction in fPM and non-Hg HAP metals emission resulting from the information provided by continuous monitoring coupled with corrective actions by plant operators could be sizeable over the existing coal-fired fleet and is not quantified in this rulemaking.

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 emission reductions in table 8 of this preamble. Please see section IX.E. of this preamble and section 4 of the RIA for detailed discussions of the projected health, welfare, and climate benefits of these emission 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 other words, these costs are an estimate of the increased power industry expenditures required to implement the final requirements of this rule. The compliance cost estimates were mainly developed using the EPA's Power Sector Modeling Platform 2023 using IPM. The incremental costs of the final rule's PM CEMS requirement were estimated outside of IPM and added to the IPM-based cost estimate presented here and in section 3 of the RIA.

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. We estimate the PV and EAV using 2, 3, and 7 percent discount rates.[90] Table 9 of this document presents the estimates of compliance costs for the final rule.

Table 9. Projected Compliance Costs of the Final Rule, 2028 through 2037 (Millions 2019$, Discounted to 2023)[a]

	2% Discount Rate	3% Discount Rate	7% Discount Rate
PV	860	790	560
EAV	96	92	80

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

The PV of the compliance costs for the final rule, discounted at the 2 percent rate, is estimated to be about $860 million, with an EAV of about $96 million. At the 3 percent discount rate, the PV of the compliance costs of the final rule is estimated to be about $790 million, with an EAV of about $92 million. At the 7 percent discount rate, the PV of the compliance costs of the rule is estimated to be about $560 million, with an EAV of about $80 million.

We note that IPM provides the EPA's best estimate of the costs of the rules to the electricity sector and related energy sectors (*i.e.,* natural gas, coal mining). These compliance cost estimates are used as a proxy for the social cost of the rule. 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?

The Agency estimates that this rule will require additional fPM and/or Hg removal at less than 15 GW of operable capacity in 2028, which is about 14 percent of the total coal-fired EGU capacity projected to operate in that year. The units requiring additional fPM and/or Hg removal are projected to generate less than 2 percent of total generation in 2028. Moreover, the EPA does not project that any EGUs will retire in response to the standards promulgated in this final rule.

Consistent with the small share of EGUs required to reduce fPM and/or Hg emissions rates, this final action has limited energy market implications. There are limited impacts on energy prices projected to result from this final rule. On a national average basis,

[89] Note that modeled projections include total PM_{10} and total $PM_{2.5}$. The EPA estimated non-Hg HAP metals reductions by multiplying the ratio of non-Hg HAP metals to fPM by modeled projections of total PM_{10} reductions under the rule. The ratios of non-Hg HAP metals to fPM were based on analysis of 2010 MATS Information Collection Request (ICR) data. As there may be substantially more fPM than PM_{10} reduced by the control techniques projected to be used under this rule, these estimates of non-Hg HAP metals reductions are likely underestimates. More detail on the estimated reduction in non-Hg HAP metals can be found in the docketed memorandum *Estimating Non-Hg HAP Metals Reductions for the 2024 Technology Review for the Coal-Fired EGU Source Category.*

[90] Results using the 2 percent discount rate were not included in the proposal for this action. The 2003 version of OMB's Circular A–4 had generally recommended 3 percent and 7 percent as default rates to discount social costs and benefits. The analysis of the proposed rule used these two recommended rates. In November 2023, OMB finalized an update to Circular A–4, in which it recommended the general application of a 2 percent rate to discount social costs and benefits (subject to regular updates). The Circular A–4 update also recommended consideration of the shadow price of capital when costs or benefits are likely to accrue to capital. As a result of the update to Circular A–4, we include cost and benefits results calculated using a 2 percent discount rate.

delivered coal, natural gas, and retail electricity prices are not projected to change. The EPA does not project incremental changes in existing operational capacity to occur in response to the final rule. 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?

The RIA for this action analyzes the benefits associated with the projected emission reductions under this rule. This final rule is projected to reduce emissions of Hg and non-Hg HAP metals, as well as $PM_{2.5}$, SO_2, NO_X and CO_2 nationwide. The potential impacts of these emission reductions are discussed in detail in section 4 of the RIA. The EPA notes that the benefits analysis is distinct from the statutory determinations finalized herein, which are based on the statutory factors the EPA is required to consider under CAA section 112. The assessment of benefits described here and in the RIA is presented solely for the purposes of complying with Executive Order 12866, as amended by Executive Order 14094, and providing the public with a complete depiction of the impacts of the rulemaking.

Hg is a persistent, bioaccumulative toxic metal emitted from power plants that exists in three forms: gaseous elemental Hg, inorganic Hg compounds, and organic Hg compounds (*e.g.,* methylmercury). Hg can also be emitted in a particle-bound form. Elemental Hg can exist as a shiny silver liquid, but readily vaporizes into air. Airborne elemental Hg does not quickly deposit or chemically react in the atmosphere, resulting in residence times that are long enough to contribute to global scale deposition. Oxidized Hg and particle-bound Hg deposit quickly from the atmosphere impacting local and regional areas in proximity to sources. Methylmercury is formed by microbial action in the top layers of sediment and soils, after Hg has precipitated from the air and deposited into waterbodies or land. Once formed, methylmercury is taken up by aquatic organisms and bioaccumulates up the aquatic food web. Larger predatory fish may have methylmercury concentrations many times that of the concentrations in the freshwater body in which they live.

All forms of Hg are toxic, and each form exhibits different health effects. Acute (short-term) exposure to high levels of elemental Hg vapors results in central nervous system (CNS) effects such as tremors, mood changes, and slowed sensory and motor nerve function. Chronic (long-term) exposure to elemental Hg in humans also affects the CNS, with effects such as erethism (increased excitability), irritability, excessive shyness, and tremors. The major effect from chronic ingestion or inhalation of low levels of inorganic Hg is kidney damage.

Methylmercury is the most common organic Hg compound in the environment. Acute exposure of humans to very high levels of methylmercury results in profound CNS effects such as blindness and spastic quadriparesis. Chronic exposure to methylmercury, most commonly by consumption of fish from Hg contaminated waters, also affects the CNS with symptoms such as paresthesia (a sensation of pricking on the skin), blurred vision, malaise, speech difficulties, and constriction of the visual field. Ingestion of methylmercury can lead to significant developmental effects, such as IQ loss measured by performance on neurobehavioral tests, particularly on tests of attention, fine motor-function, language, and visual spatial ability. In addition, evidence in humans and animals suggests that methylmercury can have adverse effects on both the developing and the adult cardiovascular system, including fatal and non-fatal ischemic heart disease (IHD). Further, nephrotoxicity, immunotoxicity, reproductive effects (impaired fertility), and developmental effects have been observed with methylmercury exposure in animal studies.[91] Methylmercury has some genotoxic activity and can cause chromosomal damage in several experimental systems. The EPA has concluded that mercuric chloride and methylmercury are possibly carcinogenic to humans.[92 93]

The projected emissions reductions of Hg are expected to lower deposition of Hg into ecosystems and reduce U.S. EGU attributable bioaccumulation of methylmercury in wildlife, particularly for areas closer to the effected units subject to near-field deposition. Subsistence fishing is associated with vulnerable populations. Methylmercury exposure to subsistence fishers from lignite-fired units is below the current RfD for methylmercury neurodevelopmental toxicity. The EPA considers exposures at or below the RfD for methylmercury unlikely to be associated with appreciable risk of deleterious effects across the population. However, the RfD for methylmercury does not represent 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. 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, which are all located in North Dakota, Texas, and Mississippi.

In addition, U.S. EGUs are a major source of HAP metals emissions including selenium, arsenic, chromium, nickel, and cobalt, cadmium, beryllium, lead, and manganese. Some HAP metals emitted by U.S. EGUs are known to be persistent and bioaccumulative and others have the potential to cause cancer. Exposure to these HAP metals, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. The emissions reductions projected under this final rule are expected to reduce human exposure to non-Hg HAP metals, including carcinogens.

Furthermore, there is the potential for reductions in Hg and non-Hg HAP metal emissions to enhance ecosystem services and improve ecological outcomes. The reductions will potentially lead to positive economic impacts although it is difficult to estimate these benefits and, consequently, they have not been included in the set of quantified benefits.

As explained in section IX.B., the continuous monitoring of fPM required in this rule may induce further reductions of fPM and non-Hg HAP metals than we project in the RIA for

[91] Agency for Toxic Substances and Disease Registry (ATSDR). Toxicological Profile for Mercury. Public Health Service, U.S. Department of Health and Human Services, Atlanta, GA. 2022.

[92] U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Methylmercury. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 2001.

[93] U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Mercuric Chloride. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 1995.

this action. As a result, there may be additional unquantified beneficial health impacts from these potential reductions. The continuous monitoring of fPM required in this rule is also likely to provide several additional benefits to the public which are not quantified in this rule, including greater certainty, accuracy, transparency, and granularity in fPM emissions information than exists today.

The 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 $PM_{2.5}$, 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. The rule is also expected to reduce ozone-season NO_X emissions nationally in most years of analysis. 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 reduces the incidence of ozone-related health effects, although 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 technical support document titled *Estimating $PM_{2.5}$* minus; *and Ozone-Attributable Health Benefits* (2023). This document describes our peer-reviewed approach for selecting and quantifying adverse effects attributable to air pollution, the demographic and health data used to perform these calculations, and our methodology for valuing these effects.

Because of projected changes in dispatch under the final requirements, the rule is also projected to impact CO_2 emissions. The EPA estimates the climate benefits of CO_2 emission reductions expected from the final rule using estimates of the social cost of carbon (SC–CO_2) that reflect recent advances in the scientific literature on climate change and its economic impacts and that incorporate recommendations made by the National Academies of Science, Engineering, and Medicine.[94] The EPA published and used these estimates in the RIA for the December 2023 Natural Gas Sector final rule titled *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* (2023 Oil and Natural Gas NSPS/EG).[95] The EPA solicited public comment on the methodology and use of these estimates in the RIA for the Agency's December 2022 Oil and Natural Gas Sector supplemental proposal [96] that preceded the 2023 Oil and Natural Gas NSPS/EG and has conducted an external peer review of these estimates. The response to public comments document and the response to peer reviewer recommendations can be found in the docket for the 2023 Oil and Natural Gas NSPS/EG action. Complete information about the peer review process is also available on the EPA's website.[97]

Section 4.4 within the RIA for this final rulemaking provides an overview of the methodological updates incorporated into the SC–CO_2 estimates used in this final RIA.[98] A more detailed explanation of each input and the modeling process is provided in the final technical report, *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*.[99]

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 and 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 CO_2 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 restrain the ability of SC–CO_2 estimates to include all physical, ecological, and economic impacts of climate change, implicitly assigning a value of zero to the omitted climate damages. The estimates are, therefore, a partial accounting of climate change impacts and likely underestimate the marginal benefits of abatement.

Table 10 of this document 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.

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[94] National Academies of Sciences, Engineering, and Medicine (National Academies). 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. National Academies Press.

[95] *Regulatory Impact Analysis of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* Docket ID No. EPA–HQ–OAR–2021–0317, December 2023.

[96] *Supplemental Notice of Proposed Rulemaking for Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* 87 FR 74702 (December 6, 2022).

[97] *https://www.epa.gov/environmental-economics/scghg-tsd-peer-review.*

[98] Note that the RIA for the proposal of this rulemaking used the SC–CO_2 estimates from the Interagency Working Group's (IWG) February 2021 Social Cost of Greenhouse Gases Technical Support Document (TSD) (IWG 2021) to estimate climate benefits. These SC–CO_2 estimates were interim values recommended for use in benefit-cost analyses until updated estimates of the impacts of climate change could be developed. Estimated climate benefits using these interim SC–CO_2 values (IWG 2021) are presented in Appendix B of the RIA for this final rulemaking for comparison purposes.

[99] Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, ''Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,'' *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances,* Docket ID No. EPA–HQ–OAR–2021–0317, November 2023.

Table 10. Projected Benefits of the Final Rule, 2028 through 2037 (Millions 2019$, Discounted to 2023)[a]

Present Value (PV)			
	2% Discount Rate	3% Discount Rate	7% Discount Rate
Health Benefits[c]	300	260	180
Climate Benefits[d]	130	130	130
Total Monetized Benefits[e]	420	390	300
Equivalent Annual Value (EAV)[b]			
	2% Discount Rate	3% Discount Rate	7% Discount Rate
Health Benefits[c]	33	31	25
Climate Benefits[d]	14	14	14
Total Monetized Benefits[e]	47	45	39
Non-Monetized Benefits	Benefits from reductions of about 900 to 1000 pounds of Hg annually		
	Benefits from reductions of at least 4 to 7 tons of non-Hg HAP metals annually		
	Benefits from improved water quality and availability		
	Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS		

[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 air quality-related 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 2, 3, and 7 percent.

[d] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of carbon dioxide (SC-CO_2) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. Please see section 4 of the RIA for the full range of monetized climate benefit estimates.

[e] The list of non-monetized benefits does not include all potential non-monetized benefits. See table 4-8 of the RIA for a more complete list.

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This final rule is projected to reduce $PM_{2.5}$ and ozone concentrations, producing a projected PV of monetized health benefits of about $300 million, with an EAV of about $33 million discounted at 2 percent. The projected PV of monetized climate benefits of the final rule is estimated to be about $130 million, with an EAV of about $14 million using the SC–$CO_2$ discounted at 2 percent.[100] Thus, this final rule would

[100] Monetized climate benefits are discounted using a 2 percent discount rate, consistent with the EPA's updated estimates of the SC–CO_2. The 2003 version of OMB's Circular A–4 had generally recommended 3 percent and 7 percent as default discount rates for costs and benefits, though as part of the Interagency Working Group on the Social Cost of Greenhouse Gases, OMB had also long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. In November 2023, OMB finalized an update to Circular A–4, in which it recommended the general application of a 2 percent discount rate to costs and benefits (subject to regular updates), as well as the consideration of the shadow price of capital when costs or benefits are likely to accrue to capital (OMB 2023). Because the SC–CO_2 estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the social rate of return on capital (7 percent under

generate a PV of monetized benefits of $420 million, with an EAV of $47 million discounted at a 2 percent rate.

At a 3 percent discount rate, this final rule is expected to generate projected PV of monetized health benefits of $260 million, with an EAV of about $31 million discounted at 3 percent. Climate benefits remain discounted at 2 percent in this benefits analysis and are estimated to be about $130 million, with an EAV of about $14 million using the SC–$CO_2$. Thus, this final rule would generate a PV of monetized benefits of $390 million, with an EAV of $45 million discounted at a 3 percent rate.

At a 7 percent discount rate, this final rule is expected to generate projected PV of monetized health benefits of $180 million, with an EAV of about $25 million discounted at 7 percent. Climate benefits remain discounted at 2 percent in this benefits analysis and are estimated to be about $130 million, with an EAV of about $14 million using the SC–$CO_2$. Thus, this final rule would generate a PV of monetized benefits of $300 million, with an EAV of $39 million discounted at a 7 percent rate.

The benefits from reducing Hg and non-Hg HAP metals and from unquantified improvements in water quality were not monetized and are therefore not directly reflected in the monetized benefit-cost estimates associated with this rulemaking. Potential benefits from the increased transparency and accelerated identification of anomalous emission anticipated from requiring PM 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 that, if we were able to monetize these beneficial impacts, the final rule would have greater net benefits than shown in table 11 of this document.

F. What analysis of environmental justice did we conduct?

For purposes of analyzing regulatory impacts, the EPA relies upon its June 2016 ''Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,'' which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance. The Technical Guidance states that a regulatory action may involve potential EJ concerns if it could: (1) create new disproportionate impacts on communities with EJ concerns; (2) exacerbate existing disproportionate impacts on communities with EJ concerns; or (3) present opportunities to address existing disproportionate impacts on communities with EJ concerns through this action under development.

The EPA's EJ technical guidance states that ''[t]he analysis of potential EJ concerns for regulatory actions should address three questions: (A) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline? (B) 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? (C) For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?'' [101]

The environmental justice analysis is presented for the purpose of providing the public with as full as possible an understanding of the potential impacts of this final action. The EPA notes that analysis of such impacts is distinct from the determinations finalized in this action under CAA section 112, which are based solely on the statutory factors the EPA is required to consider under that section. 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 this 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 (section 6 of the RIA).

For this rule, we employ two types of analysis to respond to the previous three questions: proximity analyses and exposure analyses. Both types of analysis can inform whether there are potential EJ concerns in the baseline (question 1).[102] 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 National Ambient Air Quality Standards (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 and fuel level emission data paired with facility-level baseline emissions and provided at a resolution of 12 square kilometers. Additionally, here we focus on air quality changes due to this rulemaking and infer post-policy ozone and $PM_{2.5}$ exposure burden impacts. Note, we discuss HAP and climate EJ impacts of this action qualitatively (section 6 of the RIA).

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 various local populations with potential EJ concerns (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 on the basis of race, ethnicity, poverty status, employment status, health insurance status, life expectancy, redlining, Tribal land, age, sex, educational attainment,

OMB Circular A–4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC–CO_2. See Section 4.4 of the RIA for more discussion.

[101] See *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

[102] 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).

and degree of linguistic isolation (section 6.5). It is important to note that due to the small magnitude of underlying emissions changes, and the corresponding small magnitude of the ozone and $PM_{2.5}$ concentration changes, the rule is expected to have only a small impact on the distribution of exposures across each demographic group. Each of these analyses should be considered independently of each other, as each 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 final rule, traffic, or noise. The baseline analysis indicates that on average the populations living within 10 kilometers of coal plants potentially impacted by the amended fPM 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 American Indian population living within 10 kilometers of lignite plants potentially impacted by the amended Hg standard is higher than the national average. Assessing these results, 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 various population groups 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 Review were below both the presumptive acceptable cancer risk threshold and noncancer health benchmarks and this 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. However, the potential reduction in non-Hg HAP metal emissions would likely reduce exposures to people living nearby coal plants potentially impacted by the amended fPM standards.

This 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 because 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 the EPA's EJ technical guidance more directly than the proximity analyses, as it evaluates a form of the environmental stressor targeted by the regulatory action. Baseline $PM_{2.5}$ and ozone exposure analyses show that certain populations, such as residents of redlined census tracts, those linguistically isolated, Hispanic, Asian, those without a high school diploma, and the unemployed may experience higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indian, residents of Tribal Lands, populations with higher life expectancy or with life expectancy data unavailable, children, and insured populations may also experience disproportionately higher ozone concentrations than the reference group. Hispanic, Black, below the poverty line, and uninsured populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the reference group. 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.[103]

X. 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 14094: Modernizing Regulatory Review

This action is a ''significant regulatory action,'' as defined under section 3(f)(1) of Executive Order 12866, as amended by Executive Order 14094. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. Documentation of any changes made in response to the Executive Order 12866 review is available in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, *Regulatory Impact Analysis for the Final National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review* (Ref. EPA–452/R–24–005), is briefly summarized in section IX. of this preamble and here. This analysis is also available in the docket.

Table 11 of this document presents the estimated PV and EAV of the monetizable projected health benefits, climate benefits, compliance costs, and net benefits of the final rule in 2019 dollars discounted to 2023. The estimated monetized net benefits are the projected monetized benefits minus the projected monetized costs of the final rule.

Under Executive Order 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 final rule include health benefits associated with projected reductions in $PM_{2.5}$ 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 2, 3, and 7 percent. The projected climate

[103] Please note that results for ozone and $PM_{2.5}$ exposures should not be extrapolated to other air pollutants that were not included in the assessment, including HAP. Detailed EJ analytical results can be found in section 6 of the RIA.

benefits in this table are based on estimates of the SC–CO_2 at a 2 percent near-term Ramsey discount rate and are discounted using a 2 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 finalized requirements and represent the EPA's best estimate of the social cost of the final rulemaking.

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Table 11. Projected Monetized Benefits, Compliance Costs, and Net Benefits of the Final Rule, 2028 through 2037 (Millions 2019$, Discounted to 2023)[a]

	Present Value (PV)		
	2% Discount Rate	3% Discount Rate	7% Discount Rate
Health Benefits[c]	300	260	180
Climate Benefits[d]	130	130	130
Compliance Costs	860	790	560
Net Benefits	-440	-400	-260
	Equal Annualized Value (EAV)[b]		
	2% Discount Rate	3% Discount Rate	7% Discount Rate
Health Benefits[c]	33	31	25
Climate Benefits[d]	14	14	14
Compliance Costs	96	92	80
Net Benefits	-49	-47	-41
Non-Monetized Benefits[e]	Benefits from reductions of about 900 to 1000 pounds of Hg annually		
	Benefits from reductions of at least 4 to 7 tons of non-Hg HAP metals annually		
	Benefits from improved water quality and availability		
	Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS		

[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 air quality related 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 2, 3, and 7 percent.

[d] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the SC-CO_2 (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. Please see section 4 of the RIA for the full range of monetized climate benefit estimates.

[e] The list of non-monetized benefits does not include all potential non-monetized benefits. See table 4-8 of the RIA for a more complete list.

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As shown in table 11 of this document, this rule is projected to reduce $PM_{2.5}$ and ozone concentrations, producing a projected PV of monetized health benefits of about $300 million, with an EAV of about $33 million discounted at 2 percent. The 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 $130 million, with an EAV of about $14 million using the SC–$CO_2$ discounted at 2 percent. Thus, this final rule would generate a PV of monetized benefits of $420 million, with an EAV of $47 million discounted at a 2 percent rate. The PV of the projected compliance costs are $860 million, with an EAV of about $96 million discounted at 2 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of −$440 million and EAV of −$49 million.

At a 3 percent discount rate, this rule is expected to generate projected PV of monetized health benefits of $260 million, with an EAV of about $31 million. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, this final rule would generate a PV of monetized benefits of $390 million, with an EAV of $45 million discounted at a 3 percent rate. The PV of the projected compliance costs are $790 million, with an EAV of $92 million discounted at 3 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of −$400 million and an EAV of −$47 million.

At a 7 percent discount rate, this rule is expected to generate projected PV of monetized health benefits of $160 million, with an EAV of about $23 million. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, this final rule would generate a PV of monetized benefits of $300 million, with an EAV of $39 million discounted at a 3 percent rate. The PV of the projected compliance costs are $560 million, with an EAV of $80 million discounted at 7 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of −$260 million and an EAV of −$41 million.

The potential benefits from reducing Hg and non-Hg HAP metals and potential improvements in water quality and availability were not monetized and are therefore not directly reflected in the monetized benefit-cost estimates associated with this final rule. 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 quantify and monetize these beneficial impacts, the final rule would have greater net benefits than shown in table 11 of this preamble.

B. Paperwork Reduction Act (PRA)

The information collection activities in this rule 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 requirements are not enforceable until OMB approves them. OMB has previously approved the information collection activities contained in the existing regulations and has assigned OMB control number 2060–0567.

The information collection activities in this rule include 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). The burden and cost estimates below represent the total burden and cost for the information collection requirements of the NESHAP for Coal- and Oil-Fired EGUs, not just the burden associated with the amendments in this final rule. The incremental cost associated with these amendments is $2.4 million per year.

Respondents/affected entities: The respondents are owners or operators of coal- and oil-fired EGUs. The North American Industry Classification System (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: 192 per year.[104]

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

Total estimated burden: 447,000 hours (per year). Burden is defined at 5 CFR part 1320.3(b).

Total estimated cost: $106,600,000 (per year), includes $53,100,000 in annual labor costs and $53,400,000 annualized capital and operation and maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

The EPA certifies that this action will not have a significant economic impact on a substantial number of small entities under the RFA. In the 2028 analysis year, the EPA identified 24 potentially affected small entities operating 45 units at 26 facilities, and of these 24, only one small entity may experience compliance cost increases greater than one percent of revenue under the final rule. Details of this analysis are presented in section 5 of the RIA, which is in the public docket.

D. Unfunded Mandates Reform Act (UMRA)

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

E. Executive Order 13132: Federalism

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

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

This action does not have tribal implications as specified in Executive

[104] Each facility is a respondent and some facilities have multiple EGUs.

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 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 action. The EPA did not receive any requests for 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 action.

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

Executive Order 13045 directs Federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is subject to Executive Order 13045 because it is a significant regulatory action under section 3(f)(1) of Executive Order 12866. Accordingly, we have evaluated the potential for environmental health or safety effects from exposure to HAP, ozone, and $PM_{2.5}$ on children. The EPA believes that, even though the 2020 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. The action described in this rule is also expected to lower ozone and $PM_{2.5}$ in many areas, including those areas that struggle to attain or maintain the NAAQS, and thus mitigate some pre-existing health risks across all populations evaluated, including children. The results of this evaluation are contained in the RIA and are available in the docket for this action.

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 standards, the EPA does not project a significant change in retail electricity prices on average across the contiguous U.S., coal-fired electricity generation, natural gas-fired electricity generation, or utility power sector delivered natural gas prices. 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) and 1 CFR Part 51

The following standards appear in the amendatory text of this document and were previously approved for the locations in which they appear: ANSI/ASME PTC 19.10–1981, ASTM D6348–03(R2010), and ASTM D6784–16.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All

The EPA believes that the human health or environmental conditions that exist prior to this action result in or have the potential to result in disproportionate and adverse human health or environmental effects on communities with environmental justice concerns. For this rule, we employ the proximity demographic analysis and the $PM_{2.5}$ and ozone exposure analyses to evaluate disproportionate and adverse human health and environmental effects on communities with EJ concerns that exist prior to the action. The proximity demographic analysis indicates that on average the population living within 10 kilometers of coal plants potentially impacted by the fPM 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 American Indian population living within 10 kilometers of lignite-fired plants potentially impacted by the Hg standard is higher than the national average. Baseline $PM_{2.5}$ and ozone and exposure analyses show that certain populations, such as residents of redlined census tracts, those linguistically isolated, Hispanic, Asian, those without a high school diploma, and the unemployed may experience disproportionately higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indian, residents of Tribal Lands, populations with higher life expectancy or with life expectancy data unavailable, children, and insured populations may also experience disproportionately higher ozone concentrations than the reference group. Hispanics, Blacks, those below the poverty line, and uninsured populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the reference group.

The EPA believes that this action is not likely to change existing disproportionate and adverse effects on communities with environmental justice concerns. 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 final rule, and whether potential EJ concerns will be created or mitigated. We infer that baseline disparities in ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the final regulatory option due to the small magnitude of the exposure changes across population demographics associated with the rulemaking relative to the baseline disparities. We also do not find evidence that potential EJ concerns related to ozone or $PM_{2.5}$ exposures will be exacerbated or mitigated in the final regulatory option, compared to the baseline due to the very small differences in the magnitude of post-policy ozone and $PM_{2.5}$ exposure impacts across demographic populations. Additionally, the potential reduction in Hg and non-Hg HAP metal emissions would likely reduce exposures to people living nearby coal plants potentially impacted by the amended fPM standards.

The information supporting this Executive Order review is contained in section IX.F. of this preamble and in section 6, Environmental Justice Impacts of the RIA, which is in the public docket (EPA–HQ–OAR–2018–0794).

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action meets the criteria set forth in 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 63

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

Michael S. Regan,

Administrator.

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

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

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

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

Subpart A—General Provisions

■ 2. In § 63.14, paragraph (f)(1) is amended by removing the text ''tables 4 and 5 to subpart UUUUU'' and adding, in its place, the text ''table 5 to subpart UUUUU''.

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

■ 3. Section 63.9991 is amended by revising paragraph (a)(2) to read as follows:

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

(a) * * *

(2) Before July 6, 2027, you must meet each operating limit in Table 4 to this subpart that applies to your EGU.

* * * * *

■ 4. Amend § 63.10000 by:

■ a. Revising paragraph (c)(1)(i) and paragraph (c)(1)(i)(A);

■ b. Redesignating paragraph (c)(1)(i)(C) as paragraph (c)(1)(i)(D);

■ c. Adding new paragraph (c)(1)(i)(C);

■ d. Revising paragraph (c)(1)(iv);

■ e. Adding new paragraphs (c)(1)(iv)(A) through (C);

■ f. Revising paragraphs (c)(2)(i) and (ii);

■ g. Revising paragraph (d)(5)(i); and

■ h. Revising paragraph (m) introductory text.

The revisions and additions read as follows:

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

* * * * *

(c) * * *

(1) * * *

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

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

* * * * *

(C) On or after July 6, 2027, you may not pursue the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals for coal-fired and solid oil-derived fuel-fired EGUs.

* * * * *

(iv)(A) Before July 6, 2027, if your coal-fired or solid oil derived fuel-fired EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

(B) On and after July 6, 2027, you may not pursue or continue to use the LEE option for your coal-fired or solid oil derived fuel-fired EGU for filterable PM or for non-mercury HAP metals. You must demonstrate compliance through an initial performance test, and you must monitor continuous performance with the applicable filterable PM emissions limit through the use of a PM CEMS or HAP metals CMS.

(C) If your IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable PM, you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

* * * * *

(2) * * *

(i) For an existing liquid oil-fired unit, you may conduct the performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a LEE for one or more pollutants. For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status. For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status. On or after July 6, 2027, you may not pursue the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals.

(ii) Before July 6, 2027, if your liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, performance testing conducted quarterly. On and after July 6, 2027, you may not pursue or continue to use the LEE option for your liquid oil-fired EGU for filterable PM or for non-mercury HAP metals. You must demonstrate compliance through an initial performance test, and you must monitor continuous performance with the applicable filterable PM emissions limit through the use of a PM CEMS or HAP metals CMS.

(d) * * *

(5) * * *

(i) Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.,* on or downstream of the last control device). See § 63.10010(a) for further details. For PM CPMS installations (which with the exception of IGCC units, are only applicable before July 6, 2027), follow the procedures in § 63.10010(h).

* * * * *

(m) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU (only allowed before January 2, 2025), on or before the date your EGU is subject to this subpart, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with § 63.10020(e). On and after January 2, 2025 you will no longer be able to choose paragraph (2) of the ''startup'' definition in § 63.10042.

* * * * *

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

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

(a) * * *

(1) To demonstrate initial compliance with an applicable emissions limit in Table 1 or 2 to this subpart using stack testing, the initial performance test generally consists of three runs at specified process operating conditions using approved methods. Before July 6, 2027, if you are required to establish operating limits (see paragraph (d) of this section and Table 4 to this subpart), you must collect all applicable parametric data during the performance test period. On and after July 6, 2027, the requirements in Table 4 are not applicable, with the exception of IGCC units. Also, if you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the test period.

* * * * *

(b) *Performance testing requirements.* If you choose to use performance testing to demonstrate initial compliance with the applicable emissions limits in Tables 1 and 2 to this subpart for your EGUs, you must conduct the tests according to 40 CFR 63.10007 and Table 5 to this subpart. Notwithstanding these requirements, when Table 5 specifies the use of isokinetic EPA test Method 5, 5I, 5D, 26A, or 29 for a stack test, if concurrent measurement of the stack gas flow rate or moisture content is needed to convert the pollutant concentrations to units of the standard, separate determination of these parameters using EPA test Method 2 or EPA test Method 4 is not necessary. Instead, the stack gas flow rate and moisture content can be determined from data that are collected during the EPA test Method 5, 5I, 5D, 6, 26A, or 29 test (*e.g.,* pitot tube (delta P) readings, moisture collected in the impingers, etc.). For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in 40 CFR 63.9984, provided that the following conditions are fully met:

* * * * *

(c) *Operating limits.* In accordance with § 63.10010 and Table 4 to this subpart, you may be required to establish operating limits using PM CPMS and using site-specific monitoring for certain liquid oil-fired units as part of your initial compliance demonstration. With the exception of IGCC units, on and after July 6, 2027, you may not demonstrate compliance with applicable filterable PM emissions limits with the use of PM CPMS or quarterly stack testing, you may only use PM CEMS.

* * * * *

(d) * * *

(2) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table 1 or 2 to this subpart using initial performance testing and continuous monitoring with PM CPMS (with the exception of IGCC units, the use of PM CPMS is only allowed before July 6, 2027):

* * * * *

(h) *Low emitting EGUs.* The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM. You may pursue this compliance option unless prohibited pursuant to § 63.10000(c)(1)(i).

(1) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF, filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if you collect performance test data that meet the requirements of this paragraph (h) with the exception that on or after July 6, 2027, you may not pursue the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals for any existing, new or reconstructed EGUs (this does not apply to IGCC units), and if those data demonstrate:

* * * * *

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

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

(a) For liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs and IGCC units using PM CPMS before July 6, 2027 to monitor continuous performance with an applicable emission limit as provided for under § 63.10000(c), you must conduct all applicable performance tests according to Table 5 to this subpart and § 63.10007 at least every year. On or after July 6, 2027 you may not use PM CPMS to demonstrate compliance for liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs. This prohibition against the use of PM CPMS does not apply to IGCC units.

* * * * *

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

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

(a) * * *

(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non-Hg metals emissions limit (the use of PM CPMS is only allowed before July 6, 2027 with the exception of IGCC units), operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

* * * * *

(c) If you choose the filterable PM method to comply with the PM emission limit and demonstrate continuous performance using a PM CPMS as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b), § 63.10023, and Tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits. On and after July 6, 2027, you must demonstrate continuous compliance with the applicable filterable PM emission standard through the use of a PM CEMS (with the exception that IGCC units are not required to use PM CEMS and may continue to use PM CPMS). Alternatively, you may demonstrate continuous compliance with the non-Hg metals emission standard if you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

* * * * *

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

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

(a) Flue gases from the affected units under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS (which on or after July 6, 2027 you may not use PM CPMS for filterable PM compliance demonstrations unless it is for an IGCC unit), and sorbent trap monitoring systems used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

* * * * *

(h) If you use a PM CPMS to demonstrate continuous compliance with an operating limit (only applicable before July 6, 2027 unless it is for an IGCC unit), you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in paragraphs (h)(1) through (5) of this section.

* * * * *

(i) If you choose to comply with the PM filterable emissions limit in lieu of metal HAP limits (which on or after July 6, 2027 you may not use non-mercury metal HAP limits for compliance demonstrations for existing EGUs unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f)), you may choose to install, certify, operate, and maintain a PM CEMS and record and report the output of the PM CEMS as specified in paragraphs (i)(1) through (8) of this section. With the exception of IGCC units, on or after July 6, 2027 owners/operators of existing EGUs must comply with filterable PM emissions limits in Table 2 of this subpart and demonstrate continuous compliance using a PM CEMS unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f). Compliance with the applicable PM emissions limit in Table 1 or 2 to this subpart is determined on a 30-boiler operating day rolling average basis.

* * * * *

(j) You may choose to comply with the metal HAP emissions limits using CMS approved in accordance with § 63.7(f) as an alternative to the performance test method specified in this rule. If approved to use a HAP metals CMS, the compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2. If approved, you may choose to install, certify, operate, and maintain a HAP metals CMS and record the output of the HAP metals CMS as specified in paragraphs (j)(1) through (5) of this section.

(1)(i) Install, calibrate, operate, and maintain your HAP metals CMS according to your CMS quality control program, as described in § 63.8(d)(2). The reportable measurement output from the HAP metals CMS must be expressed in units of the applicable emissions limit (*e.g.,* lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

(ii) Operate and maintain your HAP metals CMS according to the procedures and criteria in your site specific performance evaluation and quality control program plan required in § 63.8(d).

(2) Collect HAP metals CMS hourly average output data for all boiler operating hours except as indicated in section (j)(4) of this section.

(3) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average HAP metals CMS output data collected during all nonexempt boiler operating hours data.

(4) You must collect data using the HAP metals CMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for required monitoring system quality assurance or quality control activities, and any scheduled maintenance as defined in your site-specific monitoring plan.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your emission limit except:

(A) Any data collected during periods of monitoring system malfunctions and repairs associated with monitoring system malfunctions. You must report any monitoring system malfunctions as deviations in your compliance reports under 40 CFR 63.10031(c) or (g) (as applicable);

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any out of control periods as deviations in your compliance reports under 40 CFR 63.10031(c) or (g) (as applicable);

(C) Any data recorded during required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of emissions (*e.g.,* calibrations, certain audits, routine probe maintenance); and

(D) Any data recorded during periods of startup or shutdown.

(ii) You must record and report the results of HAP metals CMS system performance audits, in accordance with 40 CFR 63.10031(k). You must also record and make available upon request the dates and duration of periods when the HAP metals CMS is out of control to completion of the corrective actions necessary to return the HAP metals CMS to operation consistent with your site-specific performance evaluation and quality control program plan.

* * * * *

(l) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU (only allowed before January 2, 2025), you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice standards required to comply with § 63.10020(e). On and after January 2, 2025 you will no longer be able to choose paragraph (2) of the ''startup'' definition in § 63.10042 for your EGU.

* * * * *

■ 9. Amend § 63.10011 by revising paragraphs (b), (g)(3), and (4) introductory text to read as follows:

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

* * * * *

(b) If you are subject to an operating limit in Table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance (with the exception of existing IGCC units, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM limits and the Table 4 p.m. CPMS operating limits do not apply), or if, for an IGCC unit, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with § 63.10007 and Table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (*i.e.,* tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit. On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM limits and the Table 6 procedures for establishing PM CPMS operating limits do not apply unless it is an IGCC unit.

* * * * *

(g) * * *

(3) You must report the emissions data recorded during startup and shutdown. If you are relying on paragraph (2) of the definition of startup in 40 CFR 63.10042 (only allowed before January 2, 2025), then for startup and shutdown incidents that occur on or prior to December 31, 2023, you must also report the applicable supplementary information in 40 CFR 63.10031(c)(5) in the semiannual compliance report. For startup and shutdown incidents that occur on or after January 1, 2024, you must provide the applicable information in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i).

(4) If you choose to use paragraph (2) of the definition of ''startup'' in § 63.10042 (only allowed before January 2, 2025), and you find that you are unable to safely engage and operate your particulate matter (PM) control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel, you may choose to rely on paragraph (1) of definition of ''startup'' in § 63.10042 or you may submit a request to use an alternative non-opacity emissions standard, as described below.

* * * * *

■ 10. Section 63.10020 is amended by revising paragraphs (e) introductory text and (e)(3)(i) introductory text to read as follows:

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

* * * * *

(e) Additional requirements during startup periods or shutdown periods if you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU (only allowed before January 2, 2025).

* * * * *

(3) * * *

(i) Except for an EGU that uses PM CEMS or PM CPMS to demonstrate compliance with the PM emissions limit, or that has LEE status for filterable PM or total non-Hg HAP metals for non-liquid oil-fired EGUs (or HAP metals emissions for liquid oil-fired EGUs), or individual non-mercury metals CMS (except that unless it is for an IGCC unit, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM emissions limits, and you may not purse or continue to use the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals), you must:

* * * * *

■ 11. Section 63.10021 is amended by revising paragraphs (c) introductory text and (i) to read as follows:

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

* * * * *

(c) If you use PM CPMS data (only allowed before July 6, 2027 unless it is for an IGCC unit) to measure compliance with an operating limit in Table 4 to this subpart, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (*e.g.,* milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 9 to determine the 30 boiler operating day average. On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations unless it is for an IGCC unit.

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

Where:

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

* * * * *

(i) Before January 2, 2025, if you are relying on paragraph 2 of the definition of startup in 40 CFR 63.10042, you must provide reports concerning activities and periods of startup and shutdown that occur on or prior to January 1, 2024, in accordance with 40 CFR 63.10031(c)(5), in your semiannual compliance report. For startup and shutdown incidents that occur on and after January 1, 2024, you must provide the applicable information referenced in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i). On or after January 2, 2025 you may not use paragraph 2 of the definition of startup in 40 CFR 63.10042.

■ 12. Section 63.10022 is amended by revising paragraphs (a)(2) and (3) to read as follows:

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

(a) * * *

(2) For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test. On or after July 6, 2027 you may not use PM CPMS for filterable PM compliance demonstrations unless it is for an IGCC unit;

(3) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies. Since on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit, for compliance demonstrations with the applicable filterable PM limits, the Table 4 p.m. CPMS operating limits do not apply.

* * * * *

■ 13. Section 63.10023 is amended by adding introductory text to the section to read as follows:

§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

The provisions of this section § 63.10023 are only applicable before July 6, 2027 unless it is for an IGCC unit. On or after July 6, 2027 you may not use PM CPMS, unless it is an IGCC unit, for demonstrating compliance with the filterable PM emissions limits of this subpart.

* * * * *

■ 14. Section 63.10030 is amended by revising paragraphs (e)(3), (8) introductory text, and (8)(i) introductory text to read as follows:

§ 63.10030 What notifications must I submit and when?

* * * * *

(e) * * *

(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (*e.g.,* use of PM CPMS—which on or after July 6, 2027—you may not use for filterable PM compliance demonstrations, unless it is for an IGCC unit); CEMS; or a sorbent trap monitoring system.

* * * * *

(8) Identification of whether you plan to rely on paragraph (1) or (2) of the definition of ''startup'' in § 63.10042. On or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042.

(i) Before January 2, 2025 should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU, you shall include a report that identifies:

* * * * *

■ 15. Section 63.10031 is amended by revising paragraphs (a)(4), (c)(5) introductory text, (f)(2), (i), and (k) to read as follows:

§ 63.10031 What reports must I submit and when?

(a) * * *

(4) Before July 6, 2027, if you elect to demonstrate continuous compliance using a PM CPMS, you must meet the electronic reporting requirements of appendix D to this subpart. Except for IGCC units, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations. Electronic reporting of the hourly PM CPMS output shall begin with the later of the first operating hour on or after January 1, 2024; or the first operating hour after completion of the initial performance stack test that establishes the operating limit for the PM CPMS.

(c) * * *

(5) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU (only allowed before January 2, 2025), for each instance of startup or shutdown you shall:

* * * * *

(f) * * *

(2) If, for a particular EGU or a group of EGUs serving a common stack, you have elected to demonstrate compliance using a PM CEMS, an approved HAP metals CMS, or a PM CPMS (on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit), you must submit quarterly PDF reports in accordance with paragraph (f)(6) of this section, which include all of the 30-boiler operating day rolling average emission rates derived from the CEMS data or the 30-boiler operating day rolling average responses derived from the PM CPMS data (as applicable). The quarterly reports are due within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st. Submission of these quarterly reports in PDF files shall end with the report that covers the fourth calendar quarter of 2023. Beginning with the first calendar quarter of 2024, the compliance averages shall no longer be reported separately, but shall be incorporated into the quarterly compliance reports described in paragraph (g) of this section. In addition to the compliance averages for PM CEMS, PM CPMS, and/or HAP metals CMS, the quarterly compliance reports described in paragraph (g) of this section must also include the 30- (or, if applicable 90-) boiler operating day rolling average emission rates for Hg, HCl, HF, and/or SO_2, if you have elected to (or are required to) continuously monitor these pollutants. Further, if your EGU or common stack is in an averaging plan, your quarterly compliance reports must identify all of the EGUs or common stacks in the plan and must include all of the 30- (or 90-) group boiler operating day rolling weighted average emission rates (WAERs) for the averaging group.

* * * * *

(i) If you have elected to use paragraph (2) of the definition of ''startup'' in 40 CFR 63.10042 (only allowed before January 2, 2025), then, for startup and shutdown incidents that occur on or prior to December 31, 2023, you must include the information in 40 CFR 63.10031(c)(5) in the semiannual compliance report, in a PDF file. If you have elected to use paragraph (2) of the definition of ''startup'' in 40 CFR 63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, you must use the ECMPS Client Tool to submit the information in 40 CFR 63.10031(c)(5) and 40 CFR 63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data elements in paragraphs (f)(6)(i) through (xii) of this section must be entered into ECMPS with each startup and shutdown report.

* * * * *

(k) If you elect to demonstrate compliance using a PM CPMS (on or after July 6, 2027 you may not demonstrate compliance with filterable PM emissions limits using a PM CPMS, unless it is for an IGCC unit) or an approved HAP metals CMS, you must submit quarterly reports of your QA/QC activities (*e.g.,* calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CMS is used for the compliance demonstration in that quarter. Otherwise, submit a report for the first calendar quarter in which the PM CPMS or HAP metals CMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in paragraph (f)(6)(i) through (xii) of this section must be entered into ECMPS with the PDF report.

■ 16. Section 63.10032 is amended by revising paragraphs (a) introductory text and (f)(2) introductory text to read as follows:

§ 63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if you elect to use a PM CPMS (unless it is for an IGCC unit, you may only use PM CPMS before July 6, 2027), you must keep the records required under appendix A and/or appendix B and/or appendix C and/or appendix D to this subpart. If you elect to conduct periodic (*e.g.,* quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, you must keep records of the applicable data elements under 40 CFR 63.7(g). You must also keep records of all data elements and other information in appendix E to this subpart that apply to your compliance strategy.

* * * * *

(f) * * *

(2) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU (on or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042), you must keep records of:

* * * * *

■ 17. Section 63.10042 is amended by revising the definition ''Startup'' to read as follows:

§ 63.10042 What definitions apply to this subpart?

* * * * *

Startup means:

(1) 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. 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). Any fraction of an hour in which startup occurs constitutes a full hour of startup.

(2) Alternatively, prior to January 2, 2025, the period in which operation of an EGU is initiated for any purpose. 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. 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 (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. Any fraction of an hour in which startup occurs constitutes a full hour of startup.

* * * * *

■ 18. Revise table 1 to subpart UUUUU of part 63 to read as follows:

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

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

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM).	9.0E–2 lb/MWh [1] ...	Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn) ...	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	1.0E–2 lb/MWh	For Method 26A at appendix A–8 to part 60 of this chapter, collect a minimum of 3 dscm per run. For ASTM D6348–03(Reapproved 2010) [2] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3].	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal ...	a. Filterable particulate matter (PM).	9.0E–2 lb/MWh [1] ...	Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn) ...	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	1.0E–2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run For ASTM D6348–03(Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3].	1.0 lb/MWh	SO_2 CEMS.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	c. Mercury (Hg)	Before July 8, 2024: 4.0E–2 lb/GWh; On or after July 8, 2024: 1.3E–2 lb/GWh.	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	7.0E–2 lb/MWh [4] 9.0E–2 lb/MWh [5].	Collect a minimum catch of 3.0 milligrams or a minimum sample volume of 2 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	4.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E–2 lb/GWh.	
	Arsenic (As)	2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	4.0E–2 lb/GWh.	
	Cobalt (Co)	4.0E–3 lb/GWh.	
	Lead (Pb)	9.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	7.0E–2 lb/GWh.	
	Selenium (Se)	3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26 at appendix A–8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348–03(Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3].	4.0E–1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–1 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E–4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E–2 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	5.0E–4 lb/GWh.	
	Cadmium (Cd)	2.0E–4 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E–2 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	1.0E–4 lb/GWh	For Method 30B at appendix A–8 to part 60 of this chapter sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl).	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03(Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF).	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 (Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	2.0E–1 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	7.0E–3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Arsenic (As)	6.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–1 lb/GWh.	
	Lead (Pb)	3.0E–2 lb/GWh.	
	Manganese (Mn)	1.0E–1 lb/GWh.	
	Nickel (Ni)	4.1E0 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	4.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF).	5.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 (Reapproved 2010)[2] or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM).	3.0E–2 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	6.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	7.0E–4 lb/GWh.	
	Chromium (Cr)	6.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	7.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HCl).	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 (Reapproved 2010)[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3].	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

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

■ 19. Revise table 2 to subpart UUUUU of part 63 to read as follows:

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

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

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM).	Before July 6, 2027: 3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh[2].	Before July 6, 2027: Collect a minimum of 1 dscm per run.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
		On or after July 6, 2027: 1.0E–2 lb/MMBtu or 1.0E–1 lb/MWh[2].	On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-Hg HAP metals.	Before July 6, 2027: 5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh. On or after July 6, 2027: 1.7E–5 lb/MMBtu or 1.7E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	
	Arsenic (As)	Before July 6, 2027: 1.1E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 3.7E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Beryllium (Be)	Before July 6, 2027: 2.0E–1 lb/TBtu or 2.0E–3 lb/GWh. On or after July 6, 2027: 6.7E–2 lb/TBtu or 6.7E–4 lb/GWh.	
	Cadmium (Cd)	Before July 6, 2027: 3.0E–1 lb/TBtu or 3.0E–3 lb/GWh. On or after July 6, 2027: 1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Chromium (Cr)	Before July 6, 2027: 2.8E0 lb/TBtu or 3.0E–2 lb/GWh. On or after July 6, 2027: 9.3E–1 lb/TBtu or 1.0E–2 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Cobalt (Co)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	
	Lead (Pb)	Before July 6, 2027: 1.2E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 4.0E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Manganese (Mn)	Before July 6, 2027: 4.0E0 lb/TBtu or 5.0E–2 lb/GWh. On or after July 6, 2027: 1.3E0 lb/TBtu or 1.7E–2 lb/GWh.	
	Nickel (Ni)	Before July 6, 2027: 3.5E0 lb/TBtu or 4.0E–2 lb/GWh. On or after July 6, 2027: 1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	
	Selenium (Se)	Before July 6, 2027: 5.0E0 lb/TBtu or 6.0E–2 lb/GWh. On or after July 6, 2027: 1.7E0 lb/TBtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A at appendix A–8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[4].	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A–8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only.
		OR	
		1.0E0 lb/TBtu or 1.1E–2 lb/GWh.	LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired unit low rank virgin coal	a. Filterable particulate matter (PM).	Before July 6, 2027: 3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh[2]. On or after July 6, 2027: 1.0E–2 lb/MMBtu or 1.0E–1 lb/MWh[2].	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-Hg HAP metals.	Before July 6, 2027: 5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh. On or after July 6, 2027: 1.7E–5 lb/MMBtu or 1.7E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	
	Arsenic (As)	Before July 6, 2027: 1.1E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 3.7E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Beryllium (Be)	Before July 6, 2027: 2.0E–1 lb/TBtu or 2.0E–3 lb/GWh. On or after July 6, 2027: 6.7E–2 lb/TBtu or 6.7E–4 lb/GWh.	
	Cadmium (Cd)	Before July 6, 2027: 3.0E–1 lb/TBtu or 3.0E–3 lb/GWh. On or after July 6, 2027: 1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Chromium (Cr)	Before July 6, 2027: 2.8E0 lb/TBtu or 3.0E–2 lb/GWh. On or after July 6, 2027: 9.3E–1 lb/TBtu or 1.0E–2 lb/GWh.	
	Cobalt (Co)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Lead (Pb)	Before July 6, 2027: 1.2E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 4.0E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Manganese (Mn)	Before July 6, 2027: 4.0E0 lb/TBtu or 5.0E–2 lb/GWh. On or after July 6, 2027: 1.3E0 lb/TBtu or 1.7E–2 lb/GWh.	
	Nickel (Ni)	Before July 6, 2027: 3.5E0 lb/TBtu or 4.0E–2 lb/GWh. On or after July 6, 2027: 1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	
	Selenium (Se)	Before July 6, 2027: 5.0E0 lb/TBtu or 6.0E–2 lb/GWh. On or after July 6, 2027: 1.7E0 lb/TBtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26 at appendix A–8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010) [3] or Method 320, sample for a minimum of 1 hour.
	OR	OR	
	Sulfur dioxide (SO_2) [4].	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	Before July 6, 2027: 4.0E0 lb/TBtu or 4.0E–2 lb/GWh. On or after July 6, 2027: 1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	4.0E–2 lb/MMBtu or 4.0E–1 lb/MWh [2].	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 3.0 milligrams or a minimum sample volume of 2 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	6.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:.	....	Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Cadmium (Cd)	1.5E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E–2 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	1.9E+2 lb/TBtu or 1.8E0 lb/GWh.	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E–2 lb/GWh.	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl).	5.0E–4 lb/MMBtu or 5.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010) [3] or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total HAP metals	8.0E–4 lb/MMBtu or 8.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 1 dscm per run.
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E–1 lb/GWh.	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	5.5E0 lb/TBtu or 6.0E–2 lb/GWh.	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh.	
	Selenium (Se)	3.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MMBtu or 1.0E–2 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010) [3] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF).	4.0E–4 lb/MMBtu or 4.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010) [3] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2].	Collect a minimum of 1 dscm per run.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total HAP metals	6.0E–4 lb/MMBtu or 7.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	4.3E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Beryllium (Be)	6.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	3.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Cobalt (Co)	1.1E+2 lb/TBtu or 1.4E0 lb/GWh.	
	Lead (Pb)	4.9E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn)	2.0E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	4.7E+2 lb/TBtu or 4.1E0 lb/GWh.	
	Selenium (Se)	9.8E0 lb/TBtu or 2.0E–1 lb/GWh.	
	Mercury (Hg)	4.0E–2 lb/TBtu or 4.0E–4 lb/GWh.	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl).	2.0E–4 lb/MMBtu or 2.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010) [3] or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF).	6.0E–5 lb/MMBtu or 5.0E–4 lb/MWh.	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 (Reapproved 2010) [3] or Method 320, sample for a minimum of 2 hours.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM).	8.0E–3 lb/MMBtu or 9.0E–2 lb/MWh [2].	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-Hg HAP metals.	4.0E–5 lb/MMBtu or 6.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 7.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–1 lb/TBtu or 5.0E–3 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Beryllium (Be)	6.0E–2 lb/TBtu or 5.0E–4 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 4.0E–3 lb/GWh.	
	Chromium (Cr)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E–1 lb/GWh.	
	Selenium (Se)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	5.0E–3 lb/MMBtu or 8.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010) [3] or Method 320, sample for a minimum of 1 hour.
	OR	OR	
	Sulfur dioxide (SO_2) [4].	3.0E–1 lb/MMBtu or 2.0E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
7. Eastern Bituminous Coal Refuse (EBCR)-fired unit.	a. Filterable particulate matter (PM).	Before July 6, 2027: 3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2]. On or after July 6, 2027: 1.0E–2 lb/MMBtu or 1.0E–1 lb/MWh [2].	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-Hg HAP metals.	Before July 6, 2027: 5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh. On or after July 6, 2027: 1.7E–5 lb/MMBtu or 1.7E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Arsenic (As)	Before July 6, 2027: 1.1E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 3.7E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Beryllium (Be)	Before July 6, 2027: 2.0E–1 lb/TBtu or 2.0E–3 lb/GWh. On or after July 6, 2027: 6.7E–2 lb/TBtu or 6.7E–4 lb/GWh.	
	Cadmium (Cd)	Before July 6, 2027: 3.0E–1 lb/TBtu or 3.0E–3 lb/GWh. On or after July 6, 2027: 1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Chromium (Cr)	Before July 6, 2027: 2.8E0 lb/TBtu or 3.0E–2 lb/GWh. On or after July 6, 2027: 9.3E–1 lb/TBtu or 1.0E–2 lb/GWh.	
	Cobalt (Co)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	
	Lead (Pb)	Before July 6, 2027: 1.2E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 4.0E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Manganese (Mn)	Before July 6, 2027: 4.0E0 lb/TBtu or 5.0E–2 lb/GWh. On or after July 6, 2027: 1.3E0 lb/TBtu or 1.7E–2 lb/GWh.	
	Nickel (Ni)	Before July 6, 2027: 3.5E0 lb/TBtu or 4.0E–2 lb/GWh. On or after July 6, 2027: 1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Selenium (Se)	Before July 6, 2027: 5.0E0 lb/TBtu or 6.0E–2 lb/GWh. On or after July 6, 2027: 1.7E0 lb/TBtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	4.0E–2 lb/MMBtu or 4.0E–1 lb/MWh.	For Method 26A at appendix A–8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010) [3] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4].	6E–1 lb/MMBtu or 9E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A–8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only.
	OR		
		1.0E0 lb/TBtu or 1.1E–2 lb/GWh.	LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.

[1] For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of 2. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

[2] Gross output.

[3] Incorporated by reference, *see* § 63.14.

[4] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

■ 20. Revise table 3 to subpart UUUUU of part 63 to read as follows:

Table 3 to Subpart UUUUU of Part 63—Work Practice Standards

As stated in § 63.9991, you must comply with the following applicable work practice standards:

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
2. A new or reconstructed EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during startup.	a. Before January 2, 2025 you have the option of complying using either of the following work practice standards in paragraphs (1) and (2). On or after January 2, 2025 you may not choose to use paragraph (2) of the definition of startup in § 63.10042 and the following associated work practice standards in paragraph (2).

If your EGU is . . .	You must meet the following . . .
	(1) If you choose to comply using paragraph (1) of the definition of ''startup'' in § 63.10042, you must operate all CMS during startup. Startup means 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. 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). For startup of a unit, you must use clean fuels as defined in § 63.10042 for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this subpart. You must keep records during startup periods. You must provide reports concerning activities and startup periods, as specified in § 63.10011(g) and § 63.10021(h) and (i). If you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i). (2) If you choose to comply using paragraph (2) of the definition of ''startup'' in § 63.10042, you must operate all CMS during startup. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of startup. For startup of an EGU, you must use one or a combination of the clean fuels defined in § 63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. You must have sufficient clean fuel capacity to engage and operate your PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. You must meet the startup period work practice requirements as identified in § 63.10020(e). Once you start firing coal, residual oil, or solid oil-derived fuel, you must vent emissions to the main stack(s). You must comply with the applicable emission limits beginning with the hour after startup ends. You must engage and operate your PM control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel. You must start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this subpart that require operation of the control devices. b. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during startup, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator. c. If you choose to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, you must comply with the limit at all times; otherwise, you must comply with the applicable emission limit at all times except for startup and shutdown periods. d. You must collect monitoring data during startup periods, as specified in § 63.10020(a) and (e). You must keep records during startup periods, as provided in §§ 63.10021(h) and 63.10032. You must provide reports concerning activities and startup periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031. Before January 2, 2025, if you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i). On or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042.
4. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during shutdown.	You must operate all CMS during shutdown. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. While firing coal, residual oil, or solid oil-derived fuel during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, you must operate your controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this subpart and that require operation of the control devices. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in § 63.10042 and must be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during shutdown, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator.

If your EGU is . . .	You must meet the following . . .
	You must comply with all applicable emission limits at all times except during startup periods and shutdown periods at which time you must meet this work practice. You must collect monitoring data during shutdown periods, as specified in § 63.10020(a). You must keep records during shutdown periods, as provided in §§ 63.10032 and 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. You must provide reports concerning activities and shutdown periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031. Before January 2, 2025, if you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning shutdown periods as follows: For shutdown periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for shutdown periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i). On or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042.

■ 21. Revise table 4 to subpart UUUUU of part 63 to read as follows:

Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs

Before July 6, 2027, as stated in § 63.9991, you must comply with the applicable operating limits in table 4. However, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit.

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

■ 22. Revise table 5 to subpart UUUUU of part 63 to read as follows:

Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements

As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:[1]

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To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using . . .[2]
1. Filterable Particulate matter (PM)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the filterable PM concentration	Methods 5 and 5I at appendix A-3 to part 60 of this chapter. For positive pressure fabric filters, Method 5D at appendix A-3 to part 60 of this chapter for filterable PM emissions. Note that the Method 5 or 5I front half temperature shall be 160° ±14 °C (320° ±25 °F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	PM CEMS	a. Install, certify, operate, and	Performance Specification 11 at appendix B to part 60 of this chapter and Procedure 2 at appendix F to part 60 of this chapter.

		maintain the PM CEMS	
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
2. Total or individual non-Hg HAP metals	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine	Method 29 at appendix A-8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at appendix A-8 to part 60 of this chapter; for Method 29, you must

		each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration	report the front half and back half results separately. When using Method 29, report metals matrix spike and recovery levels.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the HCl and HF	Method 26 or Method 26A at appendix A-8 to part 60 of this chapter or Method 320 at

		emissions concentrations	appendix A to part 63 of this chapter or ASTM D6348-03 Reapproved 2010[3] with
			(1) the following conditions when using ASTM D6348-03 Reapproved 2010:
			(A) The test plan preparation and implementation in the Annexes to ASTM D6348-03 Reapproved 2010, Sections A1 through A8 are mandatory;
			(B) For ASTM D6348-03 Reapproved 2010 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);
			(C) For the ASTM D6348-03 Reapproved 2010 test data to be acceptable for a target analyte, %R must be 70% ≥R ≤130%; and
			(D) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation: $\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} \times 100$
			(2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit.
			Method 26A must be used if there are entrained water droplets in the exhaust stream.
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	HCl and/or HF CEMS	a. Install, certify, operate, and maintain the HCl or HF CEMS	Appendix B of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).

		monitoring systems	
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at appendix A-8 to part 60 of this chapter, ASTM D6784,[3] or Method 29 at appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	Hg CEMS	a. Install, certify, operate, and	Sections 3.2.1 and 5.1 of appendix A of this subpart.

		maintain the CEMS	
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of appendix A to this subpart.
	OR	OR	
	Sorbent trap monitoring system	a. Install, certify, operate, and maintain the sorbent trap monitoring system	Sections 3.2.2 and 5.2 of appendix A to this subpart.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh	Section 6 of appendix A to this subpart.

		emissions rates	
	OR	OR	
	LEE testing	a. Select sampling ports location and the number of traverse points	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G, or 2H at appendix A-1 or A-2 to part 60 of this chapter or flow monitoring system certified per appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981,[3] or diluent gas monitoring systems certified according to part 75 of this chapter.
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at appendix A-8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (*i.e.,* per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per appendix A of this subpart.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 29.0 lb/year threshold	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.

5. Sulfur dioxide (SO_2)	SO_2 CEMS	a. Install, certify, operate, and maintain the CEMS	Part 75 of this chapter and § 63.10010(a) and (f).
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).

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[1] Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and 63.10021(h). With the exception of IGCC units, on or after July 6, 2027: You may not use quarterly performance emissions testing to demonstrate compliance with the filterable PM emissions standards and for existing EGUs you may not choose to comply with the total or individual HAP metals emissions limits unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

[2] See tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.

[3] Incorporated by reference, see § 63.14.

■ 23. Revise table 6 to subpart UUUUU of part 63 to read as follows:

Table 6 to Subpart UUUUU of Part 63—Establishing PM CPMS Operating Limits

Before July 6, 2027, as stated in § 63.10007, you must comply with the following requirements for establishing operating limits in table 6. However, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit.

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

■ 24. Revise table 7 to subpart UUUUU of part 63 to read as follows:

Table 7 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance

As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following:

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
1. CEMS to measure filterable PM, SO_2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg.	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit. (On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit.).	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average of all of the quality assured hourly average PM CPMS output data (*e.g.,* milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring using CMS for liquid oil-fired EGUs for HCl and HF emission limit monitoring.	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.
4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired EGUs to measure compliance with one or more non-PM (or its alternative emission limits) applicable emissions limit in Table 1 or 2, or PM (or its alternative emission limits) applicable emissions limit in Table 2. (On or after July 6, 2027 you may not use quarterly performance testing for filterable PM compliance demonstrations, unless it is for an IGCC unit.).	Calculating the results of the testing in units of the applicable emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup.	Operating in accordance with Table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown.	Operating in accordance with Table 3.

■ 25. Revise table 8 to subpart UUUUU of part 63 to read as follows:

Table 8 to Subpart UUUUU of Part 63—Reporting Requirements

[In accordance with 40 CFR 63.10031, you must meet the following reporting requirements, as they apply to your compliance strategy]

You must submit the following reports . . .
1. The electronic reports required under 40 CFR 63.10031 (a)(1), if you continuously monitor Hg emissions.
2. The electronic reports required under 40 CFR 63.10031 (a)(2), if you continuously monitor HCl and/or HF emissions.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
3. The electronic reports required under 40 CFR 63.10031(a)(3), if you continuously monitor PM emissions.
Reporting of hourly PM emissions data using ECMPS shall begin with the first operating hour after: January 1, 2024, or the hour of completion of the initial PM CEMS correlation test, whichever is later.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
4. The electronic reports required under 40 CFR 63.10031(a)(4), if you elect to use a PM CPMS (on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit).
Reporting of hourly PM CPMS response data using ECMPS shall begin with the first operating hour after January 1, 2024, or the first operating hour after completion of the initial performance stack test that establishes the operating limit for the PM CPMS, whichever is later.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
5. The electronic reports required under 40 CFR 63.10031(a)(5), if you continuously monitor SO_2 emissions.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
6. PDF reports for all performance stack tests completed prior to January 1, 2024 (including 30- or 90-boiler operating day Hg LEE test reports and PM test reports to set operating limits for PM CPMS), according to the introductory text of 40 CFR 63.10031(f) and 40 CFR 63.10031(f)(6).
For each test, submit the PDF report no later than 60 days after the date on which testing is completed.
For a PM test that is used to set an operating limit for a PM CPMS, the report must also include the information in 40 CFR 63.10023(b)(2)(vi).
For each performance stack test completed on or after January 1, 2024, submit the test results in the relevant quarterly compliance report under 40 CFR 63.10031(g), together with the applicable reference method information in sections 17 through 31 of appendix E to this subpart.
7. PDF reports for all RATAs of Hg, HCl, HF, and/or SO_2 monitoring systems completed prior to January 1, 2024, and for correlation tests, RRAs and/or RCAs of PM CEMS completed prior to January 1, 2024, according to 40 CFR 63.10031(f)(1) and (6).
For each test, submit the PDF report no later than 60 days after the date on which testing is completed.
For each SO_2 or Hg system RATA completed on or after January 1, 2024, submit the electronic test summary required by appendix A to this subpart or part 75 of this chapter (as applicable) together with the applicable reference method information in sections 17 through 30 of appendix E to this subpart, either prior to or concurrent with the relevant quarterly emissions report.

You must submit the following reports . . .
For each HCl or HF system RATA, and for each correlation test, RRA, and RCA of a PM CEMS completed on or after January 1, 2024, submit the electronic test summary in accordance with section 11.4 of appendix B to this subpart or section 7.2.4 of appendix C to this part, as applicable, together with the applicable reference method information in sections 17 through 30 of appendix E to this subpart.
8. Quarterly reports, in PDF files, that include all 30-boiler operating day rolling averages in the reporting period derived from your PM CEMS, approved HAP metals CMS, and/or PM CPMS (on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit), according to 40 CFR 63.10031(f)(2) and (6). These reports are due no later than 60 days after the end of each calendar quarter.
The final quarterly rolling averages report in PDF files shall cover the fourth calendar quarter of 2023.
Starting with the first quarter of 2024, you must report all 30-boiler operating day rolling averages for PM CEMS, approved HAP metals CMS, PM CPMS, Hg CEMS, Hg sorbent trap systems, HCl CEMS, HF CEMS, and/or SO_2 CEMS (or 90-boiler operating day rolling averages for Hg systems), in XML format, in the quarterly compliance reports required under 40 CFR 63.10031(g).
If your EGU or common stack is in an averaging plan, each quarterly compliance report must identify the EGUs in the plan and include all of the 30- or 90-group boiler operating day WAERs for the averaging group.
The quarterly compliance reports must be submitted no later than 60 days after the end of each calendar quarter.
9. The semiannual compliance reports described in 40 CFR 63.10031(c) and (d), in PDF files, according to 40 CFR 63.10031(f)(4) and (6). The due dates for these reports are specified in 40 CFR 63.10031(b).
The final semiannual compliance report shall cover the period from July 1, 2023, through December 31, 2023.
10. Notifications of compliance status, in PDF files, according to 40 CFR 63.10031(f)(4) and (6) until December 31, 2023, and according to 40 CFR 63.10031(h) thereafter.
11. Quarterly electronic compliance reports, in accordance with 40 CFR 63.10031(g), starting with a report for the first calendar quarter of 2024. The reports must be in XML format and must include the applicable data elements in sections 2 through 13 of appendix E to this subpart.
These reports are due no later than 60 days after the end of each calendar quarter.
12. Quarterly reports, in PDF files, that include the applicable information in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) pertaining to startup and shutdown events, starting with a report for the first calendar quarter of 2024, if you have elected to use paragraph 2 of the definition of startup in 40 CFR 63.10042 (see 40 CFR 63.10031(i)). On or after January 2, 2025 you may not use paragraph 2 of the definition of startup in 40 CFR 63.10042.
These PDF reports shall be submitted no later than 60 days after the end of each calendar quarter, along with the quarterly compliance reports required under 40 CFR 63.10031(g).
13. A test report for the PS 11 correlation test of your PM CEMS, in accordance with 40 CFR 63.10031(j).
If, prior to November 9, 2020, you have begun using a certified PM CEMS to demonstrate compliance with this subpart, use the ECMPS Client Tool to submit the report, in a PDF file, no later than 60 days after that date.
For correlation tests completed on or after November 9, 2020, but prior to January 1, 2024, submit the report, in a PDF file, no later than 60 days after the date on which the test is completed.
For correlation tests completed on or after January 1, 2024, submit the test results electronically, according to section 7.2.4 of appendix C to this subpart, together with the applicable reference method data in sections 17 through 31 of appendix E to this subpart.
14. Quarterly reports that include the QA/QC activities for your PM CPMS (on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit) or approved HAP metals CMS (as applicable), in PDF files, according to 40 CFR 63.10031(k).
The first report shall cover the first calendar quarter of 2024, if the PM CPMS or HAP metals CMS is in use during that quarter. Otherwise, reporting begins with the first calendar quarter in which the PM CPMS or HAP metals CMS is used to demonstrate compliance.
These reports are due no later than 60 days after the end of each calendar quarter.

■ 26. In appendix C to subpart UUUUU:

■ a. Revise sections 1.2, 1.3, 4.1, and 4.1.1.

■ b. Add sections 4.1.1.1 and 4.2.3.

■ c. Revise sections 5.1.1, 5.1.4, and the section heading for section 6.

The revisions and additions read as follows:

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

1. General Provisions

* * * * *

1.2 *Initial Certification and Recertification Procedures.* You, as the owner or operator of an affected EGU that uses a PM CEMS to demonstrate compliance with a filterable PM emissions limit in Table 1 or 2 to this subpart must certify and, if applicable, recertify the CEMS according to Performance Specification 11 (PS–11) in appendix B to part 60 of this chapter. Beginning on July 6, 2027, when determining if your PM CEMS meets the acceptance criteria in PS–11, the value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, in the calculations.

1.3 *Quality Assurance and Quality Control Requirements.* You must meet the applicable quality assurance requirements of Procedure 2 in appendix F to part 60 of this chapter. Beginning on July 6, 2027, when determining if your PM CEMS meets the acceptance criteria in Procedure 2, the value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, in the calculations.

* * * * *

4. Certification and Recertification Requirements

4.1 *Certification Requirements.* You must certify your PM CEMS and the other CMS used to determine compliance with the applicable emissions standard before the PM CEMS can be used to provide data under this subpart. However, if you have developed and are using a correlation curve, you may continue to use that curve, provided it continues to meet the acceptance criteria in PS–11 and Procedure 2 as discussed below. Redundant backup monitoring systems (if used) are subject to the same certification requirements as the primary systems.

4.1.1 PM CEMS. You must certify your PM CEMS according to PS–11 in appendix B to part 60 of this chapter. A PM CEMS that has been installed and certified according to PS–11 as a result of another state or federal regulatory requirement or consent decree prior to the effective date of this subpart shall be considered certified for this subpart if you can demonstrate that your PM CEMS meets the acceptance criteria in PS–11 and Procedure 2 in appendix F to part 60 of this chapter.

4.1.1.1 Beginning on July 6, 2027, when determining if your PM CEMS meets the acceptance criteria in PS–11 and Procedure 2 the value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, in the calculations.

* * * * *

4.2 Recertification.

* * * * *

4.2.3 Beginning on July 6, 2027 you must use the value of 0.015 lb/MMBtu in place of the applicable emission standard, or emission limit, in the calculations when determining if your PM CEMS meets the acceptance criteria in PS–11 and Procedure 2.

* * * * *

5. Ongoing Quality Assurance (QA) and Data Validation

* * * * *

5.1.1 Required QA Tests. Following initial certification, you must conduct periodic QA testing of each primary and (if applicable) redundant backup PM CEMS. The required QA tests and the criteria that must be met are found in Procedure 2 of appendix F to part 60 of this chapter

(Procedure 2). Except as otherwise provided in section 5.1.2 of this appendix, the QA tests shall be done at the frequency specified in Procedure 2.

* * * * *

5.1.4 RCA and RRA Acceptability. The results of your RRA or RCA are considered acceptable provided that the criteria in section 10.4(5) of Procedure 2 in appendix F to part 60 of this chapter are met for an RCA or section 10.4(6) of Procedure 2 in appendix F to part 60 of this chapter are met for an RRA. However, beginning on July 6, 2027 a value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, when determining whether the RCA and RRA are acceptable.

* * * * *

6. Data Reduction and Calculations

* * * * *

■ 27. Appendix D to subpart UUUUU of part 63 is amended by adding introductory text to the appendix to read as follows:

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

On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM emissions limits, unless it is for an IGCC unit.

* * * * *

[FR Doc. 2024–09148 Filed 5–6–24; 8:45 am]

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Statutory Notes and Related Subsidiaries

EFFECTIVE DATE OF REPEAL

Repeal effective ninety days after June 27, 1988, except that such repeal not to apply to cases pending in Supreme Court on such effective date or affect right to review or manner of reviewing judgment or decree of court which was entered into before such effective date, see section 7 of Pub. L. 100–352, set out as a note under section 1254 of this title.

§ 1253. Direct appeals from decisions of three-judge courts

Except as otherwise provided by law, any party may appeal to the Supreme Court from an order granting or denying, after notice and hearing, an interlocutory or permanent injunction in any civil action, suit or proceeding required by any Act of Congress to be heard and determined by a district court of three judges.

(June 25, 1948, ch. 646, 62 Stat. 928.)

HISTORICAL AND REVISION NOTES

Based on title 28, U.S.C., 1940 ed., §§ 47, 47a, 380 and 380a (Mar. 3, 1911, ch. 231, §§ 210, 266, 36 Stat. 1150, 1162; Mar. 4, 1913, ch. 160, 37 Stat. 1013; Oct. 22, 1913, ch. 32, 38, Stat. 220; Feb. 13, 1925, ch. 229, § 1, 43 Stat. 938; Aug. 24, 1937, ch. 754, § 3, 50 Stat. 752).

This section consolidates the provisions of sections 47, 47a, 380, and 380a of title 28, U.S.C., 1940 ed., relating to direct appeals from decisions of three-judge courts involving orders of the Interstate Commerce Commission or holding State or Federal laws repugnant to the Constitution of the United States.

For distribution of other provisions of the sections on which this revised section is based, see Distribution Table.

The language in section 380 of title 28, U.S.C., 1940 ed., referring to restraining the enforcement or execution of an order made by an administrative board or a State officer was omitted as covered by this revised section and section 2281 of this title.

Words in section 380a of title 28, U.S.C., 1940 ed., ''This section shall not be construed to be in derogation of any right of direct appeal to the Supreme Court of the United States under existing provisions of law,'' were omitted as unnecessary.

Section 217 of title 7, U.S.C., 1940 ed., Agriculture, provides for a three-judge court in proceedings to suspend or restrain the enforcement of orders of the Secretary of Agriculture under the Packers and Stockyards Act of 1921.

The final proviso of section 502 of title 33, U.S.C., 1940 ed., Navigation and Navigable Waters, for direct appeal in certain criminal cases for failure to alter bridges obstructing navigation, is recommended for express repeal in view of its implied repeal by section 345 of title 28, U.S.C., 1940 ed. (See *U.S. v. Belt*, 1943, 63 S.Ct. 1278, 319 U.S. 521, 87 L.Ed. 1559. See reviser's note under section 1252 of this title.)

Section 28 of title 15, U.S.C., 1940 ed., Commerce and Trade, and section 44 of title 49, U.S.C., 1940 ed., Transportation, are identical and provide for convening of a three-judge court to hear and determine civil cases arising under the Sherman anti-trust law and the Interstate Commerce Act, respectively, wherein the United States is plaintiff and when the Attorney General deems such cases of general public importance.

Section 401(d) of title 47, U.S.C., 1940 ed., Telegraphs, Telephones, and Radiotelegraphs, made the provisions of sections 28 and 29 of title 15, U.S.C., 1940 ed., Commerce and Trade, sections 44 and 45 of title 49, U.S.C., 1940 ed., Transportation, and section 345(1) of title 28, U.S.C., 1940 ed., relating to three-judge courts and direct appeals, applicable to orders of the Federal Communications Commission enforcing the Communications Act of 1934.

§ 1254. Courts of appeals; certiorari; certified questions

Cases in the courts of appeals may be reviewed by the Supreme Court by the following methods:

(1) By writ of certiorari granted upon the petition of any party to any civil or criminal case, before or after rendition of judgment or decree;

(2) By certification at any time by a court of appeals of any question of law in any civil or criminal case as to which instructions are desired, and upon such certification the Supreme Court may give binding instructions or require the entire record to be sent up for decision of the entire matter in controversy.

(June 25, 1948, ch. 646, 62 Stat. 928; Pub. L. 100–352, § 2(a), (b), June 27, 1988, 102 Stat. 662.)

HISTORICAL AND REVISION NOTES

Based on title 28, U.S.C., 1940 ed., §§ 346 and 347 (Mar. 3, 1911, ch. 231, §§ 239, 240, 36 Stat. 1157; Feb. 13, 1925, ch. 229, § 1, 43 Stat. 938; Jan. 31, 1928, ch. 14, § 1, 45 Stat. 54; June 7, 1934, ch. 426, 48 Stat. 926).

Section consolidates sections 346 and 347 of title 28, U.S.C., 1940 ed.

Words ''or in the United States Court of Appeals for the District of Columbia'' and ''or of the United States Court of Appeals for the District of Columbia'' in sections 346 and 347 of title 28, U.S.C., 1940 ed., were omitted. (See section 41 of this title.)

The prefatory words of this section preceding paragraph (1) were substituted for subsection (c) of said section 347.

The revised section omits the words of section 347 of title 28, U.S.C., 1940 ed., ''and with like effect as if the case had been brought there with unrestricted appeal'', and the words of section 346 of such title ''in the same manner as if it had been brought there by appeal''. The effect of subsections (1) and (3) of the revised section is to preserve existing law and retain the power of unrestricted review of cases certified or brought up on certiorari. Only in subsection (2) is review restricted.

Changes were made in phraseology and arrangement.

Editorial Notes

AMENDMENTS

1988—Pub. L. 100–352, § 2(b), struck out ''appeal;'' after ''certiorari;'' in section catchline.

Pars. (2), (3). Pub. L. 100–352, § 2(a), redesignated par. (3) as (2) and struck out former par. (2) which read as follows: ''By appeal by a party relying on a State statute held by a court of appeals to be invalid as repugnant to the Constitution, treaties or laws of the United States, but such appeal shall preclude review by writ of certiorari at the instance of such appellant, and the review on appeal shall be restricted to the Federal questions presented;''.

Statutory Notes and Related Subsidiaries

EFFECTIVE DATE OF 1988 AMENDMENT

Pub. L. 100–352, § 7, June 27, 1988, 102 Stat. 664, provided that: ''The amendments made by this Act [amending sections 1254, 1257, 1258, 2101, 2104, and 2350 of this title, section 136w of Title 7, Agriculture, section 1631e of Title 22, Foreign Relations and Intercourse, section 652 of Title 25, Indians, section 988 of Title 33, Navigation and Navigable Waters, section 1652 of Title 43, Public Lands, sections 719, 743, and 1105 of Title 45, Railroads, and section 30110 of Title 52, Voting and Elections, and repealing sections 1252 and 2103 of this title] shall take effect ninety days after the date of the enactment of this Act [June 27, 1988], except that such amendments shall not apply to cases pending in the Supreme Court on the effective date of such amendments or affect the right to review or the manner of reviewing the judgment or decree of a court which was entered before such effective date.''

The last sentence in said section 344(b) relating to the right to relief under both subsections of said section 344, was omitted as unnecessary.

Changes were made in phraseology.

CHAPTER 133—REVIEW—MISCELLANEOUS PROVISIONS

HISTORICAL AND REVISION NOTES

1949 ACT

This section inserts in the chapter analysis of chapter 133 of title 28, U.S.C., a new item "2111," in view of the insertion in such title, by another section of this bill, of a new section 2111.

Editorial Notes

AMENDMENTS

1988—Pub. L. 100–352, §5(c), (d)(2), June 27, 1988, 102 Stat. 663, struck out item 2103 "Appeal from State court or from a United States court of appeals improvidently taken regarded as petition for writ of certiorari" and substituted "Reviews of State court decisions" for "Appeals from State courts" in item 2104.

1982—Pub. L. 97–164, title I, §136, Apr. 2, 1982, 96 Stat. 41, struck out item 2110 "Time for appeal to Court of Claims in tort claims cases".

1970—Pub. L. 91–358, title I, §172(a)(2)(B), July 29, 1970, 84 Stat. 590, added item 2113.

1962—Pub. L. 87–669, §2, Sept. 19, 1962, 76 Stat. 556, substituted "or from a United States court of appeals improvidently taken regarded as petition for" for "improvidently taken regarded as" in item 2103.

1958—Pub. L. 85–791, §1, Aug. 28, 1958, 72 Stat. 941, added item 2112.

1949—Act May 24, 1949, ch. 139, §105, 63 Stat. 104, added item 2111.

§ 2101. Supreme Court; time for appeal or certiorari; docketing; stay

(a) A direct appeal to the Supreme Court from any decision under section 1253 of this title, holding unconstitutional in whole or in part, any Act of Congress, shall be taken within thirty days after the entry of the interlocutory or final order, judgment or decree. The record shall be made up and the case docketed within sixty days from the time such appeal is taken under rules prescribed by the Supreme Court.

(b) Any other direct appeal to the Supreme Court which is authorized by law, from a decision of a district court in any civil action, suit or proceeding, shall be taken within thirty days from the judgment, order or decree, appealed from, if interlocutory, and within sixty days if final.

(c) Any other appeal or any writ of certiorari intended to bring any judgment or decree in a civil action, suit or proceeding before the Supreme Court for review shall be taken or applied for within ninety days after the entry of such judgment or decree. A justice of the Supreme Court, for good cause shown, may extend the time for applying for a writ of certiorari for a period not exceeding sixty days.

(d) The time for appeal or application for a writ of certiorari to review the judgment of a State court in a criminal case shall be as prescribed by rules of the Supreme Court.

(e) An application to the Supreme Court for a writ of certiorari to review a case before judgment has been rendered in the court of appeals may be made at any time before judgment.

(f) In any case in which the final judgment or decree of any court is subject to review by the Supreme Court on writ of certiorari, the execution and enforcement of such judgment or decree may be stayed for a reasonable time to enable the party aggrieved to obtain a writ of certiorari from the Supreme Court. The stay may be granted by a judge of the court rendering the judgment or decree or by a justice of the Supreme Court, and may be conditioned on the giving of security, approved by such judge or justice, that if the aggrieved party fails to make application for such writ within the period allotted therefor, or fails to obtain an order granting his application, or fails to make his plea good in the Supreme Court, he shall answer for all damages and costs which the other party may sustain by reason of the stay.

(g) The time for application for a writ of certiorari to review a decision of the United States Court of Appeals for the Armed Forces shall be as prescribed by rules of the Supreme Court.

(June 25, 1948, ch. 646, 62 Stat. 961; May 24, 1949, ch. 139, §106, 63 Stat. 104; Pub. L. 98–209, §10(b), Dec. 6, 1983, 97 Stat. 1406; Pub. L. 100–352, §5(b), June 27, 1988, 102 Stat. 663; Pub. L. 103–337, div. A, title IX, §924(d)(1)(C), Oct. 5, 1994, 108 Stat. 2832; Pub. L. 118–31, div. A, title V, §533(a)(2)(B), Dec. 22, 2023, 137 Stat. 261.)

AMENDMENT OF SUBSECTION (g)

Pub. L. 118–31, div. A, title V, §533(a)(2)(B), (b), Dec. 22, 2023, 137 Stat. 261, provided that, effective on the date that is one year after Dec. 22, 2023, and applicable with respect to any action of the United States Court of Appeals for the Armed Forces in granting or refusing to grant a petition for review submitted to such Court for the first time on or after Dec. 22, 2023, with certain provisos, subsection (g) of this section is amended to read as follows:

"(g) The time for application for a writ of certiorari to review a decision of the United States Court of Appeals for the Armed Forces, or the decision of a Court of Criminal Appeals that the United States Court of Appeals for the Armed Forces refuses to grant a petition to review, shall be as prescribed by rules of the Supreme Court."

See 2023 Amendment note below.

HISTORICAL AND REVISION NOTES

1948 ACT

Based on title 28, U.S.C., 1940 ed., §§47, 47a, 349a, 350, 380, 380a, section 29 of title 15, U.S.C., 1940 ed., Commerce and Trade, and section 45 of title 49, U.S.C., 1940 ed., Transportation (Feb. 11, 1903, ch. 544, §2, 32 Stat. 1167; Mar. 3, 1911, ch. 231, §§210, 266, 291, 36 Stat. 1150, 1162, 1167; Mar. 4, 1913, ch. 160, 37 Stat. 1013; Oct. 22, 1913, ch. 32, 38 Stat. 220; Sept. 6, 1916, ch. 448, §6, 39 Stat. 727; Feb. 13, 1925, ch. 229, §§1, 8 (a, b, d), 43 Stat. 938, 940;

erwise final is final for the purposes of this section whether or not there has been presented or determined an application for a declaratory order, for any form of reconsideration, or, unless the agency otherwise requires by rule and provides that the action meanwhile is inoperative, for an appeal to superior agency authority.

(Pub. L. 89–554, Sept. 6, 1966, 80 Stat. 392.)

HISTORICAL AND REVISION NOTES

Derivation	*U.S. Code*	*Revised Statutes and Statutes at Large*
....	5 U.S.C. 1009(c).	June 11, 1946, ch. 324, §10(c), 60 Stat. 243.

Standard changes are made to conform with the definitions applicable and the style of this title as outlined in the preface of this report.

§ 705. Relief pending review

When an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review. On such conditions as may be required and to the extent necessary to prevent irreparable injury, the reviewing court, including the court to which a case may be taken on appeal from or on application for certiorari or other writ to a reviewing court, may issue all necessary and appropriate process to postpone the effective date of an agency action or to preserve status or rights pending conclusion of the review proceedings.

(Pub. L. 89–554, Sept. 6, 1966, 80 Stat. 393.)

HISTORICAL AND REVISION NOTES

Derivation	*U.S. Code*	*Revised Statutes and Statutes at Large*
....	5 U.S.C. 1009(d).	June 11, 1946, ch. 324, §10(d), 60 Stat. 243.

Standard changes are made to conform with the definitions applicable and the style of this title as outlined in the preface of this report.

§ 706. Scope of review

To the extent necessary to decision and when presented, the reviewing court shall decide all relevant questions of law, interpret constitutional and statutory provisions, and determine the meaning or applicability of the terms of an agency action. The reviewing court shall—

(1) compel agency action unlawfully withheld or unreasonably delayed; and

(2) hold unlawful and set aside agency action, findings, and conclusions found to be—

(A) arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law;

(B) contrary to constitutional right, power, privilege, or immunity;

(C) in excess of statutory jurisdiction, authority, or limitations, or short of statutory right;

(D) without observance of procedure required by law;

(E) unsupported by substantial evidence in a case subject to sections 556 and 557 of this title or otherwise reviewed on the record of an agency hearing provided by statute; or

(F) unwarranted by the facts to the extent that the facts are subject to trial de novo by the reviewing court.

In making the foregoing determinations, the court shall review the whole record or those parts of it cited by a party, and due account shall be taken of the rule of prejudicial error.

(Pub. L. 89–554, Sept. 6, 1966, 80 Stat. 393.)

HISTORICAL AND REVISION NOTES

Derivation	*U.S. Code*	*Revised Statutes and Statutes at Large*
....	5 U.S.C. 1009(e).	June 11, 1946, ch. 324, §10(e), 60 Stat. 243.

Standard changes are made to conform with the definitions applicable and the style of this title as outlined in the preface of this report.

Statutory Notes and Related Subsidiaries

ABBREVIATION OF RECORD

Pub. L. 85–791, Aug. 28, 1958, 72 Stat. 941, which authorized abbreviation of record on review or enforcement of orders of administrative agencies and review on the original papers, provided, in section 35 thereof, that: ''This Act [see Tables for classification] shall not be construed to repeal or modify any provision of the Administrative Procedure Act [see Short Title note set out preceding section 551 of this title].''

CHAPTER 8—CONGRESSIONAL REVIEW OF AGENCY RULEMAKING

§ 801. Congressional review

(a)(1)(A) Before a rule can take effect, the Federal agency promulgating such rule shall submit to each House of the Congress and to the Comptroller General a report containing—

(i) a copy of the rule;

(ii) a concise general statement relating to the rule, including whether it is a major rule; and

(iii) the proposed effective date of the rule.

(B) On the date of the submission of the report under subparagraph (A), the Federal agency promulgating the rule shall submit to the Comptroller General and make available to each House of Congress—

(i) a complete copy of the cost-benefit analysis of the rule, if any;

(ii) the agency's actions relevant to sections 603, 604, 605, 607, and 609;

(iii) the agency's actions relevant to sections 202, 203, 204, and 205 of the Unfunded Mandates Reform Act of 1995; and

(iv) any other relevant information or requirements under any other Act and any relevant Executive orders.

(C) Upon receipt of a report submitted under subparagraph (A), each House shall provide copies of the report to the chairman and ranking member of each standing committee with jurisdiction under the rules of the House of Rep-

§ 7607. Administrative proceedings and judicial review

(a) Administrative subpenas; confidentiality; witnesses

In connection with any determination under section 7410(f) of this title, or for purposes of obtaining information under section 7521(b)(4) [1] or 7545(c)(3) of this title, any investigation, monitoring, reporting requirement, entry, compliance inspection, or administrative enforcement proceeding under the [2] chapter (including but not limited to section 7413, section 7414, section 7420, section 7429, section 7477, section 7524, section 7525, section 7542, section 7603, or section 7606 of this title),,[3] the Administrator may issue subpenas for the attendance and testimony of witnesses and the production of relevant papers, books, and documents, and he may administer oaths. Except for emission data, upon a showing satisfactory to the Administrator by such owner or operator that such papers, books, documents, or information or particular part thereof, if made public, would divulge trade secrets or secret processes of such owner or operator, the Administrator shall consider such record, report, or information or particular portion thereof confidential in accordance with the purposes of section 1905 of title 18, except that such paper, book, document, or information may be disclosed to other officers, employees, or authorized representatives of the United States concerned with carrying out this chapter, to persons carrying out the National Academy of Sciences' study and investigation provided for in section 7521(c) of this title, or when relevant in any proceeding under this chapter. Witnesses summoned shall be paid the same fees and mileage that are paid witnesses in the courts of the United States. In case of contumacy or refusal to obey a subpena served upon any person under this subparagraph,[4] the district court of the United States for any district in which such person is found or resides or transacts business, upon application by the United States and after notice to such person, shall have jurisdiction to issue an order requiring such person to appear and give testimony before the Administrator to appear and produce papers, books, and documents before the Administrator, or both, and any failure to obey such order of the court may be punished by such court as a contempt thereof.

(b) Judicial review

(1) A petition for review of action of the Administrator in promulgating any national primary or secondary ambient air quality standard, any emission standard or requirement under section 7412 of this title, any standard of performance or requirement under section 7411 of this title,,[3] any standard under section 7521 of this title (other than a standard required to be prescribed under section 7521(b)(1) of this title), any determination under section 7521(b)(5) [1] of this title, any control or prohibition under section 7545 of this title, any standard under section 7571 of this title, any rule issued under section 7413, 7419, or under section 7420 of this title, or any other nationally applicable regulations promulgated, or final action taken, by the Administrator under this chapter may be filed only in the United States Court of Appeals for the District of Columbia. A petition for review of the Administrator's action in approving or promulgating any implementation plan under section 7410 of this title or section 7411(d) of this title, any order under section 7411(j) of this title, under section 7412 of this title, under section 7419 of this title, or under section 7420 of this title, or his action under section 1857c–10(c)(2)(A), (B), or (C) of this title (as in effect before August 7, 1977) or under regulations thereunder, or revising regulations for enhanced monitoring and compliance certification programs under section 7414(a)(3) of this title, or any other final action of the Administrator under this chapter (including any denial or disapproval by the Administrator under subchapter I) which is locally or regionally applicable may be filed only in the United States Court of Appeals for the appropriate circuit. Notwithstanding the preceding sentence a petition for review of any action referred to in such sentence may be filed only in the United States Court of Appeals for the District of Columbia if such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination. Any petition for review under this subsection shall be filed within sixty days from the date notice of such promulgation, approval, or action appears in the Federal Register, except that if such petition is based solely on grounds arising after such sixtieth day, then any petition for review under this subsection shall be filed within sixty days after such grounds arise. The filing of a petition for reconsideration by the Administrator of any otherwise final rule or action shall not affect the finality of such rule or action for purposes of judicial review nor extend the time within which a petition for judicial review of such rule or action under this section may be filed, and shall not postpone the effectiveness of such rule or action.

(2) Action of the Administrator with respect to which review could have been obtained under paragraph (1) shall not be subject to judicial review in civil or criminal proceedings for enforcement. Where a final decision by the Administrator defers performance of any nondiscretionary statutory action to a later time, any person may challenge the deferral pursuant to paragraph (1).

(c) Additional evidence

In any judicial proceeding in which review is sought of a determination under this chapter required to be made on the record after notice and opportunity for hearing, if any party applies to the court for leave to adduce additional evidence, and shows to the satisfaction of the court that such additional evidence is material and that there were reasonable grounds for the failure to adduce such evidence in the proceeding before the Administrator, the court may order such additional evidence (and evidence in rebut-

[1] See References in Text note below.

[2] So in original. Probably should be "this".

[3] So in original.

[4] So in original. Probably should be "subsection,".

tal thereof) to be taken before the Administrator, in such manner and upon such terms and conditions as to[5] the court may deem proper. The Administrator may modify his findings as to the facts, or make new findings, by reason of the additional evidence so taken and he shall file such modified or new findings, and his recommendation, if any, for the modification or setting aside of his original determination, with the return of such additional evidence.

(d) Rulemaking

(1) This subsection applies to—

(A) the promulgation or revision of any national ambient air quality standard under section 7409 of this title,

(B) the promulgation or revision of an implementation plan by the Administrator under section 7410(c) of this title,

(C) the promulgation or revision of any standard of performance under section 7411 of this title, or emission standard or limitation under section 7412(d) of this title, any standard under section 7412(f) of this title, or any regulation under section 7412(g)(1)(D) and (F)[6] of this title, or any regulation under section 7412(m) or (n) of this title,

(D) the promulgation of any requirement for solid waste combustion under section 7429 of this title,

(E) the promulgation or revision of any regulation pertaining to any fuel or fuel additive under section 7545 of this title,

(F) the promulgation or revision of any aircraft emission standard under section 7571 of this title,

(G) the promulgation or revision of any regulation under subchapter IV–A (relating to control of acid deposition),

(H) promulgation or revision of regulations pertaining to primary nonferrous smelter orders under section 7419 of this title (but not including the granting or denying of any such order),

(I) promulgation or revision of regulations under subchapter VI (relating to stratosphere and ozone protection),

(J) promulgation or revision of regulations under part C of subchapter I (relating to prevention of significant deterioration of air quality and protection of visibility),

(K) promulgation or revision of regulations under section 7521 of this title and test procedures for new motor vehicles or engines under section 7525 of this title, and the revision of a standard under section 7521(a)(3) of this title,

(L) promulgation or revision of regulations for noncompliance penalties under section 7420 of this title,

(M) promulgation or revision of any regulations promulgated under section 7541 of this title (relating to warranties and compliance by vehicles in actual use),

(N) action of the Administrator under section 7426 of this title (relating to interstate pollution abatement),

(O) the promulgation or revision of any regulation pertaining to consumer and commercial products under section 7511b(e) of this title,

(P) the promulgation or revision of any regulation pertaining to field citations under section 7413(d)(3) of this title,

(Q) the promulgation or revision of any regulation pertaining to urban buses or the clean-fuel vehicle, clean-fuel fleet, and clean fuel programs under part C of subchapter II,

(R) the promulgation or revision of any regulation pertaining to nonroad engines or nonroad vehicles under section 7547 of this title,

(S) the promulgation or revision of any regulation relating to motor vehicle compliance program fees under section 7552 of this title,

(T) the promulgation or revision of any regulation under subchapter IV–A (relating to acid deposition),

(U) the promulgation or revision of any regulation under section 7511b(f) of this title pertaining to marine vessels, and

(V) such other actions as the Administrator may determine.

The provisions of section 553 through 557 and section 706 of title 5 shall not, except as expressly provided in this subsection, apply to actions to which this subsection applies. This subsection shall not apply in the case of any rule or circumstance referred to in subparagraphs (A) or (B) of subsection 553(b) of title 5.

(2) Not later than the date of proposal of any action to which this subsection applies, the Administrator shall establish a rulemaking docket for such action (hereinafter in this subsection referred to as a ''rule''). Whenever a rule applies only within a particular State, a second (identical) docket shall be simultaneously established in the appropriate regional office of the Environmental Protection Agency.

(3) In the case of any rule to which this subsection applies, notice of proposed rulemaking shall be published in the Federal Register, as provided under section 553(b) of title 5, shall be accompanied by a statement of its basis and purpose and shall specify the period available for public comment (hereinafter referred to as the ''comment period''). The notice of proposed rulemaking shall also state the docket number, the location or locations of the docket, and the times it will be open to public inspection. The statement of basis and purpose shall include a summary of—

(A) the factual data on which the proposed rule is based;

(B) the methodology used in obtaining the data and in analyzing the data; and

(C) the major legal interpretations and policy considerations underlying the proposed rule.

The statement shall also set forth or summarize and provide a reference to any pertinent findings, recommendations, and comments by the Scientific Review Committee established under section 7409(d) of this title and the National Academy of Sciences, and, if the proposal differs in any important respect from any of these recommendations, an explanation of the reasons for such differences. All data, information, and documents referred to in this paragraph on which

[5] So in original. The word ''to'' probably should not appear.

[6] So in original. There are no subpars. (D) and (F) of section 7412(g)(1) of this title.

the proposed rule relies shall be included in the docket on the date of publication of the proposed rule.

(4)(A) The rulemaking docket required under paragraph (2) shall be open for inspection by the public at reasonable times specified in the notice of proposed rulemaking. Any person may copy documents contained in the docket. The Administrator shall provide copying facilities which may be used at the expense of the person seeking copies, but the Administrator may waive or reduce such expenses in such instances as the public interest requires. Any person may request copies by mail if the person pays the expenses, including personnel costs to do the copying.

(B)(i) Promptly upon receipt by the agency, all written comments and documentary information on the proposed rule received from any person for inclusion in the docket during the comment period shall be placed in the docket. The transcript of public hearings, if any, on the proposed rule shall also be included in the docket promptly upon receipt from the person who transcribed such hearings. All documents which become available after the proposed rule has been published and which the Administrator determines are of central relevance to the rulemaking shall be placed in the docket as soon as possible after their availability.

(ii) The drafts of proposed rules submitted by the Administrator to the Office of Management and Budget for any interagency review process prior to proposal of any such rule, all documents accompanying such drafts, and all written comments thereon by other agencies and all written responses to such written comments by the Administrator shall be placed in the docket no later than the date of proposal of the rule. The drafts of the final rule submitted for such review process prior to promulgation and all such written comments thereon, all documents accompanying such drafts, and written responses thereto shall be placed in the docket no later than the date of promulgation.

(5) In promulgating a rule to which this subsection applies (i) the Administrator shall allow any person to submit written comments, data, or documentary information; (ii) the Administrator shall give interested persons an opportunity for the oral presentation of data, views, or arguments, in addition to an opportunity to make written submissions; (iii) a transcript shall be kept of any oral presentation; and (iv) the Administrator shall keep the record of such proceeding open for thirty days after completion of the proceeding to provide an opportunity for submission of rebuttal and supplementary information.

(6)(A) The promulgated rule shall be accompanied by (i) a statement of basis and purpose like that referred to in paragraph (3) with respect to a proposed rule and (ii) an explanation of the reasons for any major changes in the promulgated rule from the proposed rule.

(B) The promulgated rule shall also be accompanied by a response to each of the significant comments, criticisms, and new data submitted in written or oral presentations during the comment period.

(C) The promulgated rule may not be based (in part or whole) on any information or data which has not been placed in the docket as of the date of such promulgation.

(7)(A) The record for judicial review shall consist exclusively of the material referred to in paragraph (3), clause (i) of paragraph (4)(B), and subparagraphs (A) and (B) of paragraph (6).

(B) Only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed. If the Administrator refuses to convene such a proceeding, such person may seek review of such refusal in the United States court of appeals for the appropriate circuit (as provided in subsection (b)). Such reconsideration shall not postpone the effectiveness of the rule. The effectiveness of the rule may be stayed during such reconsideration, however, by the Administrator or the court for a period not to exceed three months.

(8) The sole forum for challenging procedural determinations made by the Administrator under this subsection shall be in the United States court of appeals for the appropriate circuit (as provided in subsection (b)) at the time of the substantive review of the rule. No interlocutory appeals shall be permitted with respect to such procedural determinations. In reviewing alleged procedural errors, the court may invalidate the rule only if the errors were so serious and related to matters of such central relevance to the rule that there is a substantial likelihood that the rule would have been significantly changed if such errors had not been made.

(9) In the case of review of any action of the Administrator to which this subsection applies, the court may reverse any such action found to be—

(A) arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law;

(B) contrary to constitutional right, power, privilege, or immunity;

(C) in excess of statutory jurisdiction, authority, or limitations, or short of statutory right; or

(D) without observance of procedure required by law, if (i) such failure to observe such procedure is arbitrary or capricious, (ii) the requirement of paragraph (7)(B) has been met, and (iii) the condition of the last sentence of paragraph (8) is met.

(10) Each statutory deadline for promulgation of rules to which this subsection applies which requires promulgation less than six months after date of proposal may be extended to not more than six months after date of proposal by the Administrator upon a determination that such extension is necessary to afford the public, and the agency, adequate opportunity to carry out the purposes of this subsection.

(11) The requirements of this subsection shall take effect with respect to any rule the proposal of which occurs after ninety days after August 7, 1977.

(e) Other methods of judicial review not authorized

Nothing in this chapter shall be construed to authorize judicial review of regulations or orders of the Administrator under this chapter, except as provided in this section.

(f) Costs

In any judicial proceeding under this section, the court may award costs of litigation (including reasonable attorney and expert witness fees) whenever it determines that such award is appropriate.

(g) Stay, injunction, or similar relief in proceedings relating to noncompliance penalties

In any action respecting the promulgation of regulations under section 7420 of this title or the administration or enforcement of section 7420 of this title no court shall grant any stay, injunctive, or similar relief before final judgment by such court in such action.

(h) Public participation

It is the intent of Congress that, consistent with the policy of subchapter II of chapter 5 of title 5, the Administrator in promulgating any regulation under this chapter, including a regulation subject to a deadline, shall ensure a reasonable period for public participation of at least 30 days, except as otherwise expressly provided in section[7] 7407(d), 7502(a), 7511(a) and (b), and 7512(a) and (b) of this title.

(July 14, 1955, ch. 360, title III, § 307, as added Pub. L. 91–604, § 12(a), Dec. 31, 1970, 84 Stat. 1707; amended Pub. L. 92–157, title III, § 302(a), Nov. 18, 1971, 85 Stat. 464; Pub. L. 93–319, § 6(c), June 22, 1974, 88 Stat. 259; Pub. L. 95–95, title III, §§ 303(d), 305(a), (c), (f)–(h), Aug. 7, 1977, 91 Stat. 772, 776, 777; Pub. L. 95–190, § 14(a)(79), (80), Nov. 16, 1977, 91 Stat. 1404; Pub. L. 101–549, title I, §§ 108(p), 110(5), title III, § 302(g), (h), title VII, §§ 702(c), 703, 706, 707(h), 710(b), Nov. 15, 1990, 104 Stat. 2469, 2470, 2574, 2681–2684.)

Editorial Notes

REFERENCES IN TEXT

Section 7521(b)(4) of this title, referred to in subsec. (a), was repealed by Pub. L. 101–549, title II, § 230(2), Nov. 15, 1990, 104 Stat. 2529.

Section 7521(b)(5) of this title, referred to in subsec. (b)(1), was repealed by Pub. L. 101–549, title II, § 230(3), Nov. 15, 1990, 104 Stat. 2529.

Section 1857c–10(c)(2)(A), (B), or (C) of this title (as in effect before August 7, 1977), referred to in subsec. (b)(1), was in the original "section 119(c)(2)(A), (B), or (C) (as in effect before the date of enactment of the Clean Air Act Amendments of 1977)", meaning section 119 of act July 14, 1955, ch. 360, title I, as added June 22, 1974, Pub. L. 93–319, § 3, 88 Stat. 248, (which was classified to section 1857c–10 of this title) as in effect prior to the enactment of Pub. L. 95–95, Aug. 7, 1977, 91 Stat. 691, effective Aug. 7, 1977. Section 112(b)(1) of Pub. L. 95–95 repealed section 119 of act July 14, 1955, ch. 360, title I, as added by Pub. L. 93–319, and provided that all references to such section 119 in any subsequent enactment which supersedes Pub. L. 93–319 shall be construed to refer to section 113(d) of the Clean Air Act and to paragraph (5) thereof in particular which is classified to subsec. (d)(5) of section 7413 of this title. Section 7413(d) of this title was subsequently amended generally by Pub. L. 101–549, title VII, § 701, Nov. 15, 1990, 104 Stat. 2672, and, as so amended, no longer relates to final compliance orders. Section 117(b) of Pub. L. 95–95 added a new section 119 of act July 14, 1955, which is classified to section 7419 of this title.

Part C of subchapter I, referred to in subsec. (d)(1)(J), was in the original "subtitle C of title I", and was translated as reading "part C of title I" to reflect the probable intent of Congress, because title I does not contain subtitles.

CODIFICATION

In subsec. (h), "subchapter II of chapter 5 of title 5" was substituted for "the Administrative Procedures Act" on authority of Pub. L. 89–554, § 7(b), Sept. 6, 1966, 80 Stat. 631, the first section of which enacted Title 5, Government Organization and Employees.

Section was formerly classified to section 1857h–5 of this title.

PRIOR PROVISIONS

A prior section 307 of act July 14, 1955, was renumbered section 314 by Pub. L. 91–604 and is classified to section 7614 of this title.

Another prior section 307 of act July 14, 1955, ch. 360, title III, formerly § 14, as added Dec. 17, 1963, Pub. L. 88–206, § 1, 77 Stat. 401, was renumbered section 307 by Pub. L. 89–272, renumbered section 310 by Pub. L. 90–148, and renumbered section 317 by Pub. L. 91–604, and is set out as a Short Title note under section 7401 of this title.

AMENDMENTS

1990—Subsec. (a). Pub. L. 101–549, § 703, struck out par. (1) designation at beginning, inserted provisions authorizing issuance of subpoenas and administration of oaths for purposes of investigations, monitoring, reporting requirements, entries, compliance inspections, or administrative enforcement proceedings under this chapter, and struck out "or section 7521(b)(5)" after "section 7410(f)".

Subsec. (b)(1). Pub. L. 101–549, § 706(2), which directed amendment of second sentence by striking "under section 7413(d) of this title" immediately before "under section 7419 of this title", was executed by striking "under section 7413(d) of this title," before "under section 7419 of this title", to reflect the probable intent of Congress.

Pub. L. 101–549, § 706(1), inserted at end: "The filing of a petition for reconsideration by the Administrator of any otherwise final rule or action shall not affect the finality of such rule or action for purposes of judicial review nor extend the time within which a petition for judicial review of such rule or action under this section may be filed, and shall not postpone the effectiveness of such rule or action."

Pub. L. 101–549, § 702(c), inserted "or revising regulations for enhanced monitoring and compliance certification programs under section 7414(a)(3) of this title," before "or any other final action of the Administrator".

Pub. L. 101–549, § 302(g), substituted "section 7412" for "section 7412(c)".

Subsec. (b)(2). Pub. L. 101–549, § 707(h), inserted sentence at end authorizing challenge to deferrals of performance of nondiscretionary statutory actions.

Subsec. (d)(1)(C). Pub. L. 101–549, § 110(5)(A), amended subpar. (C) generally. Prior to amendment, subpar. (C) read as follows: "the promulgation or revision of any standard of performance under section 7411 of this title or emission standard under section 7412 of this title,".

Subsec. (d)(1)(D), (E). Pub. L. 101–549, § 302(h), added subpar. (D) and redesignated former subpar. (D) as (E). Former subpar. (E) redesignated (F).

[7] So in original. Probably should be "sections".

Subsec. (d)(1)(F). Pub. L. 101–549, § 302(h), redesignated subpar. (E) as (F). Former subpar. (F) redesignated (G).

Pub. L. 101–549, § 110(5)(B), amended subpar. (F) generally. Prior to amendment, subpar. (F) read as follows: ''promulgation or revision of regulations pertaining to orders for coal conversion under section 7413(d)(5) of this title (but not including orders granting or denying any such orders),''.

Subsec. (d)(1)(G), (H). Pub. L. 101–549, § 302(h), redesignated subpars. (F) and (G) as (G) and (H), respectively. Former subpar. (H) redesignated (I).

Subsec. (d)(1)(I). Pub. L. 101–549, § 710(b), which directed that subpar. (H) be amended by substituting ''subchapter VI'' for ''part B of subchapter I'', was executed by making the substitution in subpar. (I), to reflect the probable intent of Congress and the intervening redesignation of subpar. (H) as (I) by Pub. L. 101–549, § 302(h), see below.

Pub. L. 101–549, § 302(h), redesignated subpar. (H) as (I). Former subpar. (I) redesignated (J).

Subsec. (d)(1)(J) to (M). Pub. L. 101–549, § 302(h), redesignated subpars. (I) to (L) as (J) to (M), respectively. Former subpar. (M) redesignated (N).

Subsec. (d)(1)(N). Pub. L. 101–549, § 302(h), redesignated subpar. (M) as (N). Former subpar. (N) redesignated (O).

Pub. L. 101–549, § 110(5)(C), added subpar. (N) and redesignated former subpar. (N) as (U).

Subsec. (d)(1)(O) to (T). Pub. L. 101–549, § 302(h), redesignated subpars. (N) to (S) as (O) to (T), respectively. Former subpar. (T) redesignated (U).

Pub. L. 101–549, § 110(5)(C), added subpars. (O) to (T).

Subsec. (d)(1)(U). Pub. L. 101–549, § 302(h), redesignated subpar. (T) as (U). Former subpar. (U) redesignated (V).

Pub. L. 101–549, § 110(5)(C), redesignated former subpar. (N) as (U).

Subsec. (d)(1)(V). Pub. L. 101–549, § 302(h), redesignated subpar. (U) as (V).

Subsec. (h). Pub. L. 101–549, § 108(p), added subsec. (h).

1977—Subsec. (b)(1). Pub. L. 95–190 in text relating to filing of petitions for review in the United States Court of Appeals for the District of Columbia inserted provision respecting requirements under sections 7411 and 7412 of this title, and substituted provisions authorizing review of any rule issued under section 7413, 7419, or 7420 of this title, for provisions authorizing review of any rule or order issued under section 7420 of this title, relating to noncompliance penalties, and in text relating to filing of petitions for review in the United States Court of Appeals for the appropriate circuit inserted provision respecting review under section 7411(j), 7412(c), 7413(d), or 7419 of this title, provision authorizing review under section 1857c–10(c)(2)(A), (B), or (C) to the period prior to Aug. 7, 1977, and provisions authorizing review of denials or disapprovals by the Administrator under subchapter I of this chapter.

Pub. L. 95–95, § 305(c), (h), inserted rules or orders issued under section 7420 of this title (relating to noncompliance penalties) and any other nationally applicable regulations promulgated, or final action taken, by the Administrator under this chapter to the enumeration of actions of the Administrator for which a petition for review may be filed only in the United States Court of Appeals for the District of Columbia, added the approval or promulgation by the Administrator of orders under section 7420 of this title, or any other final action of the Administrator under this chapter which is locally or regionally applicable to the enumeration of actions by the Administrator for which a petition for review may be filed only in the United States Court of Appeals for the appropriate circuit, inserted provision that petitions otherwise capable of being filed in the Court of Appeals for the appropriate circuit may be filed only in the Court of Appeals for the District of Columbia if the action is based on a determination of nationwide scope, and increased from 30 days to 60 days the period during which the petition must be filed.

Subsec. (d). Pub. L. 95–95, § 305(a), added subsec. (d).

Subsec. (e). Pub. L. 95–95, § 303(d), added subsec. (e).

Subsec. (f). Pub. L. 95–95, § 305(f), added subsec. (f).

Subsec. (g). Pub. L. 95–95, § 305(g), added subsec. (g).

1974—Subsec. (b)(1). Pub. L. 93–319 inserted reference to the Administrator's action under section 1857c–10(c)(2)(A), (B), or (C) of this title or under regulations thereunder and substituted reference to the filing of a petition within 30 days from the date of promulgation, approval, or action for reference to the filing of a petition within 30 days from the date of promulgation or approval.

1971—Subsec. (a)(1). Pub. L. 92–157 substituted reference to section ''7545(c)(3)'' for ''7545(c)(4)'' of this title.

Statutory Notes and Related Subsidiaries

EFFECTIVE DATE OF 1977 AMENDMENT

Amendment by Pub. L. 95–95 effective Aug. 7, 1977, except as otherwise expressly provided, see section 406(d) of Pub. L. 95–95, set out as a note under section 7401 of this title.

TERMINATION OF ADVISORY COMMITTEES

Advisory committees established after Jan. 5, 1973, to terminate not later than the expiration of the 2-year period beginning on the date of their establishment, unless, in the case of a committee established by the President or an officer of the Federal Government, such committee is renewed by appropriate action prior to the expiration of such 2-year period, or in the case of a committee established by the Congress, its duration is otherwise provided for by law. See section 1013 of Title 5, Government Organization and Employees.

PENDING ACTIONS AND PROCEEDINGS

Suits, actions, and other proceedings lawfully commenced by or against the Administrator or any other officer or employee of the United States in his official capacity or in relation to the discharge of his official duties under act July 14, 1955, the Clean Air Act, as in effect immediately prior to the enactment of Pub. L. 95–95 [Aug. 7, 1977], not to abate by reason of the taking effect of Pub. L. 95–95, see section 406(a) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

MODIFICATION OR RESCISSION OF RULES, REGULATIONS, ORDERS, DETERMINATIONS, CONTRACTS, CERTIFICATIONS, AUTHORIZATIONS, DELEGATIONS, AND OTHER ACTIONS

All rules, regulations, orders, determinations, contracts, certifications, authorizations, delegations, or other actions duly issued, made, or taken by or pursuant to act July 14, 1955, the Clean Air Act, as in effect immediately prior to the date of enactment of Pub. L. 95–95 [Aug. 7, 1977] to continue in full force and effect until modified or rescinded in accordance with act July 14, 1955, as amended by Pub. L. 95–95 [this chapter], see section 406(b) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

§ 7608. Mandatory licensing

Whenever the Attorney General determines, upon application of the Administrator—

(1) that—

(A) in the implementation of the requirements of section 7411, 7412, or 7521 of this title, a right under any United States letters patent, which is being used or intended for public or commercial use and not otherwise reasonably available, is necessary to enable any person required to comply with such limitation to so comply, and

(B) there are no reasonable alternative methods to accomplish such purpose, and

(2) that the unavailability of such right may result in a substantial lessening of competi-

§1651. Writs

(a) The Supreme Court and all courts established by Act of Congress may issue all writs necessary or appropriate in aid of their respective jurisdictions and agreeable to the usages and principles of law.

(b) An alternative writ or rule nisi may be issued by a justice or judge of a court which has jurisdiction.

(June 25, 1948, ch. 646, 62 Stat. 944; May 24, 1949, ch. 139, §90, 63 Stat. 102.)

HISTORICAL AND REVISION NOTES

1948 ACT

Based on title 28, U.S.C., 1940 ed., §§342, 376, 377 (Mar. 3, 1911, ch. 231, §§234, 261, 262, 36 Stat. 1156, 1162).

Section consolidates sections 342, 376, and 377 of title 28, U.S.C., 1940 ed., with necessary changes in phraseology.

Such section 342 provided:

"The Supreme Court shall have power to issue writs of prohibition to the district courts, when proceeding as courts of admiralty and maritime jurisdiction; and writs of mandamus, in cases warranted by the principles and usages of law, to any courts appointed under the authority of the United States, or to persons holding office under the authority of the United States, where a State, or an ambassador, or other public minister, or a consul, or vice consul is a party."

Such section 376 provided:

"Writs of ne exeat may be granted by any justice of the Supreme Court, in cases where they might be granted by the Supreme Court; and by any district judge, in cases where they might be granted by the district court of which he is a judge. But no writ of ne exeat shall be granted unless a suit in equity is commenced, and satisfactory proof is made to the court or judge granting the same that the defendant designs quickly to depart from the United States."

Such section 377 provided:

"The Supreme Court and the district courts shall have power to issue writs of scire facias. The Supreme Court, the circuit courts of appeals, and the district courts shall have power to issue all writs not specifically provided for by statute, which may be necessary for the exercise of their respective jurisdictions, and agreeable to the usages and principles of law."

The special provisions of section 342 of title 28, U.S.C., 1940 ed., with reference to writs of prohibition and mandamus, admiralty courts and other courts and officers of the United States were omitted as unnecessary in view of the revised section.

The revised section extends the power to issue writs in aid of jurisdiction, to all courts established by Act of Congress, thus making explicit the right to exercise powers implied from the creation of such courts.

The provisions of section 376 of title 28, U.S.C., 1940 ed., with respect to the powers of a justice or judge in issuing writs of ne exeat were changed and made the basis of subsection (b) of the revised section but the conditions and limitations on the writ of ne exeat were omitted as merely confirmatory of well-settled principles of law.

The provision in section 377 of title 28, U.S.C., 1940 ed., authorizing issuance of writs of scire facias, was omitted in view of rule 81(b) of the Federal Rules of Civil Procedure abolishing such writ. The revised section is expressive of the construction recently placed upon such section by the Supreme Court in *U.S. Alkali Export Assn. v. U.S.*, 65 S.Ct. 1120, 325 U.S. 196, 89 L.Ed. 1554, and *De Beers Consol. Mines v. U.S.*, 65 S.Ct. 1130, 325 U.S. 212, 89 L.Ed. 1566.

1949 ACT

This section corrects a grammatical error in subsection (a) of section 1651 of title 28, U.S.C.

AMENDMENTS

1949—Subsec. (a). Act May 24, 1949, inserted "and" after "jurisdictions".

WRIT OF ERROR

Act Jan. 31, 1928, ch. 14, §2, 45 Stat. 54, as amended Apr. 26, 1928, ch. 440, 45 Stat. 466; June 25, 1948, ch. 646, §23, 62 Stat. 990, provided that: "All Acts of Congress referring to writs of error shall be construed as amended to the extent necessary to substitute appeal for writ of error."

tablish emissions standards under subsection (d), according to the schedule in this subsection and subsection (e).

(3) Area sources

The Administrator shall list under this subsection each category or subcategory of area sources which the Administrator finds presents a threat of adverse effects to human health or the environment (by such sources individually or in the aggregate) warranting regulation under this section. The Administrator shall, not later than 5 years after November 15, 1990, and pursuant to subsection (k)(3)(B), list, based on actual or estimated aggregate emissions of a listed pollutant or pollutants, sufficient categories or subcategories of area sources to ensure that area sources representing 90 percent of the area source emissions of the 30 hazardous air pollutants that present the greatest threat to public health in the largest number of urban areas are subject to regulation under this section. Such regulations shall be promulgated not later than 10 years after November 15, 1990.

(4) Previously regulated categories

The Administrator may, in the Administrator's discretion, list any category or subcategory of sources previously regulated under this section as in effect before November 15, 1990.

(5) Additional categories

In addition to those categories and subcategories of sources listed for regulation pursuant to paragraphs (1) and (3), the Administrator may at any time list additional categories and subcategories of sources of hazardous air pollutants according to the same criteria for listing applicable under such paragraphs. In the case of source categories and subcategories listed after publication of the initial list required under paragraph (1) or (3), emission standards under subsection (d) for the category or subcategory shall be promulgated within 10 years after November 15, 1990, or within 2 years after the date on which such category or subcategory is listed, whichever is later.

(6) Specific pollutants

With respect to alkylated lead compounds, polycyclic organic matter, hexachlorobenzene, mercury, polychlorinated biphenyls, 2,3,7,8-tetrachlorodibenzofurans and 2,3,7,8-tetrachlorodibenzo-p-dioxin, the Administrator shall, not later than 5 years after November 15, 1990, list categories and subcategories of sources assuring that sources accounting for not less than 90 per centum of the aggregate emissions of each such pollutant are subject to standards under subsection (d)(2) or (d)(4). Such standards shall be promulgated not later than 10 years after November 15, 1990. This paragraph shall not be construed to require the Administrator to promulgate standards for such pollutants emitted by electric utility steam generating units.

(7) Research facilities

The Administrator shall establish a separate category covering research or laboratory facilities, as necessary to assure the equitable treatment of such facilities. For purposes of this section, ''research or laboratory facility'' means any stationary source whose primary purpose is to conduct research and development into new processes and products, where such source is operated under the close supervision of technically trained personnel and is not engaged in the manufacture of products for commercial sale in commerce, except in a de minimis manner.

(8) Boat manufacturing

When establishing emissions standards for styrene, the Administrator shall list boat manufacturing as a separate subcategory unless the Administrator finds that such listing would be inconsistent with the goals and requirements of this chapter.

(9) Deletions from the list

(A) Where the sole reason for the inclusion of a source category on the list required under this subsection is the emission of a unique chemical substance, the Administrator shall delete the source category from the list if it is appropriate because of action taken under either subparagraphs (C) or (D) of subsection (b)(3).

(B) The Administrator may delete any source category from the list under this subsection, on petition of any person or on the Administrator's own motion, whenever the Administrator makes the following determination or determinations, as applicable:

(i) In the case of hazardous air pollutants emitted by sources in the category that may result in cancer in humans, a determination that no source in the category (or group of sources in the case of area sources) emits such hazardous air pollutants in quantities which may cause a lifetime risk of cancer greater than one in one million to the individual in the population who is most exposed to emissions of such pollutants from the source (or group of sources in the case of area sources).

(ii) In the case of hazardous air pollutants that may result in adverse health effects in humans other than cancer or adverse environmental effects, a determination that emissions from no source in the category or subcategory concerned (or group of sources in the case of area sources) exceed a level which is adequate to protect public health with an ample margin of safety and no adverse environmental effect will result from emissions from any source (or from a group of sources in the case of area sources).

The Administrator shall grant or deny a petition under this paragraph within 1 year after the petition is filed.

(d) Emission standards

(1) In general

The Administrator shall promulgate regulations establishing emission standards for each category or subcategory of major sources and area sources of hazardous air pollutants listed for regulation pursuant to subsection (c) in accordance with the schedules provided in subsections (c) and (e). The Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory in establishing such standards except that, there shall be no delay in the compliance date for any standard applicable to any source under subsection (i) as the result of the authority provided by this sentence.

(2) Standards and methods

Emissions standards promulgated under this subsection and applicable to new or existing sources of hazardous air pollutants shall require the maximum degree of reduction in emissions of the hazardous air pollutants 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 for new or existing sources in the category or subcategory to which such emission standard applies, through application of measures, processes, methods, systems or techniques including, but not limited to, measures which—

(A) reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications,

(B) enclose systems or processes to eliminate emissions,

(C) collect, capture or treat such pollutants when released from a process, stack, storage or fugitive emissions point,

(D) are design, equipment, work practice, or operational standards (including requirements for operator training or certification) as provided in subsection (h), or

(E) are a combination of the above.

None of the measures described in subparagraphs (A) through (D) shall, consistent with the provisions of section 7414(c) of this title, in any way compromise any United States patent or United States trademark right, or any confidential business information, or any trade secret or any other intellectual property right.

(3) New and existing sources

The maximum degree of reduction in emissions that is deemed achievable for new sources in a category or subcategory shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined by the Administrator. Emission standards promulgated under this subsection for existing sources in a category or subcategory may be less stringent than standards for new sources in the same category or subcategory but shall not be less stringent, and may be more stringent than—

(A) the average emission limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has emissions information), excluding those sources that have, within 18 months before the emission standard is proposed or within 30 months before such standard is promulgated, whichever is later, first achieved a level of emission rate or emission reduction which complies, or would comply if the source is not subject to such standard, with the lowest achievable emission rate (as defined by section 7501 of this title) applicable to the source category and prevailing at the time, in the category or subcategory for categories and subcategories with 30 or more sources, or

(B) the average emission limitation achieved by the best performing 5 sources (for which the Administrator has or could reasonably obtain emissions information) in the category or subcategory for categories or subcategories with fewer than 30 sources.

(4) Health threshold

With respect to pollutants for which a health threshold has been established, the Administrator may consider such threshold level, with an ample margin of safety, when establishing emission standards under this subsection.

(5) Alternative standard for area sources

With respect only to categories and subcategories of area sources listed pursuant to subsection (c), the Administrator may, in lieu of the authorities provided in paragraph (2) and subsection (f), elect to promulgate standards or requirements applicable to sources in such categories or subcategories which provide for the use of generally available control technologies or management practices by such sources to reduce emissions of hazardous air pollutants.

(6) Review and revision

The Administrator shall review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards promulgated under this section no less often than every 8 years.

(7) Other requirements preserved

No emission standard or other requirement promulgated under this section shall be interpreted, construed or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established pursuant to section 7411 of this title, part C or D, or other authority of this chapter or a standard issued under State authority.

(8) Coke ovens

(A) Not later than December 31, 1992, the Administrator shall promulgate regulations establishing emission standards under paragraphs (2) and (3) of this subsection for coke oven batteries. In establishing such standards, the Administrator shall evaluate—

(i) the use of sodium silicate (or equivalent) luting compounds to prevent door leaks, and other operating practices and technologies for their effectiveness in reducing coke oven emissions, and their suitability for use on new and existing coke oven batteries, taking into account costs and reasonable commercial door warranties; and

(ii) as a basis for emission standards under this subsection for new coke oven batteries that begin construction after the date of proposal of such standards, the Jewell design Thompson non-recovery coke oven batteries and other non-recovery coke oven technologies, and other appropriate emission control and coke production technologies, as to their effectiveness in reducing coke oven emissions and their capability for production of steel quality coke.

Such regulations shall require at a minimum that coke oven batteries will not exceed 8 per centum leaking doors, 1 per centum leaking lids, 5 per centum leaking offtakes, and 16 seconds visible emissions per charge, with no exclusion for emissions during the period after the closing of self-sealing oven doors. Notwithstanding subsection (i), the compliance date for such emission standards for existing coke oven batteries shall be December 31, 1995.

(B) The Administrator shall promulgate work practice regulations under this subsection for coke oven batteries requiring, as appropriate—

(i) the use of sodium silicate (or equivalent) luting compounds, if the Administrator determines that use of sodium silicate is an effective means of emissions control and is achievable, taking into account costs and reasonable commercial warranties for doors and related equipment; and

(ii) door and jam cleaning practices.

Notwithstanding subsection (i), the compliance date for such work practice regulations for coke oven batteries shall be not later than the date 3 years after November 15, 1990.

(C) For coke oven batteries electing to qualify for an extension of the compliance date for standards promulgated under subsection (f) in accordance with subsection (i)(8), the emission standards under this subsection for coke oven batteries shall require that coke oven batteries not exceed 8 per centum leaking doors, 1 per centum leaking lids, 5 per centum leaking offtakes, and 16 seconds visible emissions per charge, with no exclusion for emissions during the period after the closing of self-sealing doors. Notwithstanding subsection (i), the compliance date for such emission standards for existing coke oven batteries seeking an extension shall be not later than the date 3 years after November 15, 1990.

(9) Sources licensed by the Nuclear Regulatory Commission

No standard for radionuclide emissions from any category or subcategory of facilities licensed by the Nuclear Regulatory Commission (or an Agreement State) is required to be promulgated under this section if the Administrator determines, by rule, and after consultation with the Nuclear Regulatory Commission, that the regulatory program established by the Nuclear Regulatory Commission pursuant to the Atomic Energy Act [42 U.S.C. 2011 et seq.] for such category or subcategory provides an ample margin of safety to protect the public health. Nothing in this subsection shall preclude or deny the right of any State or political subdivision thereof to adopt or enforce any standard or limitation respecting emissions of radionuclides which is more stringent than the standard or limitation in effect under section 7411 of this title or this section.

(10) Effective date

Emission standards or other regulations promulgated under this subsection shall be effective upon promulgation.

(e) Schedule for standards and review

(1) In general

The Administrator shall promulgate regulations establishing emission standards for categories and subcategories of sources initially listed for regulation pursuant to subsection (c)(1) as expeditiously as practicable, assuring that—

(A) emission standards for not less than 40 categories and subcategories (not counting coke oven batteries) shall be promulgated not later than 2 years after November 15, 1990;

(B) emission standards for coke oven batteries shall be promulgated not later than December 31, 1992;

(C) emission standards for 25 per centum of the listed categories and subcategories shall be promulgated not later than 4 years after November 15, 1990;

(D) emission standards for an additional 25 per centum of the listed categories and subcategories shall be promulgated not later than 7 years after November 15, 1990; and

(E) emission standards for all categories and subcategories shall be promulgated not later than 10 years after November 15, 1990.

(2) Priorities

In determining priorities for promulgating standards under subsection (d), the Administrator shall consider—

(A) the known or anticipated adverse effects of such pollutants on public health and the environment;

(B) the quantity and location of emissions or reasonably anticipated emissions of hazardous air pollutants that each category or subcategory will emit; and

(C) the efficiency of grouping categories or subcategories according to the pollutants emitted, or the processes or technologies used.

(3) Published schedule

Not later than 24 months after November 15, 1990, and after opportunity for comment, the Administrator shall publish a schedule establishing a date for the promulgation of emission standards for each category and subcategory of sources listed pursuant to subsection (c)(1) and (3) which shall be consistent with the requirements of paragraphs (1) and (2). The determination of priorities for the promulgation of standards pursuant to this paragraph is not a rulemaking and shall not be subject to judicial review, except that, failure to promulgate any standard pursuant to the schedule established by this paragraph shall be subject to review under section 7604 of this title.

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

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

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ES.1 Introduction

Exposure to hazardous air pollutants ("HAP," sometimes known as toxic air pollution, including mercury (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. These adverse effects can be particularly acute for communities living near sources of HAP. Recognizing the dangers posed by HAP, Congress enacted Clean Air Act (CAA) section 112. Under CAA section 112, EPA is required to set standards based on maximum achievable control technology (known as "MACT" standards) for major sources[1] 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 nonair quality health and environmental impacts and energy requirements, determines is achievable." 42 U.S.C. 7412(d)(2). EPA is further required to "review, and revise" those standards every eight years "as necessary (taking into account developments in practices, processes, and control technologies)." *Id.* 7412(d)(6).

On January 20, 2021, President Biden signed Executive Order (E.O.) 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 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 two parts: (1) a finding that it is not appropriate and necessary to regulate coal- and oil-fired electric utility steam generating units (EGUs) under CAA section 112; and (2) the risk and technology review (RTR) for the 2012 Mercury and Air Toxics (MATS) Final Rule.

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[1] The term "major source" means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants. 42 U.S.C. 7412(a)(1).

EPA reviewed both parts of the 2020 Final Action. The results of EPA's review of the first part, finding it is appropriate and necessary to regulate EGUs under CAA section 112, was proposed on February 9, 2022 (87 FR 7624) (2022 Proposal) and finalized on March 6, 2023 (88 FR 13956). In the 2022 Proposal, EPA also solicited information on the performance and cost of new or improved technologies that control HAP emissions, improved methods of operation, and risk-related information to further inform EPA's review of the second part, the 2020 MATS RTR. EPA proposed amendments to the RTR on April 24, 2023 (88 FR 24854) (2023 Proposal) and this action finalizes those amendments and presents the final results of EPA's review of the MATS RTR. This RIA presents the expected economic consequences of EPA's final MATS RTRRTR. As EPA determined not to reopen the 2020 Residual Risk Review, and accordingly did not propose or finalize any revisions to that review, no projected impacts are associated with the residual risk review.

This RIA is prepared in accordance with E.O. 12866 and 14904, the guidelines of OMB Circular A-4, and EPA's *Guidelines for Preparing Economic Analyses* (2014).T. The RIA analyzes the benefits and costs associated with the projected emissions reductions under the final requirements to inform EPA and the public about these projected impacts. The projected benefits and costs of the final rule and less stringent regulatory alternative are presented for the period from 2028 to 2037.[2]

ES.2 Regulatory Requirements

For coal-fired EGUs, the 2012 MATS rule established standards to limit emissions of Hg, acid gas HAP, non-Hg HAP metals (e.g., nickel, lead, chromium), and organic HAP (e.g., formaldehyde, dioxin/furan). For oil-fired EGUs, the 2012 MATS rule established standards to limit emissions of hydrogen chloride (HCl) and hydrogen fluoride (HF), total HAP metals (e.g., Hg, nickel, lead), and organic HAP (e.g., formaldehyde, dioxin/furan).

This RIA focuses on evaluating the benefits, costs, and other impacts of four amendments to the 2012 MATS rule:

[2] Circular A-4 was recently revised. The effective date of the revised Circular A-4 (2023) is March 1, 2024, for regulatory analyses received by OMB in support of proposed rules, interim final rules, and direct final rules, and January 1, 2025, for regulatory analyses received by OMB in support of other final rules. For all other rules, Circular A-4 (2003) is applicable until those dates.

- **Lowering the Standard for Non-Hg HAP Metals Emissions for Existing Coal-fired EGUs:** Existing coal-fired EGUs are subject to numeric emission limits for fPM, a surrogate for the total non-Hg HAP metals. MATS currently requires existing coal-fired EGUs to meet a fPM emission standard of 0.030 pounds per million British thermal units (lb/MMBtu) of heat input. After reviewing updated information on the current emission levels of fPM from existing coal-fired EGUs and the costs of meeting a standard more stringent than 0.030 lb/MMBtu, EPA is finalizing a fPM emission standard for existing coal-fired EGUs of 0.010 lb/MMBtu. Additionally, EPA is finalizing updated limits for non-Hg HAP metals and total non-Hg HAP metals that have been reduced proportional to the reduction of the fPM emission limit. EGU owners or operators who would choose to comply with the non-Hg HAP metals emission limits instead of the surrogate fPM limit must request and receive approval to use a non-Hg HAP metal continuous monitoring system as an alternative test method (e.g., multi-metal continuous monitoring system) under the provisions of 40 CFR 63.7(f).
- **Hg Emission Standard for Lignite-fired EGUs:** EPA is also finalizing a revision to the Hg emission standard for existing lignite-fired EGUs. Until this final rule, lignite-fired EGUs must meet a Hg emission standard of 4.0 pounds per trillion British thermal units (lb/TBtu) or 4.0E-2 pounds per gigawatt hour (lb/GWh). EPA is finalizing the requirement that lignite-fired EGUs meet the same standard as existing EGUs firing other types of coal, which is 1.2 lb/TBtu or 1.3E-2 lb/GWh.
- **Continuous Emissions Monitoring Systems:** After considering updated information on the costs for performance testing compared to the cost of PM CEMS and capabilities of PM CEMS measurement abilities, as well as the benefits of using PM CEMS, which include increased transparency, compliance assurance, and accelerated identification of anomalous emissions, EPA is finalizing the requirement that coal- and oil-fired units demonstrate compliance with the fPM emission standard by using PM CEMS. Prior to this final rule, EGUs had a choice of demonstrating compliance with the non-Hg HAP metals by monitoring fPM with quarterly sampling or using PM CEMS. EPA proposed to require PM CEMS for existing integrated gasification combined cycle (IGCC) EGUs but is not finalizing this requirement due to technical issues calibrating CEMS on these types of EGUs and the related fact that fPM emissions from IGCCs are very low.
- **Startup Definitions:** Separate from the technology review, EPA is finalizing the removal of one of the two options for defining the startup period for EGUs. The first option defines 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. In the second option, startup is defined as the period in which operation of an EGU is initiated for any purpose. EPA is removing the second option, which is currently being used by fewer than 10 EGUs.

More detail regarding these amendments can be found in the preamble of the final rule and in Section 1.3.1 of this document.

Table ES-1 summarizes how we have structured the regulatory options to be analyzed in this RIA. The finalized regulatory option includes the amendments just discussed in this section: the revision to the fPM standard to 0.010 lb/MMBtu, in which PM is a surrogate for non-Hg HAP metals, the revision to the Hg standard for lignite-fired EGUs to 1.2 lb/TBtu, the requirement to use PM CEMS to demonstrate compliance, and the removal of the startup definition number two. The less stringent regulatory option examined in this RIA assumed the fPM and Hg limits remain unchanged and examines just the finalized PM CEMS requirement and removal of startup definition number two.

Table ES-1 Summary of Regulatory Options Examined in this RIA

	Regulatory Options Examined in this RIA	
Provision	**Finalized**	**Less Stringent**
FPM Standard (Surrogate Standard for Non-Hg HAP metals)	Revised fPM standard of 0.010 lb/MMBtu	Retain existing fPM standard of 0.030 lb/MMBtu
Hg Standard	Revised Hg standard for lignite-fired EGUs of 1.2 lb/TBtu	Retain Hg standard for lignite-fired EGUs of 4.0 lb/TBtu
Continuous Emissions Monitoring Systems (PM CEMS)	Require installation of PM CEMS to demonstrate compliance	Require installation of PM CEMS to demonstrate compliance
Startup Definition	Remove startup definition #2	Remove startup definition #2

The compliance date for affected coal-fired sources to comply with the revised fPM limit of 0.010 lb/MMBtu and for lignite-fired sources to meet with the lower Hg limit of 1.2 lb/Tbtu is three years after the effective date of the final rule. EPA is finalizing the requirement that affected sources use PM CEMS for compliance demonstration by three years after the effective date of the final rule. The compliance date for existing affected sources to comply with amendments pertaining to the startup definition is 180 days after the effective date of the final rule.

Both the finalized and less stringent options described in Table ES-1 have not been changed from the final rule and less stringent options examined in the RIA for the proposal of this action. The proposal RIA included a more stringent regulatory option that projected the impacts of a lowering the fPM standard to 0.006 lb/MMBtu, while holding the other three proposed amendments unchanged from the proposed option. EPA solicited comment on this more stringent fPM standard in the preamble of the proposed rule. As explained in the preamble of the final rule, EPA determined not to pursue a more stringent standard for fPM emissions, such as a limit of 0.006 lb/MMBtu. After considering comments to the proposed rule and conducting additional analysis, EPA determined that a fPM standard lower than 0.010 lb/MMBtu would not currently be compatible with PM CEMS due to measurement uncertainty. While a fPM emission limit of 0.006 lb/MMBtu paired with the use of quarterly stack testing may appear to be more stringent than the 0.010 lb/MMBtu standard paired with the use of PM CEMS that the EPA is finalizing in this rule, there is no way to confirm emission reductions during periods in between quarterly stack tests when emission rates may be higher. Therefore, the Agency is finalizing a fPM limit of 0.010 lb/MMBtu with the use of PM CEMS as the only means of compliance demonstration. EPA has determined that this combination of fPM limit and compliance demonstration represents the most stringent option taking into account the statutory considerations.

ES.3 Baseline and Analysis Years

The impacts of regulatory actions are evaluated relative to a modeled baseline that represents expected behavior in the electricity sector under market and regulatory conditions in the absence of a regulatory action. EPA frequently updates the power sector modeling baseline to reflect the latest available electricity demand forecasts from the U.S. Energy Information Administration (EIA) as well as expected costs and availability of new and existing generating resources, fuels, emission control technologies, and regulatory requirements.

The baseline for this final rule includes the Good Neighbor Plan (GNP), the Revised Cross-State Air Pollution Rule (CSAPR) Update, CSAPR Update, and CSAPR, MATS, the 2015 Effluent Limitation Guidelines (ELG) and the 2015 Coal Combustion Residuals (CCR), and the recently finalized 2020 ELG and CCR rules.[3] This version of the model also includes recent updates to state and federal legislation affecting the power sector, including Public Law 117-169, 136 Stat. 1818 (August 16, 2022), commonly known as the Inflation Reduction Act of 2022 (the IRA). The modeling documentation includes a summary of all legislation reflected in this version

[3] For a full list of modeled policy parameters, please see: *https://www.epa.gov/power-sector-modeling*.

of the model as well as a description of how that legislation is implemented in the model.[4] Also, see Section 3.3 for additional detail about the power sector baseline for this RIA.

The year 2028 is the first year of detailed power sector modeling for this RIA and approximates when the impacts of the final rule on the power sector will begin.[5,6] In addition, the regulatory impacts are evaluated for the specific analysis years of 2030 and 2035. These results are used to estimate the present value (PV) and equivalent annualized value (EAV) of the 2028 through 2037 period, discounted to 2023.

ES.4 Emissions Impacts

EPA estimated emission reductions under the final rule for the years 2028, 2030, and 2035 based upon IPM projections. The quantified emissions estimates were developed with the EPA's Power Sector Modeling Platform 2023 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.

The quantified emission estimates presented in the RIA include changes in pollutants directly covered by this rule, such as Hg and non-Hg HAP metals, and changes in other pollutants emitted from the power sector as a result of the compliance actions projected under

[4] Documentation for EPA's Power Sector Modeling Platform 2023 using IPM can be found at *https://www.epa.gov/power-sector-modeling* and is available in the docket for this action.
[5] Note that the Agency has granted the maximum time allowed for compliance under CAA section 112(i)(3) of three years, and individual facilities may seek, if warranted, an additional 1-year extension of the compliance from their permitting authority pursuant to CAA section 112(i)(3)(B). Facilities may also request, if warranted, emergency authority to operate through the Department of Energy under section 202(c) of the Federal Power Act.
[6] We note that, while the compliance date of the rule will likely be mid- to late-2027 and all compliance costs are accounted for, any emissions reductions and benefits that in occur over a few months in 2027 are omitted from this analysis.

this final rule. The model projections capture the emissions changes associated with implementation of HAP mitigation measures at affected sources as well as the resulting effects on dispatch as the relative operating costs for some affected units have changed. Table ES-2 presents the estimated impact on power sector emissions resulting from compliance with the final rule in the contiguous U.S. As the incremental cost of operating PM CEMS relative to baseline requirements is small relative to the ongoing costs of operation, it is not necessary to model the less stringent regulatory alternative using IPM. The estimation of impacts outside of the model is a reasonable approach given the relatively small costs.

Table ES-2 Projected EGU Emissions and Emissions Changes for the Baseline and under the Final Rule for 2028, 2030, and 2035[a]

	Year	Total Emissions: Baseline	Total Emissions: Final Rule	Change from Baseline	% Change under Final Rule
Hg (lbs.)	2028	6,129	5,129	-999.1	-16.3%
	2030	5,863	4,850	-1,013	-17.3%
	2035	4,962	4,055	-907.0	-18.3%
$PM_{2.5}$ (thousand tons)	2028	70.5	69.7	-0.77	-1.09%
	2030	66.3	65.8	-0.53	-0.79%
	2035	50.7	50.2	-0.47	-0.93%
PM_{10} (thousand tons)	2028	79.5	77.4	-2.07	-2.60%
	2030	74.5	73.1	-1.33	-1.79%
	2035	56.0	54.8	-1.18	-2.11%
SO_2 (thousand tons)	2028	454.3	454.0	-0.290	-0.06%
	2030	333.5	333.5	0.025	0.01%
	2035	239.9	239.9	-0.040	-0.02%
Ozone-season NO_X (thousand tons)	2028	189.0	188.8	-0.165	-0.09%
	2030	174.99	175.4	0.488	0.28%
	2035	116.99	119.1	2.282282	1.95%
Annual NO_X (thousand tons)	2028	460.55	460.3	-0.283	-0.06%
	2030	392.88	392.7	-0.022	-0.01%
	2035	253.44	253.5	0.066	0.03%
HCl (thousand tons)	2028	2.474	2.474	0.000	0.01%
	2030	2.184	2.184	0.000	0.01%
	2035	1.484	1.485	0.001	0.06%
CO_2 (million metric tons)	2028	1,158.8	1,158.7	-0.0655	-0.01%
	2030	1,098.3	1,098.3	0.0361	0.00%
	2035	724.2	724.1	-0.099	-0.01%

[a] This analysis is limited to the geographically contiguous lower 48 states. Values are independently rounded and may not sum.

We also estimate that the final rule will reduce at least seven tons of non-Hg HAP metals in 2028, five tons of non-Hg HAP metals in 2030, and four tons of non-Hg HAP metals in 2035.[7]

[7] The estimates on non-mercury HAP metals reductions were obtained by multiplying the ratio of non-mercury HAP metals to fPM by estimates of PM_{10} reductions under the rule, as we do not have estimates of fPM reductions using IPM, only PM_{10}. The ratios of non-mercury HAP metals to fPM were based on analysis of 2010 MATS Information Collection Request (ICR) data. As there may be substantially more fPM than PM_{10} reduced by the control techniques projected to be used under this rule, these estimates of non-mercury HAP metals reductions are likely underestimates. More detail on the estimated reduction in non-mercury HAP metals can be found in the docketed memorandum *Estimating Non-Hg HAP Metals Reductions for the 2024 Technology Review for the Coal-Fired EGU Source Category*.

These reductions are composed of reductions in emissions of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

Importantly, the continuous monitoring of fPM required in this rule will likely induce additional emissions reductions that we are unable to quantify. Continuous measurements of emissions accounts for unforeseeable changes to processes and fuels, fluctuations in load, operations of pollution controls, and equipment malfunctions. By measuring emissions across all operations, power plant operators and regulators can use the data to ensure controls are operating properly and to assess compliance with relevant standards. Because CEMS enable power plant operators to quickly identify and correct problems with pollution control devices, it is possible that fPM emissions could be lower than they otherwise would have been for up to three months—or up to three years if testing less frequently under the LEE program— at a time. This potential reduction in fPM and non-Hg HAP metals emission resulting from the information provided by continuous monitoring coupled with corrective actions by plant operators could be sizeable over the existing coal-fired fleet and is not quantified in this rulemaking. Further discussion of the emissions transparency provided by PM CEMS is available in the "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category" memorandum, available in the docket.

As we are finalizing the removal of paragraph (2) of the definition of "startup," the time period for engaging fPM or non-Hg HAP metal controls after non-clean fuel use, as well as for full operation of fPM or non-Hg HAP metal controls, is expected to be reduced when transitioning to paragraph (1). The reduced time period for engaging controls therefore increases the duration in which pollution controls are employed and lowers emissions.

To the extent that the CEMS requirement and removal of the second definition of startup leads to actions that may otherwise not occur absent the amendments to those provisions in this final rule, there may be emissions impacts we are unable to estimate.

ES.5 Compliance Costs

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 other words, these costs are an estimate of the increased power industry expenditures required to implement the final requirements of this rule. The compliance cost estimates were mainly developed using the EPA's Power Sector Modeling Platform 2023 using IPM. The incremental costs of the final rule's PM CEMS requirement were estimated outside of IPM and added to the IPM-based cost estimate presented here and in Section 3 of the RIA.

The baseline includes approximately 5 GW of operational EGU capacity designed to burn low rank virgin coal (i.e., lignite) in 2028. All of this capacity is currently equipped with Activated Carbon Injection (ACI) technology, which is designed to reduce Hg emissions, and operation of this technology for compliance with existing Hg emissions limits (e.g., MATS and other enforceable state regulations) is reflected in the baseline. In the final rule modeling scenario, each of these EGUs projected to consume lignite is assigned an additional variable operating cost that is consistent with improvements in sorbent that EPA assumes are necessary to achieve the finalized lower limit. In the final rule, this additional cost does not result in incremental retirements for these units, nor does it result in a significant change to the projected generation level for these units.

In 2028, the baseline projection also includes 11.6 GW of operational coal capacity that, based on the analysis documented in the EPA memorandum titled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category," EPA assumes would either need to improve existing PM controls or install new PM controls to comply with the final rule. With the exception of one facility (Colstrip, located in Montana), all of that 11.6 GW is currently operating existing electrostatic precipitators (ESPs) and/or fabric filters, and all of that capacity is projected to install control upgrades and remain operational in 2028 in the IPM policy scenario.

Table ES-3 below summarizes the PV and EAV of the total national compliance cost estimates for EGUs for the final rule and the less stringent alternative. We present the PV of the costs over the 10-year period of 2028 to 2037. We also present the EAV, which represents a flow of constant annual values that, had they occurred annually, would yield a sum equivalent to the PV. The EAV represents the value of a typical cost for each year of the analysis.

We note that IPM provides EPA's best estimate of the costs of the rules to the electricity sector. These compliance cost estimates are used as a proxy for the social cost of the rule.

Chapter 3 reports how annual power costs are projected to change over the time period of analysis.[8]

Table ES-3 Total Compliance Cost Estimates for the Final Rule and the Less Stringent Alternative (millions of 2019 dollars, discounted to 2023)

	2% Discount Rate		3% Discount Rate		7% Discount Rate	
Regulatory Option	**PV**	**EAV**	**PV**	**EAV**	**PV**	**EAV**
Final Rule	860	96	790	92	560	80
Less Stringent	19	2.3	18	2.1	13	1.8

Note: Values have been rounded to two significant figures.

Additionally, to the extent that the CEMS requirement and removal of the second definition of startup lead to actions that may otherwise not occur absent the amendments to those provisions in this final rule, there may be cost impacts we are unable to estimate. With respect to the finalized removal of the startup definition, as the majority of EGUs currently rely on work practice standards under paragraph (1) of the definition of "startup," we believe this change is achievable by all EGUs and would result in little to no additional expenditures, especially since the additional reporting and recordkeeping requirements associated with use of paragraph (2) would no longer apply.

The compliance costs for the final rule are higher than the estimates in the RIA for the proposal of this action, largely due to changes in fPM control assumptions. At proposal, EPA estimated that incremental fPM controls would be required for about 5 GW of operational coal capacity. Based on public comments, the Agency reevaluated the unit-level data and now estimates that nearly three times more capacity would require incremental fPM controls (14 GW of operational coal capacity). It is also important to note that EPA also updated the IPM baseline power sector modeling.

[8] Results using the 2 percent discount rate were not included in the proposal for this action. The 2003 version of OMB's Circular A-4 had generally recommended 3 percent and 7 percent as default rates to discount social costs and benefits. The analysis of the proposed rule used these two recommended rates. In November 2023, OMB finalized an update to Circular A-4, in which it recommended the general application of a 2 percent rate to discount social costs and benefits (subject to regular updates), which is an estimate of consumption-based discount rate. Given the substantial evidence supporting a 2 percent discount rate, we include cost and benefits results calculated using a 2 percent discount rate consistent with the update to Circular A-4.

ES.6 Benefits

ES.6.1 Health Benefits

ES.6.1.1 Hazardous Air Pollutants

This final rule is projected to reduce emissions of Hg and non-Hg HAP metals. Hg emitted from U.S. EGUs can deposit to watersheds and associated waterbodies where it can accumulate as Methylmercury (MeHg) in fish. MeHg is formed by microbial action in the top layers of sediment and soils, after Hg has precipitated from the air and deposited into waterbodies or land. Once formed, MeHg is taken up by aquatic organisms and bioaccumulates up the aquatic food web. MeHg in fish, originating from U.S. EGUs, is consumed both as self-caught fish by subsistence fishers and as commercial fish by the general population. Exposure to MeHg is known to have adverse impacts on neurodevelopment and the cardiovascular system. MeHg is known to exert some genotoxic activity and EPA has classified MeHg as a “possible” human carcinogen. The projected reductions in Hg are expected to reduce the bioconcentration of MeHg in fish. As part of the 2020 risk review, EPA examined risk to subsistence fishers from MeHg exposure at a lake near three U.S. EGU lignite-fired facilities (U.S. EPA, 2020). While the analysis that EPA completed suggests that exposures associated with Hg emitted from EGUs, including lignite-fired EGUs, are below levels of concern from a public health standpoint, further reductions in these emissions should further decrease fish burden and exposure through fish consumption including exposures to subsistence fishers to MeHg.

In addition, U.S. EGUs are a major source of HAP metals emissions including arsenic, beryllium, cadmium, chromium, cobalt, lead, nickel, manganese, and selenium. Some HAP metals emitted by U.S. EGUs are known to be persistent and bioaccumulative and others have the potential to cause cancer. Exposure to these HAP metals, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. These adverse health effects may include chronic health disorders (e.g., irritation of the lung, skin, and mucus membranes; decreased pulmonary function, pneumonia, or lung damage; detrimental effects on the central nervous system; damage to the kidneys; and alimentary effects such as nausea and vomiting. The emissions reductions projected under this final rule from the use of PM controls are expected to reduce exposure of individuals residing near these facilities to non-Hg HAP metals, including carcinogenic HAP.

ES.6.1.1 Criteria Pollutants

This rule is expected to reduce emissions of directly emitted $PM_{2.5}$, NO_X and SO_2 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 final rule is expected to reduce ozone season NO_X emissions. 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 generally 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.

In this RIA, EPA reports estimates of the health benefits of changes in $PM_{2.5}$ and ozone concentrations. The health effect endpoints, effect estimates, benefit unit-values, and how they were selected, are described in the Technical Support Document (TSD) titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* (U.S. EPA, 2023). This document, hereafter referred to as the “Health Benefits TSD,” can be found in the docket for this rulemaking. Our approach for updating the endpoints and to identify suitable epidemiologic studies, baseline incidence rates, population demographics, and valuation estimates is summarized in Section 4.3.

ES.6.2 Climate Benefits

Elevated concentrations of carbon dioxide (CO_2) and other greenhouse gases (GHGs) in the atmosphere have been warming the planet, leading to changes in the Earth’s climate including changes in the frequency and intensity of heat waves, precipitation, and extreme weather events, rising seas, and retreating snow and ice. The well-documented atmospheric changes due to anthropogenic GHG emissions are changing the climate at a pace and in a way that threatens human health, society, and the natural environment. Climate change touches nearly every aspect of public welfare in the U.S. with resulting economic costs, including: changes in water supply and quality due to changes in drought and extreme rainfall events; increased risk of storm surge and flooding in coastal areas and land loss due to inundation; increases in peak electricity demand and risks to electricity infrastructure; and the potential for significant agricultural disruptions and crop failures (though offset to some extent by carbon fertilization).

There will be important climate benefits associated with the CO_2 emissions reductions expected from this final rule. Climate benefits from reducing emissions of CO_2 can be monetized using estimates of the social cost of carbon (SC-CO_2). See Section 4.4 for more discussion of the approach to monetization of the climate benefits associated with this rule.

ES.6.3 Additional Unquantified Benefits

As stated above, EPA is unable to quantify and monetize the potential benefits of requiring facilities to utilize CEMS rather than continuing to allow the use stack testing, but the requirement has been considered qualitatively. Relative to periodic testing practices, continuous monitoring of fPM will result in increased transparency, as well as potential emissions reductions from identifying problems more rapidly. Hence, the final rule may induce further reductions of fPM and non-Hg HAP metals than we project in this RIA, and these reductions would likely lead to additional health benefits. However, due to data and methodological challenges, EPA is unable to quantify these potential additional reductions. The continuous monitoring of fPM required in this rule is also likely to provide several additional important benefits to the public which are not quantified in this rule, including greater certainty, accuracy, transparency, and granularity in fPM emissions information than exists today. Additionally, to the extent that the CEMS requirement and removal of the second definition of startup leads to actions and emissions impacts that may otherwise not occur absent the amendment in this final rule, there may be beneficial impacts we are unable to estimate.

Regarding the potential health and ecological benefits from HAP emission reductions, data, time, and resource limitations prevent us from quantifying these potential benefits. Additionally, data, time, and resource limitations prevented EPA from quantifying the estimated health impacts or monetizing estimated benefits associated with direct exposure to NO_2 and SO_2 (independent of the role NO_2 and SO_2 play as precursors to $PM_{2.5}$ and ozone), as well as ecosystem effects, and visibility impairment due to the absence of air quality modeling data for these pollutants in this analysis. While all health benefits and welfare benefits were not able to be quantified, it does not imply that there are not additional benefits associated with reductions in exposures to HAP, ozone, $PM_{2.5}$, NO_2 or SO_2.

ES.6.4 Total Benefits

Table ES-4 presents the total monetized health and climate benefits for the final rule.[9] Note the less stringent regulatory alternative only describes the benefits associated with the requirements for PM CEMS qualitatively. As a result, there are no quantified benefits associated with this regulatory option.

Table ES-4 Total Benefits for the Final Rule from 2028 through 2037 (millions of 2019 dollars, discounted to 2023)[a]

		All Values Calculated using 2% Discount Rate	Health Benefits Calculated using 3% Discount Rate, Climate Benefits Calculated using 2% Discount Rate	Health Benefits Calculated using 7% Discount Rate, Climate Benefits Calculated using 2% Discount Rate
Health Benefits[b]	PV	300	260	180
	EAV	33	31	25
Climate Benefits[c]	PV	130	130	130
	EAV	14	14	14
Total Monetized Benefits	**PV**	**420**	**390**	**300**
	EAV	**47**	**45**	**39**
Non-Monetized Benefits[d]				
Benefits from reductions of about 900 to 1000 pounds of Hg annually				
Benefits from reductions of about 4 to 7 tons of non-Hg HAP metals annually				
Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS				

[a] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.
[b] The estimated value of the air quality-related health benefits reported here are from Table 4-5, Table 4-6, and Table 4-7. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. For discussions of the uncertainty associated with these health benefits estimates, see Section 4.3.8.
[c] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of CO_2 (SC-CO_2) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. See Table 4-10 for the full range of monetized climate benefit estimates. See Section 4.3.10 for a discussion of the uncertainties associated with the climate benefit estimates.
[d] The list of non-monetized benefits does not include all potential non-monetized benefits. See Table 4-8 for a more complete list.

[9] Monetized climate benefits are discounted using a 2 percent discount rate, consistent with EPA's updated estimates of the SC-CO_2. OMB has long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. Because the SC-CO_2 estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the social rate of return on capital (7 percent under OMB Circular A-4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC-CO_2. See Section 4.4 for more discussion.

The estimates of monetized benefits under the final rule are lower than estimated at proposal. While the estimated Hg reductions are higher under the final rule than at proposal, it is important to note that the EPA is unable to quantify the potential benefits of any HAP reductions for this rule. Additionally, while EPA is assuming more filterable PM controls in the final rule, the EPA is unable to quantify the potential benefits of any reductions of non-Hg HAP metals that are expected to result from these controls. Furthermore, because the EPA is no longer projecting any significant change in utilization or capacity at facilities that install additional fPM controls, we do not project major changes in emissions of the criteria and GHG pollutants monetized in the benefit-cost analysis. Consequently, the monetized benefits of the rule are lower than previously projected.

ES.7 Environmental Justice Impacts

EE.O. 12898 directs 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.[10] Additionally, EE.O. 13985 is intended to advance racial equity and support underserved communities through federal government actions.[11] Most recently, E.O. 14096 (88 FR 25251, April 26, 2023) strengthens the directives for achieving environmental justice that are set out in E.O. 12898. 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. 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."[12] In recognizing that minority and low-income populations often bear an unequal burden of environmental harms and risks, EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution.

[10] 59 FR 7629, February 16, 1994.
[11] 86 FR 7009, January 20, 2021.
[12] *https://www.epa.gov/environmentaljustice*.

Environmental justice (EJ) concerns for each rulemaking are unique and should be considered on a case-by-case basis, and EPA's EJ Technical Guidance (2015)[13] 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, EPA developed an analytical approach that considers the purpose and specifics of the rulemaking, as well as the nature of known and potential disproportionate and adverse exposures and impacts. For the rule, we quantitatively evaluate 1) the proximity of affected facilities to potentially vulnerable and/or overburdened populations for consideration of local pollutants impacted by this rule but not modeled here (Section 6.3) and 2) the distribution of ozone and $PM_{2.5}$ concentrations in the baseline and changes due to the rulemaking across different demographic groups on the basis of race, ethnicity, educational attainment, employment status, health insurance status, life expectancy, linguistic isolation, poverty status, redlined areas, tribal land, age, and sex (Section 6.5). It is important to note that due to the small magnitude of underlying emissions changes, and the corresponding small magnitude of the ozone and $PM_{2.5}$ concentration changes, the rule is expected to have only a small impact on the distribution of exposures across each demographic group. We also qualitatively discuss potential EJ HAP and climate impacts (Sections 6.3 and 6.6). Each of these analyses was performed to answer separate questions and is associated with unique limitations and uncertainties. Baseline demographic proximity analyses provide information as to whether there may be potential EJ concerns associated with environmental stressors, such as noise, traffic, and emissions such as NO_2 and SO_2 covered by the regulatory action for certain population groups of concern (Section 6.4). The baseline demographic proximity analyses examined the demographics of populations living within 10 km of the following sources: lignite plants with units potentially impacted by the final Hg standard revision and coal plants with units

[13] https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.

potentially impacted by the final fPM standard revision. We evaluated a 5 km radius for the demographic analysis and found it yielded several facilities with zero population within 5 km (i.e., no data) and over 10 percent of the facilities had less than 100 people within 5 km. At a 10-km radius, all facilities but one have population data and only two percent of facilities had less than 100 people within 10 km. Therefore, the 10-km distance was used on the basis that it captures large enough populations to avoid excessive demographic uncertainty.

The baseline analysis indicates that on average the population living within 10 km of coal plants potentially impacted by the final fPM standards shas 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 impacted by the final Hg standard is higher than the national average. Relating these results to question 1, above, we conclude that there may be potential EJ concerns associated with directly emitted pollutants that are affected by the regulatory action (e.g., $PM_{2.5}$ and HAP) for certain population groups of concern in the baseline. 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 MATS RTR were below both the presumptive acceptable cancer risk threshold and the reference dose (RfD), and this final regulation should further reduce exposure to HAP, there is no evidence of 'disproportionate and adverse effects' of potential EJ concern. Therefore, we did not perform a quantitative EJ assessment of HAP risk.

In contrast, ozone and $PM_{2.5}$ precursor emission changes that influence ambient concentrations of ozone and $PM_{2.5}$ are also expected from this action, and exposure analyses that evaluate demographic variables are better able to evaluate any potentially disproportionate pollution impacts of this rulemaking. The baseline ozone and $PM_{2.5}$ exposure analyses respond to question 1 from EPA's EJ Technical Guidance document more directly than the proximity analyses, as they evaluate a form of the environmental stressor affected by the regulatory action (see Section 6.5). $PM_{2.5}$ and ozone exposure analyses show that certain populations, such as residents of redlined census tracts, those who are linguistically isolated, Hispanic individuals, Asian individuals, those without a high school diploma, and the unemployed may experience disproportionately higher ozone and $PM_{2.5}$ exposures in the baseline as compared to the national average. American Indian individuals, residents of Tribal Lands, populations with higher life expectancy or with life expectancy data unavailable, children, and insured populations may also experience disproportionately higher ozone concentrations in the baseline than the reference group. Hispanic individuals, Black individuals, those below the poverty line, and uninsured populations may also experience disproportionately higher $PM_{2.5}$ concentrations in the baseline than the reference group. Therefore, there likely are potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline.

Finally, we evaluate how the final rule may be expected to differentially impact demographic populations, informing questions 2 and 3 from EPA's EJ Technical Guidance with regard to ozone and $PM_{2.5}$ exposure changes. 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 disparities in the ozone and $PM_{2.5}$ concentration burdens in the baseline are likely to remain after implementation of the regulatory action or alternatives under consideration. This is due to the small magnitude of the concentration changes associated with this rulemaking across population demographic groups, relative to the magnitude of the baseline disparities (question 2). Also, due to the very small differences observed in the distributional analyses of post-policy ozone and $PM_{2.5}$ exposure impacts across population groups, 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 (question 3).

ES.8 Comparison of Benefits and Costs

In this RIA, the regulatory impacts are evaluated for the specific years of 2028, 2030, and 2035. Comparisons of benefits to costs for these snapshot years are presented in Section 7.3 of this RIA. Here we present the PV of costs, benefits, and net benefits, calculated for the years 2028 to 2037 from the perspective of 2023, using two percent, three percent, and seven percent end-of-period discount rate. All dollars are in 2019 dollars. We also present the EAV, which represents a flow of constant annual values that, had they occurred in each year from 2028 to

2037, would yield a sum equivalent to the PV. The EAV represents the value of a typical cost or benefit for each year of the analysis, in contrast to the year-specific estimates reported in the costs and benefits sections of this RIA. The comparison of benefits and costs in PV and EAV terms for the final rule is presented in Table ES-5. The benefits associated with the less stringent regulatory alternative, from the final requirements for PM CEMS are only described qualitatively. As a result, there are no quantified benefits associated with this regulatory option, and we do not include a table reporting the quantified net benefits of that option (the quantified costs are reporting in Table ES-3).

Table ES-5 Projected Net Benefits of the Final Rule (millions of 2019 dollars, discounted to 2023)[a,b]

	Health Benefits[b]			Climate Benefits[c,d]	Compliance Costs			Net Benefits[e]		
Year	**2%**	**3%**	**7%**	**2%**	**2%**	**3%**	**7%**	**2%**	**3%**	**7%**
2028	79	71	52	13	100	99	82	-12	-15	-16
2029	79	71	50	13	100	96	77	-10	-13	-13
2030	27	24	16	-7.1	100	95	73	-82	-78	-64
2031	27	24	16	-7.1	100	92	68	-80	-76	-60
2032	14	13	8	19	79	73	52	-46	-41	-24
2033	14	13	8	19	78	71	48	-44	-39	-21
2034	14	12	7.3	19	76	69	45	-43	-37	-19
2035	14	12	7.0	19	75	67	42	-41	-35	-16
2036	14	12	6.7	19	73	65	39	-40	-33	-14
2037	14	12.0	6.4	19	72	63	37	-39	-32	-11
	Health Benefits[b]			**Climate Benefits[c]**	**Compliance Costs**			**Net Benefits[e]**		
	Discount Rate									
	2%	**3%**	**7%**	**2%**	**2%**	**3%**	**7%**	**2%**	**3%**	**7%**
PV	**300**	**260**	**180**	**130**	**860**	**790**	**560**	**-440**	**-400**	**-260**
EAV	**33**	**31**	**25**	**14**	**96**	**92**	**80**	**-49**	**-47**	**-41**

Non-Monetized Benefits[e]
Benefits from reductions of about 900 to 1000 pounds of Hg annually
Benefits from reductions of about 4 to 7 tons of non-Hg HAP metals annually
Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS

[a] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.
[b] The estimated value of the air quality-related health benefits reported here are the larger of the two estimates presented in Table 4-5, Table 4-6, and Table 4-7. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. For discussions of the uncertainty associated with these health benefits estimates, see Section 4.3.8.
[c] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of CO_2 (SC-CO_2) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. See Table 4-10 for the full range of monetized climate benefit estimates.
[d] The small increases and decreases in climate and health benefits and related EJ impacts result from very small changes in fossil dispatch and coal use relative to the baseline. For context, the projected increase in CO_2 emission of less than 40,000 tons in 2030 is roughly one percent of the emissions of a mid-size coal plant operating at availability (about 4 million tons).
[e] The list of non-monetized benefits does not include all potential non-monetized benefits. See Table 4-8 for a more complete list.

The monetized estimates of benefits presented in this section are underestimated because important categories of benefits, including benefits from reducing Hg and non-Hg HAP metals emissions and the increased transparency, compliance assurance, and accelerated identification of anomalous emissions anticipated from requiring PM CEMS, were not monetized in our analysis. Simultaneously, the estimates of compliance costs used in the net benefits analysis may provide an incomplete characterization of the true costs of the rule. We nonetheless consider these potential impacts in our evaluation of the net benefits of the rule. As the EPA no longer projects incremental facility retirement and expects less change in capacity and utilization, higher compliance costs are expected along with smaller monetized benefits than in the proposal analysis of this rulemaking. The result of combining those updated estimates is a lower estimate of net benefits than in the proposal analysis.

ES.9 References

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INTRODUCTION AND BACKGROUND

1.1 Introduction

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; damaging their kidneys; and causing cancer. Recognizing the dangers posed by HAP, Congress enacted Clean Air Act (CAA) section 112. Under CAA section 112, the Environmental Protection Agency (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). On January 20, 2021, President Biden signed EE.O. 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 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) 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 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, EPA also solicited information on the performance and cost of new or improved technologies that control HAP emissions, improved methods of operation, and risk-related information to further inform EPA's review of the 2020 MATS RTR. The review of the RTR was proposed on April 24, 2023 (88 FR 24854) and this action presents the final results of EPA's review of the MATS RTR. This RIA presents the expected economic consequences of EPA's final MATS Risk and Technology Review.

Several statutes and executive orders apply to federal rulemakings. In accordance with E.O. 12866 and E.O. 14094 and the guidelines of OMB Circular A-4, the RIA presents the benefits and costs associated with the projected emissions reductions under the final rule.[14] The benefits and costs of the final rule and regulatory alternative are presented for the 2028 to 2037 time period. The estimated monetized benefits are those health benefits expected to arise from reduced $PM_{2.5}$ and ozone concentrations and the climate benefits from reductions in GHGs. Several categories of benefits remain unmonetized including important benefits from reductions in Hg and non-Hg HAP metal emissions. The estimated monetized costs for EGUs are the costs of installing and operating controls and the increased costs of producing electricity. Unquantified benefits and costs are described qualitatively. This section contains background information relevant to the rule and an outline of the sections of this RIA.

1.2 Legal and Economic Basis for Rulemaking

In this section, we summarize the statutory requirements in the CAA that serve as the legal basis for the final rule and the economic theory that supports environmental regulation as a mechanism to enhance social welfare. The CAA requires EPA to prescribe regulations for new and existing sources. In turn, those regulations attempt to address negative externalities created when private entities fail to internalize the social costs of air pollution.

1.2.1 Statutory Requirement

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 two-stage regulatory process to develop standards for emissions of HAP from stationary sources. Generally, the first stage involves establishing technology-based standards and the second stage involves evaluating those standards that are based on maximum achievable control technology (MACT) 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 to the residual risk review, the CAA also requires EPA to review standards set under CAA section

[14] Circular A-4 was recently revised. The effective date of the revised Circular A-4 (2023) is March 1, 2024, for regulatory analyses received by OMB in support of proposed rules, interim final rules, and direct final rules, and January 1, 2025, for regulatory analyses received by OMB in support of other final rules. For all other rules, Circular A-4 (2003) is applicable until those dates.

112 no less than every eight years and revise the standards as necessary taking into account any “developments in practices, processes, or control technologies.” This review is commonly referred to as the “technology review,” and is the subject of this rulemaking.

1.2.2 Regulated Pollutants

For coal-fired EGUs, the 2012 MATS rule established standards to limit emissions of Hg, acid gas HAP, non-Hg HAP metals (e.g., nickel, lead, chromium), and organic HAP (e.g., formaldehyde, dioxin/furan). Standards for hydrochloric acid (HCl) serve as a surrogate for the acid gas HAP, with an alternate standard for sulfur dioxide (SO_2) that may be used as a surrogate for acid gas HAP for those coal-fired EGUs with flue gas desulfurization (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 emission of the organic HAP.

For oil-fired EGUs, the 2012 MATS rule established standards to limit emissions of HCl and hydrogen fluoride (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 emission of the organic HAP.

1.2.2.1 Definition of Affected Source

The source category that is the subject of this final rule is Coal- and Oil-Fired EGUs regulated under 40 CFR 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 action is likely to affect. The final standards 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 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 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.

1.2.3 The Potential Need for Regulation

OMB Circular A-4 indicates that one of the reasons a regulation may be issued is to address a market failure. The major types of market failure include externalities, market power, and inadequate or asymmetric information. Correcting market failures is one reason for regulation; it is not the only reason. Other possible justifications include improving the function of government, correcting distributional unfairness, or securing privacy or personal freedom.

Environmental problems are classic examples of externalities – uncompensated benefits or costs imposed on another party as a result of one's actions. For example, the smoke from a factory may adversely affect the health of local residents and soil the property in nearby neighborhoods. For the regulatory action analyzed in this RIA, the good produced is electricity from coal- and oil-fired EGUs. If these electricity producers pollute the atmosphere when generating power, the social costs will not be borne exclusively by the polluting firm but rather by society as a whole. Thus, the producer is imposing a negative externality, or a social cost of emissions, on society. The equilibrium market price of electricity may fail to incorporate the full opportunity cost to society of these products. Consequently, absent a regulation on emissions, producers will not internalize the social cost of emissions and social costs will be higher as a result. This regulation will work towards addressing this market failure by causing affected producers to begin internalizing the negative externality associated with HAP emissions from electricity generation by coal- and oil-fired EGUs.

1.3 Overview of Regulatory Impact Analysis

1.3.1 Regulatory Options

This RIA focuses on four amendments to the MATS rule, which are described in more detail in this section.

1.3.1.1 Filterable Particulate Matter Standards for Existing Coal-fired EGUs

Existing coal-fired EGUs are subject to numeric emission limits for fPM, a surrogate for the total non-Hg HAP metals.[15] Before this final rule, MATS required existing coal-fired EGUs to meet a fPM emission standard of 0.030 pounds per million British thermal units (lb/MMBtu) of heat input. The standards for fPM serve as a surrogate for standards for non-Hg HAP metals. After reviewing updated information on the current emission levels of fPM from existing coal-fired EGUs and the costs of meeting a standard more stringent than 0.030 lb/MMBtu, EPA is revising the fPM emission standard for existing coal-fired EGUs to 0.010 lb/MMBtu. Additionally, EPA is finalizing updated limits for non-Hg metals and total non-Hg metals that have been reduced proportional to the reduction of the fPM emission limit. EGU owners or operators who would choose to comply with the non-Hg HAP metals emission limits instead of the fPM limit must request and receive approval of a non-Hg HAP metal continuous monitoring system as an alternative test method (e.g., multi-metal continuous monitoring system) under the provisions of 40 CFR 63.7(f).

1.3.1.2 Hg Emission Standard for Lignite-fired EGUs

EPA is revising the Hg emission standard for lignite-fired EGUs. Before this final rule, lignite-fired EGUs were required to meet a Hg emission standard of 4.0 pounds per trillion British thermal units (lb/TBtu) or 4.0E-2 pounds per gigawatt hour (lb/GWh). EPA recently collected information on current emission levels and Hg emission controls for lignite-fired EGUs using the authority provided under CAA section 114.[16] That information showed that many units are able to achieve a Hg emission rate that is much lower than the current standard, and there are cost-effective control technologies and methods of operation that are available to achieve a more

[15] As described in section III of the preamble to 2023 proposal, EGUs in seven subcategories are subject to numeric emission limits for specific HAP or fPM, a surrogate for the total non-mercury HAP metals. The fPM was chosen as a surrogate in the original rulemaking because the non-mercury HAP metals are predominantly a component of PM, and control of PM will also result in co-reduction of non-mercury HAP metals. Additionally, not all fuels emit the same type and amount of HAP metals, but most generally emit PM that include some amount and combination of all the HAP metals. Lastly, the use of fPM as a surrogate eliminates the cost of performance testing to comply with numerous standards for individual non-mercury HAP metals (Docket ID No. EPA-HQ-OAR-2009-0234). For these reasons, EPA focused its review on the fPM emissions of coal-fired EGUs as a surrogate for the non-mercury HAP metals.

[16] For further information, see EPA memorandum titled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category" which is available in the docket.

stringent standard. EPA is finalizing a standard for lignite-fired EGUs of 1.2 lb/TBtu or 1.3E-2 lb/GWh, the same standard applied to EGUs firing other types of coal.

1.3.1.3 Require that All Coal- and Oil-Fired EGUs Demonstrate Compliance with the fPM Emission Standard by Using PM CEMS

In addition to revising the PM emission standard for existing coal-fired EGUs, EPA is revising the requirements for demonstrating compliance with the PM emission standard for coal- and oil-fired EGUs. Before this final rule, EGUs that were not part of the low-emitting EGU (LEE) program could demonstrate compliance with the fPM standard either by conducting performance testing quarterly or by using PM CEMS. After considering updated information on the costs for performance testing, the costs of PM CEMS, the capabilities of PM CEMS measurement abilities, and the benefits of using PM CEMS, including increased transparency, compliance assurance, and accelerated identification of anomalous emissions, EPA is requiring that all coal- and oil-fired fired EGUs demonstrate compliance with the PM emission standard by using PM CEMS. EPA proposed to require PM CEMS for existing IGCC EGUs but is not finalizing this requirement due to technical issues calibrating CEMS on these types of EGUs and the related fact that fPM emissions from IGCCs are very low.

1.3.1.4 Startup Definitions

Finally, separate from the technology review, EPA is removing one of the two options for defining the startup period for EGUs. The first option defines 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. 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. 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. Startup ends four hours after the EGU generates electricity that is sold or used for any other purpose (including on-site use), or four hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes, whichever is earlier. EPA is removing the second option, which is currently being used by fewer than 10 EGUs.

1.3.1.5 Summary of Regulatory Options Examined in this RIA

Table 1-1 summarizes how we have structured the regulatory options to be analyzed in this RIA. The final regulatory option includes the amendments just discussed in this section: the revision to the fPM standard to 0.010 lb/MMBtu, in which fPM is a surrogate for non-Hg HAP metals, the revision to the Hg standard for lignite-fired EGUs to 1.2 lb/TBtu, the requirement to use PM CEMS to demonstrate compliance, and the removal of the startup definition number two. The less stringent regulatory option examined in this RIA assumed the PM and Hg limits remain unchanged and examines just the PM CEMS requirement and removal of startup definition number two.

Table 1-1 Summary of Regulatory Options Examined in this RIA

	Regulatory Options Examined in this RIA	
Provision	**Less Stringent**	**Final Rule**
FPM Standard (Surrogate Standard for Non-Hg HAP Metals)	Retain existing fPM standard of 0.030 lb/MMBtu	Revised fPM standard of 0.010 lb/MMBtu
Hg Standard	Retain Hg standard for lignite-fired EGUs of 4.0 lb/TBtu	Revised Hg standard for lignite-fired EGUs of 1.2 lb/TBtu
Continuous Emissions Monitoring Systems (PM CEMS)	Require installation of PM CEMS to demonstrate compliance	Require installation of PM CEMS to demonstrate compliance
Startup Definition	Remove startup definition #2	Remove startup definition #2

The compliance date for affected coal-fired sources to comply with the revised fPM limit of 0.010 lb/MMBtu and for lignite-fired sources to meet with the lower Hg limit of 1.2 lb/Tbtu is three years after the effective date of the final rule. EPA is finalizing the requirement that affected sources use PM CEMS for compliance demonstration by three years after the effective date of the final rule. The compliance date for existing affected sources to comply with amendments pertaining to the startup definition is 180 days after the effective date of the final rule.

Both the final rule and less stringent options described in Table 1-1 have not been changed from the proposed and less stringent options examined in the RIA for the proposal of this action. The proposal RIA included a more stringent regulatory option that projected the impacts of lowering the fPM standard to 0.006 lb/MMBtu, while holding the other three proposed amendments unchanged from the proposed option. As explained in the preamble of the final rule, EPA determined not to pursue a more stringent standard for fPM emissions, such as a limit of 0.006 lb/MMBtu. After considering comments to the proposed rule and conducting additional analysis, EPA determined that a fPM standard lower than 0.010 lb/MMBtu would not be compatible with PM CEMS due to measurement uncertainty. While a fPM emission limit of 0.006 lb/MMBtu may appear to be more stringent than the 0.010 lb/MMBtu standard that the EPA is finalizing in this rule, there is no way to confirm emission reductions during periods where emission rates may be higher. Therefore, the Agency is finalizing a fPM limit of 0.010 lb/MMBtu with the use of PM CEMS as the only means of compliance demonstration. The EPA has determined that this combination of fPM limit and compliance demonstration represents the most stringent option taking into account the statutory considerations.

1.3.2 Baseline and Analysis Years

The impacts of regulatory actions are evaluated relative to a baseline that represents the world without the action. This version of the model ("EPA's Power Sector Modeling Platform 2023") used for the baseline in this RIA includes recent updates to state and federal legislation affecting the power sector, including Public Law 117-169, 136 Stat. 1818 (August 16, 2022), commonly known as the Inflation Reduction Act of 2022 (IRA). The modeling documentation includes a summary of all legislation reflected in this version of the model as well as a description of how that legislation is implemented in the model.[17] Also, see Section 3.3 for additional detail about the power sector baseline for this RIA.

The year 2028 is the first year of detailed power sector modeling for this RIA and approximates when the regulatory impacts of the final rule on the power sector will begin.[18,19] In

[17] Documentation for EPA's Power Sector Modeling Platform 2023 using IPM can be found at *https://www.epa.gov/power-sector-modeling* and is available in the docket for this action. For information regarding inclusion of the IRA in the baseline, see section 3.10.4 and 4.5.

[18] Note that the Agency has granted the maximum time allowed for compliance under CAA section 112(i)(3) of three years, and individual facilities may seek, if warranted, an additional 1-year extension of the compliance from their permitting authority pursuant to CAA section 112(i)(3)(B). Facilities may also request, if warranted, emergency authority to operate through the Department of Energy under section 202(c) of the Federal Power Act.

[19] We note that, while the compliance date of the rule will likely be mid- to late-2027 and all compliance costs are accounted for, any emissions reductions and benefits that in occur over a few months in 2027 are omitted from this analysis.

addition, the regulatory impacts are evaluated for the specific analysis years of 2030 and 2035. These results are used to estimate the PV and EAV of the 2028 through 2037 period.

1.4 Organization of the Regulatory Impact Analysis

This RIA is organized into the following remaining sections:

- **Section 2: Power Sector Industry Profile.** This section describes the electric power sector in detail.
- **Section 3: Cost, Emissions, and Energy Impacts.** The section summarizes the projected compliance costs and other energy impacts associated with the regulatory options.
- **Section 4: Benefits Analysis.** The section presents the projected health and environmental benefits of reductions in emissions of HAP, direct $PM_{2.5}$, and $PM_{2.5}$ and ozone precursors and the climate benefits of CO_2 emissions reductions across regulatory options.
- **Section 5: Economic Impacts.** The section includes a discussion of potential small entity, economic, and labor impacts.
- **Section 6: Environmental Justice Impacts.** This section includes an assessment of potential impacts to potential EJ populations.
- **Section 7: Comparison of Benefits and Costs.** The section compares of the total projected benefits with total projected costs and summarizes the projected net benefits of the three regulatory options examined. The section also includes a discussion of potential benefits that EPA is unable to quantify and monetize.

1.5 References

OMB. (2003). Circular A-4: Regulatory Analysis. Washington DC. https://www.whitehouse.gov/wp-content/uploads/legacy_drupal_files/omb/circulars/A4/a-4.pdf

OMB. (2023). Circular A-4: Regulatory Analysis. Washington DC. https://www.whitehouse.gov/wp-content/uploads/2023/11/CircularA-4.pdf

INDUSTRY PROFILE

2.1 Background

In the past decade, there have been substantial structural changes in both the mix of generating capacity and in the share of electricity generation supplied by different types of generation. These changes are the result of multiple factors in the power sector, including replacements of older generating units with new units, changes in the electricity intensity of the U.S. economy, growth and regional changes in the U.S. population, technological improvements in electricity generation from both existing and new units, changes in the prices and availability of different fuels, and substantial growth in electricity generation from renewable energy sources. Many of these trends will likely continue to contribute to the evolution of the power sector.[20] The evolving economics of the power sector, specifically the increased natural gas supply and subsequent relatively low natural gas prices, have resulted in more natural gas being used to produce both base and peak load electricity. Additionally, rapid growth in the deployment of wind and solar technologies has led to their now constituting a significant share of generation. The combination of these factors has led to a decline in the share of electricity generated from coal. This section presents data on the evolution of the power sector over the past two decades from 2010 through 2022, as well as a focus on the period 2015 through 2022. Projections of future power sector behavior and the projected impacts of the final rule are discussed in more detail in Section 3 of this RIA.

2.2 Power Sector Overview

The production and delivery of electricity to customers consists of three distinct segments: generation, transmission, and distribution.

2.2.1 Generation

Electricity generation is the first process in the delivery of electricity to consumers. There are two important aspects of electricity generation: capacity and net generation. *Generating Capacity* refers to the maximum amount of production an EGU is capable of producing in a

[20] For details on the evolution of EPA's power sector projections, please see archive of IPM outputs available at: *epa.gov/power-sector-modeling*.

typical hour, typically measured in megawatts (MW) for individual units, or gigawatts (1 GW = 1000 MW) for multiple EGUs. *Electricity Generation* refers to the amount of electricity actually produced by an EGU over some period of time, measured in kilowatt-hours (kWh) or gigawatt-hours (1 GWh = 1 million kWh). *Net Generation* is the amount of electricity that is available to the grid from the EGU (i.e., excluding the amount of electricity generated but used within the generating station for operations). Electricity generation is most often reported as the total annual generation (or some other period, such as seasonal). In addition to producing electricity for sale to the grid, EGUs perform other services important to reliable electricity supply, such as providing backup generating capacity in the event of unexpected changes in demand or unexpected changes in the availability of other generators. Other important services provided by generators include facilitating the regulation of the voltage of supplied generation.

Individual EGUs are not used to generate electricity 100 percent of the time. Individual EGUs are periodically not needed to meet the regular daily and seasonal fluctuations of electricity demand. Units are also unavailable during routine and unanticipated outages for maintenance. Furthermore, EGUs relying on renewable resources such as wind, sunlight, and surface water to generate electricity are routinely constrained by the availability of adequate wind, sunlight, or water at different times of the day and season. These factors result in the share of potential generating capacity being substantially different from the share of actual electricity produced by each type of EGU in a given season or year.

Most of the existing capacity generates electricity by creating heat to create high pressure steam that is released to rotate turbines which, in turn, create electricity. Natural gas combined cycle (NGCC) units have two generating components operating from a single source of heat. The first cycle is a gas-fired combustion turbine, which generates electricity directly from the heat of burning natural gas. The second cycle reuses the waste heat from the first cycle to generate steam, which is then used to generate electricity from a steam turbine. Other EGUs generate electricity by using water or wind to rotate turbines, and a variety of other methods including direct photovoltaic generation also make up a small, but growing, share of the overall electricity supply. The most common generating capacity includes fossil-fuel-fired units, nuclear units, and hydroelectric and other renewable sources (see Table 2-1 and Table 2-2). Table 2-1 and Table 2-2 also show the comparison between the generating capacity in 2010 to 2022 and 2015 to 2022, respectively.

In 2022 the power sector comprised a total capacity[21] of 1,201 GW, an increase of 162 GW (or 16 percent) from the capacity in 2010 (1,039 GW). The largest change over this period was the decline of 127 GW of coal capacity, reflecting the retirement/rerating of close to 40 percent of the coal fleet. This reduction in coal capacity was offset by increases in natural gas, solar, and wind capacities of 95 GW, 72 GW, and 102 GW respectively. Substantial amounts of distributed solar (40 GW) were also added.

These trends persist over the shorter 2015-21 period as well; total capacity in 2022 (1,201 GW) increased by 127 GW (or 12 percent). The largest change in capacity was driven by a reduction of 90 GW of coal capacity. This was offset by a net increase of 63 GW of natural gas capacity, an increase of 69 GW of wind, and an increase of 59 GW of solar. Additionally, 30 GW of distributed solar were also added over the 2015-22 period.

Table 2-1 Total Net Summer Electricity Generating Capacity by Energy Source, 2010-2022

	2010		2022		Change Between '10 and '22	
Energy Source	**Net Summer Capacity (GW)**	**% Total Capacity**	**Net Summer Capacity (GW)**	**Net Summer Capacity (GW)**	**% Total Capacity**	**Net Summer Capacity (GW)**
Coal	317	30%	189	16%	-40%	-127
Natural Gas	407	39%	502	42%	23%	95
Nuclear	101	10%	95	8%	-6%	-7
Hydro	101	10%	103	9%	2%	2
Petroleum	56	5%	31	3%	-45%	-25
Wind	39	4%	141	12%	261%	102
Solar	1	0%	73	6%	8310%	72
Distributed Solar	0	0%	40	3%		40
Other Renewable	14	1%	15	1%	7%	1
Misc	4	0%	12	1%	239%	9
Total	1,039	100%	1,201	100%	16%	162

Source: EIA. Electric Power Annual 2022, Table 3.1.A and 3.1.B

[21] This includes generating capacity at EGUs primarily operated to supply electricity to the grid and combined heat and power facilities classified as Independent Power Producers (IPP) and excludes generating capacity at commercial and industrial facilities that does not operate primarily as an EGU. Natural Gas information in this section (unless otherwise stated) reflects data for all generating units using natural gas as the primary fossil heat source. This includes Combined Cycle Combustion Turbine, Gas Turbine, steam, and miscellaneous (< 1 percent).

Table 2-2 Total Net Summer Electricity Generating Capacity by Energy Source, 2015-2022

	2015		2022		Change Between '15 and '22	
Energy Source	**Net Summer Capacity (GW)**	**% Total Capacity**	**Net Summer Capacity (GW)**	**% Total Capacity**	**% Increase**	**Capacity Change (GW)**
Coal	280	26%	189	16%	-32%	-90
Natural Gas	439	41%	502	42%	14%	63
Nuclear	99	9%	95	8%	-4%	-4
Hydro	102	10%	103	9%	1%	1
Petroleum	37	3%	31	3%	-16%	-6
Wind	73	7%	141	12%	95%	69
Solar	14	1%	73	6%	433%	59
Distributed Solar	10	1%	40	3%	307%	30
Other Renewable	17	2%	15	1%	-11%	-2
Misc	4	0%	12	1%	182%	8
Total	1,074	100%	1,201	100%	12%	127

Source: EIA. Electric Power Annual 2022, Table 3.1.A and 3.1.B

The average age of coal-fired power plants that retired between 2015 and 2023 was over 50 years. Older power plants tend to become uneconomic over time as they become more costly to maintain and operate, and as newer and more efficient alternative generating technologies are built. As a result, coal's share of total U.S. electricity generation has been declining for over a decade, while generation from natural gas and renewables has increased significantly.[22] As shown in Figure 2-1 below, 70 percent of the coal fleet in 2023 had an average age of over 40 years.

[22] EIA, Today in Energy (April 17, 2017) available at *https://www.eia.gov/todayinenergy/detail.php?id=30812*.

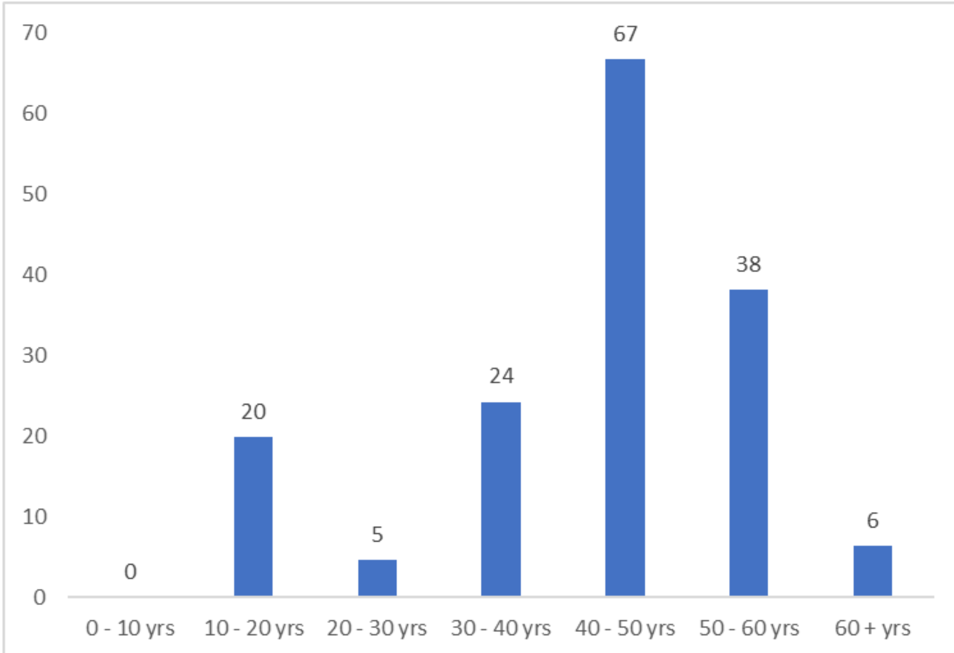

Figure 2-1 National Coal-fired Capacity (GW) by Age of EGU, 2023
Source: NEEDS v6

In 2022, electric generating sources produced a net 4,292 TWh to meet national electricity demand, which was around 4 percent higher than 2010. As presented in Table 2-2, 60 percent of electricity in 2022 was produced through the combustion of fossil fuels, primarily coal and natural gas, with natural gas accounting for the largest single share. The total generation share from fossil fuels in 2022 (60 percent) was 10 percent less than the share in 2010 (70 percent). Moreover, the share of fossil generation supplied by coal fell from 65 percent in 2010 to 33 percent by 2022, while the share of fossil generation supplied by natural gas rose from 35 percent to 67 percent over the same period. In absolute terms, coal generation declined by 55 percent, while natural gas generation increased by 71 percent. This reflects both the increase in natural gas capacity during that period as well as an increase in the utilization of new and existing gas EGUs during that period. The combination of wind and solar generation also grew from 2 percent of the mix in 2010 to 14 percent in 2022.

Table 2-3 Net Generation by Energy Source, 2010 to 2022 (Trillion kWh = TWh)

	2010		2022		Change Between '10 and '22	
Energy Source	Net Generation (TWh)	Fuel Source Share	Net Generation (TWh)	Fuel Source Share	% Increase	Generation Change (TWh)
Coal	1,847	45%	832	19%	-55%	-1,016
Natural Gas	988	24%	1,687	39%	71%	699
Nuclear	807	20%	772	18%	-4%	-35
Hydro	255	6%	249	6%	-2%	-6
Petroleum	37	1%	23	1%	-38%	-14
Wind	95	2%	434	10%	359%	340
Solar	1	0%	144	3%	11764%	143
Distributed Solar	0	0%	61	1%		61
Other Renewable	71	2%	68	2%	-5%	-3
Misc	24	1%	23	1%	-6%	-1
Total	4,125	100%	4,292	100%	4%	167

Table 2-4 Net Generation by Energy Source, 2015 to 2022 (Trillion kWh = TWh)

	2015		2022		Change Between '15 and '22	
Energy Source	Net Generation (TWh)	Fuel Source Share	Net Generation (TWh)	Fuel Source Share	% Increase	Generation Change (TWh)
Coal	1,352	33%	832	19%	-39%	-521
Natural Gas	1,335	33%	1,687	39%	27%	354
Nuclear	797	19%	772	18%	-3%	-26
Hydro	249	6%	249	6%	2%	5
Petroleum	28	1%	23	1%	-19%	-5
Wind	191	5%	434	10%	128%	244
Solar	25	1%	144	3%	478%	119
Distributed Solar	14	0%	61	1%	333%	47
Other Renewable	80	2%	68	2%	-15%	-12
Misc	27	1%	23	1%	-16%	-4
Total	4,092	100%	4,292	100%	5%	200

Coal-fired and nuclear generating units have historically supplied "base load" electricity, meaning that these units operate through most hours of the year and serve the portion of electricity load that is continually present. Although much of the coal fleet has historically operated as base load, there can be notable differences in the design of various facilities (see Table 2-3 and Table 2-4) which, along with relative fuel prices, can impact the operation of coal-fired power plants. As one example of design variations, coal-fired units less than 100 MW in size comprise 17 percent of the total number of coal-fired units, but only 2 percent of total coal-fired capacity, and they tend to have higher heat rates. Gas-fired generation is generally better able to vary output, is a primary option used to meet the variable portion of the electricity load and has historically supplied "peak" and "intermediate" power, when there is increased demand for electricity (for example, when businesses operate throughout the day or when people return home from work and run appliances and heating/air-conditioning), versus late at night or very early in the morning, when demand for electricity is reduced. Over the last decade, however, the generally low price of natural gas and the growing age of the coal fleet has resulted in increasing capacity factors for many gas-fired plants and decreasing capacity factors for many coal-fired plants. As shown in Figure 2-2, average annual coal capacity factors have declined from 67 percent to 50 percent over the 2010 to 2022 period, indicating that a larger share of units are operating in non-baseload fashion. Over the same period, natural gas combined cycle capacity factors have risen from an annual average of 44 percent to 57 percent.

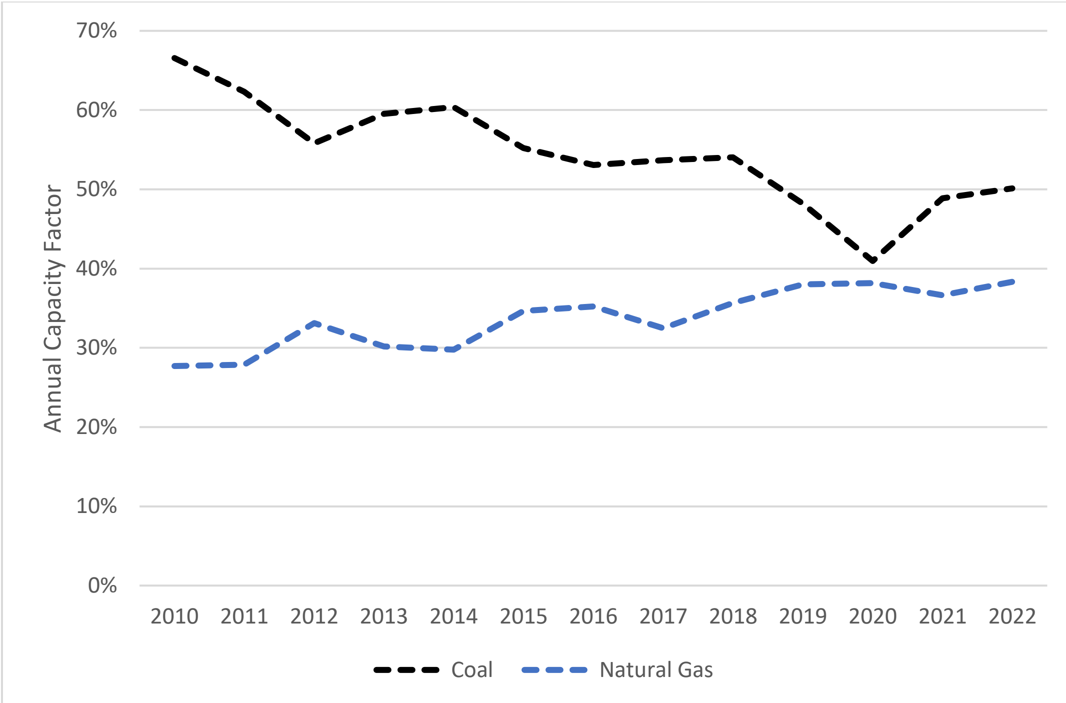

Figure 2-2 Average Annual Capacity Factor by Energy Source
Source: EIA. Electric Power Annual 2022 Table 4.08.A

Table 2-5 also shows comparable data for the capacity and age distribution of coal and natural gas units. Compared with the fleet of coal EGUs, the natural gas fleet of EGUs is generally smaller and newer. While 69 percent of the coal EGU fleet capacity is over 500 MW per unit, 82 percent of the gas fleet is between 50 and 500 MW per unit.

Table 2-5 Coal and Natural Gas Generating Units, by Size, Age, Capacity, and Average Heat Rate in 2023

Unit Size Grouping (MW)	No. Units	% of All Units	Avg. Age	Avg. Net Summer Capacity (MW)	Total Net Summer Capacity (MW)	% Total Capacity	Avg. Heat Rate (Btu/kWh)
COAL							
0 – 24	17	4%	56	13	218	0%	12,103
25 – 49	27	7%	37	36	978	1%	11,739
50 – 99	20	5%	32	76	1,510	1%	11,858
100 – 149	24	6%	52	120	2,869	2%	11,195
150 – 249	38	10%	47	195	7,394	5%	10,809
250 – 499	95	25%	42	379	36,008	23%	10,660
500 – 749	104	28%	41	612	63,604	40%	10,243
750 – 999	44	12%	39	818	35,979	22%	10,167
1000 – 1500	9	2%	46	1,264	11,380	7%	9,813
Total Coal	378	100%	42	423	159,940	100%	10,722
NATURAL GAS							
0 – 24	4,679	56%	30	4	20,963	4%	13,006
25 – 49	899	11%	26	41	36,619	7%	11,545
50 – 99	1,000	12%	29	72	71,611	14%	12,194
100 – 149	391	5%	26	125	48,863	10%	9,548
150 – 249	1,037	12%	20	180	186,503	37%	8,194
250 – 499	309	4%	21	330	101,969	20%	8,072
500 – 749	47	1%	30	585	27,495	5%	9,374
750 – 999	8	0%	47	838	6,706	1%	11,366
1000 – 1500	0	0%			0	0%	
Total Gas	8,362	100%	27	60	500,730	100%	11,790

Source: National Electric Energy Data System (NEEDS) v.6
Note: The average heat rate reported is the mean of the heat rate of the units in each size category (as opposed to a generation-weighted or capacity-weighted average heat rate.) A lower heat rate indicates a higher level of fuel efficiency.

In terms of the age of the generating units, almost 67 percent of the total coal generating capacity has been in service for more than 40 years, while nearly 81 percent of the natural gas capacity has been in service less than 40 years. Figure 2-3 presents the cumulative age distributions of the coal and gas fleets, highlighting the pronounced differences in the ages of the fleets of these two types of fossil-fuel generating capacity. Figure 2-3 also includes the distribution of generation, which is similar to the distribution of capacity.

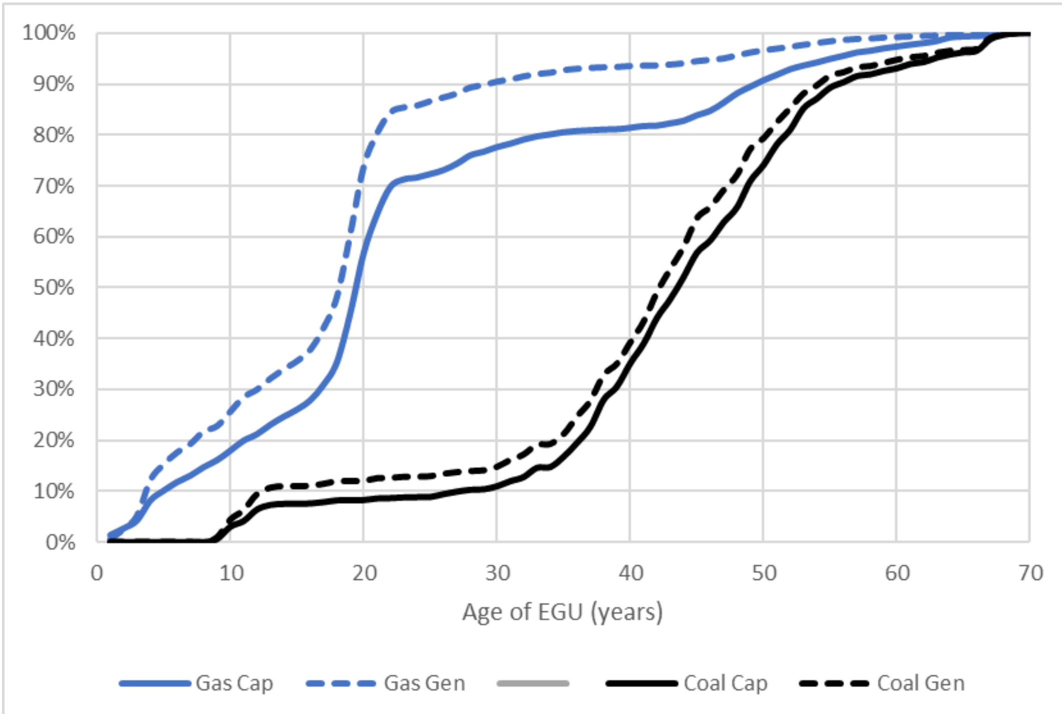

Figure 2-3 Cumulative Distribution in 2021 of Coal and Natural Gas Electricity Capacity and Generation, by Age

Source: eGRID 2021 (November 2023 release from EPA eGRID website). Figure presents data from generators that came online between 1950 and 2021 (inclusive); a 71-year period. Full eGRID data include generators that came online as far back as 1915. Full data from 1915 onward are used in calculating cumulative distributions; figure truncation at 70 years is merely to improve visibility of diagram.

The locations of existing fossil units in EPA's National Electric Energy Data System (NEEDS) v.6 are shown in Figure 2-4.

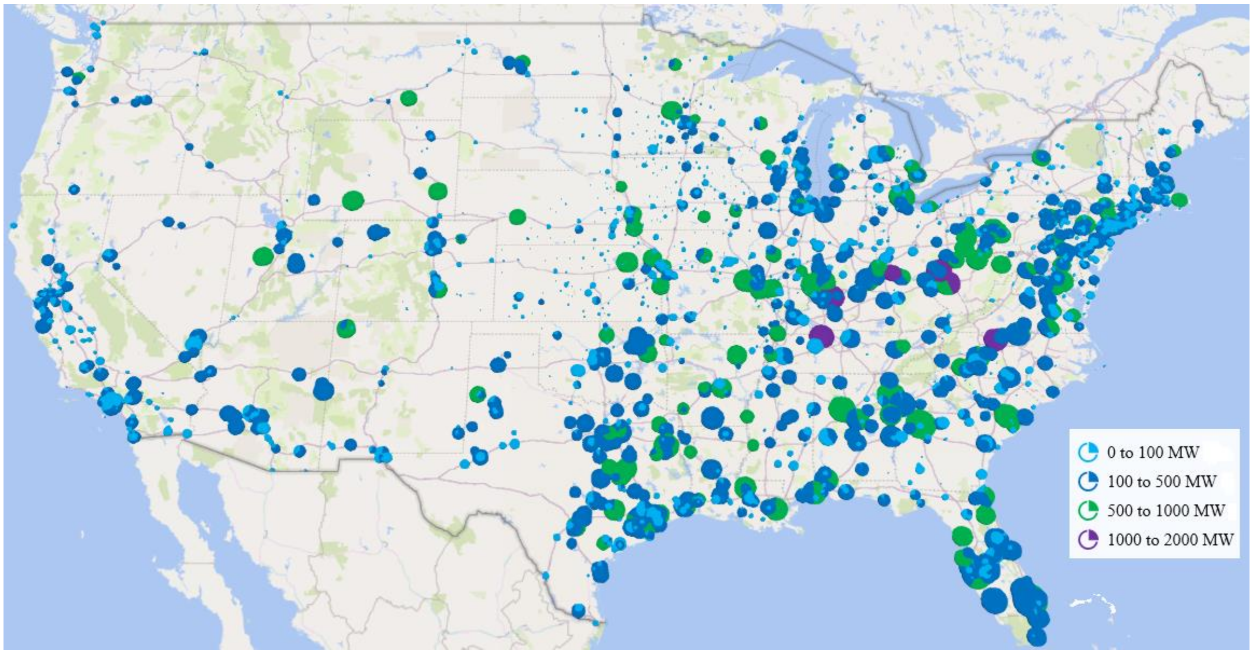

Figure 2-4 Fossil Fuel-Fired Electricity Generating Facilities, by Size
Source: National Electric Energy Data System (NEEDS) v.6
Note: This map displays fossil capacity at facilities in the NEEDS v.6 IPM frame. NEEDS v.6 reflects generating capacity expected to be on-line at the end of 2023. This includes planned new builds already under construction and planned retirements. In areas with a dense concentration of facilities, some facilities may be obscured.

The costs of renewable generation have fallen significantly due to technological advances, improvements in performance, and local, state, and federal incentives such as the recent extension of federal tax credits. According to Lazard, a financial advisory and asset management firm, the current unsubsidized levelized cost of electricity for wind and solar energy technologies is lower than the cost of technologies like coal, natural gas or nuclear, and in some cases even lower than just the operating cost, which is expected to lead to ongoing and significant deployment of renewable energy. Levelized cost of electricity is only one metric used to compare the cost of different generating technologies. It contains a number of uncertainties including utilization and regional factors.[23] While this chart illustrates general trends, unit specific build decisions will incorporate many other variables. These trends of declining costs

[23] Lazard, Levelized Cost of Energy Analysis-Version 16.0, 2023. *https://www.lazard.com/media/typdgxmm/lazards-lcoeplus-april-2023.pdf*.

and cost projections for renewable resources are borne out by a range of other studies including the NREL Annual Technology Baseline,[24] DOE's Land-Based Wind Market Report,[25] LBNL's Utility Scale solar report,[26] EIA's Annual Energy Outlook,[27] and DOE's 2022 Grid Energy Storage Technology Cost and Performance Assessment.[28]

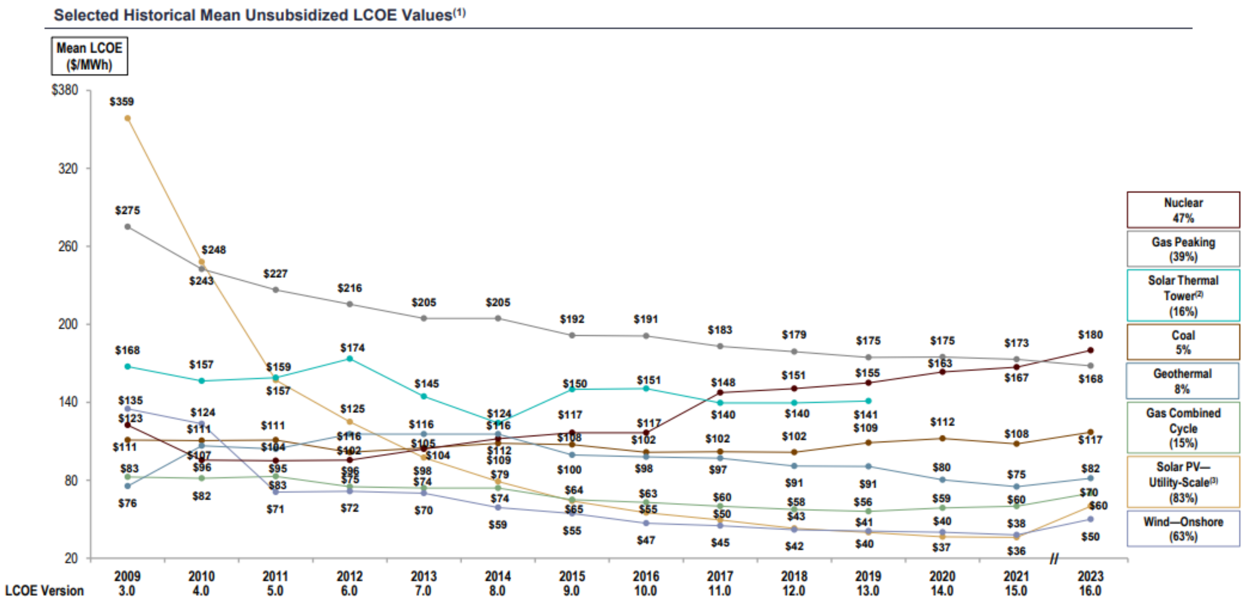

Figure 2-5 Selected Historical Mean LCOE Values
Source: Lazard, Levelized Cost of Energy Analysis-Version 16.0, April 2023

The broad trends away from coal-fired generation and toward lower-emitting generation are reflected in the recent actions and recently announced plans of many power plants across the industry — spanning all types of companies in all locations. Throughout the country, utilities have included commitments towards cleaner energy in public releases, planning documents, and integrated resource plans (IRPs). For strategic business reasons and driven by the economics of different supply options, most major utilities plan to increase their renewable energy holdings and continue reducing GHG emissions, regardless of what federal regulatory requirements might exist.

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24 Available at: *https://atb.nrel.gov/*.
25 Available at: *https://www.energy.gov/eere/wind/articles/land-based-wind-market-report-2022-edition*.
26 Available at: *https://emp.lbl.gov/utility-scale-solar/*.
27 Available at: *https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf*.
28 Available at: *https://www.energy.gov/eere/analysis/2022-grid-energy-storage-technology-cost-and-performance-assessment*.

While EPA does not account for future planning statements from utility providers in the economic modeling since they are not legally enforceable, the number and scale of these announcements is significant on a systemic level. These statements are part of long-term planning processes that cannot be easily revoked due to considerable stakeholder involvement in the planning process, including the involvement of regulators. The direction to which these utility providers have publicly stated they are moving is consistent across the sector and undergirded by market fundamentals lending economic credibility to these commitments and confidence that that most plans will be implemented.

2.2.2 Transmission

Transmission is the term used to describe the bulk transfer of electricity over a network of high voltage lines, from electric generators to substations where power is stepped down for local distribution. In the U.S. and Canada, there are three separate interconnected networks of high voltage transmission lines,[29] each operating synchronously. Within each of these transmission networks, there are multiple areas where the operation of power plants is monitored and controlled by regional organizations to ensure that electricity generation and load are kept in balance. In some areas, the operation of the transmission system is under the control of a single regional operator;[30] in others, individual utilities[31] coordinate the operations of their generation, transmission, and distribution systems to balance the system across their respective service territories.

2.2.3 Distribution

Distribution of electricity involves networks of lower voltage lines and substations that take the higher voltage power from the transmission system and step it down to lower voltage levels to match the needs of customers. The transmission and distribution system is the classic example of a natural monopoly, in part because it is not practical to have more than one set of

[29] These three network interconnections are the Western Interconnection, comprising the western parts of both the U.S. and Canada (approximately the area to the west of the Rocky Mountains), the Eastern Interconnection, comprising the eastern parts of both the U.S. and Canada (except those part of eastern Canada that are in the Quebec Interconnection), and the Texas Interconnection (which encompasses the portion of the Texas electricity system commonly known as the Electric Reliability Council of Texas (ERCOT)). See map of all NERC interconnections at *https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC%20Interconnections.pdf*.
[30] For example, PJM Interconnection, LLC.
[31] For example, Los Angeles Department of Water and Power, Florida Power and Light.

lines running from the electricity generating sources to substations or from substations to residences and businesses.

Over the last few decades, several jurisdictions in the U.S. began restructuring the power industry to separate transmission and distribution from generation, ownership, and operation. Historically, vertically integrated utilities established much of the existing transmission infrastructure. However, as parts of the country have restructured the industry, transmission infrastructure has also been developed by transmission utilities, electric cooperatives, and merchant transmission companies, among others. Distribution, also historically developed by vertically integrated utilities, is now often managed by a number of utilities that purchase and sell electricity, but do not generate it. Electricity restructuring has focused primarily on efforts to reorganize the industry to encourage competition in the generation segment of the industry, including ensuring open access of generation to the transmission and distribution services needed to deliver power to consumers. In many states, such efforts have also included separating generation assets from transmission and distribution assets to form distinct economic entities. Transmission and distribution remain price-regulated throughout the country based on the cost of service.

2.3 Sales, Expenses, and Prices

Electric generating sources provide electricity for ultimate commercial, industrial, and residential customers. Each of the three major ultimate categories consume roughly a quarter to a third of the total electricity produced (see Table 2-6).[32] Some of these uses are highly variable, such as heating and air conditioning in residential and commercial buildings, while others are relatively constant, such as industrial processes that operate 24 hours a day. The distribution between the end use categories changed very little between 2010 and 2022.

[32] Transportation (primarily urban and regional electrical trains) is a fourth ultimate customer category which accounts less than one percent of electricity consumption.

Table 2-6 Total U.S. Electric Power Industry Retail Sales, 2010-22 and 2014-22 (billion kWh)

		2010		2022	
		Sales/Direct Use (Billion kWh)	**Share of Total End Use**	**Sales/Direct Use (Billion kWh)**	**Share of Total End Use**
Sales	Residential	1,446	37%	1,509	37%
	Commercial	1,330	34%	1,391	34%
	Industrial	971	25%	1,020	25%
	Transportation	8	0%	7	0%
Total		3,755	97%	3,927	97%
Direct Use			132		140
Total End Use			**3,887**		**4,067**
		2015		**2022**	
		Sales/Direct Use (Billion kWh)	**Share of Total End Use**	**Sales/Direct Use (Billion kWh)**	**Share of Total End Use**
Sales	Residential	1,404	36%	1,509	37%
	Commercial	1,361	35%	1,391	34%
	Industrial	987	25%	1,020	25%
	Transportation	8	0%	7	0%
Total		3,759	96%	3,927	97%
Direct Use			141		140
Total End Use			**3,900**		**4,067**

Source: Table 2.2, EIA Electric Power Annual, 2022 (October 19, 2023, release)
Notes: Retail sales are not equal to net generation (Table 2-2) because net generation includes net imported electricity and loss of electricity that occurs through transmission and distribution, along with data collection frame differences and non-sampling error. Direct Use represents commercial and industrial facility use of onsite net electricity generation; electricity sales or transfers to adjacent or co-located facilities; and barter transactions.

2.3.1 Electricity Prices

Electricity prices vary substantially across the U.S., differing both between the ultimate customer categories and by state and region of the country. Electricity prices are typically highest for residential and commercial customers because of the relatively high costs of distributing electricity to individual homes and commercial establishments. The higher prices for residential and commercial customers are the result of the extensive distribution network reaching to virtually every building in every part of the country and the fact that generating stations are increasingly located relatively far from population centers, increasing transmission costs. Industrial customers generally pay the lowest average prices, reflecting both their proximity to generating stations and the fact that industrial customers receive electricity at higher voltages (which makes transmission more efficient and less expensive). Industrial customers frequently pay variable prices for electricity, varying by the season and time of day, while residential and commercial prices have historically been less variable. Overall, industrial customer prices are usually considerably closer to the wholesale marginal cost of generating electricity than residential and commercial prices.

On a state-by-state basis, all retail electricity prices vary considerably. In 2022, the national average retail electricity price (all sectors) was 12.4 cents/kWh, with a range from 8.2 cents (Wyoming) to 39.72 cents (Hawaii).[33]

The real year prices for 2010 through 2022 are shown in Figure 2-6. Average national retail electricity prices decreased between 2010 and 2022 by 4 percent in real terms (2022 dollars), and 2 percent between 2015-22.[34] The amount of decrease differed for the three major end use categories (residential, commercial, and industrial). National average commercial prices decreased the most (4 percent), and industrial prices decreased the least (1 percent) between 2015-21.

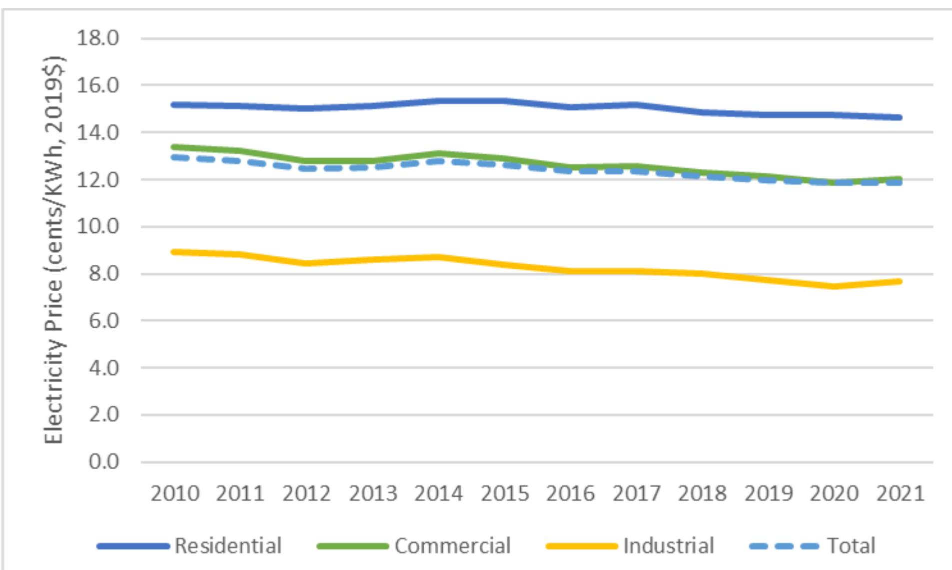

Figure 2-6 Real National Average Electricity Prices (including taxes) for Three Major End-Use Categories
Source: EIA. Electric Power Annual 2022 and 2021, Table 2.4.

[33] EIA State Electricity Profiles with Data for 2022 (*http://www.eia.gov/electricity/state/*).
[34] All prices in this section are estimated as real 2022 prices adjusted using the GDP implicit price deflator unless otherwise indicated.

2.3.2 Prices of Fossil Fuel Used for Generating Electricity

Another important factor in the changes in electricity prices are the changes in delivered fuel prices[35] for the three major fossil fuels used in electricity generation: coal, natural gas, and petroleum products. Relative to real prices in 2015, the national average real price (in 2022 dollars) of coal delivered to EGUs in 2022 had decreased by 12 percent, while the real price of natural gas increased by 84 percent. The real price of delivered petroleum products also increased by 102 percent, and petroleum products declined as an EGU fuel (in 2022 petroleum products generated 1 percent of electricity). The combined real delivered price of all fossil fuels (weighted by heat input) in 2022 increased by 62 percent over 2015 prices. Figure 2-7 shows the relative changes in real price of all three fossil fuels between 2010 and 2022.

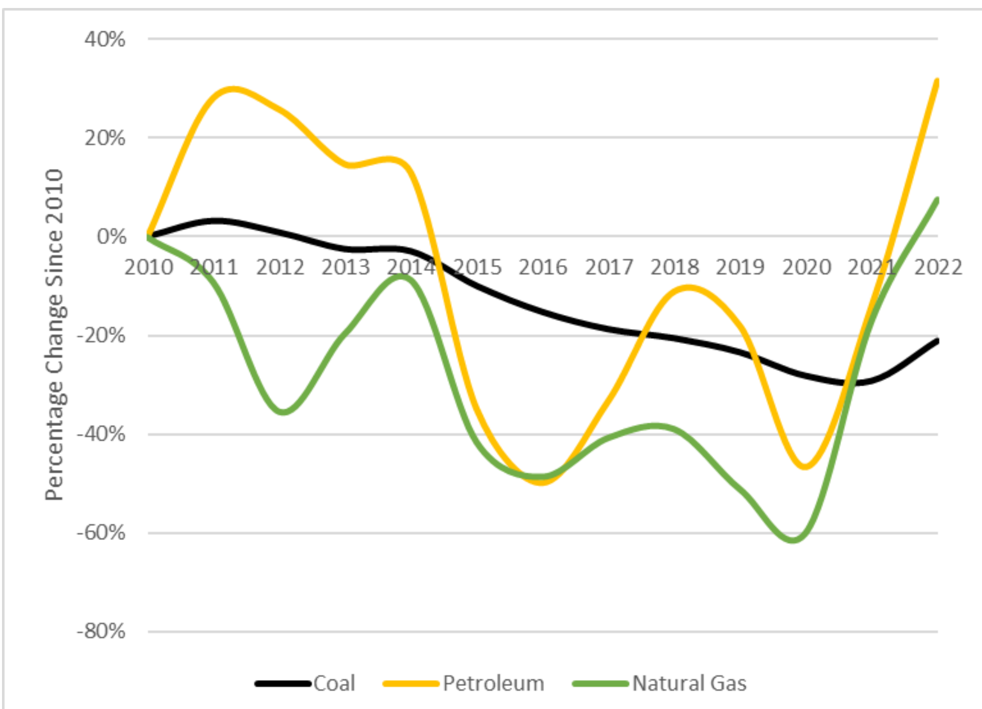

Figure 2-7 Relative Real Prices of Fossil Fuels for Electricity Generation; Change in National Average Real Price per MMBtu Delivered to EGU

Source: EIA. Electric Power Annual 2022, Table 7.1.

[35] Fuel prices in this section are all presented in terms of price per MMBtu to make the prices comparable.

2.3.3 Changes in Electricity Intensity of the U.S. Economy from 2010 to 2021

An important aspect of the changes in electricity generation (i.e., electricity demand) between 2010 and 2022 is that while total net generation increased by 4 percent over that period, the demand growth for generation was lower than both the population growth (8 percent) and real GDP growth (30 percent). Figure 2-8 shows the growth of electricity generation, population, and real GDP during this period.

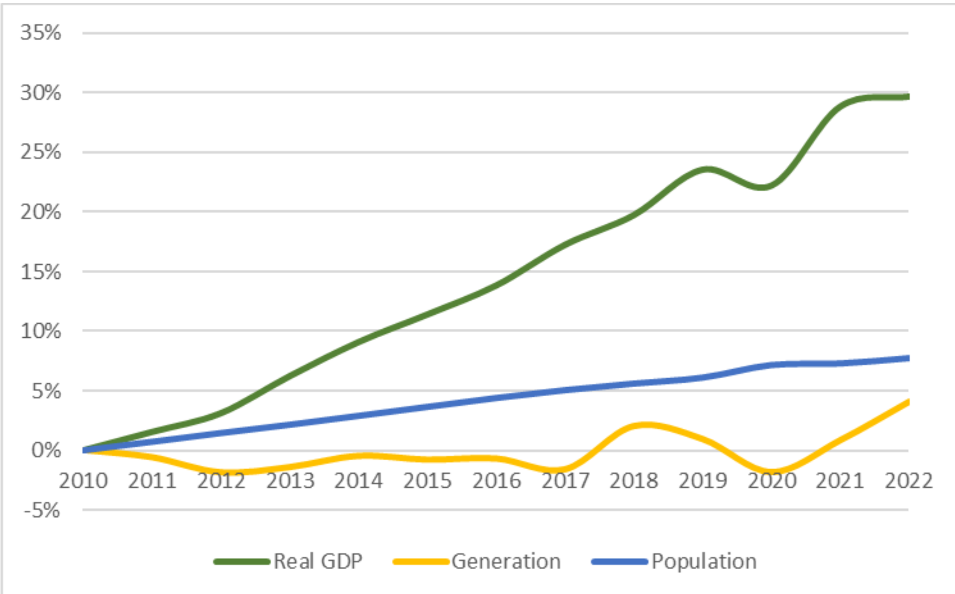

Figure 2-8 Relative Growth of Electricity Generation, Population and Real GDP Since 2010

Sources: Generation: U.S. EIA Electric Power Annual 2022. Population: U.S. Census. Real GDP: U.S. Bureau of Economic Analysis

Because demand for electricity generation grew more slowly than both the population and GDP, the relative electric intensity of the U.S. economy improved (i.e., less electricity used per person and per real dollar of output) during 2010 to 2022. On a per capita basis, real GDP per capita grew by 20 percent between 2010 and 2022. At the same time, electricity generation per capita decreased by 3 percent. The combined effect of these two changes improved the overall electricity generation efficiency in the U.S. market economy. Electricity generation per dollar of real GDP decreased 20 percent. These relative changes are shown in Figure 2-9.

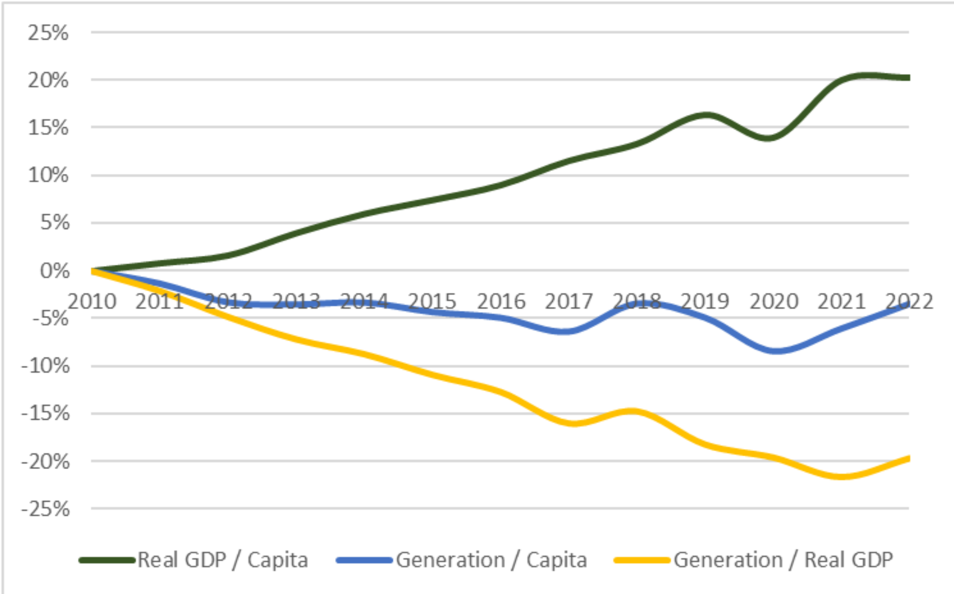

Figure 2-9 Relative Change of Real GDP, Population and Electricity Generation Intensity Since 2010

Sources: Generation: U.S. EIA Electric Power Annual 2021 and 2020. Population: U.S. Census. Real GDP: 2022 Economic Report of the President, Table B-3.

COSTS, EMISSIONS, AND ENERGY IMPACTS

3.1 Introduction

This section presents the compliance cost, emissions, and energy impact analysis performed for the MATS RTR. EPA used the Integrated Planning Model (IPM), developed by ICF Consulting, to conduct its analysis. IPM is a dynamic linear programming model that can be used to examine air pollution control policies for SO_2, NO_X, Hg, HCl, PM, and other air pollutants throughout the U.S. for the entire power system. Documentation for EPA's Power Sector Modeling Platform 2023 using IPM (hereafter IPM Documentation) can be found at *https://www.epa.gov/power-sector-modeling* and is available in the docket for this action.

3.2 EPA's Power Sector Modeling Platform 2023 using IPM

IPM is a state-of-the-art, peer-reviewed, dynamic linear programming model that can be used to project power sector behavior under future business-as-usual conditions and to examine prospective air pollution control policies throughout the contiguous U.S. for the entire electric power system. For this RIA, EPA used IPM to project likely future electricity market conditions with and without this rulemaking.

IPM, developed by ICF, is a multi-regional, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. It provides estimates of least cost capacity expansion, electricity dispatch, and emissions control strategies while meeting energy demand and 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. Notably, the model includes cost and performance estimates for state-of-the-art air pollution control technologies with respect to Hg, fPM, and other HAP controls.

EPA has used IPM for almost three decades to better understand power sector behavior under future business-as-usual conditions and to evaluate the economic and emissions impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions discussed here as well as all other model assumptions and inputs.[36]

The model incorporates a detailed representation of the fossil-fuel supply system that is used to estimate equilibrium fuel prices. The model uses natural gas fuel supply curves and regional gas delivery costs (basis differentials) to simulate the fuel price associated with a given level of gas consumption within the system. These inputs are derived using ICF's Gas Market Model (GMM), a supply/demand equilibrium model of the North American gas market.[37]

IPM also endogenously models the partial equilibrium of coal supply and EGU coal demand levels throughout the contiguous U.S., taking into account assumed non-power sector demand and imports/exports. IPM reflects 36 coal supply regions, 14 coal grades, and the coal transport network, which consists of over four thousand linkages representing rail, barge, and truck and conveyer linkages. The coal supply curves in IPM were developed during a thorough bottom-up, mine-by-mine approach that depicts the coal choices and associated supply costs that power plants would face if selecting that coal over the modeling time horizon. The IPM documentation outlines the methods and data used to quantify the economically recoverable coal reserves, characterize their cost, and build the 36 coal regions' supply curves.[38]

To estimate the annualized costs of additional capital investments in the power sector, EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. The CRF is derived from estimates of the power sector's cost of capital (i.e., private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital.[39] It is important to note that there is no single CRF factor applied in the model; rather, the

[36] Detailed information and documentation of EPA's Baseline run using EPA's Power Sector Modeling Platform 2023 using IPM, including all the underlying assumptions, data sources, and architecture parameters can be found on EPA's website at: *https://www.epa.gov/power-sector-modeling*.
[37] See Chapter 8 of EPA's IPM Documentation, available at: *https://www.epa.gov/power-sector-modeling*.
[38] See Chapter 7 EPA's IPM Documentation, available at: *https://www.epa.gov/power-sector-modeling*.
[39] See Chapter 10 of EPA's IPM Documentation, available at: *https://www.epa.gov/power-sector-modeling*.

CRF varies across technologies, book life of the capital investments, and regions in the model in order to better simulate power sector decision-making.

EPA has used IPM extensively over the past three decades to analyze options for reducing power sector emissions. Previously, the model has been used to estimate the costs, emission changes, and power sector impacts in the RIAs for the Clean Air Interstate Rule (U.S. EPA, 2005), the Cross-State Air Pollution Rule (U.S. EPA, 2011a), the Mercury and Air Toxics Standards (U.S. EPA, 2011b), the Clean Power Plan for Existing Power Plants (U.S. EPA, 2015b), the Cross-State Air Pollution Update Rule (U.S. EPA, 2016), the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units (U.S. EPA, 2019), the Revised Cross-State Air Pollution Update Rule (U.S. EPA, 2021), and the Good Neighbor Plan (2023b).

EPA has also used IPM to estimate the air pollution reductions and power sector impacts of water and waste regulations affecting EGUs, including contributing to RIAs for the Cooling Water Intakes (316(b)) Rule (U.S. EPA, 2014a), the Disposal of Coal Combustion Residuals from Electric Utilities rule (U.S. EPA, 2015c), the Steam Electric Effluent Limitation Guidelines (U.S. EPA, 2015a), and the Steam Electric Reconsideration Rule (U.S. EPA, 2020).

The model and EPA's input assumptions undergo periodic formal peer review. The rulemaking process also provides opportunity for expert review and comment by a variety of stakeholders, including owners and operators of capacity in the electricity sector that is represented by the model, public interest groups, and other developers of U.S. electricity sector models. The feedback that the Agency receives provides a highly detailed review of key input assumptions, model representation, and modeling results. IPM has received extensive review by energy and environmental modeling experts in a variety of contexts. For example, in September 2019, U.S. EPA commissioned a peer review[40] of EPA's v6 Reference Case using the Integrated Planning Model (IPM). Additionally, and in the late 1990s, the Science Advisory Board reviewed IPM as part of the CAA Amendments Section 812 prospective studies[41] that are periodically conducted. The Agency has also used the model in a number of comparative modeling exercises sponsored by Stanford University's Energy Modeling Forum over the past 20

[40] See Response and Peer Review Report EPA Reference Case Version 6 Using IPM, available at: *https://www.epa.gov/power-sector-modeling/ipm-peer-reviews*.

[41] *http://www2.epa.gov/clean-air-act-overview/benefits-and-costs-clean-air-act*.

years. IPM has also been employed by states (e.g., for the Regional Greenhouse Gas Initiative, the Western Regional Air Partnership, Ozone Transport Assessment Group), other Federal and state agencies, environmental groups, and industry.

3.3 Baseline

The modeled "baseline" for any regulatory impact analysis is a business-as-usual scenario that represents expected behavior in the electricity sector under market and regulatory conditions in the absence of a regulatory action. As such, the baseline run represents an element of the baseline for this RIA.[42] EPA frequently updates the baseline modeling to reflect the latest available electricity demand forecasts from the U.S. EIA as well as expected costs and availability of new and existing generating resources, fuels, emission control technologies, and regulatory requirements.

For our analysis of the MATS RTR rule, EPA used EPA's Power Sector Modeling Platform 2023 using IPM to provide power sector emissions projections for air quality modeling, as well as a companion updated database of EGU units (the National Electricity Energy Data System or NEEDS for IPM 2023[43]) that is used in EPA's modeling applications of IPM. The baseline for this final rule includes the Good Neighbor Plan (Final GNP), the Revised CSAPR Update, CSAPR Update, and CSAPR, as well as MATS. The baseline run also includes the 2015 Effluent Limitation Guidelines (ELG) and the 2015 Coal Combustion Residuals (CCR), and the recently finalized 2020 ELG and CCR rules.[44]

This version of the model, which is used as the baseline for this RIA, also includes recent updates to state and federal legislation affecting the power sector, including Public Law 117-169, 136 Stat. 1818 (August 16, 2022), commonly known as the Inflation Reduction Act of 2022 (the IRA). The IPM Documentation includes a summary of all legislation reflected in this version of the model as well as a description of how that legislation is implemented in the model.

[42] As described in Chapter 5 of EPA's *Guidelines for Preparing Economic Analyses*, the baseline "should incorporate assumptions about exogenous changes in the economy that may affect relevant benefits and costs (e.g., changes in demographics, economic activity, consumer preferences, and technology), industry compliance rates, other regulations promulgated by EPA or other government entities, and behavioral responses to the proposed rule by firms and the public." (U.S. EPA, 2014b).
[43] *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs*.
[44] For a full list of modeled policy parameters, please see: *https://www.epa.gov/power-sector-modeling*.

Under the baseline, the impacts of the IRA result in an acceleration of the ongoing shift towards lower emitting generation and declining generation share for fossil-fuel fired generation. A range of studies have outlined how reliability continues to be maintained under high variable renewable penetration scenarios. U.S. EPA (2023a) summarized results from fourteen multi-sector and power sector models under the IRA in 2030 and 2035. Across the models, wind and solar resources provide 22 to 54 percent of generation (with median of 45 percent) in 2030 and 21 to 80 percent (with median of 50 percent) in 2035. The North American Renewable Integration Study (Brinkman et al., 2021) showed how the U.S. could accommodate between 70 to 79 percent of wind and solar generation by 2050. The Solar Futures Study (DOE, 2021) illustrated power systems with upwards of 80 percent of renewable energy by 2050. Finally, Cole et al. (2021) demonstrates a 100 percent renewable power system for the contiguous U.S.

The inclusion of the final GNP and other regulatory actions (including federal, state, and local actions) in the base case is necessary in order to reflect the level of controls that are likely to be in place in response to other requirements apart from the scenarios analyzed in this section. This base case will provide meaningful projections of how the power sector will respond to the cumulative regulatory requirements for air emissions in totality, while isolating the incremental impacts of MATS RTR relative to a base case with other air emission reduction requirements separate from this final action.

The analysis of power sector cost and impacts presented in this section is based on a single policy run compared to the baseline run. The difference between the two runs represents the incremental impacts projected solely as a result of compliance with the final MATS RTR.

3.4 Regulatory Options Analyzed

For this RIA, EPA analyzed the regulatory options summarized in the table below, which are described in more detail in Section 1.3.1. The remainder of this section discusses the approach used for estimating the costs and/or emissions impacts of each provision of this final rule.

Table 3-1 Summary of Final Regulatory Options Examined in this RIA

Provision	Regulatory Options Examined in this RIA: Less Stringent	Regulatory Options Examined in this RIA: Final Rule
FPM Standard (Surrogate Standard for Non-Hg HAP Metals)	Retain existing fPM standard of 0.030 lb/MMBtu	Revised fPM standard of 0.010 lb/MMBtu
Hg Standard	Retain Hg standard for lignite-fired EGUs of 4.0 lb/TBtu	Revised Hg standard for lignite-fired EGUs of 1.2 lb/TBtu
Continuous Emissions Monitoring Systems (PM CEMS)	Require installation of PM CEMS to demonstrate compliance	Require installation of PM CEMS to demonstrate compliance
Startup Definition	Remove startup definition #2	Remove startup definition #2

As explained in Section 1.3.1, both the final rule and less stringent options described in Table 3-1 have not been changed from the proposed and less stringent options examined in the RIA for the proposal of this action. The proposal RIA included a more stringent regulatory option that projected the impacts of lowering the fPM standard to 0.006 lb/MMBtu, while holding the other three proposed amendments unchanged from the proposed option. EPA solicited comment on this more stringent fPM standard in the preamble of the proposed rule. As explained in section V.A.4. of the preamble of the final rule, EPA determined not to pursue a more stringent standard for fPM emissions, such as a limit of 0.006 lb/MMBtu. After considering comments to the proposed rule and after conducting additional analysis, EPA determined that a lower fPM standard would not be compatible with PM CEMS due to measurement uncertainty. As a result, this RIA does not examine a more stringent option than the suite of requirements that constitute the final rule; the final rule represents the most stringent suite of regulatory options available under the technology review.

The revisions to the fPM standard and the Hg standard are modeled endogenously within IPM. For the fPM standard, emissions controls and associated costs are modeled based on information available in the memorandum titled “2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category,” which is available in the docket. This memorandum summarizes the fPM emissions rate for each existing EGU. Based on the emissions rates detailed in this memorandum, EPA assumed various levels of O&M, ESP upgrades, upgrades to existing fabric filters, or new fabric filter installations to comply with each of the finalized standards in the modeling. Those assumptions are detailed in Table 3-2.

Table 3-2 PM Control Technology Modeling Assumptions[a]

PM Control Strategy	Cost (in 2019 dollars)	fPM Reduction
Operation & Maintenance (O&M)	$100,000/year	Unit-specific
Minor ESP Upgrades	$20/kW	20%
Typical ESP Upgrades	$40/kW	40%
ESP Rebuild	$80/kW	55% (0.005lb/MMBtu floor)
Upgrade Existing FF Bags	Unit-specific, approximately $15K - $500K annual O&M	50% (0.002 lb/MMBtu floor)
New Fabric Filter (6.0 A/C Ratio)	Unit-specific, $150-360/kW*	90% (0.002 lb/MMBtu floor)

[a] Capital costs are expressed here in terms of $/kW. O&M costs are expressed here on an annual basis.
* *https://www.epa.gov/system/files/documents/2021-09/attachment_5-7_pm_control_cost_development_methodology.pdf*

The cost and reductions associated with control of Hg emissions at lignite-fired EGUs are also modeled endogenously and reflect the assumption that each of these EGUs replace standard powdered activated carbon (PAC) sorbent with halogenated PAC sorbent.

While more detail on the costs associated with the PM CEMS requirement and the change in the startup definition is presented in Section 3.5.2, we note here that these costs were estimated exogenously without the use of the model that provides the bulk of the cost analysis for this RIA. As a result, the results of the power sector modeling do not include costs associated with these provisions, but the costs associated with requiring PM CEMS and the change in the startup definition are included in the total cost projections for the rule for each of the regulatory options analyzed in this RIA. As the incremental costs of requiring PM CEMS are small relative to the ongoing costs of operations, we do not think the endogenous incorporation of these costs would change any projected results in a meaningful way.

3.5 Power Sector Impacts

3.5.1 Emissions

As indicated previously, this RIA presents emissions reductions estimates in years 2028, 2030, and 2035 based on IPM projections.[45] Table 3-3 presents the estimated impact on power sector emissions resulting from compliance with the final rule in the contiguous U.S. The quantified emission estimates presented in the RIA include changes in pollutants directly covered by this rule, such as Hg and non-Hg HAP metals, and changes in other pollutants emitted from the power sector as a result of the compliance actions projected under this final rule. The model projections capture the emissions changes associated with implementation of HAP mitigation measures at affected sources as well as the resulting effects on dispatch as the relative operating costs for some affected units have changed. The projections indicate that the final rule results in reductions in emissions of Hg in all run years, of 16 percent, 17 percent, and 18 percent in 2028, 2030, and 2035, respectively, as well as reductions in $PM_{2.5}$ and PM_{10} emissions in all run years.

[45] Note that baseline mercury emissions projections are higher than proposal due to a revision in final baseline modeling to better reflect current ACI performance at existing lignite-fired units.

Table 3-3 EGU Emissions and Projected Emissions Changes for the Baseline and the Final Rule for 2028, 2030, and 2035[a]

	Year	Total Emissions: Baseline	Total Emissions: Final Rule	Change from Baseline	% Change under Final Rule
Hg (lbs.)	2028	6,129	5,129	-999.1	-16.3%
	2030	5,863	4,850	-1,013	-17.3%
	2035	4,962	4,055	-907.0	-18.3%
$PM_{2.5}$ (thousand tons)	2028	70.5	69.7	-0.77	-1.09%
	2030	66.3	65.8	-0.53	-0.79%
	2035	50.7	50.2	-0.47	-0.93%
PM_{10} (thousand tons)	2028	79.5	77.4	-2.07	-2.60%
	2030	74.5	73.1	-1.33	-1.79%
	2035	56.0	54.8	-1.18	-2.11%
SO_2 (thousand tons)	2028	454.3	454.0	-0.290	-0.06%
	2030	333.5	333.5	0.025	0.01%
	2035	239.9	239.9	-0.040	-0.02%
Ozone-season NO_X (thousand tons)	2028	189.0	188.8	-0.165	-0.09%
	2030	174.99	175.4	0.488	0.28%
	2035	116.99	119.1	2.282282	1.95%
Annual NO_X (thousand tons)	2028	460.55	460.3	-0.283	-0.06%
	2030	392.88	392.7	-0.022	-0.01%
	2035	253.44	253.5	0.066	0.03%
HCl (thousand tons)	2028	2.474	2.474	0.000	0.01%
	2030	2.184	2.184	0.000	0.01%
	2035	1.484	1.485	0.001	0.06%
CO_2 (million metric tons)	2028	1,158.8	1,158.7	-0.0655	-0.01%
	2030	1,098.3	1,098.3	0.0361	0.00%
	2035	724.2	724.1	-0.099	-0.01%

[a] This analysis is limited to the geographically contiguous lower 48 states. Values are independently rounded and may not sum.

We also estimate that the final rule will reduce at least seven tons of non-Hg HAP metals in 2028, five tons of non-Hg HAP metals in 2030, and four tons of non-Hg HAP metals in 2035. These reductions are composed of reductions in emissions of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.[46] Table 3-4 summarizes the total emissions reductions projected over the 2028 to 2037 analysis period.

Table 3-4 Cumulative Projected Emissions Reductions for the Final Rule, 2028 to 2037[a,b]

Pollutant	Emissions Reductions
Hg (pounds)	9,500
$PM_{2.5}$ (tons)	5,400
CO_2 (thousand tons)	650
SO_2 (tons)	770
NO_x (tons)	220
Non-Hg HAP metals (tons)	49

[a] Values rounded to two significant figures.
[b] Estimated reductions from model year 2028 are applied to 2028 and 2029, those from model year 2030 are applied to 2031 and 2032, and those from model year 2035 are applied to 2032 through 2037. These values are summed to generate total reduction figures.

Importantly, the continuous monitoring of fPM required in this rule will likely induce additional emissions reductions that we are unable to quantify. Continuous measurements of emissions accounts for changes to processes and fuels, fluctuations in load, operations of pollution controls, and equipment malfunctions. By measuring emissions across all operations, power plant operators and regulators can use the data to ensure controls are operating properly and to assess continuous compliance with relevant standards. Because CEMS enable power plant operators to quickly identify and correct problems with pollution control devices, it is possible that fPM emissions could be lower than they otherwise would have been for up to three months—or up to three years if testing less frequently under the LEE program— at a time. This potential reduction in fPM and non-Hg HAP metals emission resulting from the information provided by continuous monitoring coupled with corrective actions by plant operators could be sizeable over the existing coal-fired fleet and is not quantified in this rulemaking.

As we are finalizing the removal of paragraph (2) of the definition of "startup," the time period for engaging fPM or non-Hg HAP metal controls after non-clean fuel use, as well as for full operation of fPM or non-Hg HAP metal controls, is expected to be reduced when

[46] The estimates on non-mercury HAP metals reductions were obtained my multiplying the ratio of non-mercury HAP metals to fPM by estimates of PM_{10} reductions under the rule, as we do not have estimates of fPM reductions using IPM, only PM_{10}. The ratios of non-mercury HAP metals to fPM were based on analysis of 2010 MATS Information Collection Request (ICR) data. As there may be substantially more fPM than PM_{10} reduced by the control techniques projected to be used under this rule, these estimates of non-mercury HAP metals reductions are likely underestimates. More detail on the estimated reduction in non-mercury HAP metals can be found in the docketed memorandum *Estimating Non-Hg HAP Metals Reductions for the 2024 Technology Review for the Coal-Fired EGU Source Category*.

transitioning to paragraph (1). The reduced time period for engaging controls therefore increases the duration in which pollution controls are employed and lowers emissions.

To the extent that the CEMS requirement and removal of the second definition of startup leads to actions that may otherwise not occur absent the amendments to those provisions in this final rule, there may be emissions impacts we are unable to estimate.

3.5.2 Compliance Costs

3.5.2.1 Power Sector Costs

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 and are presented in Table 3-5. In other words, these costs are an estimate of the increased power industry expenditures required to implement the final rule requirements. The total compliance costs, presented in Section 3.5.2.4, are estimated for this RIA as the sum of two components. The first component, estimated using the modeling discussed above, is presented below in Table 3-5. This component constitutes the majority of the incremental costs for the final. The second component, the costs of the final rule PM CEMS requirement, is discussed in Section 3.5.2.2.

EPA projects that the annual incremental compliance cost of the final rule is $110 million, $110 million, and $93 million (2019 dollars) in 2028, 2030, and 2035, respectively. The annual incremental cost is the projected additional cost of complying with the final rule in the year analyzed and includes the amortized cost of capital investment and any applicable costs of operating additional pollution controls, investments in new generating sources, shifts between or amongst various fuels, and other actions associated with compliance. This projected cost does not include the compliance calculated outside of IPM modeling, namely the compliance costs related to PM CEMS. See Section 3.5.2.2 for further details on these costs. EPA believes that the cost assumptions used for this RIA reflect, as closely as possible, the best information available to the Agency today. See Section 3.5.4 for a discussion of projected capacity changes and Section 3.6 for a discussion of the uncertainty regarding necessary pollution controls.

Table 3-5 Power Sector Annualized Compliance Cost Estimates under the Final Rule in 2028, 2030, and 2035 (millions of 2019 dollars)

Analysis Year	Final Rule
2028	110
2030	110
2035	93

Note: Values have been rounded to two significant figures. As explained in Section 3.4, the incremental costs of requiring PM CEMS are small relative to the ongoing costs of operation, so the less stringent regulatory alternative in this RIA was not modeled using IPM. As a result, power sector impacts are not estimated for the less stringent regulatory option, but the costs associated with requiring PM CEMS (Table 3-6) are included in the total cost across regulatory options (Table 3-7).

3.5.2.2 PM CEMS Costs

In addition to revising the PM emission standard for existing coal-fired EGUs, EPA is revising the requirements for demonstrating compliance with the PM emission standard for coal- and oil-fired EGUs. The final PM standard renders the current limit for the LEE program moot since it is lower than the current PM LEE limit. Therefore, EPA is removing PM from the LEE program. Currently, EGUs that are not LEE units can demonstrate compliance with the fPM standard either by conducting performance testing quarterly, use of PM continuous parameter monitoring systems (CPMS) or using PM CEMS.

After considering updated information on the costs for performance testing compared to the cost of PM CEMS and capabilities of PM CEMS measurement abilities, as well as the benefits of using PM CEMS, which include increased transparency, compliance assurance, and accelerated identification of anomalous emissions, EPA is finalizing the requirement that all coal-fired EGUs and oil-fired EGUs demonstrate compliance with the PM emission standard by using PM CEMS.

The revision of PM limits alters the composition and duration of testing runs in facilities that use either compliance testing methodology. Estimated costs for quarterly fPM testing and PM CEMS are provided in the “Revised Estimated Non-Beta Gauge PM CEMS and Filterable PM Testing Costs” memorandum, available in the docket. The annualized costs for units currently employing EPA Method 5 quarterly testing are estimated at about $60,000.[47] EPA calibrated its cost estimates for PM CEMS in response to observed installations, manufacturer input, public comment, and engineering analyses. These calibrations include an assumed

[47] EGUs receiving contractual or quantity discounts from performance test provides may incur lower costs.

replacement lifespan of 15 years and an interest rate of 7 percent to approximate the prevailing bank prime rate. For the portion of EGUs that employ PM CEMS, we estimate the annualized costs to be about $72,000.

To produce an inventory of total units which would require the installation of PM CEMS under the final rule as well as the incremental costs of the requirement, EPA began with an inventory of all existing coal-fired EGUs with capacity great enough to be regulated by MATS. That inventory was then filtered to remove EGUs with planned retirements or coal to gas conversions prior to 2028 from analysis of both the baseline and final rule. Within that remaining inventory of 314 EGUs, we used recent compliance data to determine that 120 units have installed PM CEMS, while 177 units use quarterly testing and do not have existing PM CEMS installations. The remaining 17 units (for which fPM compliance data were not available) are assumed to use quarterly testing and not have existing PM CEMS installations.

Table 3-6 Incremental Cost of Final Continuous Emissions Monitoring (PM CEMS) Requirement

Compliance Approach in Baseline	Units (no.)	Baseline Cost (per year per unit)	Total Baseline Costs (per year)	Final Rule (per year per unit)	Final Rule Costs (per year)	Incremental Costs (per year)
Quarterly Testing	190	$60,000	$12,000,000	$72,000	$14,000,000	$2,300,000
PM CEMS	120	$72,000	$8,700,000	$72,000	$8,700,000	$0
Total	**320**	**---**	**$20,000,000**	**---**	**$23,000,000**	**$2,300,000**

Note: Values rounded to two significant figures. Rows may not appear to add correctly due to rounding.

As detailed in Table 3-6, relative to the baseline scenario, revised PM CEMS cost estimates in the final rule leads to an estimated incremental cost of about $12,000 per year per unit for EGUs currently employing quarterly testing. The final rule results in costs of about $2.3 million per year in total.

3.5.2.3 Startup Definition Costs

EPA is finalizing the removal of one of the two options for defining the startup period for EGUs. The first option defines 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. 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. 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. Startup ends four hours after the EGU generates electricity that is sold or used for any other purpose (including on-site use), or four hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes, whichever is earlier. This second option, 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 one 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 four 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.

According to EPA analysis, 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 and/or better design structure, or a combination of factors, to be able to meet the requirements of paragraph (1) of the startup definition. This ability points out an improvement in operation that all EGUs should be able to meet at little to no additional expenditure since the additional recordkeeping and reporting provisions associated with the work practice standards of paragraph (2) of the startup definition were more expensive than the requirements of paragraph (1) of the definition. As a result, this RIA does not incorporate any additional costs of this finalized provision.

3.5.2.4 Total Compliance Costs

The estimates of the total compliance costs are presented in Table 3-7. The total costs are composed of the change in electric power generation costs between the baseline and policy scenarios as presented in Table 3-5 and the incremental cost of the final PM CEMS requirement as detailed in Table 3-6. There are no anticipated costs associated with this rule prior to 2028.

Table 3-7 Stream of Projected Compliance Costs for the Final Rule and Less Stringent Regulatory Alternative (millions of 2019 dollars)[a]

	Regulatory Alternative	
Year	**Final Rule[b]**	**Less Stringent**
2028 (applied to 2028 and 2029)[b]	110	2.3
2030 (applied to 2030 and 2031)[b]	120	2.3
2035 (applied to 2032 to 2037)[b]	95	2.3
2% Discount Rate		
PV	**860**	**19**
EAV	**96**	**2.3**
3% Discount Rate		
PV	**790**	**18**
EAV	**92**	**2.1**
7% Discount Rate		
PV	**560**	**13**
EAV	**80**	**1.8**

[a] Values rounded to two significant figures. PV and EAV discounted to 2023.
[b] IPM run years apply to particular calendar years as reported in the table. The run year information as applied to individual calendar years is thus used to calculate PV and EAVs. Values rounded to two significant figures.

3.5.3 Projected Compliance Actions for Emissions Reductions

Electric generating units subject to the Hg and fPM emission limits in this final rule will likely use various Hg and PM control strategies to comply. This section summarizes the projected compliance actions related to each of these emissions limits.

The 2028 baseline includes approximately 5 GW of operational minemouth EGU capacity designed to burn low rank virgin coal. All of this capacity is currently equipped with Activated Carbon Injection (ACI) technology, and operation of this technology is reflected in the baseline. Each of these EGUs projected to consume lignite is assigned an additional variable operating cost that is consistent with achieving a 1.2 lb/MMBtu limit. Under the final rule, this additional cost does not result in incremental retirements for these units, nor does it result in a significant change to the projected generation level for these units.

The baseline also includes 11.6 GW of operational coal capacity that, based on the analysis documented in the EPA docketed memorandum titled “2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category,” EPA assumes would either need to improve existing PM controls or install new PM controls to comply with the final rule in 2028. The various PM control upgrades that EPA assumes would be necessary to achieve the emissions limits analyzed are summarized in Table 3-8.

Table 3-8 Projected PM Control Strategies under the Final Rule in 2028 (GW)

PM Control Strategy	Projected Actions and Retrofits under the Final Rule
Additional O&M	3.7
Minor ESP Upgrades	0.7
Typical ESP Upgrades	2.0
ESP Rebuild	2.4
FF Bag Upgrade	1.3
New Fabric Filter	1.5
Total	**11.6**

Except for one facility (Colstrip, located in Montana), all of the 11.6 GW of operational coal capacity that EPA assumes would need to take some compliance action to meet the final standards are currently operating existing ESPs and/or fabric filters. All of that capacity is projected to install the controls summarized in Table 3-8 and remain operational in 2028.

3.5.4 Generating Capacity

In this section, we discuss the projected changes in capacity by fuel type, building on and adding greater context to the information presented in the previous section. We first look at total capacity by fuel type, then retirements by fuel type, and finally new capacity builds by fuel type for the 2028, 2030, and 2035 run years.

Table 3-9 shows the total net projected capacity by fuel type for the baseline and the final rule for 2028, 2030, and 2035. Here, we see the net effects of projected retirements (Table 3-10) and new capacity builds (see Table 3-11). There are no significant incremental changes in capacity projected in response to the final rule for any given fuel type.

Table 3-9 2028, 2030, and 2035 Projected U.S. Capacity by Fuel Type for the Baseline and the Final Rule

	Total Generation Capacity (GW)			
	Baseline	Final Rule	Change under Final Rule	
			GW	%
2028				
Coal	105.8	105.8	0.0	0.0%
Natural Gas	471.0	471.0	0.0	0.0%
Oil/Gas Steam	62.6	62.6	0.0	0.0%
Non-Hydro RE	394.1	394.1	0.0	0.0%
Hydro	102.4	102.4	0.0	0.0%
Energy Storage	46.7	46.7	0.0	0.0%
Nuclear	93.6	93.6	0.0	0.0%
Other	6.5	6.5	0.0	0.0%
Total	**1,282.7**	**1,282.7**	**0.0**	**0.0%**
2030				
Coal	85.0	85.0	0.0	0.0%
Natural Gas	478.6	478.6	0.0	0.0%
Oil/Gas Steam	64.3	64.3	0.0	0.0%
Non-Hydro RE	440.2	440.2	0.0	0.0%
Hydro	103.7	103.7	0.0	0.0%
Energy Storage	58.6	58.6	0.0	0.0%
Nuclear	90.9	90.9	0.0	0.0%
Other	6.5	6.5	0.0	0.0%
Total	**1,327.7**	**1,327.7**	**0.0**	**0.0%**
2035				
Coal	51.6	51.6	0.0	0.0%
Natural Gas	476.0	476.0	0.0	0.0%
Oil/Gas Steam	55.3	55.3	0.0	0.0%
Non-Hydro RE	698.5	698.5	0.0	0.0%
Hydro	107.3	107.3	0.0	0.0%
Energy Storage	113.6	113.6	0.0	0.0%
Nuclear	83.7	83.7	0.0	0.0%
Other	6.5	6.5	0.0	0.0%
Total	**1,592.4**	**1,592.4**	**0.0**	**0.0%**

Note: In this table, “Non-Hydro RE” includes biomass, geothermal, landfill gas, solar, and wind.

Table 3-10 shows the total capacity projected to retire by fuel type for the baseline and the final rule in all run years. The final rule is not projected to result in changes to projected retirements.

Table 3-10 2028, 2030, and 2035 Projected U.S. Retirements by Fuel Type for the Baseline and the Final Rule

	Projected Retirements (GW)		% Change under Final Rule
	Baseline	**Final Rule**	
	2028		
Coal	37.8	37.8	0.0%
Natural Gas	1.3	1.3	0.0%
Oil/Gas Steam	12.4	12.4	0.0%
Non-Hydro RE	2.9	2.9	0.0%
Hydro	0.1	0.1	0.0%
Nuclear	0.0	0.0	0.0%
Other	0.0	0.0	0.0%
Total	**54.4**	**54.4**	**0.0%**
	2030		
Coal	56.7	56.6	0.0%
Natural Gas	1.7	1.7	0.0%
Oil/Gas Steam	12.4	12.4	0.0%
Non-Hydro RE	2.9	2.9	0.0%
Hydro	0.1	0.1	0.0%
Nuclear	2.7	2.7	0.0%
Other	0.0	0.0	0.0%
Total	**76.5**	**76.5**	**0.0%**
	2035		
Coal	83.7	83.7	0.0%
Natural Gas	4.3	4.3	0.0%
Oil/Gas Steam	22.7	22.7	0.0%
Non-Hydro RE	3.0	3.0	0.0%
Hydro	0.1	0.1	0.0%
Nuclear	9.9	9.9	0.0%
Other	0.1	0.1	0.0%
Total	**123.7**	**123.7**	**0.0%**

Note: In this table, “Non-Hydro RE” includes biomass, geothermal, landfill gas, solar, and wind.

Finally, Table 3-11 shows the projected U.S. new capacity builds by fuel type for the baseline and the final rule in all run years. For the final rule, the incremental changes in projected new capacity for any given fuel type are negligible.

Table 3-11 2028, 2030, and 2035 Projected U.S. New Capacity Builds by Fuel Type for the Baseline and the Final Rule

	New Capacity (GW)		% Change under Final Rule
	Baseline	**Final Rule**	
	2028		
Coal	0.0	0.0	0.0%
Natural Gas	26.2	26.2	0.0%
Energy Storage	3.2	3.2	0.2%
Non-Hydro RE	44.8	44.8	0.0%
Hydro	0.0	0.0	0.0%
Nuclear	0.0	0.0	0.0%
Other	0.0	0.0	0.0%
Total	**74.3**	**74.3**	**0.0%**
	2030		
Coal	0.0	0.0	0.0%
Natural Gas	34.3	34.3	0.0%
Energy Storage	15.2	15.2	0.0%
Non-Hydro RE	90.8	90.8	0.0%
Hydro	1.3	1.3	0.0%
Nuclear	0.0	0.0	0.0%
Other	0.0	0.0	0.0%
Total	**141.5**	**141.6**	**0.0%**
	2035		
Coal	0.0	0.0	0.0%
Natural Gas	34.2	34.2	0.0%
Energy Storage	70.2	70.2	0.1%
Non-Hydro RE	349.4	349.4	0.0%
Hydro	4.9	4.9	0.0%
Nuclear	0.0	0.0	0.0%
Other	0.0	0.0	0.0%
Total	**458.6**	**458.6**	**0.0%**

Note: In this table, “Non-Hydro RE” includes biomass, geothermal, landfill gas, solar, and wind.

3.5.5 Generation Mix

In this section, we discuss the projected changes in generation mix for 2028, 2030, and 2035 for the final rule. Table 3-12 presents the projected generation and percentage changes in national generation mix by fuel type for run years 2028, 2030, and 2035. These generation mix estimates reflect limited changes in energy generation as a result of the final rule in any run year. Estimated changes in coal and natural gas use under the final rule are examined further in Section 3.5.6.

Table 3-12 2028, 2030, and 2035 Projected U.S. Generation by Fuel Type for the Baseline and the Final Rule

	Generation Mix (TWh)		Incremental Change under Final Rule	
	Baseline	**Final Rule**	**TWh**	**%**
		2028		
Coal	472	472	-0.1	0.0%
Natural Gas	1,652	1,652	0.1	0.0%
Oil/Gas Steam	26	26	0.0	0.0%
Non-Hydro RE	1,141	1,141	0.0	0.0%
Hydro	293	293	0.0	0.0%
Energy Storage	53	53	0.0	0.1%
Nuclear	751	751	0.0	0.0%
Other	31	31	0.0	0.0%
Total	**4,418**	**4,418**	**0.0**	**0.0%**
		2030		
Coal	410	410	0.0	0.0%
Natural Gas	1,670	1,670	0.0	0.0%
Oil/Gas Steam	25	25	0.0	0.0%
Non-Hydro RE	1,329	1,329	0.0	0.0%
Hydro	298	298	0.0	0.0%
Energy Storage	69	69	0.0	0.0%
Nuclear	729	729	0.0	0.0%
Other	31	31	0.0	0.0%
Total	**4,560**	**4,560**	**0.0**	**0.0%**
		2035		
Coal	236	236	-0.1	0.0%
Natural Gas	1,344	1,344	0.0	0.0%
Oil/Gas Steam	8	8	0.0	-0.4%
Non-Hydro RE	2,229	2,229	0.0	0.0%
Hydro	319	319	0.0	0.0%
Energy Storage	148	148	0.1	0.1%
Nuclear	667	667	0.0	0.0%
Other	31	31	0.0	0.0%
Total	**4,981**	**4,981**	**0.0**	**0.0%**

Note: In this table, "Non-Hydro RE" includes biomass, geothermal, landfill gas, solar, and wind.

3.5.6 Coal and Natural Gas Use for the Electric Power Sector

In this section we discuss the estimated changes in coal use and natural gas use in 2028, 2030, and 2035. Table 3-13 and Table 3-14 present percentage changes in national coal usage by EGUs by coal supply region and coal rank, respectively. These fuel use estimates show small changes in national coal use in the final rule relative to the baseline in all run years. Additionally, the final rule is not projected to result in significant coal switching between supply regions or coal rank.

Table 3-13 2028, 2030, and 2035 Projected U.S. Power Sector Coal Use by Coal Supply Region for the Baseline and the Final Rule

Region	Year	Million Tons		% Change under Final Rule
		Baseline	**Final Rule**	
Appalachia	**2028**	39.8	39.8	0.1%
Interior		37.8	37.8	-0.1%
Waste Coal		7.3	7.3	0.0%
West		166.1	166.0	-0.1%
Total		**250.9**	**250.8**	**0.0%**
Appalachia	**2030**	38.8	38.8	0.0%
Interior		35.1	35.1	0.0%
Waste Coal		7.1	7.1	0.0%
West		141.5	141.5	0.0%
Total		**222.5**	**222.5**	**0.0%**
Appalachia	**2035**	31.8	31.9	0.1%
Interior		19.4	19.4	-0.1%
Waste Coal		6.8	6.8	0.0%
West		89.0	89.1	0.1%
Total		**147.1**	**147.2**	**0.0%**

Table 3-14 2028, 2030, and 2035 Projected U.S. Power Sector Coal Use by Rank for the Baseline and the Final Rule

Rank	Year	Million Tons		% Change under Final Rule
		Baseline	Final Rule	
Bituminous	2028	72.1	72.1	0.00%
Subbituminous		145.1	145.1	0.00%
Lignite		32.5	32.3	-0.60%
Total		**249.6**	**249.5**	**0.00%**
Bituminous	2030	62.8	62.8	0.00%
Subbituminous		125.8	125.8	0.00%
Lignite		29.3	29.3	0.00%
Total		**218**	**218**	**0.00%**
Bituminous	2035	42.4	42.4	0.00%
Subbituminous		74.1	74.2	0.10%
Lignite		24.5	24.5	0.00%
Total		**140.9**	**141**	**0.00%**

Table 3-15 presents the projected changes in national natural gas usage by EGUs in the 2028, 2030, and 2035 run years. These fuel use estimates reflect negligible changes in projected gas generation in 2028, 2030, and 2035.

Table 3-15 2028, 2030, and 2035 Projected U.S. Power Sector Natural Gas Use for the Baseline and the Final Rule

Year	Trillion Cubic Feet		% Change under Final Rule
	Baseline	Final Rule	
2028	11.6	11.6	0.0%
2030	11.7	11.7	0.0%
2035	9.3	9.3	0.0%

3.5.7 Fuel Price, Market, and Infrastructure

The projected impacts of the final rule on coal and natural gas prices are presented below in Table 3-16 and Table 3-17, respectively. As with the projected impact of the final rule on fuel use, there is no significant change projected for minemouth and delivered coal prices due to the final rule.

Table 3-16 2028, 2030, and 2035 Projected Minemouth and Power Sector Delivered Coal Price (2019 dollars) for the Baseline and the Final Rule

	Year	$/MMBtu Baseline	$/MMBtu Final Rule	% Change under Final Rule
Minemouth	2028	0.98	0.98	0.0%
Delivered		1.54	1.54	0.0%
Minemouth	2030	1.02	1.02	0.0%
Delivered		1.56	1.56	0.0%
Minemouth	2035	1.07	1.07	0.0%
Delivered		1.55	1.55	0.0%

Consistent with the projection of no significant change in natural gas use under the final rule, Henry Hub and power sector delivered natural gas prices are not projected to significantly change under the final rule over the period analyzed. Table 3-17 summarizes the projected impacts on Henry Hub and delivered natural gas prices in 2028, 2030, and 2035.

Table 3-17 2028, 2030, and 2035 Projected Henry Hub and Power Sector Delivered Natural Gas Price (2019 dollars) for the Baseline and the Final Rule

	Year	$/MMBtu Baseline	$/MMBtu Final Rule	% Change under Final Rule
Henry Hub	2028	2.78	2.78	0.0%
Delivered		2.84	2.84	0.0%
Henry Hub	2030	2.89	2.89	0.0%
Delivered		2.95	2.95	0.0%
Henry Hub	2035	2.87	2.87	0.0%
Delivered		2.88	2.88	0.0%

3.5.8 Retail Electricity Prices

EPA estimated the change in the retail price of electricity (2019 dollars) using the Retail Price Model (RPM).[48] The RPM was developed by ICF for EPA and uses the IPM estimates of changes in the cost of generating electricity to estimate the changes in average retail electricity prices. The prices are average prices over consumer classes (i.e., consumer, commercial, and industrial) and regions, weighted by the amount of electricity used by each class and in each region. The RPM combines the IPM annual cost estimates in each of the 64 IPM regions with

[48] See documentation available at: *https://www.epa.gov/airmarkets/retail-price-model*.

EIA electricity market data for each of the 25 electricity supply regions (shown in Figure 3-1) in the electricity market module of the National Energy Modeling System (NEMS).[49]

Table 3-18, Table 3-19, and Table 3-20 present the projected percentage changes in the retail price of electricity for the regulatory control alternatives in 2028, 2030, and 2035, respectively. Consistent with other projected impacts presented above, the projected impacts on average retail electricity prices at both the national and regional level are projected to be small in all run years.

[49] See documentation available at: *https://www.eia.gov/outlooks/aeo/nems/documentation/electricity/pdf/EMM_2022.pdf*.

Table 3-18 Projected Average Retail Electricity Price by Region for the Baseline and under the Final Rule, 2028

All Sectors	2028 Average Retail Electricity Price (2019 mills/kWh)		
Region	**Baseline**	**Final Rule**	**% Change under Final Rule**
TRE	73.4	73.4	0.0%
FRCC	96.4	96.4	0.0%
MISW	92.3	92.3	0.0%
MISC	87.9	88.0	0.2%
MISE	95.2	95.2	0.0%
MISS	81.3	81.3	0.0%
ISNE	141.8	141.8	0.0%
NYCW	208.4	208.4	0.0%
NYUP	121.5	121.5	0.0%
PJME	116.9	116.9	0.0%
PJMW	90.4	90.4	0.0%
PJMC	72.4	72.4	0.0%
PJMD	70.8	70.8	0.0%
SRCA	94.7	94.7	0.0%
SRSE	96.7	96.7	0.0%
SRCE	71.6	71.6	0.0%
SPPS	75.3	75.3	0.0%
SPPC	98.5	98.4	0.0%
SPPN	64.1	64.1	0.0%
SRSG	101.3	101.3	0.0%
CANO	138.7	138.7	0.0%
CASO	170.5	170.5	0.0%
NWPP	75.0	75.4	0.5%
RMRG	96.4	96.4	0.0%
BASN	96.8	96.8	0.0%
National	97.1	97.1	0.0%

Table 3-19 Projected Average Retail Electricity Price by Region for the Baseline and under the Final Rule, 2030

All Sectors	2030 Average Retail Electricity Price (2019 mills/kWh)		
Region	**Baseline**	**Final Rule**	**% Change under Final Rule**
TRE	73.3	73.3	0.0%
FRCC	97.6	97.6	0.0%
MISW	93.2	93.2	0.0%
MISC	91.3	91.5	0.2%
MISE	109.4	109.4	0.0%
MISS	85.7	85.7	0.0%
ISNE	156.6	156.6	0.0%
NYCW	210.3	210.3	0.0%
NYUP	125.7	125.7	0.0%
PJME	109.9	109.9	0.0%
PJMW	97.3	97.3	0.0%
PJMC	89.3	89.3	0.0%
PJMD	76.5	76.5	0.0%
SRCA	92.1	92.2	0.0%
SRSE	94.7	94.7	0.0%
SRCE	70.7	70.7	0.0%
SPPS	77.7	77.8	0.0%
SPPC	97.3	97.3	0.0%
SPPN	65.1	65.1	0.0%
SRSG	101.7	101.6	0.0%
CANO	142.9	142.9	0.0%
CASO	173.8	173.9	0.0%
NWPP	81.6	81.7	0.1%
RMRG	100.7	100.7	0.0%
BASN	96.3	96.3	0.0%
National	99.6	99.6	0.0%

Table 3-20 Projected Average Retail Electricity Price by Region for the Baseline and under the Final Rule, 2035

All Sectors	2035 Average Retail Electricity Price (2019 mills/kWh)		
Region	**Baseline**	**Final Rule**	**% Change under Final Rule**
TRE	78.4	78.4	0.0%
FRCC	91.9	91.9	0.0%
MISW	84.5	84.5	0.0%
MISC	81.5	81.5	0.1%
MISE	95.7	95.7	0.0%
MISS	79.2	79.2	0.0%
ISNE	156.1	155.8	-0.2%
NYCW	208.9	208.9	0.0%
NYUP	124.6	124.6	0.0%
PJME	108.5	108.5	0.0%
PJMW	91.8	91.8	0.0%
PJMC	75.1	75.1	0.0%
PJMD	71.4	71.4	0.0%
SRCA	89.4	89.4	0.0%
SRSE	90.1	90.1	0.0%
SRCE	67.1	67.1	0.0%
SPPS	69.5	69.5	0.0%
SPPC	80.4	80.4	0.0%
SPPN	63.0	63.0	0.0%
SRSG	103.4	103.4	0.0%
CANO	139.5	139.5	0.0%
CASO	172.8	172.8	0.0%
NWPP	78.5	78.9	0.4%
RMRG	93.4	93.4	0.0%
BASN	96.9	97.0	0.0%
National	95.9	95.9	0.0%

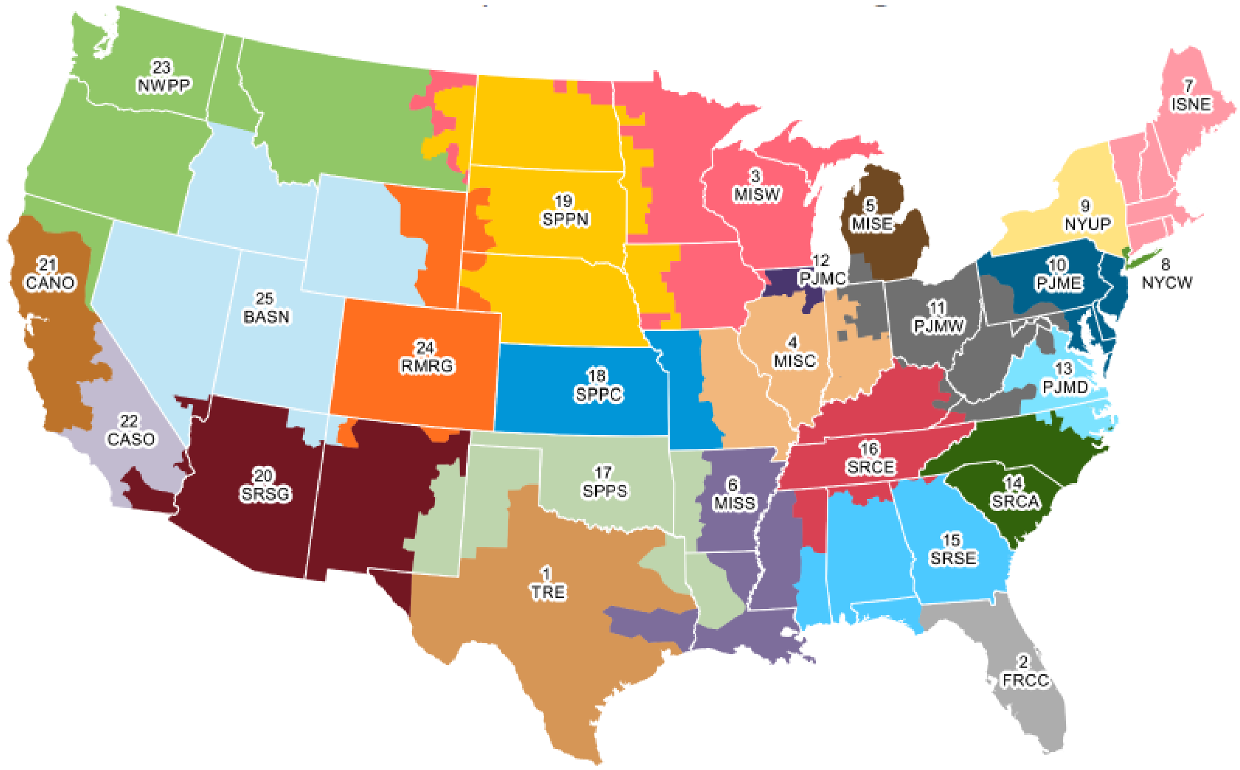

Figure 3-1 Electricity Market Module Regions
Source: EIA (*http://www.eia.gov/forecasts/aeo/pdf/nerc_map.pdf*)

3.6 Limitations of Analysis and Key Areas of Uncertainty

EPA's power sector modeling is based on expert judgment of various input assumptions for variables whose outcomes are uncertain. As a general matter, the Agency reviews the best available information from engineering studies of air pollution controls and new capacity construction costs to support a reasonable modeling framework for analyzing the cost, emission changes, and other impacts of regulatory actions for EGUs. The annualized cost of the final rule, as quantified here, is EPA's best assessment of the cost of implementing the rule on the power sector.

The IPM-projected annualized cost estimates of private compliance costs provided in this analysis are meant to show the increase in production (generating) costs to the power sector in response to the finalized requirements. To estimate these annualized costs, as discussed earlier, EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses to calculate annual costs. The CRF is derived from estimates of the cost of capital (private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital. The private compliance costs presented earlier are EPA's best estimate of the direct private compliance costs of the rule.

In addition, there are several key areas of uncertainty related to the electric power sector that are worth noting, including:

- **Electricity demand:** The analysis includes an assumption for future electricity demand. To the extent electricity demand is higher and lower, it may increase/decrease the projected future composition of the fleet.
- **Natural gas supply and demand:** To the extent natural gas supply and delivered prices are higher or lower, it would influence the use of natural gas for electricity generation and overall competitiveness of other EGUs (e.g., coal and nuclear units).
- **Longer-term planning by utilities:** Many utilities have announced long-term clean energy and/or climate commitments, with a phasing out of large amounts of coal capacity by 2030 and continuing through 2050. These announcements are not necessarily reflected in the baseline and may alter the amount of coal capacity projected in the baseline that would be covered under this rule.
- **FPM emissions and control:** As discussed above, the baseline fPM emissions rates for each unit are based on the analysis documented in the memorandum titled "2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category." For those EGUs with rates greater than the final limit, EPA assumes that control technology summarized in Section 3.4 would be necessary to remain operational. While the baseline emissions rate for each EGU and the cost and performance assumption for each PM control technology are the best available to EPA at this time, it is possible that some EGUs may be able to achieve the revised fPM emissions limits with less costly control technology (e.g., an ESP upgrade instead of a fabric filter installation). It is also possible that EPA's cost assumptions reflect higher technology costs than might be incurred by EGUs.

These are key uncertainties that may affect the overall composition of electric power generation fleet and/or compliance with the finalized emissions limits and could thus have an effect on the estimated costs and impacts of this action. While it is important to recognize these key areas of uncertainty, they do not change EPA's overall confidence in the projected impacts of the final rule presented in this section. EPA continues to monitor industry developments and makes appropriate updates to the modeling platforms in order to reflect the best and most current data available.

Estimated impacts of the Revised 2023 and Later Model Year Light-Duty Vehicle GHG Emissions Standards are captured in the baseline,[50] while estimated impacts of the Proposed Rule: Model Years 2027 and Later Light-Duty and Medium-Duty Vehicle Emissions Standards are not captured in the baseline.[51] The latter rule (in its proposal) is projected to increase the total demand for electricity by 0.4 percent in 2030 and 3.4 percent in 2040 relative to the baseline electricity demand projections assumed in this analysis. Estimated impacts of the 2023 Final Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review are also not included in this analysis. The RIA for oil and natural gas sector rule projected small increases in the price of natural gas as result of the requirements (U.S. EPA, 2023c). All else equal, inclusion of these two programs would likely result in a modest increase in the fPM reductions and total cost of compliance for this rule. While we might see less retired capacity in the baseline due to higher electricity demand, and thus more PM controls under the RTR, the magnitude of the potential incremental impacts would likely be very small.

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BENEFITS ANALYSIS

4.1 Introduction

This rule is projected to reduce emissions of Hg and non-Hg HAP metals, fine particulate matter ($PM_{2.5}$), sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2) nationally. The projected reductions in Hg are expected to reduce the bioconcentration of MeHg in fish. Subsistence fishing is associated with vulnerable populations, including minorities and those of low socioeconomic status. Further reductions in Hg emissions should reduce fish concentrations and exposure to HAP particularly for the subsistence fisher sub-population. The projected reductions in HAP emissions should help EPA maintain an ample margin of safety by reducing exposure to MeHg and carcinogenic HAP metals.

Regarding the potential health and ecological benefits of the rule from projected HAP reductions, we note that these are discussed only qualitatively and not quantitatively. Exposure to the HAP emitted by the source category, depending on the exposure duration and level of exposure, is associated with a variety of adverse health effects. These adverse health effects may include chronic health disorders (e.g., irritation of the lung, skin, and mucus membranes; decreased pulmonary function, pneumonia, or lung damage; detrimental effects on the central nervous system; cardiovascular disease; damage to the kidneys; and alimentary effects such as nausea and vomiting), adverse neurodevelopmental impacts, and increased risk of cancer. See 76 FR 25003–25005 for a fuller discussion of the health effects associated with HAP.

The analysis of the overall EGU sector completed for EPA's review of the 2020 appropriate and necessary finding (2023 Final A&N Review) identified significant reductions in cardiovascular and neuro-developmental effects from exposure to MeHg (88 FR 13956). However, the amount of Hg reduction projected under this rule is a fraction of the Hg estimates used in the 2023 Final A&N Review. Overall, the uncertainty associated with modeling potential benefits of Hg reduction for fish consumers would be sufficiently large as to compromise the utility of those benefit estimates—though importantly, such uncertainty does not decrease our confidence that reductions in emissions should result in reduced exposures of HAP to the general population, including MeHg exposures to subsistence fishers located near these facilities. Further, estimated risks from exposure to non-Hg HAP metals were not expected to exceed acceptable levels, although we note that these emissions reductions should result in decreased exposure to HAP for individuals living near these facilities.

ReducingPM$_{2.5}$ and SO_2 emissions is expected to reduce ground-level PM$_{2.5}$ concentrations. Reducing NO_X emissions is expected to reduce both ground-level ozone and PM$_{2.5}$ concentrations. Below we present the estimated number and economic value of these avoided PM$_{2.5}$ and ozone-attributable premature deaths and illnesses. We also present the estimated monetized climate and health benefits associated with emission reductions projected under the final rule.

In addition to reporting results, this section details the methods used to estimate the benefits to human health of reducing concentrations of PM$_{2.5}$ and ozone resulting from the projected emissions reductions. This analysis uses methods for determining air quality changes that have been used in the RIAs from multiple previous proposed and final rules (U.S. EPA, 2019b, 2020a, 2020b, 2021a, 2022c), including the RIA for the proposal of this rule (U.S. EPA, 2023b). The approach involves two major steps: (1) developing spatial fields of air quality across the U.S. for a baseline scenario and the final rule for 2028, 2030, and 2035 using nationwide photochemical modeling and related analyses (see Air Quality Modeling Appendix, Appendix A, for more details); and (2) using these spatial fields in BenMAP-CE to quantify the benefits under the final rule and each year as compared to the baseline in that year.[52] See Section 4.3.3 for more detail on BenMAP-CE. When estimating the value of improved air quality over a multi-year time horizon, the analysis applies population growth and income growth projections for each future year through 2037 and estimates of baseline mortality incidence rates at five-year increments.

Additionally, elevated concentrations of GHGs in the atmosphere have been warming the planet, leading to changes in the Earth's climate including changes in the frequency and intensity of heat waves, precipitation, and extreme weather events, rising seas, and retreating snow and ice. The well-documented atmospheric changes due to anthropogenic GHG emissions are changing the climate at a pace and in a way that threatens human health, society, and the natural environment. There will likely be important climate benefits associated with the CO_2 emissions

[52] Note we do not perform air quality analysis on the less stringent regulatory option because it has no quantified emissions reductions associated with the finalized requirements for CEMS and the removal of startup definition number two.

reductions expected from this rule. In this RIA, we monetize climate benefits from reducing emissions of CO_2 using estimates of the SC-CO_2.

EPA is unable to quantify and monetize the potential benefits of requiring facilities to utilize CEMS rather than continuing to allow the use of quarterly testing, but the requirement has been considered qualitatively. Relative to periodic testing practices, continuous monitoring of fPM will result in increased transparency, as well as potential emissions reductions from identifying problems more rapidly. Hence, the final rule may induce further reductions of fPM and non-Hg HAP metals than we project in this RIA, and these reductions would likely lead to additional health benefits. However, due to data and methodological challenges, EPA is unable to quantify these potential additional reductions. The continuous monitoring of fPM required in this rule is also likely to provide several additional important benefits to the public which are not quantified in this rule, including greater certainty, accuracy, transparency, and granularity in fPM emissions information than exists today. Additionally, to the extent that the removal of the second definition of startup leads to actions that may otherwise not occur absent this final rule, there may be beneficial impacts we are unable to estimate. Though the rule is likely to also yield positive benefits associated with reducing pollutants other than Hg, non-Hg HAP metals, $PM_{2.5}$, ozone, and CO_2, time, resource, and data limitations prevented us from quantifying and estimating the economic value of those reductions. Specifically, in this RIA EPA does not monetize health benefits of reducing direct exposure to NO_2 and SO_2 nor ecosystem effects and visibility impairment associated with changes in air quality. We qualitatively discuss these unquantified impacts in this section of the RIA.

4.2 Hazardous Air Pollutant Benefits

This final rule is projected to reduce emissions of Hg and non-Hg HAP metals. Specifically, projected reductions in Hg are expected to help reduce exposure to MeHg for sub-populations that rely on subsistence fishing. In addition, projected emissions reductions should also reduce exposure to non-Hg HAP metals including carcinogens such as nickel, arsenic, and hexavalent chromium, for residents located in the vicinity of these facilities.

4.2.1 Hg

Hg is a persistent, bioaccumulative toxic metal that is emitted from power plants in three forms: gaseous elemental Hg (Hg0), oxidized Hg compounds (Hg+2), and particle-bound Hg (HgP). Elemental Hg does not quickly deposit or chemically react in the atmosphere, resulting in residence times that are long enough to contribute to global scale deposition. Oxidized Hg and HgP deposit quickly from the atmosphere impacting local and regional areas in proximity to sources. MeHg is formed by microbial action in the top layers of sediment and soils, after Hg has precipitated from the air and deposited into waterbodies or land. Once formed, MeHg is taken up by aquatic organisms and bioaccumulates up the aquatic food web. Larger predatory fish may have MeHg concentrations many times that of the concentrations in the freshwater body in which they live (ATSDR, 2022). MeHg can adversely impact ecosystems and wildlife.

Human exposure to MeHg is known to have several adverse neurodevelopmental impacts, such as IQ loss measured by performance on neurobehavioral tests, particularly on tests of attention, fine motor-function, language, and visual spatial ability. In addition, evidence in humans and animals suggests that MeHg can have adverse effects on both the developing and the adult cardiovascular system, including fatal and non-fatal ischemic heart disease (IHD). Further, nephrotoxicity, immunotoxicity, reproductive effects (impaired fertility), and developmental effects have been observed with MeHg exposure in animal studies (ATSDR, 2022). MeHg has some genotoxic activity and is capable of causing chromosomal damage in a number of experimental systems. EPA has classified MeHg as a “possible” human carcinogen (U.S. EPA, 2001).

The projected reductions in Hg under this final rule are expected to reduce the bioconcentration of MeHg in fish due to Hg emissions from MATS-affected sources. Risk from near-field deposition of Hg to subsistence fishers has previously been evaluated, using a site-specific assessment of a lake near three lignite-fired facilities (U.S. EPA, 2020d). The results suggest that MeHg exposure to subsistence fishers from lignite-fired units is below the current RfD for MeHg neurodevelopmental toxicity or IQ loss, with an estimated hazard quotient (HQ) of 0.06. In general, EPA believes that exposures at or below the RfD are unlikely to be associated with appreciable risk of deleterious effects.

Regarding the potential magnitude of human health risk reductions and benefits associated with this rule, we make the following observations. All of the exposure results generated as part of the 2020 Residual Risk analysis were below the presumptive acceptable cancer risk threshold and noncancer health-based thresholds. While these results suggest that the residual risks from HAP exposure are low, we do recognize that this regulation should still reduce exposure to HAP.

Regarding potential benefits of the rule to the general population of fish consumers, while we note that the analysis of the overall EGU sector completed for the 2023 Final A&N Review did identify significant reductions in cardiovascular and neuro-developmental effects, given the substantially smaller Hg reduction associated with this rule (approximately 900 to 1000 pounds per year under the final rule compared to the approximately 29 tons of Hg evaluated in the 2023 Final A&N Review), overall uncertainty associated with modeling potential benefits for the broader population of fish consumers would be sufficiently large as to compromise the utility of those benefit estimates.

Despite the lack of quantifiable risks from Hg emissions, reductions would be expected to have some impact (reduction) on the overall MeHg burden in fish for waterbodies near covered facilities. In the appropriate and necessary determination, EPA illustrated that the burden of Hg exposure is not equally distributed across the population and that some subpopulations bore disproportionate risks associated with exposure to emissions from U.S. EGUs. High levels of fish consumption observed with subsistence fishing were associated with vulnerable populations, including minorities and those with low socioeconomic status (SES). Reductions in Hg emissions should reduce MeHg exposure and body burden for subsistence fishers.

U.S. EGU Hg emissions can lead to increased deposition of Hg to nearby waterbodies. Deposition of Hg to waterbodies can also have an impact on ecosystems and wildlife. Hg contamination is present in all environmental media with aquatic systems being particularly impacted due to bioaccumulation. Bioaccumulation refers to the net uptake of a contaminant from all possible pathways and includes the accumulation that may occur by direct exposure to contaminated media as well as uptake from food. Atmospheric Hg enters freshwater ecosystems by direct deposition and through runoff from terrestrial watersheds. Once Hg deposits, it may be converted to organic MeHg mediated primarily by sulfate-reducing bacteria. Methylation is enhanced in anaerobic and acidic environments, greatly increasing Hg toxicity and potential to bioaccumulate in aquatic foodwebs (Munthe et al. 2007). The highest levels of MeHg accumulation are most often measured in fish eating (piscivorous) animals and those which prey on other fish eaters. In laboratory studies, adverse effects from exposure to MeHg in wildlife have been observed in fish, mink, otters, and several avian species at exposure levels as low as 0.25 micrograms of MeHg per gram of body weight (U.S. EPA, 1997). The risk of Hg exposure may also extend to insectivorous terrestrial species such as songbirds, bats, spiders, and amphibians that receive Hg deposition or from aquatic systems near the forest areas they inhabit (Bergeron et al., 2010a, 2010b; Cristol et al., 2008; Rimmer et al., 2005; Wada et al., 2009; Wada et al., 2010)

The projected emissions reductions of Hg are expected to lower deposition of Hg into ecosystems and reduce U.S. EGU attributable bioaccumulation of MeHg in wildlife, particularly for areas closer to the effected units subject to near-field deposition. Because Hg emissions from U.S. EGUs can both become deposited in or bioaccumulate in organisms living in foreign and international waters, reduction of Hg emissions from U.S. EGUs could lead to some benefits internationally as well. EPA is currently unable to quantify or monetize such effects.

4.2.2 Non-Hg HAP Metal

U.S. EGUs are the largest source of selenium emissions and a major source of non-Hg HAP metals emissions including arsenic, chromium, cobalt, and nickel. Additionally, U.S. EGUs emit beryllium, cadmium, lead, and manganese. These emissions include HAP metals that are persistent and bioaccumulate (arsenic, cadmium, and lead) and others have cancer-causing potential (beryllium, cadmium, chromium, cobalt, lead, and nickel). PM controls are expected to reduce HAP metals emissions and therefore reduce exposure to HAP metals for the general population including those living near these facilities.

Exposure to these HAP metals, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. These adverse health effects may include chronic health disorders (e.g., irritation of the lung, skin, and mucus membranes; decreased pulmonary function, pneumonia, or lung damage; detrimental effects on the central nervous system; damage to the kidneys; and alimentary effects such as nausea and vomiting). As of 2023, three of the key HAP metals or their compounds emitted by EGUs (arsenic, chromium as hexavalent chromium, and nickel as nickel refinery dust and nickel subsulfide) are classified as carcinogenic to humans. Specifically, hexavalent chromium is carcinogenic to humans by the inhalation of exposure. Two other key HAP emitted by EGUs (cadmium and selenium as selenium sulfide) are classified as probable human carcinogens.

U.S. EGU source category emissions of non-Hg HAP are not expected to exceed 1 in a million for inhalation cancer risk for those facilities impacted by the control requirements in the final rule. Further, cancer risk was determined to fall within the acceptable range for multipathway exposure to the persistent and bioaccumulative non-Hg HAP metals, such as arsenic, cadmium, and lead.[53] However, the projected emissions reductions should reduce levels of exposure to carcinogenic HAP in communities near the impacted facilities.

EPA also evaluated the potential for noncancer risks from exposure to non-Hg HAP metals in 2020. To address the risk from chronic inhalation exposure to multiple pollutants, we aggregated the health risks associated with pollutants that affect the same target organ. Further, we examined the potential for adverse health effects from acute inhalation exposure to individual pollutants. Lastly, we also examined the potential for health impacts stemming from multiple pathways of exposure for arsenic, cadmium, and lead. The estimated risks were not expected to exceed current health thresholds for adverse effects (U.S. EPA, 2020d). Therefore, we are unable to identify or quantify noncancer benefits from the projected non-Hg HAP metals emission reductions, although we do note that emissions reductions associated with this rule should further reduce exposure to these non-Hg HAP metals in communities near these facilities.

In the subsequent sections, we describe the health effects associated with the main non-Hg HAP metals of concern: antimony (Section 4.2.2.1), arsenic (Section 4.2.2.2), beryllium (Section 4.2.2.3), cadmium (Section 4.2.2.4), chromium (Section 4.2.2.5), cobalt (Section 4.2.2.6), lead (Section 4.2.2.7), manganese (Section 4.2.2.8), nickel (Section 4.2.2.9), and selenium (Section 4.2.2.10). This final rule is projected to reduce at least four to seven tons of non-Hg HAP metals emissions per year. With the data available, it was not possible to estimate the change in emissions of each individual HAP.

[53] *https://www.regulations.gov/document/EPA-HQ-OAR-2018-0794-0014*.

4.2.2.1 Antimony

Antimony (Sb), a naturally occurring element, is released into the environment by incinerators and coal-burning power plants and is considered toxic through the oral, inhalation and dermal routes. The respiratory tract is most sensitive to the effects of inhaled Sb. Acute (short-term) inhalation exposure to Sb results in effects including respiratory irritation, pulmonary inflammation, increases in lung macrophages and impaired lung clearance. Acute high-level inhalation exposure to Sb has been associated with degeneration in heart and EKG alterations (ATSDR, 2019). Chronic (long-term) inhalation exposure to Sb has been associated with interstitial fibrosis and lung neoplasms. EPA has not assessed Sb for carcinogenicity under the IRIS program (U.S. EPA, 1987a)

4.2.2.2 Arsenic

Arsenic (As), a naturally occurring element, is found throughout the environment, and is considered toxic through the oral, inhalation and dermal routes. Acute (short-term) high-level inhalation exposure to as dust or fumes has resulted in gastrointestinal effects (nausea, diarrhea, abdominal pain, and gastrointestinal hemorrhage); central and peripheral nervous system disorders have occurred in workers acutely exposed to inorganic As. Chronic (long-term) inhalation exposure to inorganic as in humans is associated with irritation of the skin and mucous membranes. Chronic inhalation can also lead to conjunctivitis, irritation of the throat and respiratory tract, and perforation of the nasal septum (ATSDR, 2007). Chronic oral exposure has resulted in gastrointestinal effects, anemia, peripheral neuropathy, skin lesions, hyperpigmentation, and liver or kidney damage in humans. Inorganic As exposure in humans, by the inhalation route, has been shown to be strongly associated with lung cancer, while ingestion of inorganic as in humans has been linked to a form of skin cancer and also to bladder, liver, and lung cancer. EPA has classified inorganic arsenic as a Group A, human carcinogen (U.S. EPA, 1995a).

4.2.2.3 Beryllium

The major sources of beryllium emissions are from the combustion of fossil fuels like coal and fuel oil. Acute exposure to beryllium compounds can lead to skin irritation, dermatitis, upper and lower airway inflammation, and pulmonary edema (Jakubowski and Palczynski, 2007). Inhalation of beryllium compounds can lead to the storage of the compound in the lung tissue and cause a specific lung disease called chronic beryllium disease (CBD) which starts with beryllium sensitization (Seidler et al., 2012). Common symptoms of CBD include fatigue, coughing, weight loss, and fevers. Research has shown that beryllium exposure causes cancer in rats and monkeys, and while some research shows a relationship with cancer in humans, it is not definitive. Beryllium is considered to be a Group B1 probable human carcinogen by EPA (U.S. EPA, 1998a).

4.2.2.4 Cadmium

The main sources of cadmium in air are the burning of fossil fuels and the incineration of municipal waste. Acute inhalation in humans causes adverse effects in the lung, such as pulmonary irritation. Chronic inhalation in humans can result in a build-up of cadmium in the kidney, and if sufficiently high, may result in kidney disease. Animal studies indicate that cadmium may cause adverse developmental effects, including reduced body weight, skeletal malformation, and altered behavior and learning (ATSDR, 2012a). Lung cancer has been found in some studies of workers exposed to Cd in the air and studies of rats that inhaled cadmium. EPA has classified cadmium as a probable human carcinogen (Group B1) (U.S. EPA, 1987b).

4.2.2.5 Chromium

Chromium (Cr) may be emitted in two forms, trivalent Cr (Cr+3) or hexavalent Cr (Cr+6). The respiratory tract is the major target organ for Cr+6 toxicity, for acute and chronic inhalation exposures. Shortness of breath, coughing, and wheezing have been reported from acute exposure to Cr+6, while perforations and ulcerations of the septum, bronchitis, decreased pulmonary function, pneumonia, and other respiratory effects have been noted from chronic exposures. Animal studies have reported adverse reproductive effects from exposure to Cr+6. Human and animal studies have clearly established the carcinogenic potential of Cr+6 by the inhalation route, resulting in an increased risk of lung cancer (ATSDR, 2012b). EPA has classified Cr+6 as a Group A, human carcinogen (U.S. EPA, 1998c). Trivalent Cr is less toxic than Cr+6. The respiratory tract is also the major target organ for Cr+3 toxicity, similar to Cr+6. EPA has not classified Cr+3 with respect to carcinogenicity (U.S. EPA, 1998b).

4.2.2.6 Cobalt

Cobalt (Co) and cobalt compounds are naturally occuring and possess physiochemical properties like iron and nickel. The primary anthropogenic sources of Co in the environment are from the burning of fossil fuels, mining and smelting of Co ores, and processing of cobalt-containing alloys. Exposure to Co in the general population occurs through inhalation of ambient air or ingestion of food and drinking water. The respiratory tract is most sensitive to the effects of inhaled Co. Acute (short-term) inhalation exposure to Co results in pulmonary irritation and edema. Chronic (long-term) inhalation exposure to Co results in decreased lung function, inflammation, and lesions cobalt (ATSDR, 2023a). EPA has not yet assessed Co for carcinogenicity under the IRIS program (U.S. EPA, 2008).

4.2.2.7 Lead

Lead is found naturally in ore deposits. A major source of lead in the U.S. environment has historically been from combustion of leaded gasoline, which was phased out of use after 1973. Other sources of lead have included mining and smelting of ore; manufacture of and use of lead-containing products (e.g., lead-based paints, pigments, and glazes; electrical shielding; plumbing; storage batteries; solder; and welding fluxes); manufacture and application of lead-containing pesticides; combustion of coal and oil; and waste incineration. Lead is associated with toxic effects in every organ system including adverse renal, cardiovascular, hematological, reproductive, and developmental effects. However, the major target for lead toxicity is the nervous system, both in adults and children. Long-term exposure of adults to lead at work has resulted in decreased performance in some tests that measure functions of the nervous system. Lead exposure may also cause weakness in fingers, wrists, or ankles. Lead exposure also causes small increases in blood pressure, particularly in middle-aged and older people and may also cause anemia. Children are more sensitive to the health effects of lead than adults. No safe blood lead level in children has been determined. At lower levels of exposure, lead can affect a child's mental and physical growth. Fetuses exposed to lead in the womb may be born prematurely and have lower weights at birth. Exposure in the womb, in infancy, or in early childhood also may slow mental development and cause lower intelligence later in childhood. There is evidence that these effects may persist beyond childhood (ATSDR, 2023b). EPA has determined that lead is a probable human carcinogen (Group 2B) (U.S. EPA, 1988).

4.2.2.8 Manganese

Manganese (Mn) is a naturally occuring metal found in rock and used in steel production or as an additive in gasoline. Chronic exposure to high levels of Mn by inhalation in humans results primarily in central nervous system effects. Visual reaction time, hand steadiness, and eye-hand coordination were affected in chronically-exposed workers. Manganism, characterized by feelings of weakness and lethargy, tremors, a masklike face, and psychological disturbances, may result from chronic exposure to higher levels. Impotence and loss of libido have been noted in male workers afflicted with Manganism attributed to inhalation exposures. High levels of exposure have been associated with lung irritation and reproductive effects. In animals, nervous system and reproductive effects have been observed (ATSDR, 2012c). EPA has classified Mn in Group D, not classifiable as to carcinogenicity in humans (U.S. EPA, 1995b).

4.2.2.9 Nickel

Nickel (Ni) is found in ambient air as a result of releases from oil and coal combustion, nickel metal refining, sewage sludge incineration, manufacturing facilities, and other sources. Respiratory effects have been reported in humans from inhalation exposure to nickel. Acute exposure to nickel carbonyl has been associated with reports of pulmonary fibrosis and renal edema in both animals and humans. Chronic inhalation of nickel in workers can cause chronic bronchitis and reduced lung function (ATSDR, 2005, 2023b). Human and animal studies have reported an increased risk of lung and nasal cancers from exposure to nickle refinery dusts and nickel subsulfide. EPA has classified nickel subsulfide and nickel refinery dusts as human carcinogens and nickel carbonyl as a probable human carcinogen (U.S. EPA, 1987c, 1987d, 1987e).

4.2.2.10 Selenium

Selenium has many uses including in the electronics industry; the glass industry; in pigments used in plastics, paints, enamels, inks, and rubber; as a catalyst in the preparation of pharmaceuticals; and in special trades. Dizziness, fatigue, and irritation of mucous membranes have been reported in people exposed to high levels of selenium in the air in the workplace. High amounts of selenium have been associated with adverse reproductive effects in animal studies. However, the relevance of the effects observed in rats and monkeys to humans is not known (ATSDR, 2003). One selenium compound, selenium sulfide, is carcinogenic in animals exposed orally. EPA has classified elemental Se as a Group D2, not classifiable as to human carcinogenicity, and selenium sulfide as a Group B2, probable human carcinogen (U.S. EPA, 1991).

4.2.3 Additional HAP Benefits

As discussed in detail in the 2023 Final A&N Review, it is challenging to quantify the full range of benefits of HAP reductions. But that does not mean that these benefits are small, insignificant, or nonexistent. In the 2011 MATS RIA (U.S. EPA, 2011), EPA discussed the potential for non-monetizable benefits from effects on fish, birds, and mammals, in part represented through the commercial and recreational fishing economy. A report submitted to EPA in comments concluded that recreational and commercial fishing are substantial contributors to regional U.S. economies with dollar values in the tens of billions (IEc, 2019). At this scale of economic activity, even small shifts in consumer behavior prompted by further HAP reductions can result in substantial economic impacts.

As another example of the potential value of these emissions reductions, EPA received numerous comments in the public comment periods of past EGU HAP regulations highlighting that benefits of Hg reductions to tribal health, subsistence, fishing rights, and cultural identity, while not easily quantified or monetized, are nonetheless important to consider. Finally, EPA also qualitatively considers impacts on ecosystem services, which are generally defined as the economic benefits that individuals and organizations obtain from ecosystems. The monetization of endpoints like ecosystem services, tribal culture, and the activity related to fishing remains challenging. While EPA is not able to monetize the impacts of reduced HAP exposures projected for this rule, we note the importance of the contributions of further reductions of HAP emissions to the sustainability of these important economic and cultural values.

4.3 Criteria Pollutant Benefits

The benefits analysis presented in this section applies methods consistent with those employed most recently in the RIA for the proposed PM National Ambient Air Quality Standards (NAAQS). EPA's approach for selecting $PM_{2.5}$ and ozone-related health endpoints to quantify and monetize is summarized below and we refer readers to the referenced Health Benefits TSD for a full description of our methods (U.S. EPA, 2023a).

Estimating the health benefits of reductions in $PM_{2.5}$ and ozone exposure begins with estimating the change in exposure for each individual and then estimating the change in each individual's risks for those health outcomes affected by exposure. The benefit of the reduction in each health risk is based on the exposed individual's willingness to pay (WTP) for the risk change, assuming that each outcome is independent of one another. The greater the magnitude of the risk reduction from a given change in concentration, the greater the individual's WTP, all else equal. The social benefit of the change in health risks equals the sum of the individual WTP estimates across all of the affected individuals residing in the U.S.[54]

We conduct this analysis by adapting primary research—specifically, air pollution epidemiology studies and economic value studies—from similar contexts. This approach is sometimes referred to as "benefits transfer." Below we describe the procedure we follow for: (1) developing spatial fields of air quality for the baseline and final rule (2) selecting air pollution health endpoints to quantify; (3) calculating counts of air pollution effects using a health impact function; (4) specifying the health impact function with concentration-response parameters drawn from the epidemiological literature to calculate the economic value of the health impacts. We estimate the quantity and economic value of air pollution-related effects using a "damage-function." This approach quantifies counts of air pollution-attributable cases of adverse health outcomes and assigns dollar values to those counts, while assuming that each outcome is independent of one another.

As structured, the final rule would affect the distribution of ozone and $PM_{2.5}$ concentrations in much of the U.S. This RIA estimates avoided ozone- and $PM_{2.5}$-related health impacts that are distinct from those reported in the RIAs for both ozone and PM NAAQS (U.S. EPA, 2015, 2022d) The ozone and PM NAAQS RIAs illustrate, but do not predict, the benefits and costs of strategies that states may choose to enact when implementing a revised NAAQS; these costs and benefits are illustrative and cannot be added to the costs and benefits of policies that prescribe specific emission control measures. This RIA estimates the benefits (and costs) of specific emissions control measures. The benefit estimates are based on these modeled changes in $PM_{2.5}$ and summer season average ozone concentrations.

[54] This RIA also reports the change in the sum of the risk, or the change in the total incidence, of a health outcome across the population. If the benefit per unit of risk is invariant across individuals, the total expected change in the incidence of the health outcome across the population can be multiplied by the benefit per unit of risk to estimate the social benefit of the total expected change in the incidence of the health outcome.

4.3.1 Air Quality Modeling Methodology

The final rule influences the level of pollutants emitted in the atmosphere that adversely affect human health, including directly emitted $PM_{2.5}$, as well as SO_2 and NO_X, which are both precursors to ambient $PM_{2.5}$. NO_X emissions are also a precursor to ambient ground-level ozone. EPA used air quality modeling to estimate changes in ozone and $PM_{2.5}$ concentrations that may occur as a result of the final rule relative to the baseline.

As described in the Air Quality Modeling Appendix (Appendix A), gridded spatial fields of ozone and $PM_{2.5}$ concentrations representing the baseline and final rule were derived from CAMx source apportionment modeling in combination with NO_X, SO_2, and primary $PM_{2.5}$ EGU emissions obtained from the outputs of the IPM runs described in Section 3 of this RIA. While the air quality modeling includes all inventoried pollution sources in the contiguous U.S., contributions from all sources other than EGUs are held constant at projected 2026 levels in this analysis, and the only changes quantified between the baseline and the final rule are those associated with the projected impacts of this final rule on EGU emissions. EPA prepared gridded spatial fields of air quality for the baseline and the final rule for two health-impact metrics: annual mean $PM_{2.5}$ and April through September seasonal average eight-hour daily maximum (MDA8) ozone (AS-MO3). These ozone and $PM_{2.5}$ gridded spatial fields cover all locations in the contiguous U.S. and were used as inputs to BenMAP-CE which, in turn, was used to quantify the benefits from this rule.

The basic methodology for determining air quality changes is the same as that used in the RIAs from multiple previous rules (U.S. EPA, 2019b, 2020a, 2020b, 2021a, 2022c). The Air Quality Modeling Appendix (Appendix A) provides additional details on the air quality modeling and the methodologies EPA used to develop gridded spatial fields of summertime ozone and annual $PM_{2.5}$ concentrations. The appendix also provides figures showing the geographical distribution of air quality changes.

4.3.2 Selecting Air Pollution Health Endpoints to Quantify

The methods used in this RIA incorporate evidence reported in the most recent completed PM Integrated Science Assessment (PM ISA) and Ozone Integrated Science Assessments (Ozone ISA) and accounts for recommendations from the Science Advisory Board (U.S. EPA, 2022e). When updating each health endpoint EPA considered: (1) the extent to which there exists a causal relationship between that pollutant and the adverse effect; (2) whether suitable epidemiologic studies exist to support quantifying health impacts; (3) and whether robust economic approaches are available for estimating the value of the impact of reducing human exposure to the pollutant. Our approach for updating the endpoints and to identify suitable epidemiologic studies, baseline incidence rates, population demographics, and valuation estimates is summarized below. Detailed descriptions of these updates are available in the Health Benefits TSD, which is in the docket for this rulemaking. The Health Benefits TSD describes the Agency's approach for quantifying the number and value of estimated air pollution-related impacts. Updates since the publication of the Health Benefits TSD are described below. In this document the reader can find the rationale for selecting health endpoints to quantify; the demographic, health and economic data used; modeling assumptions; and our techniques for quantifying uncertainty.[55]

[55] The analysis was completed using BenMAP-CE version 1.5.8, which is a variant of the current publicly available version. We also include new estimates of the cost of asthma onset and stroke beyond those described in the Health Benefits TSD.

Table 4-1 Health Effects of $PM_{2.5}$, Ambient Ozone, and Climate Effects

Category	Effect	Effect Quantified	Effect Monetized	More Information
Premature mortality from exposure to $PM_{2.5}$	Adult premature mortality based on cohort study estimates and expert elicitation estimates (age 65-99 or age 30-99)	✓	✓	PM ISA
	Infant mortality (age <1)	✓	✓	PM ISA
Nonfatal morbidity from exposure to $PM_{2.5}$	Heart attacks (age > 18)	✓	✓[1]	PM ISA
	Hospital admissions—cardiovascular (ages 65-99)	✓	✓	PM ISA
	Emergency department visits— cardiovascular (age 0-99)	✓	✓	PM ISA
	Hospital admissions—respiratory (ages 0-18 and 65-99)	✓	✓	PM ISA
	Emergency room visits—respiratory (all ages)	✓	✓	PM ISA
	Cardiac arrest (ages 0-99; excludes initial hospital and/or emergency department visits)	✓	✓[1]	PM ISA
	Stroke (ages 65-99)	✓	✓[1]	PM ISA
	Asthma onset (ages 0-17)	✓	✓	PM ISA
	Asthma symptoms/exacerbation (6-17)	✓	✓	PM ISA
	Lung cancer (ages 30-99)	✓	✓	PM ISA
	Allergic rhinitis (hay fever) symptoms (ages 3-17)	✓	✓	PM ISA
	Lost work days (age 18-65)	✓	✓	PM ISA
	Minor restricted-activity days (age 18-65)	✓	✓	PM ISA
	Hospital admissions—Alzheimer's disease (ages 65-99)	✓	✓	PM ISA
	Hospital admissions—Parkinson's disease (ages 65-99)	✓	✓	PM ISA
	Other cardiovascular effects (e.g., other ages)	—	—	PM ISA[2]
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages, and populations)	—	—	PM ISA[2]
	Other nervous system effects (e.g., autism, cognitive decline, dementia)	—	—	PM ISA[2]
	Metabolic effects (e.g., diabetes)	—	—	PM ISA[2]
	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc.)	—	—	PM ISA[2]
	Cancer, mutagenicity, and genotoxicity effects	—	—	PM ISA[2]
Mortality from exposure to ozone	Premature respiratory mortality based on short-term study estimates (0-99)	✓	✓	Ozone ISA
	Premature respiratory mortality based on long-term study estimates (age 30–99)	✓	✓	Ozone ISA
Nonfatal morbidity from exposure to ozone	Hospital admissions—respiratory (ages 0-99)	✓	✓	Ozone ISA
	Emergency department visits—respiratory (ages 0-99)	✓	✓	Ozone ISA
	Asthma onset (0-17)	✓	✓	Ozone ISA
	Asthma symptoms/exacerbation (asthmatics age 2-17)	✓	✓	Ozone ISA
	Allergic rhinitis (hay fever) symptoms (ages 3-17)	✓	✓	Ozone ISA
	Minor restricted-activity days (age 18–65)	✓	✓	Ozone ISA
	School absence days (age 5–17)	✓	✓	Ozone ISA
	Decreased outdoor worker productivity (age 18–65)	—	—	Ozone ISA[2]
	Metabolic effects (e.g., diabetes)	—	—	Ozone ISA[2]
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone ISA[2]

Table 4-1 Health Effects of $PM_{2.5}$, Ambient Ozone, and Climate Effects

Category	Effect	Effect Quantified	Effect Monetized	More Information
	Cardiovascular and nervous system effects	—	—	Ozone ISA[2]
	Reproductive and developmental effects	—	—	Ozone ISA[2]
Climate effects	Climate impacts from carbon dioxide (CO_2)	—	✓	Section 4.4
	Other climate impacts (e.g., ozone, black carbon, aerosols, other impacts)	—	—	IPCC, Ozone ISA, PM ISA

[1] Valuation estimate excludes initial hospital and/or emergency department visits.
[2] Not quantified due to data availability limitations and/or because current evidence is only suggestive of causality.

4.3.3 Calculating Counts of Air Pollution Effects Using the Health Impact Function

We use the environmental Benefits Mapping and Analysis Program—Community Edition (BenMAP-CE) software program to quantify counts of premature deaths and illnesses attributable to photochemical modeled changes in annual mean $PM_{2.5}$ and summer season average ozone concentrations for the years 2030, 2035, and 2040 using health impact functions (Sacks et al., 2020). A health impact function combines information regarding: the concentration-response relationship between air quality changes and the risk of a given adverse outcome; the population exposed to the air quality change; the baseline rate of death or disease in that population; and the air pollution concentration to which the population is exposed.

BenMAP quantifies counts of attributable effects using health impact functions, which combine information regarding the: concentration-response relationship between air quality changes and the risk of a given adverse outcome; population exposed to the air quality change; baseline rate of death or disease in that population; and air pollution concentration to which the population is exposed.

The following provides an example of a health impact function, in this case for $PM_{2.5}$ mortality risk. We estimate counts of $PM_{2.5}$-related total deaths (y_{ij}) during each year *i* among adults aged 18 and older (a) in each county *j* in the contiguous U.S. (where $j = 1, \ldots, J$ and *J* is the total number of counties) as:

$$y_{ij} = \Sigma_a \, y_{ija}$$

$$y_{ija} = mo_{ija} \times (e^{\beta \cdot \Delta C_{ij}} - 1) \times P_{ija}, \qquad \text{Eq[1]}$$

where mo_{ija} is the baseline total mortality rate for adults aged a = 18-99 in county *j* in year *i* stratified in 10-year age groups, β is the risk coefficient for total mortality for adults associated with annual average $PM_{2.5}$ exposure, C_{ij} is the annual mean $PM_{2.5}$ concentration in county j in year i, and P_{ija} is the number of county adult residents aged a = 18-99 in county j in year i stratified into 5-year age groups.[56]

The BenMAP-CE tool is pre-loaded with projected population from the Woods & Poole company; cause-specific and age-stratified death rates from the Centers for Disease Control and Prevention, projected to future years; recent-year baseline rates of hospital admissions, emergency department visits and other morbidity outcomes from the Healthcare Cost and Utilization Program and other sources; concentration-response parameters from the published epidemiologic literature cited in the ISAs for fine particles and ground-level ozone; and cost of illness or WTPWTP economic unit values for each endpoint. Consistent with advice received from the U.S. EPA Science Advisory Board, EPA will substitute the existing Woods & Poole population projections with those that are not proprietary (U.S. EPA Science Advisory Board, 2024).

To assess economic value in a damage-function framework, the changes in environmental quality must be translated into effects on people or on the things that people value. In some cases, the changes in environmental quality can be directly valued. In other cases, such as for changes in ozone and PM, a health and welfare impact analysis must first be conducted to convert air quality changes into effects that can be assigned dollar values.

We note at the outset that EPA rarely has the time or resources to perform extensive new research to measure directly either the health outcomes or their values for regulatory analyses. Thus, similar to work by Künzli et al. (2000) and co-authors and other, more recent health impact analyses, our estimates are based on the best available methods of benefits transfer. Benefits transfer is the science and art of adapting primary research from similar contexts to obtain the most accurate measure of benefits for the environmental quality change under analysis. Adjustments are made for the level of environmental quality change, the socio-demographic and economic characteristics of the affected population, and other factors to improve the accuracy and robustness of benefits estimates.

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[56] In this illustrative example, the air quality is resolved at the county level. For this RIA, we simulate air quality concentrations at a 12 km grid cell resolution The BenMAP-CE tool assigns the rates of baseline death and disease stored at the county level to the 12 km grid cells using an area-weighted algorithm. This approach is described in greater detail in the appendices to the BenMAP-CE user manual.

4.3.4 Calculating the Economic Valuation of Health Impacts

After quantifying the change in adverse health impacts, the final step is to estimate the economic value of these avoided impacts. The appropriate economic value for a change in a health effect depends on whether the health effect is viewed ex ante (before the effect has occurred) or ex post (after the effect has occurred). Reductions in ambient concentrations of air pollution generally lower the risk of future adverse health effects by a small amount for a large population. The appropriate economic measure is therefore ex ante WTP for changes in risk. However, epidemiological studies generally provide estimates of the relative risks of a particular health effect avoided due to a reduction in air pollution. A convenient way to use these data in a consistent framework is to convert probabilities to units of avoided statistical incidences. This measure is calculated by dividing individual WTP for a risk reduction by the related observed change in risk. For example, suppose a regulation reduces the risk of premature mortality from 2 in 10,000 to 1 in 10,000 (a reduction of 1 in 10,000). If individual WTP for this risk reduction is $1,000, then the WTP for an avoided statistical premature mortality amounts to $10 million ($1,000/0.0001 change in risk). Hence, this value is population-normalized, as it accounts for the size of the population and the percentage of that population experiencing the risk. The same type of calculation can produce values for statistical incidences of other health endpoints.

For some health effects, such as hospital admissions, WTP estimates are generally not available. In these cases, we instead use the cost of treating or mitigating the effect to economically value the health impact. For example, for the valuation of hospital admissions we use the avoided medical costs as an estimate of the value of avoiding the health effects causing the admission. These cost-of-illness (COI) estimates generally (although not in every case) understate the true value of reductions in risk of a health effect. They tend to reflect the direct expenditures related to treatment but not the value of avoided pain and suffering from the health effect.

4.3.5 Benefits Analysis Data Inputs

In Figure 4-1, we summarize the key data inputs to the health impact and economic valuation estimates, which were calculated using BenMAP-CE tool version 1.5.1. (Sacks et al., 2020). In the sections below we summarize the data sources for each of these inputs, including demographic projections, incidence and prevalence rates, effect coefficients, and economic valuation.

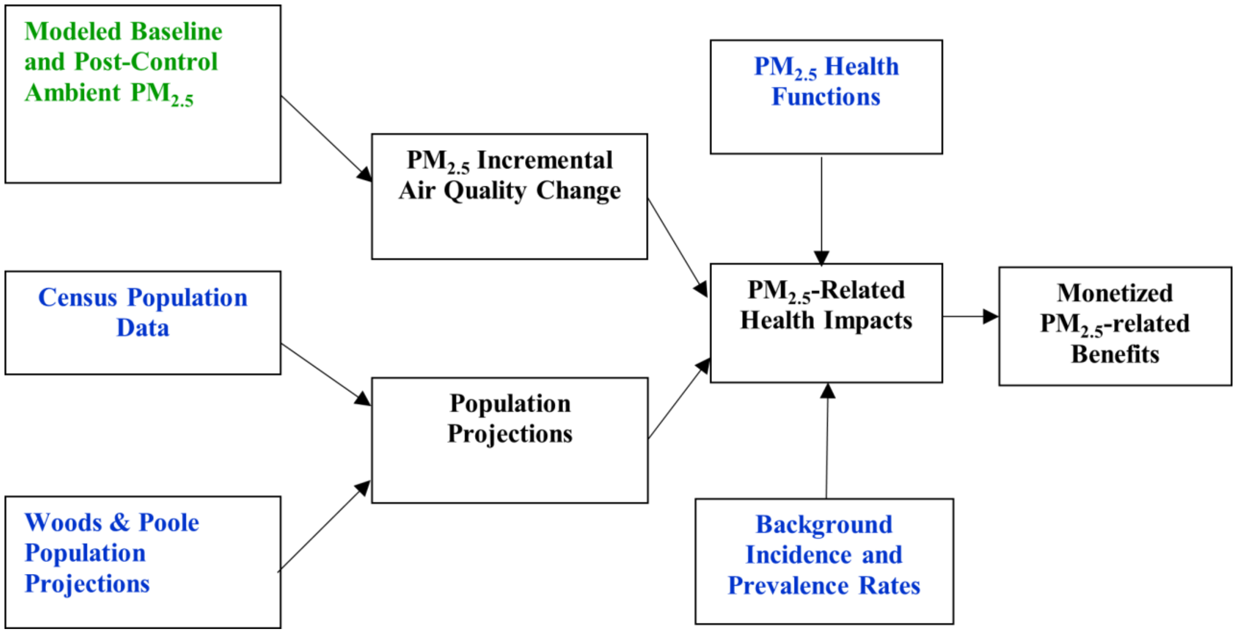

Figure 4-1 Data Inputs and Outputs for the BenMAP-CE Tool

4.3.5.1 Demographic Data

Quantified and monetized human health impacts depend on the demographic characteristics of the population, including age, location, and income. We use projections based on economic forecasting models developed by Woods & Poole, Inc. (2015). The Woods & Poole database contains county-level projections of population by age, sex, and race to 2060, relative to a baseline using the 2010 Census data. Projections in each county are determined simultaneously with every other county in the U.S. to consider patterns of economic growth and migration. The sum of growth in county-level populations is constrained to equal a previously determined national population growth, based on Bureau of Census estimates (Hollmann et al., 2000). According to Woods & Poole, linking county-level growth projections together and constraining the projected population to a national-level total growth avoids potential errors introduced by forecasting each county independently (for example, the projected sum of county-level populations cannot exceed the national total). County projections are developed in a four-stage process:

- First, national-level variables such as income, employment, and populations are forecasted.
- Second, employment projections are made for 179 economic areas defined by the Bureau of Economic Analysis, using an "export-base" approach, which relies on linking industrial-sector production of non-locally consumed production items, such as outputs from mining, agriculture, and manufacturing with the national economy. The export-based approach requires estimation of demand equations or calculation of historical growth rates for output and employment by sector.
- Third, population is projected for each economic area based on net migration rates derived from employment opportunities and following a cohort-component method based on fertility and mortality in each area.
- Fourth, employment and population projections are repeated for counties, using the economic region totals as bounds. The age, sex, and race distributions for each region or county are determined by aging the population by single year by sex and race for each year through 2060 based on historical rates of mortality, fertility, and migration.

4.3.5.2 Baseline Incidence and Prevalence Estimates

Epidemiological studies of the association between pollution levels and adverse health effects generally provide a direct estimate of the relationship of air quality changes to the relative risk of a health effect, rather than estimating the absolute number of avoided cases. For example, a typical result might be that a 5 µg/m^3 decrease in daily $PM_{2.5}$ levels is associated with a decrease in hospital admissions of 3 percent. A baseline incidence rate, necessary to convert this relative change into a number of cases, is the estimate of the number of cases of the health effect per year in the assessment location, as it corresponds to baseline pollutant levels in that location. To derive the total baseline incidence per year, this rate must be multiplied by the corresponding population number. For example, if the baseline incidence rate is the number of cases per year per million people, that number must be multiplied by the millions of people in the total population.

The Health Benefits TSD (see Table 12) summarizes the sources of baseline incidence rates and reports average incidence rates for the endpoints included in the analysis. For both baseline incidence and prevalence data, we used age-specific rates where available. We applied concentration-response functions to individual age groups and then summed over the relevant age range to provide an estimate of total population benefits. National-level incidence rates were used for most morbidity endpoints, whereas county-level data are available for premature mortality. Whenever possible, the national rates used are national averages, because these data are most applicable to a national assessment of benefits. When quantifying some endpoints, we were unable to identify a suitable administrative database supplying baseline rates of the event of interest; in these cases, we selected an incidence rate reported within the study supplying the risk estimate.

We projected mortality rates such that future mortality rates are consistent with our projections of population growth. To perform this calculation, we began first with an average of 2007-2016 cause-specific mortality rates. Using Census Bureau projected national-level annual mortality rates stratified by age range, we projected these mortality rates to 2060 in 5-year increments (U.S. Census Bureau). Further information regarding this procedure may be found in the Health Benefits TSD and the appendices to the BenMAP user manual (U.S. EPA, 2022a).

The baseline incidence rates for hospital admissions and emergency department visits reflect the revised rates first applied in the Revised Cross-State Air Pollution Rule Update (U.S. EPA, 2021a). In addition, we revised the baseline incidence rates for acute myocardial infarction. These revised rates are more recent than the rates they replace and more accurately represent the rates at which populations of different ages, and in different locations, visit the hospital and emergency department for air pollution-related illnesses. Lastly, these rates reflect unscheduled hospital admissions only, which represents a conservative assumption that most air pollution-related visits are likely to be unscheduled. If air pollution-related hospital admissions are scheduled, this assumption would underestimate these benefits.

4.3.5.3 Effect Coefficients

Our approach for selecting and parametrizing effect coefficients for the benefits analysis is described fully in the Health Benefits TSD. Because of the substantial economic value associated with estimated counts of $PM_{2.5}$-attributable deaths, we describe our rationale for selecting among long-term exposure epidemiologic studies below; a detailed description of all remaining endpoints may be found in the Health Benefits TSD.

A substantial body of published scientific literature documents the association between $PM_{2.5}$ concentrations and the risk of premature death (U.S. EPA, 2019a, 2022e). This body of literature reflects thousands of epidemiology, toxicology, and clinical studies. The PM ISA, completed as part of this review of the fPM standards and reviewed by the Clean Air Scientific Advisory Committee (CASAC) (U.S. EPA Science Advisory Board, 2022) concluded that there is a causal relationship between mortality and both long-term and short-term exposure to $PM_{2.5}$ based on the full body of scientific evidence. The size of the mortality effect estimates from epidemiologic studies, the serious nature of the effect itself, and the high monetary value ascribed to prolonging life make mortality risk reduction the most significant health endpoint quantified in this analysis.

EPA selects Hazard Ratios from cohort studies to estimate counts of PM-related premature death, following a systematic approach detailed in the Health Benefits TSD accompanying this RIA that is generally consistent with previous RIAs. Briefly, clinically significant epidemiologic studies of health endpoints for which ISAs report strong evidence are evaluated using established minimum and preferred criteria for identifying studies and hazard ratios best characterizing risk. Following this systematic approach led to the identification of three studies best characterizing the risk of premature death associated with long-term exposure to $PM_{2.5}$ in the U.S. (Pope et al., 2019; Turner et al., 2016; X Wu et al., 2020). The 2019 PM ISA (U.S. EPA, 2019a), the 2022 Supplement to the PM ISA (U.S. EPA, 2022e), and the 2022 PM Policy Assessment (U.S. EPA, 2022b) also identified these three studies as providing key evidence of the association between long-term $PM_{2.5}$ exposure and mortality. These studies used data from three U.S. cohorts: (1) an analysis of Medicare beneficiaries (Medicare); (2) the American Cancer Society (ACS); and (3) the National Health Interview Survey (NHIS). As premature mortality typically constitutes the vast majority of monetized benefits in a $PM_{2.5}$ benefits assessment, quantifying effects using risk estimates reported from multiple long-term exposure studies using different cohorts helps account for uncertainty in the estimated number of PM-related premature deaths. Below we summarize the three identified studies and hazard ratios and then describe our rationale for quantifying premature PM-attributable deaths using two of these studies.

Wu et al. (2020) evaluated the relationship between long-term $PM_{2.5}$ exposure and all-cause mortality in more than 68.5 million Medicare enrollees (over the age of 64), using Medicare claims data from 2000-2016 representing over 573 million person-years of follow up and over 27 million deaths. This cohort included over 20 percent of the U.S. population and was, at the time of publishing, the largest air pollution study cohort to date. The authors modeled $PM_{2.5}$ exposure at a 1 km grid resolution using a hybrid ensemble-based prediction model that combined three machine learning models and relied on satellite data, land-use information, weather variables, chemical transport model simulation outputs, and monitor data. Wu et al., 2020 fit five different statistical models: a Cox proportional hazards model, a Poisson regression model, and three causal inference approaches (GPS estimation, GPS matching, and GPS weighting). All five statistical approaches provided consistent results; we report the results of the Cox proportional hazards model here. The authors adjusted for numerous individual-level and community-level confounders, and sensitivity analyses suggest that the results are robust to unmeasured confounding bias. In a single-pollutant model, the coefficient and standard error for $PM_{2.5}$ are estimated from the hazard ratio (1.066) and 95 percent confidence interval (1.058-1.074) associated with a change in annual mean $PM_{2.5}$ exposure of 10.0 $\mu g/m^3$ (Wu et al., 2020, Table S3, Main analysis, 2000-2016 Cohort, Cox PH). We use a risk estimate from this study in place of the risk estimate from Di et al. (2017). These two epidemiologic studies share many attributes, including the Medicare cohort and statistical model used to characterize population exposure to $PM_{2.5}$. As compared to Di et al. (2017), Wu et al. (2020) includes a longer follow-up period and reflects more recent $PM_{2.5}$ concentrations.

Pope et al. (2019) examined the relationship between long-term $PM_{2.5}$ exposure and all-cause mortality in a cohort of 1,599,329 U.S. adults (aged 18-84 years) who were interviewed in the National Health Interview Surveys (NHIS) between 1986 and 2014 and linked to the National Death Index (NDI) through 2015. The authors also constructed a sub-cohort of 635,539 adults from the full cohort for whom body mass index (BMI) and smoking status data were available. The authors employed a hybrid modeling technique to estimate annual-average $PM_{2.5}$ concentrations derived from regulatory monitoring data and constructed in a universal kriging framework using geographic variables including land use, population, and satellite estimates. Pope et al. (2019) assigned annual-average $PM_{2.5}$ exposure from 1999-2015 to each individual by census tract and used complex (accounting for NHIS's sample design) and simple Cox proportional hazards models for the full cohort and the sub-cohort. We select the Hazard Ratio calculated using the complex model for the sub-cohort, which controls for individual-level covariates including age, sex, race-ethnicity, inflation-adjusted income, education level, marital status, rural versus urban, region, survey year, BMI, and smoking status. In a single-pollutant model, the coefficient and standard error for $PM_{2.5}$ are estimated from the hazard ratio (1.12) and 95 percent confidence interval (1.08-1.15) associated with a change in annual mean $PM_{2.5}$ exposure of 10.0 $\mu g/m^3$ (Pope et al., 2019, Table 2, Subcohort). This study exhibits two key strengths that makes it particularly well suited for a benefits analysis: (1) it includes a long follow-up period with recent (and thus relatively low) $PM_{2.5}$ concentrations; (2) the NHIS cohort is representative of the U.S. population, especially with respect to the distribution of individuals by race, ethnicity, income, and education.

EPA has historically used estimated Hazard Ratios from extended analyses of the ACS cohort to estimate PM-related risk of premature death Krewski (Krewski et al., 2009; Pope et al., 2002; Pope et al., 1995). A more recent ACS analysis, Turner et al. (2016):

- extended the follow-up period of the ACS CSP-II to 22 years (1982-2004),
- evaluated 669,046 participants over 12,662,562 person-years of follow up and 237,201 observed deaths, and

  applied a more advanced exposure estimation approach than had previously been used when analyzing the ACS cohort, combining the geostatistical Bayesian Maximum Entropy framework with national-level land use regression models.

The total mortality hazard ratio best estimating risk from these ACS cohort studies was based on a random-effects Cox proportional hazard model incorporating multiple individual and ecological covariates (relative risk =1.06, 95 percent confidence intervals 1.04–1.08 per 10 $\mu g/m^3$ increase in $PM_{2.5}$) from Turner et al. (2016). The relative risk estimate is identical to a risk estimate drawn from earlier ACS analysis of all-cause long-term exposure $PM_{2.5}$-attributable mortality (Krewski et al., 2009). However, as the ACS hazard ratio is quite similar to the Medicare estimate of (1.066, 1.058-1.074), especially when considering the broader age range (greater than 29 versus greater than 64), only Wu et al. (2020) and Pope et al. (2019) are included in the main benefits assessments, with Wu et al. (2020) representing results from both the Medicare and ACS cohorts.

4.3.6 Quantifying Cases of Ozone-Attributable Premature Death

Mortality risk reductions account for the majority of monetized ozone-related and $PM_{2.5}$-related benefits. For this reason, this subsection and the following provide a brief background of the scientific assessments that underly the quantification of these mortality risks and identifies the risk studies used to quantify them in this RIA, for ozone and $PM_{2.5}$ respectively. As noted above, U.S. EPA (2023a) describes fully the Agency's approach for quantifying the number and value of ozone and $PM_{2.5}$ air pollution-related impacts, including additional discussion of how the Agency selected the risk studies used to quantify them in this RIA. The Health Benefits TSD also includes additional discussion of the assessments that support quantification of these mortality risk than provide here.

In 2008, the National Academies of Science issued a series of recommendations to EPA regarding the procedure for quantifying and valuing ozone-related mortality due to short-term exposures (National Research Council, 2008). Chief among these was that "…short-term exposure to ambient ozone is likely to contribute to premature deaths" and the committee recommended that "ozone-related mortality be included in future estimates of the health benefits of reducing ozone exposures…" The NAS also recommended that "…the greatest emphasis be placed on the multicity and [National Mortality and Morbidity Air Pollution Studies (NMMAPS)] …studies without exclusion of the meta-analyses" (National Research Council, 2008). Prior to the 2015 Ozone NAAQS RIA, the Agency estimated ozone-attributable premature deaths using an NMMAPS-based analysis of total mortality (Bell et al., 2004), two multi-city studies of cardiopulmonary and total mortality (Huang et al., 2005; Schwartz, 2005), and effect estimates from three meta-analyses of non-accidental mortality (Bell et al., 2005; Ito et al., 2005; Levy et al., 2005). Beginning with the 2015 Ozone NAAQS RIA, the Agency began quantifying ozone-attributable premature deaths using two newer multi-city studies of non-accidental mortality (R. L. Smith et al., 2009; Zanobetti and Schwartz, 2008) and one long-term cohort study of respiratory mortality (Jerrett et al. 2009).

EPA quantifies and monetizes effects the Integrated Science Assessment (ISA) identifies as having either a causal or likely-to-be-causal relationship with the pollutant. Relative to the 2015 ISA, the 2020 ISA for Ozone reclassified the casual relationship between short-term ozone exposure and total mortality, changing it from "likely to be causal" to "suggestive of, but not sufficient to infer, a causal relationship." The 2020 Ozone ISA separately classified short-term ozone exposure and respiratory outcomes as being "causal" and long-term exposure as being "likely to be causal." When determining whether there existed a causal relationship between short- or long-term ozone exposure and respiratory effects, EPA evaluated the evidence for both morbidity and mortality effects. The ISA identified evidence in the epidemiologic literature of an association between ozone exposure and respiratory mortality, finding that the evidence was not entirely consistent and there remained uncertainties in the evidence base.

EPA continues to quantify premature respiratory mortality attributable to both short- and long-term exposure to ozone because doing so is consistent with: (1) the evaluation of causality noted above; and (2) EPA's approach for selecting and quantifying endpoints described in the Technical Support Document (TSD) "Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits," which was recently reviewed by the U.S. EPA Science Advisory Board (U.S. EPA, 2023; U.S. EPA-SAB 2024).

We estimate counts of ozone-attributable respiratory death from short-term exposures a pooled risk estimate calculated using parameters from Zanobetti and Schwartz (2008) and Katsouyanni et al. (2009). Consistent with the RIA for the Final Revised CSAPR Update (U.S. EPA, 2021a), we use two estimates of ozone-attributable respiratory deaths from short-term exposures are estimated using the risk estimate parameters from Zanobetti and Schwartz (2008) and Katsouyanni et al. (2009). Ozone-attributable respiratory deaths from long-term exposures are estimated using Turner et al. (2016). Due to time and resource limitations, we were unable to reflect the warm season defined by Zanobetti and Schwartz (2008) as June-August. Instead, we apply this risk estimate to our standard warm season of May-September.

4.3.7 Quantifying Cases of $PM_{2.5}$-Attributable Premature Death

When quantifying PM-attributable cases of adult mortality, we use the effect coefficients from two epidemiology studies examining two large population cohorts: the American Cancer Society cohort (Turner et al., 2016) and the Medicare cohort (Di et al., 2017). The 2019 PM ISA indicates that the ACS and Medicare cohorts provide strong evidence of an association between long-term $PM_{2.5}$ exposure and premature mortality with support from additional cohort studies. There are distinct attributes of both the ACS and Medicare cohort studies that make them well-suited to being used in a PM benefits assessment and so here we present $PM_{2.5}$ related effects derived using relative risk estimates from both cohorts.

The PM ISA, which was reviewed by the Clean Air Scientific Advisory Committee of EPA's Science Advisory Board (U.S. EPA Science Advisory Board, 2022), concluded that there is a causal relationship between mortality and both long-term and short-term exposure to $PM_{2.5}$ based on the entire body of scientific evidence. The PM ISA also concluded that the scientific literature supports the use of a no-threshold log-linear model to portray the PM-mortality concentration-response relationship while recognizing potential uncertainty about the exact shape of the concentration-response relationship. The 2019 PM ISA, which informed the setting of the 2020 PM NAAQS, reviewed available studies that examined the potential for a population-level threshold to exist in the concentration-response relationship. Based on such studies, the ISA concluded that the evidence supports the use of a "no-threshold" model and that "little evidence was observed to suggest that a threshold exists" (U.S. EPA, 2009a). Consistent with this evidence, the Agency historically has estimated health impacts above and below the prevailing NAAQS (U.S. EPA, 2019b, 2021a, 2022c).

4.3.8 Characterizing Uncertainty in the Estimated Benefits

Like other complex analyses using estimated parameters and inputs from numerous models, there are sources of uncertainty. The Health Benefits TSD details our approach to characterizing uncertainty in both quantitative and qualitative terms (U.S. EPA, 2023a). The Health Benefits TSD describes the sources of uncertainty associated with key input parameters including emissions inventories, air quality data from models (with their associated parameters and inputs), population data, population estimates, health effect estimates from epidemiology studies, economic data for monetizing benefits, and assumptions regarding the future state of the country (i.e., regulations, technology, and human behavior). Each of these inputs is uncertain and affects the size and distribution of the estimated benefits. When the uncertainties from each stage of the analysis are compounded, even small uncertainties can have large effects on the total quantified benefits.

To characterize uncertainty and variability into this assessment, we incorporate three quantitative analyses described below and in greater detail within the Health Benefits TSD (Section 7.1):

1. A Monte Carlo assessment that accounts for random sampling error and between study variability in the epidemiological and economic valuation studies;
2. The quantification of PM-related mortality using alternative $PM_{2.5}$ mortality effect estimates drawn from two long-term cohort studies; and
3. Presentation of 95th percentile confidence interval around each risk estimate.

Quantitative characterization of other sources of $PM_{2.5}$ uncertainties are discussed only in Section 7.1 of the Health Benefits TSD:

1. For adult all-cause mortality:

a. The distributions of air quality concentrations experienced by the original cohort population (Health Benefits TSD Section 7.1.2.1);

b. Methods of estimating and assigning exposures in epidemiologic studies (Health Benefits TSD Section 7.1.2.2);

c. Confounding by ozone (Health Benefits TSD Section 7.1.2.3); and

d. The statistical technique used to generate hazard ratios in the epidemiologic study (Health Benefits TSD Section 7.1.2.4).

2. Plausible alternative risk estimates for asthma onset in children (TSD Section 7.1.3), cardiovascular hospital admissions (Health Benefits TSD Section 7.1.4,), and respiratory hospital admissions (Health Benefits TSD Section 7.1.5);

3. Effect modification of $PM_{2.5}$-attributable health effects in at-risk populations (Health Benefits TSD Section 7.1.6).

Quantitative consideration of baseline incidence rates and economic valuation estimates are provided in Section 7.3 and 7.4 of the Health Benefits TSD, respectively. Qualitative discussions of various sources of uncertainty can be found in Section 7.5 of the Health Benefits TSD.

4.3.8.1 Monte Carlo Assessment

Similar to other recent RIAs, we used Monte Carlo methods for characterizing random sampling error associated with the concentration response functions from epidemiological studies and random effects modeling to characterize both sampling error and variability across the economic valuation functions. The Monte Carlo simulation in the BenMAP-CE software randomly samples from a distribution of incidence and valuation estimates to characterize the effects of uncertainty on output variables. Specifically, we used Monte Carlo methods to generate confidence intervals around the estimated health impact and monetized benefits. The reported standard errors in the epidemiological studies determined the distributions for individual effect estimates for endpoints estimated using a single study. For endpoints estimated using a pooled estimate of multiple studies, the confidence intervals reflect both the standard errors and the variance across studies. The confidence intervals around the monetized benefits incorporate the epidemiology standard errors as well as the distribution of the valuation function. These confidence intervals do not reflect other sources of uncertainty inherent within the estimates, such as baseline incidence rates, populations exposed, and transferability of the effect estimate to diverse locations. As a result, the reported confidence intervals and range of estimates give an incomplete picture about the overall uncertainty in the benefits estimates.

4.3.8.2 Sources of Uncertainty Treated Qualitatively

Although we strive to incorporate as many quantitative assessments of uncertainty as possible, there are several aspects we are only able to address qualitatively. These attributes are summarized below and described more fully in the Health Benefits TSD.

Key assumptions underlying the estimates for premature mortality, which account for over 98 percent of the total monetized benefits in this analysis, include the following:

1. We assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because $PM_{2.5}$ varies considerably in composition across sources, but the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. The PM ISA, which was reviewed by CASAC, concluded that "across exposure durations and health effects categories … the evidence does not indicate that any one source or component is consistently more strongly related with health effects than $PM_{2.5}$ mass" (U.S. EPA Science Advisory Board, 2022).
2. We assume that the health impact function for fine particles is log-linear down to the lowest air quality levels modeled in this analysis. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of $PM_{2.5}$, including both regions that are in attainment with the fine particle standard and those that do not meet the standard down to the lowest modeled concentrations. The PM ISA concluded that "the majority of evidence continues to indicate a linear, no-threshold concentration-response relationship for long-term exposure to $PM_{2.5}$ and total (nonaccidental) mortality" (U.S. EPA Science Advisory Board, 2022).
3. We assume that there is a "cessation" lag between the change in PM exposures and the total realization of changes in mortality effects. Specifically, we assume that some of the incidences of premature mortality related to $PM_{2.5}$ exposures occur in a distributed fashion over the 20 years following exposure based on the advice of the board (U.S. EPA Science Advisory Board, 2004), which affects the valuation of mortality benefits at different discount rates. Similarly, we assume there is a cessation lag between the change in PM exposures and both the development and diagnosis of lung cancer.

4.3.9 Estimated Number and Economic Value of Health Benefits

To directly compare benefits estimates associated with a rulemaking to cost estimates, the number of instances of each air pollution-attributable health impact must be converted to a monetary value. This requires a valuation estimate for each unique health endpoint, and potentially also discounting if the benefits are expected to accrue over more than a single year, as recommended by the Guidelines for Preparing Economic Analyses (U.S. EPA, 2014). Below we report the estimated number of reduced premature deaths and illnesses in each year relative to the baseline along with the 95 percent confidence interval (Table 4-2 or ozone-related health impacts and Table 4-3 for $PM_{2.5}$-related impacts). The number of reduced estimated deaths and illnesses from the final are calculated from the sum of individual reduced mortality and illness risk across the population.

Table 4-2 Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses for the Final Rule for 2028, 2030, and 2035 (95 percent confidence interval) [a]

		2028	2030	2035[g]
Avoided premature respiratory mortalities				
Long-term exposure	Turner et al. (2016)[b]	0.37 (0.26 to 0.48)	0.019 (0.013 to 0.025)	-0.07 (-0.091 to -0.049)
Short-term exposure	Katsouyanni et al. (2009)[b,c] and Zanobetti et al. (2008)[c] pooled	0.017 (0.0068 to 0.027)	0.0009 (0.0004 to 0.0014)	-0.0032 (-0.005 to -0.0013)
Morbidity effects				
Long-term exposure	Asthma onset[d]	2.3 (2 to 2.6)	0.25 (0.22 to 0.29)	-0.9 (-1.0 to -0.78)
	Allergic rhinitis symptoms[f]	14 (7.1 to 20)	1.5 (0.79 to 2.2)	-5.1 (-7.4 to -2.7)
Short-term exposure	Hospital admissions—respiratory[c]	0.055 (-0.014 to 0.12)	0.0041 (-0.0011 to 0.009)	-0.0098 (-0.022 to 0.0026)
	ED visits—respiratory[e]	0.62 (0.17 to 1.31)	0.58 (0.016 to 0.12)	-0.14 (-0.3 to -0.039)
	Asthma symptoms	440 (-54 to 920)	48 (-5.9 to 100)	-160 (-340 to 20)
	Minor restricted-activity days[c,e]	190 (76 to 300)	21 (8.2 to 32)	-64 (-100 to -26)
	School absence days	160 (-22 to 330)	17 (-2.5 to 37)	-58 (-120 to 8.2)

[a] Values rounded to two significant figures.
[b] Applied risk estimate derived from April-September exposures to estimates of ozone across the May-September warm season.
[c] Converted ozone risk estimate metric from MDA1 to MDA8.
[d] Applied risk estimate derived from June-August exposures to estimates of ozone across the May-September warm season.
[e] Applied risk estimate derived from full year exposures to estimates of ozone across the May-September warm season.
[f] Converted ozone risk estimate metric from DA24 to MDA8.
[g] In 2035, the IPM model projects a small projected increase in NOX emissions results from very small, modeled changes in fossil dispatch and coal use relative to the baseline. As shown in Figure 8-8, while there are small predicted ozone decreases from the final rule compared to the baseline evident in North Dakota in 2028 and Montana in 2035, there are also small predicted ozone increases evident near the border of Arizona and New Mexico in 2035. These small increases result in the very small negative health impacts presented in this table.

Table 4-3 Estimated Avoided $PM_{2.5}$-Related Premature Mortalities and Illnesses for the Final Rule in 2028, 2030, and 2035 (95 percent confidence interval)

Avoided Mortality	**2028**	**2030**	**2035**
(Pope et al., 2019) (adult mortality ages 18-99 years)	7.2 (5.2 to 9.2)	2.7 (1.9 to 3.4)	1.7 (1.2 to 2.1)
(X. Wu et al., 2020) (adult mortality ages 65-99 years)	3.4 (3 to 3.8)	1.3 (1.1 to 1.4)	0.84 (0.74 to 0.94)
(Woodruff et al., 2008) (infant mortality)	0.0087 (-0.0055 to 0.022)	0.0026 (-0.0016 to 0.0066)	0.0013 (-0.00083 to 0.0034)
Avoided Morbidity	**2028**	**2030**	**2035**
Hospital admissions—cardiovascular (age > 18)	0.5 (0.37 to 0.64)	0.19 (0.13 to 0.24)	0.12 (0.084 to 0.15)
Hospital admissions—respiratory	0.73 (0.25 to 1.2)	0.23 (0.076 to 0.37)	0.12 (0.038 to 0.20)
ED visits--cardiovascular	1.1 (-0.4 to 2.5)	0.37 (-0.14 to 0.87)	0.23 (-0.088 to 0.53)
ED visits—respiratory	2 (0.4 to 4.3)	0.72 (0.14 to 1.5)	0.41 (0.081 to 0.86)
Acute Myocardial Infarction	0.12 (0.07 to 0.17)	0.042 (0.024 to 0.059)	0.025 (0.015 to 0.036)
Cardiac arrest	0.053 (-0.022 to 0.12)	0.019 (-0.0076 to 0.043)	0.011 (-0.0045 to 0.25)
Hospital admissions--Alzheimer's Disease	2 (1.5 to 2.5)	0.6 (0.44 to 0.74)	0.33 (0.24 to 0.41)
Hospital admissions--Parkinson's Disease	0.23 (0.12 to 0.34)	0.087 (0.044 to 0.13)	0.054 (0.027 to 0.08)
Stroke	0.21 (0.0055 to 0.36)	0.077 (0.02 to 0.13)	0.047 (0.012 to 0.081)
Lung cancer	0.24 (0.072 to 0.4)	0.087 (0.026 to 0.15)	0.055 (0.017 to 0.092)
Hay Fever/Rhinitis	52 (13 to 91)	17 (4.2 to 30)	9.7 (2.3 to 17)
Asthma Onset	8.1 (7.8 to 8.4)	2.7 (2.5 to 2.8)	1.4 (1.4 to 1.5)
Asthma symptoms – Albuterol use	1,500 (-743 to 3,700)	510 (-250 to 1,200)	290 (-140 to 690)
Lost work days	390 (330 to 450)	130 (110 to 150)	73 (62 to 84)
Minor restricted-activity days	2,300 (1,900 to 2,700)	780 (640 to 930)	430 (350 to 510)

Note: Values rounded to two significant figures.

To directly compare benefits estimates associated with a rulemaking to cost estimates, the number of instances of each air pollution-attributable health impact must be converted to a monetary value. This requires a valuation estimate for each unique health endpoint, and potentially also discounting if the benefits are expected to accrue over more than a single year, as recommended by the U.S. EPA (2014). Table 4-4 reports the estimated economic value of avoided premature deaths and illness in each year relative to the baseline along with the 95 percent confidence interval. Table 4-5 through Table 4-7 presents the stream of health benefits from 2028 through 2037 for the final rule using the monetized sums of long-term ozone and $PM_{2.5}$ mortality and morbidity impacts discounted at 2, 3, and 7 percent, respectively.[57] Note the benefits of the less stringent regulatory alternative are described qualitatively. As a result, there are no quantified benefits associated with this regulatory option.

[57] EPA continues to refine its approach for estimating and reporting PM-related effects at lower concentrations. The Agency acknowledges the additional uncertainty associated with effects estimated at these lower levels and seeks to develop quantitative approaches for reflecting this uncertainty in the estimated PM benefits.

Table 4-4 Estimated Discounted Economic Value of Avoided Ozone and $PM_{2.5}$-Attributable Premature Mortality and Illness for the Final Rule 2028, 2030, and 2035 (95 percent confidence interval; millions of 2019 dollars)[a,b,c]

Disc. Rate	Pollutant	2028			2030			2035		
2%	Ozone Benefits	$1.3	*and*	$5.2	$0.13	*and*	$0.34	-$1.2	*and*	-$0.48
	$PM_{2.5}$ Benefits	$41	*and*	$82	$15	*and*	$30	$10	*and*	$19
	Ozone plus $PM_{2.5}$ Benefits	$42	*and*	$87	$15	*and*	$30	$9.50	*and*	$18
3%	Ozone Benefits	$0.71 ($0.34 to $1.3)	*and*	$4 ($0.66 to $11)	$0.066 ($0.36 to $0.11)	*and*	$0.26 ($0.053 to $0.63)	$-0.96 ($-2.3 to $-0.19)	*and*	$-0.24 ($-0.38 to -$0.13)
	$PM_{2.5}$ Benefits	$38 ($5 to $97)	*and*	$78 ($8.4 to $210)	$14 ($1.8 to $37)	*and*	$29 ($3.1 to $76)	$9.5 ($1.1 to $24)	*and*	$19 ($1.9 to $49)
	Ozone plus $PM_{2.5}$ Benefits	$39 ($5.3 to $98)	*and*	$82 ($9.1 to $220)	$14 ($2.4 to 37)	*and*	$29 ($3.2 to $77)	$9.3 ($0.72 to $24)	*and*	$18 ($-0.4 to $49)
7%	Ozone Benefits	$0.53 ($0.18 to $1.1)	*and*	$3.8 ($0.48 to $9.9)	$0.047 ($0.019 to $0.084)	*and*	$0.22 ($0.034 to $0.55)	$-0.17 ($-0.3 to $-0.068)	*and*	$-0.81 ($-2 to $-0.13)
	$PM_{2.5}$ Benefits	$34 ($4.1 to $86)	*and*	$70 ($7.2 to $180)	$13 ($1.5 to $33)	*and*	$26 ($2.6 to $69)	$8.5 ($0.95 to $22)	*and*	$17 ($1.7 to $44)
	Ozone plus $PM_{2.5}$ Benefits	$35 ($4.3 to $87)	*and*	$7 ($7.7 to $190)	$13 ($1.5 to $33)	*and*	$26 ($2.6 to $70)	$8.3 ($0.65 to $22)	*and*	$16 ($-0.3 to $44)

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.

[b] We estimated changes in NO_X for the ozone season and changes in $PM_{2.5}$ and $PM_{2.5}$ precursors in 2028, 2030, and 2035.

[c] EPA is unable to provide confidence intervals for 2 percent-based estimates currently.

[d] Sum of ozone mortality estimated using the pooled short-term ozone exposure risk estimate and the Wu et al. (2020) long-term $PM_{2.5}$ exposure mortality risk estimate.

[e] Sum of the Turner et al. (2016) long-term ozone exposure risk estimate and the Pope et al. (2019) long-term $PM_{2.5}$ exposure mortality risk estimate.

Table 4-5 Stream of Estimated Human Health Benefits from 2028 through 2037: Monetized Benefits Quantified as Sum of Long-Term Ozone Mortality and Long-Term $PM_{2.5}$ Mortality (discounted at 2 percent to 2023; millions of 2019 dollars)[a]

Year	Under the Final Rule		
2028[b]	$38	and	$79
2029	$38	and	$79
2030[b]	$13	and	$27
2031	$14	and	$27
2032	$7.4	and	$14
2033	$7.5	and	$14
2034	$7.5	and	$14
2035[b]	$7.6	and	$14
2036	$7.6	and	$14
2037	$7.6	and	$14
PV	**$150**	**and**	**$300**
EAV	**$17**	**and**	**$33**

[a] Benefits for all other years were extrapolated from years with model-based air quality estimates. Benefits calculated as value of avoided: $PM_{2.5}$-attributable deaths quantified using a concentration-response relationship from Wu et al. (2020) and Pope et al. (2019); Ozone-attributable deaths quantified using a concentration-response relationship from the Turner et al. (2017); and $PM_{2.5}$ and ozone-related morbidity effects. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] Analysis year in which air quality models were run.

Table 4-6 Stream of Estimated Human Health Benefits from 2028 through 2037: Monetized Benefits Quantified as Sum of Long-Term Ozone Mortality and Long-Term $PM_{2.5}$ Mortality (discounted at 3 percent to 2023; millions of 2019 dollars)[a]

Year		Under the Final Rule	
2028[b]	$34	and	$71
2029	$33	and	$71
2030[b]	$12	and	$24
2031	$12	and	$24
2032	$6.6	and	$13
2033	$6.6	and	$13
2034	$6.5	and	$12
2035[b]	$6.5	and	$12
2036	$6.5	and	$12
2037	$6.4	and	$12
PV	**$130**	**and**	**$260**
EAV	**$15**	**and**	**$31**

[a] Benefits for all other years were extrapolated from years with model-based air quality estimates. Benefits calculated as value of avoided: $PM_{2.5}$-attributable deaths quantified using a concentration-response relationship from Wu et al. (2020) and Pope et al. (2019); Ozone-attributable deaths quantified using a concentration-response relationship from the Turner et al. (2017); and $PM_{2.5}$ and ozone-related morbidity effects. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.

[b] Analysis year in which air quality models were run.

Table 4-7 Stream of Estimated Human Health Benefits from 2028 through 2037: Monetized Benefits Quantified as Sum of Long-Term Ozone Mortality and Long-Term $PM_{2.5}$ Mortality (discounted at 7 percent to 2023; millions of 2019 dollars)[a]

Year		Under the Final Rule	
2028[b]	$25	and	$52
2029	$24	and	$50
2030[b]	$8.0	and	$16
2031	$7.7	and	$16
2032	$4.2	and	$8.0
2033	$4.0	and	$7.7
2034	$3.9	and	$7.3
2035[b]	$3.7	and	$7.0
2036	$3.5	and	$6.7
2037	$3.4	and	$6.4
PV	**$86**	**and**	**$180**
EAV	**$12**	**and**	**$25**

[a] Benefits for all other years were extrapolated from years with model-based air quality estimates. Benefits calculated as value of avoided: $PM_{2.5}$-attributable deaths quantified using a concentration-response relationship from Wu et al. (2020) and Pope et al. (2019); Ozone-attributable deaths quantified using a concentration-response relationship from the Turner et al. (2017); and $PM_{2.5}$ and ozone-related morbidity effects. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] Analysis year in which air quality models were run.

This analysis uses several recent improvements in health endpoint valuation. School loss days now account for lost human capital formation, as was discussed in the Health Benefits TSD which was reviewed by the EPA Scientific Advisory Board's Review of BenMAP and Benefits Methods. We include new estimates of the cost asthma onset and stroke beyond those described in the Health Benefits TSD.

The new valuation estimate for school loss days is described in the Health Benefits TSD in Section 5.3.8. We include two costs of school loss days: caregiver costs and loss of learning. We calculate each separately and then sum. Caregiver costs are valued at their employers' average cost for employed caregivers. For unemployed caregivers, the opportunity cost of their time is calculated as the average take-home pay. The loss of learning is calculated based on the impact of absences on learning multiplied by the impact of school learning on adult earnings. The loss of learning estimate is currently only available for middle and high school students. The two costs are summed.

The caregiver costs assume that an adult caregiver stays home with the child and loses any wage income they would have earned that day. For working caregivers, we follow EPA guidance and value their time at the average wage including fringe benefits and overhead costs. The average daily wage in 2021 was $195 (2015 dollars, assumed to be the average weekly wage divided by 5),[58] which yields an average daily labor cost of $340 for employed parents after applying average multipliers of 1.46 for fringe benefits and 1.2 for overhead. For nonworking caregivers, we assume that the opportunity cost of time is the average after-tax earnings. We estimate the income tax rate for a median household to be 7 percent, yielding net earnings of $195 multiplied by 0.93 or $181 (2015 dollars). The income tax rate of 7 percent is the percentage difference in median post-tax income and median income from Tables A1 and C1 in Shrider et al. (2021).

The probability that a parent is working is measured with the employment population ratio among people with their own children under 18 and is 77.2 percent.[59] Combining the cost of working and nonworking caregivers yields a caregiver cost of $305 per school loss day.

To measure the loss of learning, we update the Liu et al. (2021) estimate. Liu et al. (2021) estimated the impact of a school absence on learnings as measured by an end-of-course test score. We multiply by an estimate of the impact of learning as measured by end-of-course test scores on adult income from Chetty et al. (2014). This approach yields an estimated learning loss of $2,842 per school absence (discounted at 2 percent), $2,230 per school absence (discounted at 3 percent) and $975 per school absence (discounted at 7 percent).

We updated the Chetty et al. (2014) estimate to use 2010 income and to estimate lifetime incomes discounted at 3 percent and 7 percent. Liu et al. (2021) estimate that a school absence leads to a $1,200 reduction in lifetime earnings, based on the Chetty et al. (2014) estimate that lifetime earnings are $522,000 (2010 dollars). We use 2010 ACS data from IPUMS to calculate expected lifetime earnings of $1,137,732 (discounting at 2 percent), $892,579 (discounting at 3 percent) and $390,393 (discounting at 7 percent). We then multiply the Liu et al. (2021) estimate of $1,200 by ($1,137,732 divided by $522,000) and ($892,579 divided by $522,000) and

[58] U.S, Bureau of Labor Statistics (2022), series Employment, Hours, and Earnings from the Current Employment Statistics (Series ID CES0500000011).
[59] US Bureau of Labor Statistics Employment Characteristics of Families, 2021, Table 5.

($390,393 divided by $522,000) and convert from 2010 dollars to 2015 dollars based on the Consumer Price Index for All Urban Consumers.

We use caregiver costs for preschool and elementary school children and the sum of caregiver costs and loss of learning for middle school and high school students. We calculate that 31 percent of children under 18 are middle school and high school ages 13-18, assuming each bin is distributed equally, so the combined average effect is $1,186 ($305 plus $2,842 multiplied by 0.31) with 2 percent discounting, $1,000 ($305 plus $2,230 multiplied by 0.31) with 3 percent discounting, and $610 ($305 plus $975 multiplied by 0.31) with 7 percent discounting in 2015 dollars (U.S. Census Bureau, 2010).[60]

We include a new estimate of the cost of illness of asthma onset based on Maniloff and Fann (2023). These estimates are $181,249 with a 2 percent discount rate, $146,370 with a 3 percent discount rate, and $76,629 with a 7 percent discount rate (2015 dollars). We also include a new estimate of the cost of illness of stroke onset based on Maniloff and Fann (2023).These estimates are $158,763 with a 2 percent discount rate, $150,675 with a 3 percent discount rate, and $123,984 with a 7 percent discount rate (2015 dollars).

4.3.10 Additional Unquantified Benefits

Data, time, and resource limitations prevented EPA from quantifying the estimated health impacts or monetizing estimated benefits associated with direct exposure to NO_2 and SO_2, independent of the role NO_2 and SO_2 play as precursors to $PM_{2.5}$ and ozone, ecosystem effects, and visibility impairment due to the absence of air quality modeling data for these pollutants in this analysis. While all health benefits and welfare benefits were not able to be quantified, it does not imply that there are not additional benefits associated with reductions in exposures to ozone, $PM_{2.5}$, NO_2 or SO_2. Criteria pollutants from U.S. EGUs can also be transported downwind into foreign countries, in particular Canada and Mexico. Therefore, reduced criteria pollutants from U.S. EGUs can lead to public health and welfare benefits in foreign countries. EPA is currently unable to quantify or monetize these effects.

The EPA is also unable to quantify and monetize the incremental potential benefits of requiring facilities to utilize CEMS rather than continuing to allow the use of quarterly testing,

[60] U.S. Census Bureau, Age and Sex Composition in the United States: 2010, Table 1, *https://www.census.gov/data/tables/2010/demo/age-and-sex/2010-age-sex-composition.html.*

but the requirement has been considered qualitatively. The continuous monitoring of fPM required in this rule is also likely to provide several additional benefits to the public which are not quantified in this rule, including greater certainty, accuracy, transparency, and granularity in fPM emissions information than exists today.

Table 4-8 Additional Unquantified Benefit Categories

Category	Effect	Effect Quantified	Effect Monetized	More Information
Improved Human Health				
Reduced incidence of morbidity from exposure to NO_2	Asthma hospital admissions	—	—	NO_2 ISA[1]
	Chronic lung disease hospital admissions	—	—	NO_2 ISA[1]
	Respiratory emergency department visits	—	—	NO_2 ISA[1]
	Asthma exacerbation	—	—	NO_2 ISA[1]
	Acute respiratory symptoms	—	—	NO_2 ISA[1]
	Premature mortality	—	—	NO_2 ISA[1,2,3]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages, and populations)	—	—	NO_2 ISA[2,3]
Improved Environment				
Reduced visibility impairment	Visibility in Class 1 areas	—	—	PM ISA[1]
	Visibility in residential areas	—	—	PM ISA[1]
Reduced effects on materials	Household soiling	—	—	PM ISA[1,2]
	Materials damage (e.g., corrosion, increased wear)	—	—	PM ISA[2]
Reduced effects from PM deposition (metals and organics)	Effects on individual organisms and ecosystems	—	—	PM ISA[2]
Reduced vegetation and ecosystem effects from exposure to ozone	Visible foliar injury on vegetation	—	—	Ozone ISA[1]
	Reduced vegetation growth and reproduction	—	—	Ozone ISA[1]
	Yield and quality of commercial forest products and crops	—	—	Ozone ISA[1]
	Damage to urban ornamental plants	—	—	Ozone ISA[2]
	Carbon sequestration in terrestrial ecosystems	—	—	Ozone ISA[1]
	Recreational demand associated with forest aesthetics	—	—	Ozone ISA[2]
	Other non-use effects			Ozone ISA[2]

Table 4-8 Additional Unquantified Benefit Categories

Category	Effect	Effect Quantified	Effect Monetized	More Information
	Ecosystem functions (e.g., water cycling, biogeochemical cycles, net primary productivity, leaf-gas exchange, community composition)	—	—	Ozone ISA[2]
Reduced effects from acid deposition	Recreational fishing	—	—	NO_X SO_X ISA[1]
	Tree mortality and decline	—	—	NO_X SO_X ISA[2]
	Commercial fishing and forestry effects	—	—	NO_X SO_X ISA[2]
	Recreational demand in terrestrial and aquatic ecosystems	—	—	NO_X SO_X ISA[2]
	Other non-use effects			NO_X SO_X ISA[2]
	Ecosystem functions (e.g., biogeochemical cycles)	—	—	NO_X SO_X ISA[2]
Reduced effects from nutrient enrichment from deposition.	Species composition and biodiversity in terrestrial and estuarine ecosystems	—	—	NO_X SO_X ISA[2]
	Coastal eutrophication	—	—	NO_X SO_X ISA[2]
	Recreational demand in terrestrial and estuarine ecosystems	—	—	NO_X SO_X ISA[2]
	Other non-use effects			NO_X SO_X ISA[2]
	Ecosystem functions (e.g., biogeochemical cycles, fire regulation)	—	—	NO_X SO_X ISA[2]
Reduced vegetation effects from ambient exposure to SO_2 and NO_x	Injury to vegetation from SO_2 exposure	—	—	NO_X SO_X ISA[2]
	Injury to vegetation from NO_x exposure	—	—	NO_X SO_X ISA[2]

[1] We assess these benefits qualitatively due to data and resource limitations for this RIA.
[2] We assess these benefits qualitatively because we do not have sufficient confidence in available data or methods.
[3] We assess these benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association.

4.3.10.1 NO_2 Health Benefits

In addition to being a precursor to $PM_{2.5}$ and ozone, NO_X emissions are also linked to a variety of adverse health effects associated with direct exposure. We were unable to estimate the health benefits associated with reduced NO_2 exposure in this analysis. Following a comprehensive review of health evidence from epidemiologic and laboratory studies, the ISA for Oxides of Nitrogen —Health Criteria (NO_X ISA) concluded that there is a likely causal relationship between respiratory health effects and short-term exposure to NO_2 (U.S. EPA, 2016). These epidemiologic and experimental studies encompass a number of endpoints including emergency department visits and hospitalizations, respiratory symptoms, airway hyperresponsiveness, airway inflammation, and lung function. The NO_X ISA also concluded that the relationship between short-term NO_2 exposure and premature mortality was "suggestive but not sufficient to infer a causal relationship," because it is difficult to attribute the mortality risk effects to NO_2 alone. Although the NO_X ISA stated that studies consistently reported a relationship between NO_2 exposure and mortality, the effect was generally smaller than that for other pollutants such as PM.

4.3.10.2 SO_2 Health Benefits

In addition to being a precursor to $PM_{2.5}$, SO_2 emissions are also linked to a variety of adverse health effects associated with direct exposure. We were unable to estimate the health benefits associated with reduced SO_2 in this analysis. Therefore, this analysis only quantifies and monetizes the $PM_{2.5}$ benefits associated with the reductions in SO_2 emissions. Following an extensive evaluation of health evidence from epidemiologic and laboratory studies, the ISA for Oxides of Sulfur—Health Criteria (SO_2 ISA) concluded that there is a causal relationship between respiratory health effects and short-term exposure to SO_2 sulfur (U.S. EPA, 2017). The immediate effect of SO_2 on the respiratory system in humans is bronchoconstriction. Asthmatics are more sensitive to the effects of SO_2, likely resulting from preexisting inflammation associated with this disease. A clear concentration-response relationship has been demonstrated in laboratory studies following exposures to SO_2 at concentrations between 20 and 100 parts per billion (ppb), both in terms of increasing severity of effect and percentage of asthmatics adversely affected. Based on our review of this information, we identified three short-term morbidity endpoints that the SO_2 ISA identified as a "causal relationship": asthma exacerbation, respiratory-related emergency department visits, and respiratory-related hospitalizations. The differing evidence and associated strength of the evidence for these different effects is described in detail in the SO_2 ISA. The SO_2 ISA also concluded that the relationship between short-term SO_2 exposure and premature mortality was "suggestive of a causal relationship" because it is difficult to attribute the mortality risk effects to SO_2 alone. Although the SO_2 ISA stated that studies are generally consistent in reporting a relationship between SO_2 exposure and mortality, there was a lack of robustness of the observed associations to adjustment for other pollutants.

4.3.10.3 Ozone Welfare Benefits

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature ecological (U.S. EPA, 2020c). Sensitivity to ozone is highly variable across species, with over 65 plant species identified as "ozone-sensitive," many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects can include reduced growth and/or biomass production in sensitive plant species, including forest trees, reduced yield and quality of crops, visible foliar injury, species composition shift, and changes in ecosystems and associated ecosystem services. See Section F of the *Ozone Transport Policy Analysis Proposed Rule TSD* for a summary of an assessment of risk of ozone-related growth impacts on selected forest tree species (U.S. EPA, 2022f).

4.3.10.4 NO_2 and SO_2 Welfare Benefits

As described in the ISAs for Oxides of Nitrogen, Oxides of Sulfur and Particulate Matter Ecological Criteria (U.S. EPA, 2020c), NO_X and SO_2 emissions also contribute to a variety of adverse welfare effects, including those associated with acidic deposition, visibility impairment, and nutrient enrichment. Deposition of nitrogen and sulfur causes acidification, which can cause a loss of biodiversity of fishes, zooplankton, and macro invertebrates in aquatic ecosystems, as well as a decline in sensitive tree species, such as red spruce (*Picea rubens*) and sugar maple (Acer saccharum) in terrestrial ecosystems. In the northeastern U.S., the surface waters affected by acidification are a source of food for some recreational and subsistence fishermen and for other consumers and support several cultural services, including aesthetic and educational services and recreational fishing. Biological effects of acidification in terrestrial ecosystems are generally linked to aluminum toxicity, which can cause reduced root growth, restricting the ability of the plant to take up water and nutrients. These direct effects can, in turn, increase the sensitivity of these plants to stresses, such as droughts, cold temperatures, insect pests, and disease, leading to increased mortality of canopy trees. Terrestrial acidification affects several important ecological services, including declines in habitat for threatened and endangered species (cultural), declines in forest aesthetics (cultural), declines in forest productivity (provisioning), and increases in forest soil erosion and reductions in water retention (cultural and regulating).

Deposition of nitrogen is also associated with aquatic and terrestrial nutrient enrichment. In estuarine waters, excess nutrient enrichment can lead to eutrophication. Eutrophication of estuaries can disrupt an important source of food production, particularly fish and shellfish production, and a variety of cultural ecosystem services, including water-based recreational and aesthetic services. Terrestrial nutrient enrichment is associated with changes in the types and number of species and biodiversity in terrestrial systems. Excessive nitrogen deposition upsets the balance between native and nonnative plants, changing the ability of an area to support biodiversity. When the composition of species changes, then fire frequency and intensity can also change, as nonnative grasses fuel more frequent and more intense wildfires.

4.3.10.5 Visibility Impairment Benefits

Reducing secondary formation of $PM_{2.5}$ would improve levels of visibility in the U.S. because suspended particles and gases degrade visibility by scattering and absorbing light (U.S. EPA 2009). Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil. Visibility has direct significance to people's enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Particulate sulfate is the dominant source of regional haze in the eastern U.S. and particulate nitrate is an important contributor to light extinction in California and the upper Midwestern U.S., particularly during winter (U.S. EPA, 2009b). Previous analyses such as U.S. EPA (2012) show that visibility benefits can be a significant welfare benefit category. Without air quality modeling, we are unable to estimate visibility-related benefits, and we are also unable to determine whether the emission reductions associated with this rule would be likely to have a significant impact on visibility in urban areas or Class I areas.

Reductions in emissions of NO_2 will improve the level of visibility throughout the U.S. because these gases (and the particles of nitrate and sulfate formed from these gases) impair visibility by scattering and absorbing light (U.S. EPA, 2009b). Visibility is also referred to as visual air quality (VAQ), and it directly affects people's enjoyment of a variety of daily activities (U.S. EPA, 2009b). Good visibility increases quality of life where individuals live and work, and where they travel for recreational activities, including sites of unique public value, such as the Great Smoky Mountains National Park (U.S. EPA, 2009b).

4.4 Climate Benefits

EPA estimates the climate benefits of CO_2 emissions reductions expected from the final rule using estimates of the social cost of carbon (SC-CO_2) that reflect recent advances in the scientific literature on climate change and its economic impacts and incorporate recommendations made by the National Academies of Science, Engineering, and Medicine (National Academies, 2017). EPA published and used these estimates in the RIA for the December 2023 final oil and natural gas sector rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (US EPA 2023c). EPA solicited public comment on the methodology and use of these estimates in the RIA for the Agency's December 2022 oil and natural gas sector supplemental proposal and has conducted an external peer review of these estimates, as described further below. [61]

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 net 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 and 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 CO_2 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 restrain the ability of SC-CO_2 estimates to include all physical, ecological, and economic impacts of climate change, implicitly assigning a value of zero to the omitted climate damages. The estimates are, therefore, a partial accounting of climate change impacts and likely underestimate the marginal benefits of abatement.

Since 2008, EPA has used estimates of the social cost of various GHGs (i.e., SC-CO_2, SC-CH_4, and SC-N_2O), collectively referred to as the "social cost of greenhouse gases" (SC-GHG), in analyses of actions that affect GHG emissions. The values used by EPA from 2009 to

[61] See *https://www.epa.gov/environmental-economics/scghg* for a copy of the final report and other related materials.

2016, and since 2021 — including in the proposal for this rulemaking — have been consistent with those developed and recommended by the Interagency Working Group (IWG) on the SC-GHG; and the values used from 2017 to 2020 were consistent with those required by E.O. 13783, which disbanded the IWG. During 2015–2017, the National Academies conducted a comprehensive review of the SC-CO_2 and issued a final report in 2017 recommending specific criteria for future updates to the SC-CO_2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process. The IWG was reconstituted in 2021 and E.O. 13990 directed it to develop a comprehensive update of its SC-GHG estimates, recommendations regarding areas of decision-making to which SC-GHG should be applied, and a standardized review and updating process to ensure that the recommended estimates continue to be based on the best available economics and science going forward.

EPA is a member of the IWG and is participating in the IWG's work under E.O. 13990. As noted in previous EPA RIAs, while that process continues, 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.[62] In the December 2022 oil and natural gas sector supplemental proposal RIA, the Agency included a sensitivity analysis of the climate benefits of the supplemental proposal using a new set of SC-GHG estimates that incorporates recent research addressing recommendations of the National Academies (National Academies, 2017) in addition to using the interim SC-GHG estimates presented in *the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990* (IWG, 2021) that the IWG recommended for use until updated estimates that address the National Academies' recommendations are available.

EPA solicited public comment on the sensitivity analysis and the accompanying draft technical report, *External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, which explains the methodology underlying

[62] EPA strives to base its analyses on the best available science and economics, consistent with its responsibilities, for example, under the Information Quality Act.

the new set of estimates, in the December 2022 oil and natural gas supplemental proposal RIA. The response to comments document can be found in the docket for that action.[63]

To ensure that the methodological updates adopted in the technical report are consistent with economic theory and reflect the latest science, EPA also initiated an external peer review panel to conduct a high-quality review of the technical report, completed in May 2023. The peer reviewers commended the agency on its development of the draft update, calling it a much-needed improvement in estimating the SC-GHG and a significant step toward addressing the National Academies' recommendations with defensible modeling choices based on current science. The peer reviewers provided numerous recommendations for refining the presentation and for future modeling improvements, especially with respect to climate change impacts and associated damages that are not currently included in the analysis. Additional discussion of omitted impacts and other updates have been incorporated in the technical report to address peer reviewer recommendations. Complete information about the external peer review, including the peer reviewer selection process, the final report with individual recommendations from peer reviewers, and EPA's response to each recommendation is available on EPA's website.[64]

The remainder of this section provides an overview of the methodological updates incorporated into the SC-GHG estimates used in this final RIA. A more detailed explanation of each input and the modeling process is provided in the final technical report, *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*.[65] Appendix B presents the projected benefits of the final rule using the interim SC-GHG (IWG, 2021) estimates used in the proposal RIA for comparison purposes.

The steps necessary to estimate the SC-GHG with a climate change integrated assessment model (IAM) can generally be grouped into four modules: socioeconomics and emissions, climate, damages, and discounting. The emissions trajectories from the socioeconomic module are used to project future temperatures in the climate module. The damage module then translates the temperature and other climate endpoints (along with the projections of socioeconomic variables) into physical impacts and associated monetized economic damages, where the damages are calculated as the amount of money the individuals experiencing the

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[63] *https://www.regulations.gov/docket/EPA-HQ-OAR-2021-0317*.
[64] *https://www.epa.gov/environmental-economics/scghg-tsd-peer-review*.
[65] See *https://www.epa.gov/environmental-economics/scghg* for a copy of the final report and other related materials.

climate change impacts would be willing to pay to avoid them. To calculate the marginal effect of emissions, i.e., the SC-GHG in year "*t*," the entire model is run twice – first as a baseline and second with an additional pulse of emissions in year "*t*." After recalculating the temperature effects and damages expected in all years beyond "*t*" resulting from the adjusted path of emissions, the losses are discounted to a present value in the discounting module. Many sources of uncertainty in the estimation process are incorporated using Monte Carlo techniques by taking draws from probability distributions that reflect the uncertainty in parameters.

The SC-GHG estimates used by EPA and many other federal agencies since 2009 have relied on an ensemble of three widely used IAMs: Dynamic Integrated Climate and Economy (DICE) (Nordhaus, 2010); Climate Framework for Uncertainty, Negotiation, and Distribution (FUND) (Anthoff and Tol, 2013a, 2013b); and Policy Analysis of the Greenhouse Gas Effect (PAGE) (Hope, 2013). In 2010, the IWG harmonized key inputs across the IAMs, but all other model features were left unchanged, relying on the model developers' best estimates and judgments. That is, the representation of climate dynamics and damage functions included in the default version of each IAM as used in the published literature was retained.

The SC-GHG estimates in this RIA no longer rely on the three IAMs (i.e., DICE, FUND, and PAGE) used in previous SC-GHG estimates. As explained previously, EPA uses a modular approach to estimate the SC-GHG, consistent with the National Academies' near-term recommendations. That is, the methodology underlying each component, or module, of the SC-GHG estimation process is developed by drawing on the latest research and expertise from the scientific disciplines relevant to that component. Under this approach, each step in the SC-GHG estimation improves consistency with the current state of scientific knowledge, enhances transparency, and allows for more explicit representation of uncertainty.

The socioeconomic and emissions module relies on a new set of probabilistic projections for population, income, and GHG emissions developed under the Resources for the Future (RFF) Social Cost of Carbon Initiative (Rennert, Prest, et al., 2022). These socioeconomic projections (hereinafter collectively referred to as the RFF-SPs) are an internally consistent set of probabilistic projections of population, GDP, and GHG emissions (CO_2, CH_4, and N_2O) to 2300. Based on a review of available sources of long-run projections necessary for damage calculations, the RFF-SPs stand out as being most consistent with the National Academies' recommendations. Consistent with the National Academies' recommendation, the RFF-SPs were developed using a mix of statistical and expert elicitation techniques to capture uncertainty in a single probabilistic approach, taking into account the likelihood of future emissions mitigation policies and technological developments, and provide the level of disaggregation necessary for damage calculations. Unlike other sources of projections, they provide inputs for estimation out to 2300 without further extrapolation assumptions. Conditional on the modeling conducted for the SC-GHG estimates, this time horizon is far enough in the future to capture the majority of discounted climate damages. Including damages beyond 2300 would increase the estimates of the SC-GHG. As discussed in U.S. EPA (2023c), the use of the RFF-SPs allows for capturing economic growth uncertainty within the discounting module.

The climate module relies on the Finite Amplitude Impulse Response (FaIR) model (IPCC, 2021b; Millar et al., 2017; C. J. Smith et al., 2018), a widely used Earth system model which captures the relationships between GHG emissions, atmospheric GHG concentrations, and global mean surface temperature. The FaIR model was originally developed by Richard Millar, Zeb Nicholls, and Myles Allen at Oxford University, as a modification of the approach used in IPCC AR5 to assess the GWP and GTP (Global Temperature Potential) of different gases. It is open source, widely used (e.g., IPCC (2018, 2021a)) and was highlighted by the National Academies (2017) as a model that satisfies their recommendations for a near-term update of the climate module in SC-GHG estimation. Specifically, it translates GHG emissions into mean surface temperature response and represents the current understanding of the climate and GHG cycle systems and associated uncertainties within a probabilistic framework. The SC-GHG estimates used in this RIA rely on FaIR version 1.6.2 as used by the IPCC (2021a). It provides, with high confidence, an accurate representation of the latest scientific consensus on the relationship between global emissions and global mean surface temperature and offers a code base that is fully transparent and available online. The uncertainty capabilities in FaIR 1.6.2 have been calibrated to the most recent assessment of the IPCC (which importantly narrowed the range of likely climate sensitivities relative to prior assessments). See U.S. EPA (2023c) for more details.

The socioeconomic projections and outputs of the climate module are inputs into the damage module to estimate monetized future damages from climate change.[66] The National Academies' recommendations for the damage module, scientific literature on climate damages, updates to models that have been developed since 2010, as well as the public comments received on individual EPA rulemakings and the IWG's February 2021 TSD, have all helped to identify available sources of improved damage functions. The IWG (e.g., IWG 2010, 2016a, 2021), the National Academies (2017), comprehensive studies (e.g., Rose et al. (2014)), and public comments have all recognized that the damages functions underlying the IWG SC-GHG estimates used since 2013 (taken from DICE 2010 (Nordhaus, 2010); FUND 3.8 (Anthoff and Tol, 2013a, 2013b); and PAGE 2009 (Hope, 2013)) do not include all the important physical, ecological, and economic impacts of climate change. The climate change literature and the science underlying the economic damage functions have evolved, and DICE 2010, FUND 3.8, and PAGE 2009 now lag behind the most recent research. The IWG (e.g., IWG (2010, 2016a, 2021)), the National Academies (2017), comprehensive studies (e.g., Rose et al. (2014)), and public comments have all recognized that the damages functions underlying the IWG SC-GHG estimates used since 2013 (taken from DICE 2010 (Nordhaus, 2010); FUND 3.8 (Anthoff and Tol, 2013a, 2013b); and PAGE 2009 (Hope, 2013)) do not include all of the important physical, ecological, and economic impacts of climate change. The climate change literature and the science underlying the economic damage functions have evolved, and DICE 2010, FUND 3.8, and PAGE 2009 now lag behind the most recent research.

The challenges involved with updating damage functions have been widely recognized. Functional forms and calibrations are constrained by the available literature and need to extrapolate beyond warming levels or locations studied in that literature. Research and public resources focused on understanding how these physical changes translate into economic impacts have been significantly less than the resources focused on modeling and improving our understanding of climate system dynamics and the physical impacts from climate change

[66] In addition to temperature change, two of the three damage modules used in the SC-GHG estimation require global mean sea level (GMSL) projections as an input to estimate coastal damages. Those two damage modules use different models for generating estimates of GMSL. Both are based off reduced complexity models that can use the FaIR temperature outputs as inputs to the model and generate projections of GMSL accounting for the contributions of thermal expansion and glacial and ice sheet melting based on recent scientific research. Absent clear evidence on a preferred model, the SC-GHG estimates presented in this RIA retain both methods used by the damage module developers. See U.S. EPA (2023c) for more details.

(Auffhammer, 2018). Even so, there has been a large increase in research on climate impacts and damages in the time since DICE 2010, FUND 3.8, and PAGE 2009 were published. Along with this growth, there continues to be wide variation in methodologies and scope of studies, such that care is required when synthesizing the current understanding of impacts or damages. Based on a review of available studies and approaches to damage function estimation, EPA uses three separate damage functions to form the damage module: (1) a subnational-scale, sectoral damage function (based on the Data-driven Spatial Climate Impact Model (DSCIM) developed by the Climate Impact Lab (Carleton et al., 2022; Climate Impact Lab (CIL), 2023; Rode et al., 2021); (2) a country-scale, sectoral damage function (based on the Greenhouse Gas Impact Value Estimator (GIVE) model developed under RFF's Social Cost of Carbon Initiative (Rennert, Errickson, et al., 2022); and (3) a meta-analysis-based damage function (based on Howard and Sterner (2017)).

The damage functions in DSCIM and GIVE represent substantial improvements relative to the damage functions underlying the SC-GHG estimates used by EPA to date and reflect the forefront of scientific understanding about how temperature change and SLR lead to monetized net (market and nonmarket) damages for several categories of climate impacts. The models' spatially explicit and impact-specific modeling of relevant processes allow for improved understanding and transparency about mechanisms through which climate impacts are occurring and how each damage component contributes to the overall results, consistent with the National Academies' recommendations. DSCIM addresses common criticisms related to the damage functions underlying current SC-GHG estimates (e.g., Pindyck (2017)) by developing multi-sector, empirically grounded damage functions. The damage functions in the GIVE model offer a direct implementation of the National Academies' near-term recommendation to develop updated sectoral damage functions that are based on recently published work and reflective of the current state of knowledge about damages in each sector. Specifically, the National Academies noted that "[t]he literature on agriculture, mortality, coastal damages, and energy demand provide immediate opportunities to update the [models]" (p. 199 in National Academies (2017)), which are the four damage categories currently in GIVE. A limitation of both models is that the sectoral coverage is still limited, and even the categories that are represented are incomplete. Neither DSCIM nor GIVE yet accommodate estimation of several categories of temperature driven climate impacts (e.g., morbidity, conflict, migration, biodiversity loss) and only represent a limited subset of damages from changes in precipitation. For example, while precipitation is considered in the agriculture sectors in both DSCIM and GIVE, neither model takes into account impacts of flooding, changes in rainfall from tropical storms, and other precipitation related impacts. As another example, the coastal damage estimates in both models do not fully reflect the consequences of SLR-driven salt-water intrusion and erosion, or SLR damages to coastal tourism and recreation. Other missing elements are damages that result from other physical impacts (e.g., ocean acidification, non-temperature-related mortality such as diarrheal disease and malaria) and the many feedbacks and interactions across sectors and regions that can lead to additional damages.[67] See U.S. EPA (2023c) for more discussion of omitted damage categories and other modeling limitations. DSCIM and GIVE do account for the most commonly cited benefits associated with CO_2 emissions and climate change – CO_2 crop fertilization and declines in cold related mortality. As such, while the GIVE- and DSCIM-based results provide state-of-the-science assessments of key climate change impacts, they remain partial estimates of future climate damages resulting from incremental changes in CO_2, CH_4, and N_2O.[68]

Finally, given the still relatively narrow sectoral scope of the recently developed DSCIM and GIVE models, the damage module includes a third damage function that reflects a synthesis of the state of knowledge in other published climate damages literature. Studies that employ meta-analytic techniques[69] offer a tractable and straightforward way to combine the results of multiple studies into a single damage function that represents the body of evidence on climate damages that pre-date CIL and RFF's research initiatives. The first use of meta-analysis to combine multiple climate damage studies was done by Tol (2009) and included 14 studies. The studies in Tol (2009) served as the basis for the global damage function in DICE starting in version 2013R (Nordhaus, 2014). The damage function in the most recent published version of

[67] The one exception is that the agricultural damage function in DSCIM and GIVE reflects the ways that trade can help mitigate damages arising from crop yield impacts.
[68] One advantage of the modular approach used by these models is that future research on new or alternative damage functions can be incorporated in a relatively straightforward way. DSCIM and GIVE developers have work underway on other impact categories that may be ready for consideration in future updates (e.g., morbidity and biodiversity loss).
[69] Meta-analysis is a statistical method of pooling data and/or results from a set of comparable studies of a problem. Pooling in this way provides a larger sample size for evaluation and allows for a stronger conclusion than can be provided by any single study. Meta-analysis yields a quantitative summary of the combined results and current state of the literature.

DICE, DICE 2016, is from an updated meta-analysis based on a rereview of existing damage studies and included 26 studies published over 1994-2013 (Nordhaus and Moffat, 2017). Howard and Sterner (2017) provide a more recent published peer-reviewed meta-analysis of existing damage studies (published through 2016) and account for additional features of the underlying studies. This study addresses differences in measurement across studies by adjusting estimates such that the data are relative to the same base period. They also eliminate double counting by removing duplicative estimates. Howard and Sterner's final sample is drawn from 20 studies that were published through 2015. Howard and Sterner (2017) present results under several specifications and show that the estimates are somewhat sensitive to defensible alternative modeling choices. As discussed in detail in U.S. EPA (2023c), the damage module underlying the SC-GHG estimates in this RIA includes the damage function specification (that excludes duplicate studies) from Howard and Sterner (2017) that leads to the lowest SC-GHG estimates, all else equal.

The discounting module discounts the stream of future net climate damages to its present value in the year when the additional unit of emissions was released. Given the long-time horizon over which the damages are expected to occur, the discount rate has a large influence on the present value of future damages. Consistent with the findings of National Academies (2017), the economic literature, OMB Circular A-4's guidance for regulatory analysis, and IWG recommendations to date (IWG, 2010, 2013, 2016a, 2016b, 2021), EPA continues to conclude that the consumption rate of interest is the theoretically appropriate discount rate to discount the future benefits of reducing GHG emissions and that discount rate uncertainty should be accounted for in selecting future discount rates in this intergenerational context. OMB's Circular A-4 points out that "the analytically preferred method of handling temporal differences between benefits and costs is to adjust all the benefits and costs to reflect their value in equivalent units of consumption and to discount them at the rate consumers and savers would normally use in discounting future consumption benefits" (OMB, 2003).[70] The damage module described above calculates future net damages in terms of reduced consumption (or monetary consumption equivalents), and so an application of this guidance is to use the consumption discount rate to

[70] Similarly, OMB's Circular A-4 (2023) points out that "The analytically preferred method of handling temporal differences between benefits and costs is to adjust all the benefits and costs to reflect their value in equivalent units of consumption before discounting them."

calculate the SC-GHG. Thus, EPA concludes that the use of the social rate of return on capital (7 percent under the 2003 OMB Circular A-4 guidance), which does not reflect the consumption rate, to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC-GHG.[71]

For the SC-GHG estimates used in this RIA, EPA relies on a dynamic discounting approach that more fully captures the role of uncertainty in the discount rate in a manner consistent with the other modules. Based on a review of the literature and data on consumption discount rates, the public comments received on individual EPA rulemakings, and the February 2021 TSD, and the National Academies (2017) recommendations for updating the discounting module, the SC-GHG estimates rely on discount rates that reflect more recent data on the consumption interest rate and uncertainty in future rates. Specifically, rather than using a constant discount rate, the evolution of the discount rate over time is defined following the latest empirical evidence on interest rate uncertainty and using a framework originally developed by Ramsey (1928) that connects economic growth and interest rates. The Ramsey approach explicitly reflects (1) preferences for utility in one period relative to utility in a later period and (2) the value of additional consumption as income changes. The dynamic discount rates used to develop the SC-GHG estimates applied in this RIA have been calibrated following the Newell et al. (2022) approach, as applied in Rennert, Errickson, et al. (2022); Rennert, Prest, et al. (2022). This approach uses the Ramsey (1928) discounting formula in which the parameters are calibrated such that (1) the decline in the certainty-equivalent discount rate matches the latest empirical evidence on interest rate uncertainty estimated by Bauer and Rudebusch (2020, 2023) and (2) the average of the certainty-equivalent discount rate over the first decade matches a near-term consumption rate of interest. Uncertainty in the starting rate is addressed by using three near-term target rates (1.5, 2.0, and 2.5 percent) based on multiple lines of evidence on observed market interest rates.

The resulting dynamic discount rate provides a notable improvement over the constant discount rate framework used for SC-GHG estimation in previous EPA RIAs. Specifically, it provides internal consistency within the modeling and a more complete accounting of

[71] See also the discussion of the inappropriateness of discounting consumption-equivalent measures of benefits and costs using a rate of return on capital in Circular A-4 (OMB, 2003).

uncertainty consistent with economic theory (Arrow et al., 2013; Cropper et al., 2014) and the National Academies' (2017) recommendation to employ a more structural, Ramsey-like approach to discounting that explicitly recognizes the relationship between economic growth and discounting uncertainty. This approach is also consistent with the National Academies (2017) recommendation to use three sets of Ramsey parameters that reflect a range of near-term certainty-equivalent discount rates and are consistent with theory and empirical evidence on consumption rate uncertainty. Finally, the value of aversion to risk associated with net damages from GHG emissions is explicitly incorporated into the modeling framework following the economic literature. See U.S. EPA (2023c) for a more detailed discussion of the entire discounting module and methodology used to value risk aversion in the SC-GHG estimates.

Taken together, the methodologies adopted in this SC-GHG estimation process allow for a more holistic treatment of uncertainty than past estimates used by EPA. The updates incorporate a quantitative consideration of uncertainty into all modules and use a Monte Carlo approach that captures the compounding uncertainties across modules. The estimation process generates nine separate distributions of discounted marginal damages per metric ton – the product of using three damage modules and three near-term target discount rates – for each gas in each emissions year. These distributions have long right tails reflecting the extensive evidence in the scientific and economic literature that shows the potential for lower-probability but higher-impact outcomes from climate change, which would be particularly harmful to society. The uncertainty grows over the modeled time horizon. Therefore, under cases with a lower near-term target discount rate – that give relatively more weight to impacts in the future – the distribution of results is wider. To produce a range of estimates that reflects the uncertainty in the estimation exercise while also providing a manageable number of estimates for policy analysis, EPA combines the multiple lines of evidence on damage modules by averaging the results across the three damage module specifications. The full results generated from the updated methodology for methane and other GHGs (SC-CO_2, SC-CH_4, and SC-N_2O) for emissions years 2020 through 2080 are provided in U.S. EPA (2023c).

Table 4-9 summarizes the resulting averaged certainty-equivalent SC-CO_2 estimates under each near-term discount rate that are used to estimate the climate benefits of the CO_2 emission reductions expected from the final rule. These estimates are reported in 2019 dollars but are otherwise identical to those presented in U.S. EPA (2023c). The SC-CO_2 increase over time within the models — i.e., the societal harm from one metric ton emitted in 2030 is higher than the harm caused by one metric ton emitted in 2027 — because future emissions produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change, and because GDP is growing over time and many damage categories are modeled as proportional to GDP.

Table 4-9 Estimates of the Social Cost of CO_2 Values, 2028-2037 (2019 dollars per Metric Tonne CO_2) [a]

	Near-term Ramsey Discount Rate		
Emission Year	**2.5%**	**2%**	**1.5%**
2028	140	220	370
2029	140	220	380
2030	140	230	380
2031	150	230	380
2032	150	230	390
2033	150	240	390
2034	150	240	400
2035	160	240	400
2036	160	250	410
2037	160	250	410

[a] Source: U.S. EPA (2023c). Note: These SC-CO_2 values are identical to those reported in the technical report U.S. EPA (2023c) adjusted for inflation to 2019 dollars using the annual GDP Implicit Price Deflator values in the U.S. Bureau of Economic Analysis' (BEA) NIPA Table 1.1.9 (U.S. BEA, 2021). The values are stated in $/metric ton CO_2 and vary depending on the year of CO_2 emissions. This table displays the values rounded to two significant figures. The annual unrounded values used in the calculations in this RIA are available in Appendix A.4 of U.S. EPA (2023c) and at: *www.epa.gov/environmental-economics/scghg*.

The methodological updates described above represent a major step forward in bringing SC-GHG estimation closer to the frontier of climate science and economics and address many of the National Academies' (2017) near-term recommendations. Nevertheless, the resulting SC-CO_2 estimates presented in Table 4-9, still have several limitations, as would be expected for any modeling exercise that covers such a broad scope of scientific and economic issues across a complex global landscape. There are still many categories of climate impacts and associated damages that are only partially or not reflected yet in these estimates and sources of uncertainty that have not been fully characterized due to data and modeling limitations. For example, the modeling omits most of the consequences of changes in precipitation, damages from extreme weather events, the potential for nongradual damages from passing critical thresholds (e.g., tipping elements) in natural or socioeconomic systems, and non-climate mediated effects of

GHG emissions. Importantly, the updated SC-GHG methodology does not yet reflect interactions and feedback effects within, and across, Earth and human systems. For example, it does not explicitly reflect potential interactions among damage categories, such as those stemming from the interdependencies of energy, water, and land use. These, and other, interactions and feedbacks were highlighted by the National Academies as an important area of future research for longer-term enhancements in the SC-GHG estimation framework.

Table 4-10 presents the estimated annual, undiscounted climate benefits of the estimated changes in CO_2 emissions the final rule, using the SC-CO_2 estimates presented in Table 4-9, for the stream of years beginning in 2028 through 2037. Also shown are the present value (PV) of monetized climate benefits discounted back to 2023 and equivalent annualized values (EAV) associated with each of the three SC-CO_2 values. To calculate the present and annualized values of climate benefits in Table 4-10, EPA uses the same discount rate as the near-term target Ramsey rate used to discount the climate benefits from future CO_2 reductions.[72] That is, future climate benefits estimated with the SC-CO_2 at the near-term 2.5 percent, 2 percent, and 1.5 percent Ramsey rate are discounted to the base year of the analysis using a constant 2.5, 2, and 1.5 percent rate, respectively. Note the less stringent regulatory alternative only has unquantified benefits associated with the finalized requirements for PM CEMS. As a result, there are no quantified benefits associated with this regulatory option.

[72] As discussed in U.S. EPA (2023c), the error associated with using a constant discount rate rather than the certainty-equivalent rate path to calculate the present value of a future stream of monetized climate benefits is small for analyses with moderate time frames (e.g., 30 years or less). EPA (2023c) also provides an illustration of the amount that climate benefits from reductions in future emissions will be underestimated by using a constant discount rate relative to the more complicated certainty-equivalent rate path.

Table 4-10 Stream of Projected Climate Benefits under the Final Rule from 2028 through 2037 (discounted to 2023, millions of 2019 dollars)[a]

	Near-term Ramsey Discount Rate		
Emission Year	**2.5%**	**2%**	**1.5%**
2028[b]	7.9	13	22
2029	7.9	13	22
2030[b]	-4.3	-7.1	-12
2031	-4.3	-7.1	-12
2032	12	19	34
2033	12	19	33
2034	12	19	33
2035[b]	11	19	33
2036	11	19	33
2037	11	19	33
PV and EAV			
PV	**76**	**130**	**220**
EAV	**8.7**	**14**	**24**

[a] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using updated estimates of the SC-CO_2 from U.S. EPA (2023c).
[b] IPM run years.

Unlike many environmental problems where the causes and impacts are distributed more locally, GHG emissions are a global externality making climate change a true global challenge. GHG emissions contribute to damages around the world regardless of where they are emitted. Because of the distinctive global nature of climate change, in the RIA for this final rule EPA centers attention on a global measure of climate benefits from GHG reductions.

Consistent with all IWG recommended SC-GHG estimates to date, the SC-GHG values presented in Table 4-9 provide a global measure of monetized damages from CO_2, and Table 4-10and Table 4-11present the monetized global climate benefits of the CO_2 emission reductions expected from the final rule. This approach is the same as that taken in EPA regulatory analyses from 2009 through 2016 and since 2021. It is also consistent with guidance in OMB Circular A-4 (OMB 2003, 2023) that recommends reporting of important international effects.[73] EPA also

[73] The 2003 version of OMB Circular A-4 states when a regulation is likely to have international effects, "these effects should be reported"; while OMB recommends that international effects be reported separately, the guidance also explains that "[d]ifferent regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues." (OMB 2003). The 2023 update to Circular A-4 states that "In certain contexts, it may be particularly appropriate to include effects experienced by noncitizens residing abroad in your primary analysis. Such contexts include, for example, when:

notes that EPA's cost estimates in RIAs, including the cost estimates contained in this RIA, regularly do not differentiate between the share of compliance costs expected to accrue to U.S. firms versus foreign interests, such as to foreign investors in regulated entities.[74] A global perspective on climate effects is therefore consistent with the approach EPA takes on costs. There are many reasons, as summarized in this section —and as articulated by OMB and in IWG assessments (IWG, 2010, 2013, 2016a, 2016b, 2021), the 2015 Response to Comments (IWG, 2015), in detail in U.S. EPA (2023c), in Appendix A of the Response to Comments document for the December 2023 final oil and natural gas sector rulemaking — why EPA focuses on the global value of climate change impacts when analyzing policies that affect GHG emissions.

International cooperation and reciprocity are essential to successfully addressing climate change, as the global nature of GHGs means that a ton of GHGs emitted in any other country harms those in the U.S. just as much as a ton emitted within the territorial U.S. Assessing the benefits of U.S. GHG mitigation activities requires consideration of how those actions may affect mitigation activities by other countries, as those international mitigation actions will provide a benefit to U.S. citizens and residents by mitigating climate impacts that affect U.S. citizens and residents. This is a classic public goods problem because each country's reductions benefit everyone else, and no country can be excluded from enjoying the benefits of other countries' reductions. The only way to achieve an efficient allocation of resources for emissions reduction on a global basis — and so benefit the U.S. and its citizens and residents — is for all

• assessing effects on noncitizens residing abroad provides a useful proxy for effects on U.S. citizens and residents that are difficult to otherwise estimate;
• assessing effects on noncitizens residing abroad provides a useful proxy for effects on U.S. national interests that are not otherwise fully captured by effects experienced by particular U.S. citizens and residents (e.g., national security interests, diplomatic interests, etc.);
• regulating an externality on the basis of its global effects supports a cooperative international approach to the regulation of the externality by potentially inducing other countries to follow suit or maintain existing efforts; or
• international or domestic legal obligations require or support a global calculation of regulatory effects" (OMB 2023. Due to the global nature of the climate change problem, the OMB recommendations of appropriate contexts for considering international effects are relevant to the CO_2 emission reductions expected from the final rule. For example, as discussed in this RIA, a global focus in evaluating the climate impacts of changes in CO_2 emissions supports a cooperative international approach to GHG mitigation by potentially inducing other countries to follow suit or maintain existing efforts, and the global SC-CO_2 estimates better capture effects on U.S. citizens and residents and U.S. national interests that are difficult to estimate and not otherwise fully captured.

[74] For example, in the RIA for the 2018 Proposed Reconsideration of the Oil and Natural Gas Sector Emission Standards for New, Reconstructed, and Modified Sources, EPA acknowledged that some portion of regulatory costs will likely "accru[e] to entities outside U.S. borders" through foreign ownership, employment, or consumption (EPA 2018, p. 3-13). In general, a significant share of U.S. corporate debt and equities are foreign-owned, including in the oil and gas industry.

countries to base their policies on global estimates of damages. A wide range of scientific and economic experts have emphasized the issue of international cooperation and reciprocity as support for assessing global damages of GHG emission in domestic policy analysis. Using a global estimate of damages in U.S. analyses of regulatory actions allows the U.S. to continue to actively encourage other nations, including emerging major economies, to also assess global climate damages of their policies and to take steps to reduce emissions. For example, many countries and international institutions have already explicitly adapted the global SC-GHG estimates used by EPA in their domestic analyses (e.g., Canada, Israel) or developed their own estimates of global damages (e.g., Germany), and recently, there has been renewed interest by other countries to update their estimates since the draft release of the updated SC-GHG estimates presented in the December 2022 oil and natural gas sector supplemental proposal RIA.[75] Several recent studies have empirically examined the evidence on international GHG mitigation reciprocity, through both policy diffusion and technology diffusion effects. See U.S. EPA (2023c) for more discussion.

For all of these reasons, EPA believes that a global metric is appropriate for assessing the climate benefits of avoided GHG emissions in this final RIA. In addition, as emphasized in the National Academies (2017) recommendations, "[i]t is important to consider what constitutes a domestic impact in the case of a global pollutant that could have international implications that impact the United States." The global nature of GHG pollution and its impacts means that U.S. interests are affected by climate change impacts through a multitude of pathways and these need to be considered when evaluating the benefits of GHG mitigation to U.S. citizens and residents. The increasing interconnectedness of global economy and populations means that impacts occuring outside of U.S. borders can have significant impacts on U.S. interests. Examples of affected interests include direct effects on U.S. citizens and assets located abroad, international trade, and tourism, and spillover pathways such as economic and political destabilization and global migration that can lead to adverse impacts on U.S. national security, public health, and

[75] In April 2023, the government of Canada announced the publication of an interim update to their SC-GHG guidance, recommending SC-GHG estimates identical to EPA's updated estimates presented in the December 2022 Supplemental Proposal RIA. The Canadian interim guidance will be used across all Canadian federal departments and agencies, with the values expected to be finalized by the end of the year. *https://www.canada.ca/en/environment-climate-change/services/climate-change/science-research-data/social-cost-ghg.html*.

humanitarian concerns. Those impacts point to the global nature of the climate change problem and are better captured within global measures of the social cost of GHGs.

In the case of these global pollutants, for the reasons articulated in this section, the assessment of global net damages of GHG emissions allows EPA to fully disclose and contextualize the net climate benefits of CO_2 emission reductions expected from this final rule. EPA disagrees with public comments received on the December 2022 oil and natural gas sector supplemental proposal that suggested that EPA can or should use a metric focused on benefits resulting solely from changes in climate impacts occuring within U.S. borders. The global models used in the SC-GHG modeling described above do not lend themselves to be disaggregated in a way that could provide sufficiently robust information about the distribution of the rule's climate benefits to citizens and residents of particular countries, or population groups across the globe and within the U.S. Two of the models used to inform the damage module, the GIVE and DSCIM models, have spatial resolution that allows for some geographic disaggregation of future climate impacts across the world. This permits the calculation of a partial GIVE and DSCIM-based SC-GHG measuring the damages from four or five climate impact categories projected to physically occur within the U.S., respectively, subject to caveats. As discussed at length in U.S. EPA (2023c), these damage modules are only a partial accounting and do not capture all of the pathways through which climate change affects public health and welfare. For example, this modeling omits most of the consequences of changes in precipitation, damages from extreme weather events (e.g., wildfires), the potential for nongradual damages from passing critical thresholds (e.g., tipping elements) in natural or socioeconomic systems, and non-climate mediated effects of GHG emissions other than CO_2 fertilization (e.g., tropospheric ozone formation due to CH_4 emissions). Thus, they only cover a subset of potential climate change impacts. Furthermore, as discussed at length in U.S. EPA (EPA, 2023f), the damage modules do not capture spillover or indirect effects whereby climate impacts in one country or region can affect the welfare of residents in other countries or regions—such as how economic and health conditions across countries will impact U.S. business, investments, and travel abroad.

Additional modeling efforts can and have shed further light on some omitted damage categories. For example, the Framework for Evaluating Damages and Impacts (FrEDI) is an open-source modeling framework developed by EPA to facilitate the characterization of net annual climate change impacts in numerous impact categories within the contiguous U.S. and monetize the associated distribution of modeled damages (Sarofim et al., 2021; U.S. EPA, 2021b)).[76] The additional impact categories included in FrEDI reflect the availability of U.S.-specific data and research on climate change effects. As discussed in U.S. EPA (2023c), results from FrEDI show that annual damages resulting from climate change impacts within the contiguous U.S. (CONUS) (i.e., excluding Hawaii, Alaska, and U.S. territories) and for impact categories not represented in GIVE and DSCIM are expected to be substantial. For example, FrEDI estimates a partial SC-CO_2 of \$36/mtCO_2 for damages physically occurring within CONUS for 2030 emissions (under a 2 percent near-term Ramsey discount rate), compared to a GIVE and DSCIM-based U.S.-specific SC-CO_2 of \$16/mtCO_2 and \$14/mtCO_2, respectively, for 2030 emissions (2019 dollars).

While the FrEDI results help to illustrate how monetized damages physically occurring within CONUS increase as more impacts are reflected in the modeling framework, they are still subject to many of the same limitations associated with the DSCIM and GIVE damage modules, including the omission or partial modeling of important damage categories.[77,78] Finally, none of these modeling efforts–GIVE, DSCIM, and FrEDI–reflect non-climate mediated effects of GHG emissions experienced by U.S. populations (other than CO_2 fertilization effects on agriculture).

Taken together, applying the U.S.-specific partial SC-GHG estimates derived from the multiple lines of evidence described above to the GHG emissions reduction expected under the final rule would yield substantial benefits. For example, the present value of the climate benefits of the final rule over the 2028 to 2037 period as measured by FrEDI from climate change

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[76] The FrEDI framework and Technical Documentation have been subject to a public review comment period and an independent external peer review, following guidance in the EPA Peer-Review Handbook for Influential Scientific Information (ISI). Information on the FrEDI peer-review is available at the EPA Science Inventory (EPA Science Inventory, 2021).

[77] Another method that has produced estimates of the effect of climate change on U.S.-specific outcomes uses a top-down approach to estimate aggregate damage functions. Published research using this approach include total-economy empirical studies that econometrically estimate the relationship between GDP and a climate variable, usually temperature. As discussed in U.S. EPA (2023c), the modeling framework used in the existing published studies using this approach differ in important ways from the inputs underlying the SC-GHG estimates described above (e.g., discounting, risk aversion, and scenario uncertainty). Hence, we do not consider this line of evidence in the analysis for this RIA. Updating the framework of total-economy empirical damage functions to be consistent with the methods described in this RIA and U.S. EPA (2023c) would require new analysis. Finally, because total-economy empirical studies estimate market impacts, they do not include any non-market impacts of climate change (e.g., heat related mortality) and therefore are also only a partial estimate. EPA will continue to review developments in the literature and explore ways to better inform the public of the full range of GHG impacts.

[78] FrEDI estimates a partial SC-CO_2 of \$33/mtCO_2 for damages physically occurring within CONUS for 2030 emissions (under a 2 percent near-term Ramsey discount rate) (Hartin et al., 2023), compared to a GIVE and DSCIM-based U.S.-specific SC-CO_2 of \$14/mtCO_2 and \$12/mtCO_2, respectively, for 2030 emissions (2019 USD).

impacts in CONUS are estimated to be $19 million under a 2 percent near-term Ramsey discount rate.[79] However, the numerous explicitly omitted damage categories and other modeling limitations discussed above and throughout U.S. EPA (2023c) make it likely that these estimates underestimate the benefits to U.S. citizens and residents of the GHG reductions from the final rule; the limitations in developing a U.S.-specific estimate that accurately captures direct and spillover effects on U.S. citizens and residents further demonstrates that it is more appropriate to use a global measure of climate benefits from GHG reductions. EPA will continue to review developments in the literature, including more robust methodologies for estimating the magnitude of the various damages to U.S. populations from climate impacts and reciprocal international mitigation activities, and explore ways to better inform the public of the full range of GHG impacts.

4.5 Total Benefits

Table 4-11 presents the total health and climate benefits[80] for the final rule. Note that while we do not project emissions reductions under the less stringent option, we do expect there to be benefits from the CEMS requirement. However, since we are unable to quantify these benefits, for simplicity, we omit results for the less stringent option in this section.

[79] DCIM and GIVE use global damage functions. Damage functions based on only U.S.-data and research, but not for other parts of the world, were not included in those models. FrEDI does make use of some of this U.S.-specific data and research and as a result has a broader coverage of climate impact categories.

[80] Monetized climate benefits are discounted using a 2 percent discount rate, consistent with EPA's updated estimates of the SC-CO_2. OMB has long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. Because the SC-CO_2 estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the social rate of return on capital (7 percent under OMB Circular A-4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC-CO_2. See Section 4 for more discussion.

Table 4-11 Stream of Monetized Benefits under the Final Rule from 2028 through 2037 (discounted to 2023, millions of 2019 dollars)[a]

Year	Values Calculated using 2% Discount Rate			Values Calculated using 3% Discount Rate			Values Calculated using 7% Discount Rate		
	Health Benefits[b]	Climate Benefits[c,d]	Total	Health Benefits	Climate Benefits (discounted at 2%)[c,d]	Total	Health Benefits	Climate Benefits (discounted at 2%)[c,d]	Total
2028	79	13	92	71	13	84	52	13	66
2029	79	13	92	71	13	84	50	13	63
2030	27	-7.1	20	24	-7.1	17	16	-7.1	9.1
2031	27	-7.1	20	24	-7.1	16	16	-7.1	8.4
2032	14	19	33	13	19	32	8.0	19	27
2033	14	19	34	13	19	32	7.7	19	27
2034	14	19	34	12	19	32	7.3	19	27
2035	14	19	33	12	19	31	7.0	19	26
2036	14	19	33	12	19	31	6.7	19	26
2037	14	19	33	12	19	31	6.4	19	25
PV	**300**	**130**	**420**	**260**	**130**	**390**	**180**	**130**	**300**
EAV	**33**	**14**	**47**	**31**	**14**	**45**	**25**	**14**	**39**
Non-Monetized Benefits[e]									
Benefits from reductions of about 900 to 1000 pounds of Hg annually									
Benefits from reductions about 4 to 7 tons of non-Hg HAP metals annually									
Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS									

[a] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.
[b] Monetized air quality-related benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The estimated value of the air quality-related health benefits included here are the larger of the two estimates presented in Table 4-5, Table 4-6, and Table 4-7.
[c] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of carbon dioxide (SC-CO_2) (under 1.5 percent, 2 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. Please see Table 4-10 for the full range of monetized climate benefit estimates.
[d] The small increases and decreases in climate and health benefits and related EJ impacts result from very small changes in fossil dispatch and coal use relative to the baseline. For context, the projected increase in CO_2 emission of less than 40,000 tons in 2030 is roughly one percent of the emissions of a mid-size coal plant operating at availability (about 4 million tons).
[e] The list of non-monetized benefits does not include all potential non-monetized benefits. See Table 4-8 for a more complete list.

4.6 References

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ECONOMIC IMPACTS

5.1 Overview

Economic impact analyses focus on changes in market prices and output levels. If changes in market prices and output levels in the primary markets are significant enough, impacts on other markets may also be examined. Both the magnitude of costs needed to comply with a rule and the distribution of these costs among affected facilities can have a role in determining how the market will change in response to a rule. This section analyzes the potential impacts on small entities and the potential labor impacts associated with this rulemaking. For additional discussion of impacts on fuel use and electricity prices, see Section 3.

5.2 Small Entity Analysis

For the final rule, EPA performed a small entity screening analysis for impacts on all affected EGUs and non-EGU facilities by comparing compliance costs to historic revenues at the ultimate parent company level. This is known as the cost-to-revenue or cost-to-sales test, or the "sales test." The sales test is an impact methodology EPA employs in analyzing entity impacts as opposed to a "profits test," in which annualized compliance costs are calculated as a share of profits. The sales test is frequently used because revenues or sales data are commonly available for entities impacted by EPA regulations, and profits data normally made available are often not the true profit earned by firms because of accounting and tax considerations. Also, the use of a sales test for estimating small business impacts for a rulemaking is consistent with guidance offered by EPA on compliance with the Regulatory Flexibility Act (RFA)[81] and is consistent with guidance published by the U.S. Small Business Administration's (SBA) Office of Advocacy that suggests that cost as a percentage of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities.[82]

[81] See U.S. EPA. (2006). *Final Guidance for EPA Rulewriters: Regulatory Flexibility Act as Amended by the Small Business and Regulatory Enforcement Fairness Act.* Available at: *https://www.epa.gov/sites/production/files/2015-06/documents/guidance-regflexact.pdf.*

[82] See U.S. SBA Office of Advocacy. (2017). *A Guide for Government Agencies: How to Comply with the Regulatory Flexibility Act.* Available at*: https://advocacy.sba.gov/2017/08/31/a-guide-for-government-agencies-how-to-comply-with-the-regulatory-flexibility-act*.

5.2.1 Methodology

This section presents the methodology and results for estimating the impact of the rule on small EGU entities in the year of compliance, 2028, based on the following endpoints:

- annual economic impacts of the final rule on small entities, and
- ratio of small entity impacts to revenues from electricity generation.

For this analysis, EPA first considered EGUs that are subject to MATS requirements and for which EPA assumed additional controls would be necessary to meet the requirements of the finalized rule. We then refined this list of MATS-affected EGUs, complementing the list with units for which the projected impacts exceeds either of the two criteria below relative to the baseline:

- Fuel use (BTUs) changes by +/- 1 percent or more
- Generation (GWh) changes by +/- 1 percent or more

Please see Section 3 for more discussion of the power sector modeling.

Based on these criteria, EPA identified a total of 377 potentially affected EGUs warranting examination in 2028 in this RFA analysis. Next, we determined power plant ownership information, including the name of associated owning entities, ownership shares, and each entity's type of ownership. We primarily used data from Hitachi — Power Grids, The Velocity Suite I 2020 ("VS"), supplemented by limited research using publicly available data. Majority owners of power plants with affected EGUs were categorized as one of the seven ownership types. These ownership types are:

1. **Investor-Owned Utility (IOU):** Investor-owned assets (e.g., a marketer, independent power producer, financial entity) and electric companies owned by stockholders, etc.
2. **Cooperative (Co-Op):** Non-profit, customer-owned electric companies that generate and/or distribute electric power.
3. **Municipal:** A municipal utility, responsible for power supply and distribution in a small region, such as a city.
4. **Sub-division**: Political subdivision utility is a county, municipality, school district, hospital district, or any other political subdivision that is not classified as a municipality under state law.
5. **Private**: Similar to an investor-owned utility, however, ownership shares are not openly traded on the stock markets.

6. **State:** Utility owned by the state.
7. **Federal:** Utility owned by the federal government.

Next, EPA used both the D&B Hoovers online database and the VS database to identify the ultimate owners of power plant owners identified in the VS database. This was necessary, as many majority owners of power plants (listed in VS) are themselves owned by other ultimate parent entities (listed in D&B Hoovers). In these cases, the ultimate parent entity was identified via D&B Hoovers, whether domestically or internationally owned.

EPA followed SBA size standards to determine which non-government ultimate parent entities should be considered small entities in this analysis. These SBA size standards are specific to each industry, each having a threshold level of either employees, revenue, or assets below which an entity is considered small. SBA guidelines list all industries, along with their associated North American Industry Classification System (NAICS) code and SBA size standard. Therefore, it was necessary to identify the specific NAICS code associated with each ultimate parent entity in order to understand the appropriate size standard to apply. Data from D&B Hoovers were used to identify the NAICS codes for most of the ultimate parent entities. In many cases, an entity that is a majority owner of a power plant is itself owned by an ultimate parent entity with a primary business other than electric power generation. Therefore, it was necessary to consider SBA entity size guidelines for the range of NAICS codes listed in Table 5-1. This table represents the range of NAICS codes and areas of primary business of ultimate parent entities that are majority owners of potentially affected EGUs in EPA's IPM base case.

Table 5-1 SBA Size Standards by NAICS Code

NAICS Code	NAICS U.S. Industry Title	Size Standard (millions of dollars)	Size Standard (number of employees)
211120	Crude Petroleum Extraction		1,250
212221	Gold Ore Mining		1,500
221111	Hydroelectric Power Generation		500
221112	Fossil Fuel Electric Power Generation		750
221113	Nuclear Electric Power Generation		750
221114	Solar Electric Power Generation		250
221115	Wind Electric Power Generation		250
221116	Geothermal Electric Power Generation		250
221117	Biomass Electric Power Generation		250
221118	Other Electric Power Generation		250
221121	Electric Bulk Power Transmission and Control		500
221122	Electric Power Distribution		1,000
221210	Natural Gas Distribution		1,000
221310	Water Supply and Irrigation Systems	$41.00	
221320	Sewage Treatment Facilities	$35.00	
221330	Steam and Air Conditioning Supply	$30.00	
311221	Wet Corn Milling		1,250
311224	Soybean and Other Oilseed Processing		1,000
322121	Paper (except Newsprint) Mills		1,250
325611	Soap and Other Detergent Manufacturing		1,000
325920	Explosives Manufacturing		750
331110	Iron and Steel Mills and Ferroalloy Manufacturing		1,500
332313	Plate Work Manufacturing		750
332911	Industrial Valve Manufacturing		750
333611	Turbine and Turbine Generator Set Unit Manufacturing		1,500
333613	Mechanical Power Transmission Equipment Manufacturing		750
423520	Coal and Other Mineral and Ore Merchant Wholesalers		200
423990	Other Miscellaneous Durable Goods Merchant Wholesalers		100
424690	Other Chemical and Allied Products Merchant Wholesalers		175
424720	Petroleum and Petroleum Products Merchant Wholesalers		200
522110	Commercial Banking	$750.00	
523210	Securities and Commodity Exchanges	$47.00	
523910	Miscellaneous Intermediation	$44.25	
523930	Investment Advice	$41.50	
524126	Direct Property and Casualty Insurance Carriers		1,500
525910	Open-End Investment Funds	$37.50	
525990	Other Financial Vehicles	$40.00	
541330	Engineering Services	$22.50	
541611	Administrative Management and General Management Consulting Services	$21.50	
541715	Research and Development in the Physical, Engineering, and Life Sciences (except Nanotechnology and Biotechnology)		1,000
551112	Offices of Other Holding Companies	$45.50	

NAICS Code	NAICS U.S. Industry Title	Size Standard (millions of dollars)	Size Standard (number of employees)
611310	Colleges, Universities and Professional Schools	$30.50	
721110	Hotels (except Casino Hotels) and Motels	$35.00	
813910	Business Associations	$13.50	

Note: Based on size standards effective at the time EPA conducted this analysis (SBA size standards, effective December 19, 2022. Available at the following link: *https://www.sba.gov/document/support—table-size-standards*). Source: SBA, 2022.

EPA compared the relevant entity size criterion for each ultimate parent entity to the SBA size standard noted in Table 5-1. We used the following data sources and methodology to estimate the relevant size criterion values for each ultimate parent entity:

- **Employment, Revenue, and Assets**: EPA used the D&B Hoovers database as the primary source for information on ultimate parent entity employee numbers, revenue, and assets.[83] In parallel, EPA also considered estimated revenues from affected EGUs based on analysis of IPM parsed-file[84] estimates for the baseline for 2028. EPA assumed that the ultimate parent entity revenue was the larger of the two revenue estimates. In limited instances, supplemental research was also conducted to estimate an ultimate parent entity's number of employees, revenue, or assets.

- **Population**: Municipal entities are defined as small if they serve populations of less than 50,000.[85] EPA primarily relied on data from the Ventyx database and the U.S. Census Bureau to inform this determination.

Ultimate parent entities for which the relevant measure is less than the SBA size standard were identified as small entities and carried forward in this analysis.

In the projected results for 2028, EPA identified 377 potentially affected EGUs, owned by 104 entities. Of these, EPA identified 45 potentially affected EGUs owned by 24 small entities included in the power sector baseline.

[83] Estimates of sales were used in lieu of revenue estimates when revenue data were unavailable.
[84] IPM output files report aggregated results for "model" plants (i.e., aggregates of generating units with similar operating characteristics). Parsed files approximate the IPM results at the generating unit level.
[85] The Regulatory Flexibility Act defines a small government jurisdiction as the government of a city, county, town, township, village, school district, or special district with a population of less than 50,000 (5 U.S.C. section 601(5)). For the purposes of the RFA, States and tribal governments are not considered small governments. EPA's *Final Guidance for EPA Rulewriters: Regulatory Flexibility Act* is located here: *https://www.epa.gov/sites/default/files/2015-06/documents/guidance-regflexact.pdf*.

The chosen compliance strategy will be primarily a function of the unit's marginal control costs and its position relative to the marginal control costs of other units. To attempt to account for each potential control strategy, EPA estimates compliance costs as follows:

$$C_{Compliance} = \Delta\ C_{Operating+Retrofit} + \Delta\ C_{Fuel} + \Delta\ R$$

where C represents a component of cost as labeled and Δ R represents the change in revenues, calculated as the difference in value of electricity generation between the baseline case and the rule in in 2028.

Realistically, compliance choices and market conditions can combine such that an entity may actually experience a reduction in any of the individual components of cost. Under the rule, some units will forgo some level of electricity generation (and thus revenues) to comply, and this impact will be lessened on these entities by the projected increase in electricity prices under the rule. On the other hand, those units increasing generation levels will see an increase in electricity revenues and as a result, lower net compliance costs. If entities are able to increase revenue more than an increase in fuel cost and other operating costs, ultimately, they will have negative net compliance costs (or increased profit). Overall, small entities are not projected to install relatively costly emissions control retrofits but may choose to do so in some instances. Because this analysis evaluates the total costs along each of the compliance strategies laid out above for each entity, it inevitably captures gains such as those described. As a result, what we describe as cost is actually a measure of the net economic impact of the rule on small entities.

For this analysis, EPA used IPM-parsed output to estimate costs based on the parameters above, at the unit level. These impacts were then summed for each small entity, adjusting for ownership share. Net impact estimates were based on the following: operating and retrofit costs, sale or purchase of allowances, and the change in fuel costs or electricity generation revenues under the finalized MATS requirements relative to the base case. These individual components of compliance costs were estimated as follows:

1. **Operating and retrofit costs** ($\Delta\ C_{Operating+Retrofit}$): EPA projected which compliance option would be selected by each EGU in 2028 and applied the appropriate cost to this choice (for details, please see Section 3 of this RIA). For 2028, IPM projected retrofit costs were also included in the calculation.

2. **Fuel costs** ($\Delta\ C_{Fuel}$)**:** The change in fuel expenditures under the final requirements was estimated by taking the difference in projected fuel expenditures between the IPM estimates under the final requirements and the baseline.

3. **Value of electricity generated** ($\Delta\ C_{Fuel}$)**:** To estimate the value of electricity generated, the projected level of electricity generation is multiplied by the regional-adjusted retail electricity price ($/MWh) estimate, for all entities except those categorized as private in Ventyx. See Section 3 for a discussion of the Retail Price Model, which was used to estimate the change in the retail price of electricity. For private entities, EPA used the wholesale electricity price instead of the retail electricity price because most of the private entities are independent power producers (IPP). IPPs sell their electricity to wholesale purchasers and do not own transmission facilities. Thus, their revenue was estimated with wholesale electricity prices.

5.2.2 Results

As indicated above, the use of a sales test for estimating small business impacts for a rulemaking is consistent with guidance offered by EPA on compliance with the RFA and is consistent with guidance published by the SBA's Office of Advocacy that suggests that cost as a percentage of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities. EPA assessed the economic and financial impacts of the rule using the ratio of compliance costs to the value of revenues from electricity generation, focusing in particular on entities for which this measure is greater than 1 percent.

The projected impacts, including compliance costs, of the rule on small entities are summarized in Table 5-2. All costs are presented in 2019 dollars. We projected the annual net compliance cost to small entities to be approximately $2.0 million in 2028. Relative to the baseline, the rule is projected to generate compliance cost reductions greater than 1 percent of baseline revenue for one of the 24 small entities directly impacted, and compliance cost increases greater than 1 percent are projected for two. The remaining 23 entities are not projected to experience compliance cost changes of more than 1 percent. Of the 24 entities considered in this analysis, two are holding units projected to experience compliance cost increases greater than 1 percent of generation revenue at a facility level as well as at a parent holding company level.

Table 5-2 Projected Impacts of Final Rule on Small Entities in 2028

EGU Ownership Type	Number of Potentially Affected Entities	Total Net Compliance Cost (millions 2019 dollars)	Number of Small Entities with Compliance Costs >1% of Generation Revenues
Subdivision	1	-0.029	0
Investor Owned	3	-0.056	0
Private	7	-0.059	0
Co-op	13	2.1	1
Total	**24**	**2.0**	1

5.2.3 Conclusion

Making a determination that there is not a significant economic impact on a substantial number of small entities (often referred to as a "SISNOSE") requires an assessment of whether an estimated economic impact is significant and whether that impact affects a substantial number of small entities. EPA identified 104 potentially affected EGU entities in the projection year of 2028. Of these, EPA identified 24 small entities affected by the rule, and of these, three small entities may experience costs of greater than 1 percent of revenues. Based on this analysis, for this rule overall we conclude that the estimated costs for the final rule will not have a significant economic impact on a substantial number of small entities.

5.3 Labor Impacts

This section discusses potential employment impacts of this regulation. As economic activity shifts in response to a regulation, typically there will be a mix of declines and gains in employment in different parts of the economy over time and across regions. To present a complete picture, an employment impact analysis will describe the potential positive and negative changes in employment levels. There are significant challenges when trying to evaluate the employment effects of an environmental regulation due to a wide variety of other economic changes that can affect employment, including the impact of the coronavirus pandemic on labor markets and the state of the macroeconomy generally. Considering these challenges, we look to the economics literature to provide a constructive framework and empirical evidence. To simplify, we focus on impacts on labor demand related to compliance behavior. Environmental regulation may also affect labor supply through changes in worker health and productivity (Zivin and Neidell, 2018).

Economic theory of labor demand indicates that employers affected by environmental regulation may increase their demand for some types of labor, decrease demand for other types, or for still other types, not change their demand at all (Berman and Bui, 2001; Deschenes, 2018; Morgenstern et al., 2002). To study labor demand impacts empirically, a growing literature has compared employment levels at facilities subject to an environmental regulation to employment levels at similar facilities not subject to that environmental regulation; some studies find no employment effects, and others find significant differences. For example, see Berman and Bui (2001), Greenstone (2002), Ferris et al. (2014), and Curtis (2018, 2020). A variety of conditions can affect employment impacts of environmental regulation, including baseline labor market conditions and employer and worker characteristics such as occupation and industry. Changes in employment may also occur in different sectors related to the regulated industry, both upstream and downstream, or in sectors producing substitute or complimentary products. Employment impacts in related sectors are often difficult to measure. Consequently, we focus our labor impacts analysis primarily on the directly regulated facilities and other EGUs and related fuel markets.

This section discusses and projects potential employment impacts for the utility power, coal and natural gas production sectors that may result from the final rule. EPA has a long history of analyzing the potential impacts of air pollution regulations on changes in the amount of labor needed in the power generation sector and directly related sectors. The analysis conducted for this RIA builds upon the approaches used in the past and takes advantage of newly available data to improve the assumptions and methodology.[86]

The results presented in this section are based on a methodology that estimates the impact on employment based on the differences in projections between two modeling scenarios: the baseline scenario, and a scenario that represents the implementation of the rule. The estimated employment difference between these scenarios can be interpreted as the incremental effect of the rule on employment in this sector. As discussed in Section 3, there is uncertainty related to the future baseline projections. Because the incremental employment estimates presented in this section are based on projections discussed in Section 3, it is important to highlight the relevance

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[86] For a detailed overview of this methodology, including all underlying assumptions, see the U.S. EPA Methodology for Power Sector-Specific Employment Analysis, available in the docket.

of the Section 3 uncertainty discussion to the analysis presented in this section. Note that there is also uncertainty related to the employment factors applied in this analysis, particularly factors informing job-years related to relatively new technologies, such as energy storage, on which there is limited data to base assumptions.

Like previous analyses, this analysis represents an evaluation of "first-order employment impacts" using a partial equilibrium modeling approach. It includes some of the potential ripple effects of these impacts on the broader economy. These ripple effects include the secondary job impacts in both upstream and downstream sectors. The analysis includes impacts on upstream sectors including coal, natural gas, and uranium. However, the approach does not analyze impacts on other fuel sectors, nor does it analyze potential impacts related to transmission or distribution. This approach excludes the economy-wide employment effects of changes to energy markets (such as higher or lower forecasted electricity prices). This approach also excludes labor impacts that are sometimes reflected in a benefits analysis for an environmental policy, such as increased productivity from a healthier workforce and reduced absenteeism due to fewer sick days of employees and dependent family members (e.g., children).

5.3.1 Overview of Methodology

The methodology includes the following two general approaches, based on the available data. The first approach uses detailed employment data that are available for several types of generation technologies in the 2020 U.S. Energy and Employment Report (USEER).[87] For employment related to other electric power sector generating and pollution control technologies, the second approach uses information available in the U.S. Economic Census.

Detailed employment inventory data are available regarding recent employment related to coal, hydro, natural gas, geothermal, wind, and solar generation technologies as well as battery storage. The data enables the creation of technology-specific factors that can be applied to model projections of capacity (reported in MW) and generation (reported in megawatt-hours, or MWh) to estimate impacts on employment. Since employment data are only available in aggregate by fuel type, it is necessary to disaggregate by labor type to differentiate between types of jobs or tasks for categories of workers. For example, some types of employment remain constant

[87] *https://www.usenergyjobs.org/*.

throughout the year and are largely a function of the size of a generator, e.g., fixed operation and maintenance activities, while others are variable and are related to the amount of electricity produced by the generator, e.g., variable operation and maintenance activities.

The approach can be summarized in three basic steps:

- Quantify the total number of employees by fuel type in a given year;
- Estimate total fixed operating & maintenance (FOM), variable operating & maintenance (VOM), and capital expenditures by fuel type in that year; and
- Disaggregate total employees into three expenditure-based groups and develop factors for each group (FTE/MWh, FTE/MW-year, FTE/MW new capacity).

Where detailed employment data are unavailable, it is possible to estimate labor impacts using labor intensity ratios. These factors provide a relationship between employment and economic output and are used to estimate employment impacts related to construction and operation of pollution control retrofits, as well as some types of electric generation technologies.

For a detailed overview of this methodology, including all underlying assumptions and the types of employment represented by this analysis, see the U.S. EPA Methodology for Power Sector-Specific Employment Analysis, available in the docket.

5.3.2 Overview of Power Sector Employment

In this section we focus on employment related to electric power generation, as well as coal and natural gas extraction because these are the segments of the power sector that are most relevant to the projected impacts of the rule. Other segments not discussed here include other fuels, energy efficiency, and transmission, distribution, and storage. The statistics presented here are based on the 2020 USEER, which reports data from 2019.[88]

In 2019, the electric power generation sector employed nearly 900,000 people. Relative to 2018, this sector grew by over 2 percent, despite job losses related to nuclear and coal generation. These losses were offset by increases in employment related to other generating technologies, including natural gas, solar, and wind. The largest component of total 2019

[88] While 2020 data are available in the 2021 version of this report, this section of the RIA utilizes 2019 data because this year does not reflect any short-term trends related to the COVID-19 pandemic. The annual report is available at: *https://www.usenergyjobs.org/*.

employment in this sector is construction (33 percent). Other components of the electric power generation workforce include utility workers (20 percent), professional and business service employees (20 percent), manufacturing (13 percent), wholesale trade (8 percent), and other (5 percent). In 2019, jobs related to solar and wind generation represent 31 percent and 14 percent of total jobs, respectively, and jobs related to coal generation represent 10 percent of total employment.

In addition to generation-related employment, we also look at employment related to coal and natural gas use in the electric power sector. In 2019, the coal industry employed about 75,000 workers. Mining and extraction jobs represent the vast majority of total coal-related employment in 2019 (74 percent). The natural gas fuel sector employed about 276,000 employees in 2019. About 60 percent of those jobs were related to mining and extraction.

5.3.3 Projected Sectoral Employment Changes due to the Final Rule

Electric generating units subject to the Hg and fPM emission limits in this rule will likely use various Hg and PM control strategies to comply. EPA estimates that 11.6 GW of operational coal capacity would either need to improve existing PM controls or install new PM controls to comply with the final rule in 2028. The various PM control upgrades that EPA assumes would be necessary to achieve with the emissions limits analyzed are summarized in Table 3-8.

Based on these power sector modeling projections, we estimate an increase in construction-related job-years related to the installation of new pollution controls under the rule, as well as the construction of new generating capacity. In 2028, we estimate an increase of approximately 1,600 construction-related job-years related to the construction of new pollution controls or control upgrades and an increase of approximately 200 job-years related to the construction of new capacity. In 2030, we estimate a small decrease in construction job-years for new pollution controls and new capacity, followed by an increase of 500 construction job-years for new capacity in 2035. Construction-related job-year changes are one-time impacts, occurring during each year of the multi-year periods during which construction of new capacity is completed. Construction-related figures in Table 5-3 represent a point estimate of incremental changes in construction jobs for each year (for a three-year construction projection, this table presents one-third of the total jobs for that project).

Table 5-3 Projected Changes in Labor Utilization: Construction-Related (Number of Job-Years of Employment in a Single Year)

	2028	2030	2035
New Pollution Controls	1,600	<100	<100
New Capacity	200	<100	500

Notes: "<100" denotes an increase or decrease of fewer than 100 job-years. A large share of the construction-related job years is attributable to construction of energy storage, a relatively new technology on which there is limited data to base labor assumptions.

We also estimate changes in the number of job-years related to recurring non-construction employment. Recurring employment changes are job-years associated with annual recurring jobs including operating and maintenance activities and fuel extraction jobs. Newly built generating capacity creates a recurring stream of positive job-years, while retiring generating capacity, as well as avoided capacity builds, create a stream of negative job-years. Consistent with the small projected changes in generation over 2028 through 2035, this rule is expected to result in small impacts in recurring non-construction jobs. Table 5-4 provides detailed estimates of recurring non-construction employment changes.

Table 5-4 Projected Changes in Labor Utilization: Recurring Non-Construction (Number of Job-Years of Employment in a Single Year)

	2028	2030	2035
Pollution Controls	<100	<100	<100
Existing Capacity	<100	<100	<100
New Capacity	<100	<100	<100
Fuels (Coal, Natural Gas, Uranium)	<100	<100	<100
Coal	*<100*	*<100*	*<100*
Natural Gas	*<100*	*<100*	*<100*
Uranium	*<100*	*<100*	*<100*

Note: "<100" denotes an increase or decrease of fewer than 100 job-years; Numbers may not sum due to rounding.

5.3.4 Conclusions

Generally, there are significant challenges when trying to evaluate the employment effects due to an environmental regulation from employment effects due to a wide variety of other economic changes, including the impact of the coronavirus pandemic on labor markets and the state of the macroeconomy generally. For EGUs, this rule may result in a sizable near-term increase in construction-related jobs related to the installation of new pollution controls, and any changes in recurring non-construction employment are expected to be small.

5.4 References

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ENVIRONMENTAL JUSTICE IMPACTS

6.1 Introduction

E.O. 12898 directs EPA to "achiev[e] environmental justice (EJ) by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects" (59 FR 7629, February 16, 1994), termed disproportionate impacts in this section. Additionally, E.O. 13985 was signed to advance racial equity and support underserved communities through Federal government actions (86 FR 7009, January 20, 2021). Most recently, E.O. 14096 (88 FR 25251, April 26, 2023) strengthens the directives for achieving environmental justice that are set out in E.O. 12898. EPA defines EJ as the just treatment and meaningful involvement of all people regardless of race, color, national origin, Tribal affiliation, disability, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. EPA further defines the term just 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."[89] Meaningful involvement means that: (1) potentially affected populations have an appropriate opportunity to participate in decisions about a proposed activity that will affect their environment and/or health; (2) the public's contribution can influence the regulatory Agency's decision; (3) the concerns of all participants involved will be considered in the decision-making process; and (4) the rule-writers and decision-makers seek out and facilitate the involvement of those potentially affected.

The term "disproportionate impacts" refers to differences in impacts or risks that are extensive enough that they may merit Agency action.[90] In general, the determination of whether a disproportionate impact exists is ultimately a policy judgment which, while informed by analysis, is the responsibility of the decision-maker. The terms "difference" or "differential" indicate an analytically discernible distinction in impacts or risks across population groups. It is the role of the analyst to assess and present differences in anticipated impacts across population

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[89] See, e.g., "Environmental Justice." *EPA.gov*, U.S. Environmental Protection Agency, 4 Mar. 2021, *https://www.epa.gov/environmentaljustice*.
[90] See *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis*.

groups of concern for both the baseline and regulatory options, using the best available information (both quantitative and qualitative) to inform the decision-maker and the public.

The Presidential Memorandum on Modernizing Regulatory Review (86 FR 7223; January 20, 2021) calls for procedures to “take into account the distributional consequences of regulations, including as part of a quantitative or qualitative analysis of the costs and benefits of regulations, to ensure that regulatory initiatives appropriately benefit, and do not inappropriately burden disadvantaged, vulnerable, or marginalized communities.” Under E.O. 13563, federal agencies may consider equity, human dignity, fairness, and distributional considerations, where appropriate and permitted by law. For purposes of analyzing regulatory impacts, EPA relies upon its June 2016 “Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,”[91] which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance. The Technical Guidance states that a regulatory action may involve potential EJ concerns if it could: (1) create new disproportionate impacts; (2) exacerbate existing disproportionate impacts; or (3) present opportunities to address existing disproportionate impacts through the action under development.

A reasonable starting point for assessing the need for a more detailed EJ analysis is to review the available evidence from the published literature and from community input on what factors may make population groups of concern more vulnerable to adverse effects (e.g., underlying risk factors that may contribute to higher exposures and/or impacts). It is also important to evaluate the data and methods available for conducting an EJ analysis. EJ analyses can be grouped into two types, both of which are informative, but not always feasible for a given rulemaking:

1. **Baseline:** Describes the current (pre-control) distribution of exposures and risk, identifying potential disparities.
2. **Policy:** Describes the distribution of exposures and risk after the regulatory option(s) have been applied (post-control), identifying how potential disparities change in response to the rulemaking.

[91] See *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis*.

EPA's 2016 Technical Guidance does not prescribe or recommend a specific approach or methodology for conducting EJ analyses, though a key consideration is consistency with the assumptions underlying other parts of the regulatory analysis when evaluating the baseline and regulatory options.

6.2 Analyzing EJ Impacts in this Final Rule

In addition to the benefits assessment (see Section 4), EPA considers potential EJ concerns associated with this final rulemaking. A potential EJ concern is defined as "the actual or potential lack of fair treatment or meaningful involvement of communities with EJ concerns in the development, implementation and enforcement of environmental laws, regulations and policies."[92] For analytical purposes, this concept refers more specifically to "disproportionate impacts on communities with EJ concerns that may exist prior to or that may be created by the final regulatory action." Although EJ concerns for each rulemaking are unique and should be considered on a case-by-case basis, EPA's EJ Technical Guidance 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 [, exacerbated,] or mitigated compared to the baseline?"

To address these questions, EPA developed an analytical approach that considers the purpose and specifics of the rulemaking, as well as the nature of known and potential exposures across various demographic groups. While the final rule targets HAP emissions, other local air pollutants emissions may also be reduced, such as NO_X and SO_2. NO_X and SO_2 emissions can lead to localized exposures that may be associated with health effects in nearby populations at sufficiently high concentrations and certain populations may be at increased risk of exposure-related health effects, such as people with asthma.

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[92] See *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis*.

As HAP exposure results generated as part of the 2020 Residual Risk analysis were below both the presumptive acceptable cancer risk threshold and the noncancer health benchmarks, and this final 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. In addition, technical limitations prevented analysis of NO_X and SO_2 emission reductions. While HAP, NO_2, and SO_2 exposures and concentrations were not directly evaluated as part of this EJ assessment, due to the potential for reductions in these and other environmental stressors nearby affected sources, EPA qualitatively discussed EJ impacts of HAP (Section 6.3) and conducted a proximity analysis to evaluate the potential EJ implications of changes in localized exposures (Section 6.4).[93]

As this final rule is also expected to reduce ambient $PM_{2.5}$ and ozone concentrations, EPA conducted a quantitative analysis of modeled changes in $PM_{2.5}$ and ozone concentrations across the continental U.S. resulting from the control strategies projected to occur under the rule, characterizing aggregated and distributional exposures both prior to and following implementation of the final regulatory option in 2028, 2030, and 2035 (Section 6.5 and 6.7). It is important to note that due to the small magnitude of underlying emissions changes, and the corresponding small magnitude of the ozone and $PM_{2.5}$ concentration changes, the rule is expected to have only a small impact on the distribution of exposures across each demographic group. As the final rule is also focused on climate impacts resulting from emissions reductions directly targeted in this rulemaking, EPA qualitatively discussed climate impacts in Section 6.6.

Unique limitations and uncertainties are specific to each type of analysis, which are described prior to presentation of analytic results in the subsections below.

6.3 Qualitative Assessment of HAP Impacts

As required by section 112(n)(1)(A) of the CAA, EPA has determined that it is appropriate and necessary to regulate HAP emissions from coal- and oil-fired EGUs. This determination was driven by the significant public health risks and harms posed by prior levels of EGU emissions as evaluated against the availability and costs of emissions controls that could be employed to reduce this harmful pollution. As part of the appropriate and necessary

[93] The 2016 NO_X ISA and 2017 SO_X ISA identified people with asthma, children, and older adults as being at increased risk of NO_2- and SO_2-related health effects and the 2017 SO_X ISA.

determination, the Administrator specifically considered the impacts of EGU HAP emissions on different populations and concluded that certain parts of the U.S. population may be especially vulnerable to Hg emissions based on their characteristics or circumstances. In some cases, the enhanced vulnerability relates to life stage (e.g., fetuses, infants, young children). In other cases, the enhanced vulnerability can be ascribed to the communities in which the population lives. In this second category, the greater sensitivity to HAP emissions can be attributed to poorer levels of overall health (e.g., higher rates of cardiovascular disease, nutritional deficiencies) or to dietary practices which are more common in some low-income communities of color (e.g., subsistence fishers). The net effect is that certain sub-populations may be especially vulnerable to EGU HAP emissions and that these emissions are a potential EJ concern.

Of the HAP potentially impacted by this final rulemaking, Hg is a persistent and bioaccumulative toxic metal that can be readily transported and deposited to soil and aquatic environments where it is transformed by microbial action into MeHg.[94] Consumption of fish is the primary pathway for human exposure to MeHg. MeHg bioaccumulates in the aquatic food web eventually resulting in highly concentrated levels of MeHg within larger fish.[95] A NAS Study reviewed the effects of MeHg on human health and concluded that it is highly toxic to multiple human and animal organ systems. Of particular concern is chronic prenatal exposure via maternal consumption of foods containing MeHg. Elevated exposure has been associated with developmental neurotoxicity and manifests as poor performance on neurobehavioral tests, particularly on tests of attention, fine motor function, language, verbal memory, and visual-spatial ability. Because the impacts of the neurodevelopmental effects of MeHg are greatest during periods of rapid brain development, developing fetuses, infants, and young children are particularly vulnerable. In particular, children born to populations with high fish consumption (e.g., people consuming fish as a dietary staple) or impaired nutritional status may be especially susceptible to adverse neurodevelopmental outcomes. As part of the 2023 Final A&N Review, EPA evaluated how the neurodevelopmental and cardiovascular risks varied across populations. That analysis completed in support of the appropriate and necessary determination (addressing the EGU sector collectively) suggested that subsistence fisher populations that are racially,

[94] U.S. EPA. 1997. Mercury Study Report to Congress. EPA–452/R–97–003 December 1997.
[95] National Research Council (NAS). 2000. Toxicological Effects of MeHg. Committee on the Toxicological Effects of MeHg, Board on Environmental Studies and Toxicology, National Research Council.

culturally, geographically, and/or income-differentiated could experience elevated exposures relative to not only the general population but also the population of subsistence fishers generally. As noted in Section 4 of this document, while previous EPA assessments have shown that current modeled exposures are well below the RfD, we conclude that further reductions in Hg emissions from lignite-fired EGUs covered in this final action should further reduce exposures for the subsistence fisher sub-population. However, as we do not expect appreciable adverse health effects as a result of HAP emissions from this source category, we have not conducted quantitative or qualitative analyses to assess specific Hg-related impacts of this action for EJ communities of potential concern or how those impacts differ from U.S. population-wide effects.

6.4 Demographic Proximity Analyses of Existing Facilities

Demographic proximity analyses allow one to assess the potentially vulnerable populations residing near affected facilities as a proxy for exposure and the potential for adverse health impacts that may occur at a local scale due to economic activity at a given location including noise, odors, traffic, and emissions such as NO_2 and SO_2 covered under this EPA action and not modeled elsewhere in this RIA.

Although baseline proximity analyses are presented here, several important caveats should be noted. Emissions are expected to both decrease and increase from the rulemaking in the three modeled future years, so communities near affected facilities could experience either improvements or worsening in air quality from directly emitted pollutants. It should also be noted that facilities may vary widely in terms of the impacts they already pose to nearby populations. In addition, proximity to affected facilities does not capture variation in baseline exposure across communities, nor does it indicate that any exposures or impacts will occur and should not be interpreted as a direct measure of exposure or impact. These points limit the usefulness of proximity analyses when attempting to answer questions from EPA's EJ Technical Guidance.

Demographic proximity analyses were performed for all plants with at least one coal-fired unit greater than 25 MW without retirement or gas conversion plans before 2029 affected by this final rulemaking. Due to the distinct regulatory requirements, the following subsets of affected facilities were separately evaluated:

- Coal plants with units potentially impacted by the final Hg standard revision (12 facilities): Comparison of the percentage of various populations (race/ethnicity, age, education, poverty status, income, and linguistic isolation) living near the facilities to average national levels.
- Coal plants with units potentially impacted by the final fPM standard revision (21 facilities): Comparison of the percentage of various populations (race/ethnicity, age, education, poverty status, income, and linguistic isolation) living near the facilities to average national levels.

The current analysis identified all census blocks with centroids within a 10-km radius of the latitude/longitude location of each facility, and then linked each block with census-based demographic data.[96] The total population within a specific radius around each facility is the sum of the population for every census block within that specified radius, based on each block's population provided by the 2020 decennial Census.[97] Statistics on race, ethnicity, age, education level, poverty status and linguistic isolation were obtained from the Census' American Community Survey (ACS) 5-year averages for 2016-2020. These data are provided at the block group level. For the purposes of this analysis, the demographic characteristics of a given block group – that is, the percentage of people in different races/ethnicities, the percentage without a high school diploma, the percentage that are below the poverty level, the percentage that are below two times the poverty level, and the percentage that are linguistically isolated – are presumed to also describe each census block located within that block group.

In addition to facility-specific demographics, the demographic composition of the total population within the specified radius (e.g., 10 km) for all facilities was also computed (e.g., all EGUs potentially impacted by the Hg standard revision). In calculating the total populations, to avoid double-counting, each census block population was only counted once. That is, if a census block was located within the selected radius (i.e., 10 km) for multiple facilities, the population of that census block was only counted once in the total population. Finally, this analysis compares the demographics at each specified radius (i.e., 10 km) to the demographic composition of the nationwide population.

[96] The 10-km distance was determined to be the shortest radius around these units that captured a large enough population to avoid excessive demographic uncertainty.
[97] The location of the Census block centroid is used to determine if the entire population of the Census block is assumed to be within the specified radius. It is unknown how sensitive these results may be to different methods of population estimation, such as aerial apportionment.

Table 6-1For the population living within 10 km of lignite-fired coal plants potentially impacted by the Hg standard, the percentage of the population that is American Indian and Alaska Native Tribes is above the national average (0.9 percent versus 0.6 percent), and the percentage of the population that is Hispanic/Latino or Other/Multiracial is below the corresponding national averages. The percentage of the population that is Black, below the poverty level and below two times the poverty level is similar to the national averages. Finally, the percentage of the population that is in linguistic isolation is below the national average.

The population living within 10 km of the units potentially impacted by the PM standard is 86 percent White. The percentage of the population that is below two times the poverty level is above the national average (32 percent versus 29 percent). The percentage of the population in the other demographic categories is near or below the national averages.

Table 6-1 Proximity Demographic Assessment Results Within 10 km of Coal-Fired Units Greater than 25 MW Without Retirement or Gas Conversion Plans Before 2029 Affected by this Rulemaking [a,b]

		Population within 10 km	
Demographic Group	**Nationwide Average for Comparison**	**Coal plants potentially impacted by Hg standard**	**Coal plants potentially impacted by fPM standard**
Total Population	329,824,950	17,790	233,575
Number of Facilities	-	12	28
Race and Ethnicity by Percent			
White	60%	79%	86%
Black	12%	12%	7%
American Indian and Alaska Native Tribes	0.60%	0.9%	0.3%
Hispanic or Latino[2]	19%	5%	5%
Other and Multiracial	9%	2%	3%
Income by Percent			
Below Poverty Level	13%	12%	14%
Below 2x Poverty Level	29%	28%	32%
Education by Percent			
>25 and w/o a HS Diploma	12%	13%	12%
Linguistically Isolated by Percent			
Linguistically Isolated	5%	2%	1%

[a] The nationwide population count and all demographic percentages are based on the Census' 2016-2020 American Community Survey five-year block group averages and include Puerto Rico. Demographic percentages based on different averages may differ. The total population counts are based on the 2020 Decennial Census block populations.
[b] To avoid double counting, the "Hispanic or Latino" category is treated as a distinct demographic category for these analyses. A person is identified as one of five racial/ethnic categories above: White, Black, American Indian and Alaska Native Tribes, Other and Multiracial, or Hispanic/Latino. A person who identifies as Hispanic or Latino is counted as Hispanic/Latino for this analysis, regardless of what race this person may have also identified as in the Census. Includes white and nonwhite.

6.5 EJ $PM_{2.5}$ and Ozone Exposure Impacts

This EJ air pollutant exposure[98] analysis aims to evaluate the potential for EJ concerns related to $PM_{2.5}$ and ozone exposures[99] among potentially vulnerable populations. To assess EJ ozone and $PM_{2.5}$ exposure impacts, we focus on the first and third of the three EJ questions from

[98] The term exposure is used here to describe estimated $PM_{2.5}$ and ozone concentrations and not individual dosage.
[99] Air quality surfaces used to estimate exposures are based on 12-km grids. Additional information on air quality modeling can be found in the air quality modeling information section.

EPA's 2016 EJ Technical Guidance,[100] which ask if there are potential EJ concerns associated with stressors affected by the regulatory action for population groups of concern in the baseline and if those potential EJ concerns in the baseline are exacerbated, unchanged, or mitigated under the regulatory options being considered.[101]

To address these questions with respect to the $PM_{2.5}$ and ozone exposures, EPA developed an analytical approach that considers the purpose and specifics of this rulemaking, as well as the nature of known and potential exposures and impacts. Specifically, as 1) this final rule affects EGUs across the U.S., which typically have tall stacks that result in emissions from these sources being dispersed over large distances, and 2) both ozone and $PM_{2.5}$ can undergo long-range transport, it is appropriate to conduct an EJ assessment of the contiguous U.S. Given the availability of modeled $PM_{2.5}$ and ozone air quality surfaces under the baseline and final regulatory option, we conduct an analysis of changes in $PM_{2.5}$ and ozone concentrations resulting from the emission changes projected under the final rule as compared to the baseline scenario, characterizing average and distributional exposures the analysis years 2028, 2030, and 2035. However, several important caveats of this analysis are as follows:

- The baseline scenarios for 2028, 2030, and 2035 represent EGU emissions expected in 2028, 2030, and 2035 respectively, but emissions from all other sources are projected to the year 2026. The 2028, 2030, and 2035 baselines therefore do not capture any anticipated changes in ambient ozone and $PM_{2.5}$ between 2026 and 2028, 2030, or 2035 that would occur due to emissions changes from sources other than EGUs.
- Modeling of post-policy air quality concentration changes are based on state-level emission data paired with facility-level baseline 2026 emissions that were available in the summer 2021 version of IPM. While the baseline spatial patterns represent ozone and $PM_{2.5}$ concentrations associated with the facility level emissions described above, the post-policy air quality surfaces will capture expected ozone and $PM_{2.5}$ changes that result

[100] U.S. Environmental Protection Agency (EPA), 2015. Guidance on Considering Environmental Justice During the Development of Regulatory Actions. *https://www.epa.gov/sites/default/files/2015-06/documents/considering-ej-in-rulemaking-guide-final.pdf*.

[101] EJ question 2 asks if there are potential EJ concerns (i.e., disproportionate burdens across population groups) associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory options under consideration We use the results from questions 1 and 3 to gain insight into the answer to EJ question 2 in the summary (Section 6.7), for several reasons. Importantly, the total magnitude of differential exposure burdens with respect to ozone and $PM_{2.5}$ among population groups at the national scale has been fairly consistent pre- and post-policy implementation across recent rulemakings. As such, differences in nationally aggregated exposure burden averages between population groups before and after the rulemaking tend to be very similar. Therefore, as disparities in pre- and post-policy burden results appear virtually indistinguishable, the difference attributable to the rulemaking can be more easily observed when viewing the change in exposure impacts, and as we had limited available time and resources, we chose to provide quantitative results on the pre-policy baseline and policy-specific impacts only, which related to EJ questions 1 and 3.

from state-to-state emissions changes but will not capture heterogenous changes in emissions from multiple facilities within a single state.

- Air quality simulation input information are at a 12-km grid resolution and population information is either at the Census tract- or county-level, potentially masking impacts at geographic scales more highly resolved than the input information.
- The two specific air pollutant metrics evaluated in this assessment, warm season maximum daily eight-hour ozone average concentrations and average annual $PM_{2.5}$ concentrations, are focused on longer-term exposures that have been linked to adverse health effects. This assessment does not evaluate disparities in other potentially health-relevant metrics, such as shorter-term exposures to ozone and $PM_{2.5}$.
- $PM_{2.5}$ EJ impacts were limited to exposures, and do not extend to health effects, given additional uncertainties associated with estimating health effects stratified by demographic population and the ability to predict differential $PM_{2.5}$-attributable EJ health impacts.

Population variables considered in this EJ exposure assessment include race, ethnicity, educational attainment, employment status, health insurance status, life expectancy, linguistic isolation, poverty status, redlined areas, tribal land, age, and sex (Table 6-2).[102,103,104,105] Note that these variables are different than the proximity analysis because criteria pollutants have nationwide impacts rather than the localized impacts that are investigated for HAP in the proximity analysis. There are also fewer demographic uncertainties at a national scale which allows us to use an expanded set of variables for a nationwide analysis.

[102] Population projections stratified by race/ethnicity, age, and sex are based on economic forecasting models developed by Woods and Poole (2015). The Woods and Poole database contains county-level projections of population by age, sex, and race out to 2050, relative to a baseline using the 2010 Census data. Population projections for each county are determined simultaneously with every other county in the U.S to consider patterns of economic growth and migration. County-level estimates of population percentages within the poverty status and educational attainment groups were derived from 2015-2019 5-year average ACS estimates. Additional information can be found in Appendix J of the BenMAP-CE User's Manual (*https://www.epa.gov/benmap/benmap-ce-manual-and-appendices*).

[103] The Tribal Land variable was also added in response to recent Executive Orders that have emphasized the need for more detailed analysis on the impacts on American Indians. The Tribal Lands variable focuses specifically on populations who live on Tribal lands in addition to quantifying those whose race is American Indian but may or may not live on Tribal lands.

[104] EPA acknowledges the recent comments about cumulative risk assessment and is currently in the process of developing cumulative risk assessment methods for our quantitative environmental justice analyses. In the interim, this rulemaking utilizes the "life expectancy" and "redlining" variables as a proxy to identify communities with higher or lower exposure to cumulative risks. EPA continues to improve its methodology based on its framework for a Cumulative Risk Assessment as well as guidance from multiple Executive Orders and intend to assess cumulative risk more accurately in future rulemakings.

[105] An additional population variable that is not included in this analysis is persons with disability. Persons with disability is a new environmental justice metric listed in E.O. 14096 (88 FR 25251, April 26, 2023), and EPA is currently developing analytical techniques/tools to evaluate its impact on our environmental analyses.

The demographic groups and processing methodology for each dataset are described below. County-level datasets were generated for 3,109 counties in the contiguous U.S.

Table 6-2 Demographic Populations Included in the $PM_{2.5}$ and Ozone EJ Exposure Analyses

Demographic	Groups	Ages	Spatial Scale of Population Data
Race	Asian; American Indian; Black; White	0-99	Census tract
Ethnicity	Hispanic; Non-Hispanic	0-99	Census tract
Educational Attainment	High school degree or more; No high school degree	25-99	Census tract
Employment Status	Employed; Unemployed; Not in the labor force	0-99	County
Health Insurance	Insured; Uninsured	0-64	County
Linguistic Isolation	Speaks English "very well" or better; Speaks English less than "very well" OR Speaks English "well" or better; Speaks English less than "well"	0-99	Census tract
Poverty Status	Above the poverty line; Below the poverty line OR Above 2x the poverty line; Below 2x the poverty line	0-99	Census tract
Redlined Areas	HOLC[a] Grades A-C; HOLC Grade D; Not graded by HOLC	0-99	Census tract
Life Expectancy	Top 75%; Bottom 25%	0-99	Census tract
Tribal Land	Tribal land; Not Tribal land	0-99	Census tract
Age	Children Adults Older Adults	0-17 18-64 65-99	Census tract
Sex	Female; Male	0-99	Census tract

[a] *Home Owners' Loan Corporation (HOLC)*

6.5.1 Populations Predicted to Experience $PM_{2.5}$ and Ozone Air Quality Changes

While EPA projects the final rule will lead to both decreases and increases in emissions in different regions, the magnitude of the air pollution exposure changes from the final rule is quite small across the three future years analyzed. For all three future years evaluated, there were no discernable $PM_{2.5}$ or ozone concentration changes out to the hundredths digit, reiterating the small magnitude of national average $PM_{2.5}$ or ozone changes (Figure 6-1 and Figure 6-2).

6.5.2 $PM_{2.5}$ EJ Exposure Analysis

We evaluated the potential for EJ concerns among potentially vulnerable populations resulting from exposure to $PM_{2.5}$ under the baseline and final regulatory option in this rule. This was done by characterizing the projected distribution of $PM_{2.5}$ exposures both prior to and following implementation of the final rule in 2028, 2030, and 2035.

As this analysis is based on the same $PM_{2.5}$ spatial fields as the benefits assessment (see Appendix A for a discussion of the spatial fields), it is subject to similar types of uncertainty (see Section 4.3.8 for a discussion of the uncertainty). A particularly germane limitation for this analysis is that the magnitude of the expected concentration changes is quite small, likely making uncertainties associated with the various input data more relevant.

6.5.2.1 National Aggregated Results

National average baseline $PM_{2.5}$ concentrations in micrograms per cubic meter ($\mu g/m^3$) in 2028, 2030, and 2035 are shown in the colored column labeled "baseline" in the Figure 6-1 heat map. Concentrations in the "baseline" columns represent the total estimated $PM_{2.5}$ exposure burden averaged over the 12-month calendar year and are colored to visualize differences more easily in average concentrations (lighter blue coloring representing smaller average concentrations and darker blue coloring representing larger average concentrations). Average national disparities observed in the baseline of this rule are similar to those described by recent rules (e.g., the Final PM NAAQS), that is, populations with national average $PM_{2.5}$ concentrations higher than the reference population ordered from most to least difference were: residents of HOLC Grade D (i.e., redlined) census tracts, linguistically isolated, residents of HOLC Grade A-C (i.e., not redlined) census tracts, Hispanic individuals, Asian individuals, those without a high school diploma, Black individuals, below the poverty line, the unemployed, and the uninsured. Average national disparities observed in the baseline of this rule are generally consistent across the three future years and similar to those described by recent rules (e.g., the Final PM NAAQS).

For all three future years evaluated, there were no discernable $PM_{2.5}$ changes under the final regulatory option for any population analyzed when showing concentrations out to the hundredths digit, reiterating the small magnitude of national average $PM_{2.5}$ changes.

The national-level assessment of $PM_{2.5}$ before and after implementation of this final rulemaking suggests that while EJ exposure disparities are present in the pre-policy scenario, EJ exposure concerns are not likely created or exacerbated by the rule for the population groups evaluated, due to the small magnitude of the $PM_{2.5}$ concentration reductions. It is also important to note that at the national-level the $PM_{2.5}$ concentrations before and after implementation for all three future years evaluated the concentrations for each demographic group are below the recently revised standard of 9 µg/m^3.[106]

Group	Population	2028		2030		2035	
		Baseline	Absolute Reductions	Baseline	Absolute Reductions	Baseline	Absolute Reductions
Reference	Reference (0-99)	7.16	0.00	7.11	0.00	7.08	0.00
Race	American Indian (0-99)	6.69	0.00	6.66	0.00	6.64	0.00
	Asian (0-99)	7.73	0.00	7.67	0.00	7.62	0.00
	Black (0-99)	7.41	0.00	7.35	0.00	7.29	0.00
	White (0-99)	7.07	0.00	7.02	0.00	7.00	0.00
Ethnicity	Hispanic (0-99)	7.94	0.00	7.90	0.00	7.85	0.00
	Non-Hispanic (0-99)	6.94	0.00	6.89	0.00	6.85	0.00
Educational Attainment	Less educated (>24; no HS)	7.49	0.00	7.44	0.00	7.43	0.00
	More educated (>24: HS or more)	7.06	0.00	7.01	0.00	6.99	0.00
Employment Status	Employed (0-99)	7.15	0.00	7.10	0.00	7.07	0.00
	Not in the labor force (0-99)	7.16	0.00	7.11	0.00	7.08	0.00
	Unemployed (0-99)	7.31	0.00	7.26	0.00	7.24	0.00
Insurance Status	Insured (0-64)	7.20	0.00	7.15	0.00	7.12	0.00
	Uninsured (0-64)	7.27	0.00	7.23	0.00	7.20	0.00
Linquistic Isolation	English < well (0-99)	8.09	0.00	8.05	0.00	8.04	0.00
	English well or better (0-99)	7.11	0.00	7.06	0.00	7.04	0.00
Life Expectancy	Bottom 25% life expectancy (0-99)	7.20	0.00	7.13	0.00	7.10	0.00
	Life expectancy data unavailable (0-99)	7.11	0.00	7.07	0.00	7.04	0.00
	Top 75% life expectancy (0-99)	7.15	0.00	7.10	0.00	7.08	0.00
Poverty Status	<Poverty line (0-99)	7.33	0.00	7.28	0.00	7.25	0.00
	>Poverty line (0-99)	7.12	0.00	7.08	0.00	7.05	0.00
Redlined Areas	HOLC Grade D (0-99)	8.20	0.00	8.15	0.00	8.12	0.00
	HOLC Grades A-C (0-99)	7.95	0.00	7.90	0.00	7.86	0.00
	Not Graded by HOLC (0-99)	6.99	0.00	6.94	0.00	6.92	0.00
Tribal Land Designation	Not Tribal land (0-99)	7.16	0.00	7.11	0.00	7.09	0.00
	Tribal land (0-99)	6.63	0.00	6.58	0.00	6.53	0.00
Ages	Adults (18-64)	7.20	0.00	7.15	0.00	7.13	0.00
	Children (0-17)	7.22	0.00	7.17	0.00	7.14	0.00
	Older Adults (65-99)	6.94	0.00	6.90	0.00	6.89	0.00
Sex	Females (0-99)	7.17	0.00	7.12	0.00	7.09	0.00
	Males (0-99)	7.14	0.00	7.10	0.00	7.07	0.00

Figure 6-1 Heat Map of the National Average $PM_{2.5}$ Concentrations in the Baseline and Reductions in Concentrations Due to the Final Regulatory Option Across Demographic Groups in 2028, 2030, and 2035 (µg/m^3)

6.5.2.2 State Aggregated Results

We also assess $PM_{2.5}$ concentration reductions by state and demographic population in 2028, 2030, and 2035 for the 48 states in the contiguous U.S, for the final rule.

[106] See *https://www.epa.gov/system/files/documents/2024-02/pm-naaqs-final-frn-pre-publication.pdf*.

The magnitude of state-level $PM_{2.5}$ concentration changes under the final regulatory option is not discernable out to the hundredths digit, reiterating the small magnitude of state-level average $PM_{2.5}$ changes. The small magnitude of differential $PM_{2.5}$ exposure impacts expected by the final rule is not likely to exacerbate or mitigate EJ concerns within individual states.

6.5.2.3 Distributional Results

We also assess the cumulative proportion of each population exposed to ascending levels of $PM_{2.5}$ concentration changes across the contiguous U.S. Results allow evaluation of what percentage of each subpopulation (e.g., Hispanics) in the contiguous U.S. experience what change in $PM_{2.5}$ concentrations compared to what percentage of the overall reference group (i.e., the total population of contiguous U.S.) experiences similar concentration changes from EGU emission changes under the final regulatory option in 2028, 2030, and 2035.

This distributional EJ analysis is also subject to additional uncertainties related to more highly resolved input parameters and additional assumptions. For example, this analysis does not account for potential difference in underlying susceptibility, vulnerability, or risk factors across populations to $PM_{2.5}$ exposure. Nor could we include information about differences in other factors that could affect the likelihood of adverse impacts (e.g., exercise patterns) across groups. Therefore, this analysis should not be used to assert that there are meaningful differences in $PM_{2.5}$ exposure impacts associated with either the baseline or the rule across population groups.

As the baseline scenario is similar to that described by other RIAs, we focus on the $PM_{2.5}$ changes due to this final rulemaking. Distributions of 12-km gridded $PM_{2.5}$ concentration changes from EGU control strategies of affected facilities analyzed for the years 2028, 2030, and 2035 were evaluated.

The vast majority of $PM_{2.5}$ concentration changes for each population distribution round to 0.00 $\mu g/m^3$ under the final regulatory option for all three future years analyzed. Therefore, there are no discernable differences in impacts in the distributional analyses of $PM_{2.5}$ concentration changes under the final regulatory option, which provides additional evidence that the final rule is not likely to exacerbate or mitigate EJ $PM_{2.5}$ exposure concerns for population groups evaluated.

6.5.3 *Ozone EJ Exposure Analysis*

To evaluate the potential for EJ concerns among potentially vulnerable populations resulting from exposure to ozone under the baseline and final rule, we characterize the projected distribution of ozone exposures both prior to and following implementation of the final rule in 2028, 2030, and 2035.

As this analysis is based on the same ozone spatial fields as the benefits assessment (see Appendix A for a discussion of the spatial fields), it is subject to similar types of uncertainty (see Section 4.3.8 for a discussion of the uncertainty). In addition to the small magnitude of differential ozone concentration changes associated with this final rulemaking when comparing across demographic populations, a particularly germane limitation is that ozone, being a secondary pollutant, is the byproduct of complex atmospheric chemistry such that direct linkages cannot be made between specific affected facilities and downwind ozone concentration changes based on available air quality modeling.

Ozone concentration and exposure metrics can take many forms, although only a small number are commonly used. The analysis presented here is based on the average April-September warm season maximum daily eight-hour average ozone concentrations (AS-MO3), consistent with the health impact functions used in the benefits assessment (Section 4). As developing spatial fields is time and resource intensive, the same spatial fields used for the benefits analysis were also used for the ozone exposure analysis performed here to assess EJ impacts.

The construct of the AS-MO3 ozone metric used for this analysis should be kept in mind when attempting to relate the results presented here to the ozone NAAQS and when interpreting the confidence in the association between exposures and health effects. Specifically, the seasonal average ozone metric used in this analysis is not constructed in a way that directly relates to NAAQS design values, which are based on daily maximum eight-hour concentrations.[107] Thus, AS-MO3 values reflecting seasonal *average* concentrations well below the level of the NAAQS at a particular location do not necessarily indicate that the location does not experience any *daily*

[107] Level of 70 ppb with an annual fourth-highest daily maximum eight-hour concentration, averaged over three years.

(eight-hour) exceedances of the ozone NAAQS. Relatedly, EPA is confident that reducing the highest ambient ozone concentrations will result in substantial improvements in public health, including reducing the risk of ozone-associated mortality. However, the Agency is less certain about the public health implications of changes in relatively low ambient ozone concentrations. Most health studies rely on a metric such as the warm-season average ozone concentration; as a result, EPA typically utilizes air quality inputs such as the AS-MO3 spatial fields in the benefits assessment, and we judge them also to be the best available air quality inputs for this EJ ozone exposure assessment.

6.5.3.1 National Aggregated Results

National average baseline ozone concentrations in ppb in 2028, 2030, and 2035 are shown in the colored column labeled "baseline" in the heat map (Figure 6-2). Concentrations in the "baseline" columns represent the total estimated daily eight-hour maximum ozone exposure burden averaged over the six-month April-September ozone season and are colored to visualize differences more easily in average concentrations, with lighter green coloring representing smaller average concentrations and darker green coloring representing larger average concentrations. Populations with national average ozone concentrations higher than the reference population ordered from most to least difference were: American Indian individuals, Hispanic individuals, those who are linguistically isolated, residents of Tribal Lands, Asian individuals, residents of HOLC Grades A-C (i.e., not redlined) census tracts, those without a high school diploma, the unemployed, populations with higher life expectancy or with life expectancy data unavailable, children, residents of HOLC Grade D (i.e., redlined) census tracts, and the insured. Average national disparities observed in the baseline of this rule are fairly consistent across the three future years and similar to those described by recent rules (e.g., the RIA for the Final GNP).

For all three future years evaluated, there were no discernable ozone changes under the final rule for any population analyzed when showing concentrations out to the hundredths digit, reiterating the small magnitude of national average ozone changes.

The national-level assessment of ozone burden concentrations in the baseline and ozone exposure changes due to the final rule suggests that while EJ exposure disparities are present in the pre-policy scenario, EJ exposure concerns are not likely created or exacerbated by the rule for the population groups evaluated, due to the small magnitude of the ozone concentration changes. Note that while we were able to compare the annual average $PM_{2.5}$ concentrations to the newly revised NAAQS, the estimated ozone impacts in terms of annual average change are difficult to compare to the ozone NAAQS as the annual fourth-highest daily maximum 8-hour concentration.

Group	Population	2028		2030		2035	
		Baseline	Absolute Reductions	Baseline	Absolute Reductions	Baseline	Absolute Reductions
Reference	Reference (0-99)	40.25	0.00	40.21	0.00	40.01	0.00
Race	American Indian (0-99)	42.61	0.00	42.57	0.00	42.41	0.00
	Asian (0-99)	41.61	0.00	41.54	0.00	41.27	0.00
	Black (0-99)	38.86	0.00	38.81	0.00	38.56	0.00
	White (0-99)	40.35	0.00	40.31	0.00	40.12	0.00
Ethnicity	Hispanic (0-99)	42.50	0.00	42.44	0.00	42.20	0.00
	Non-Hispanic (0-99)	39.64	0.00	39.58	0.00	39.34	0.00
Educational Attainment	Less educated (>24; no HS)	40.75	0.00	40.72	0.00	40.55	0.00
	More educated (>24: HS or more)	40.07	0.00	40.03	0.00	39.83	0.00
Employment Status	Employed (0-99)	40.26	0.00	40.21	0.00	40.01	0.00
	Not in the labor force (0-99)	40.23	0.00	40.19	0.00	39.99	0.00
	Unemployed (0-99)	40.70	0.00	40.66	0.00	40.48	0.00
Insurance Status	Insured (0-64)	40.40	0.00	40.36	0.00	40.16	0.00
	Uninsured (0-64)	39.97	0.00	39.93	0.00	39.71	0.00
Linquistic Isolation	English < well (0-99)	41.86	0.00	41.82	0.00	41.64	0.00
	English well or better (0-99)	40.18	0.00	40.13	0.00	39.93	0.00
Life Expectancy	Bottom 25% life expectancy (0-99)	39.11	0.00	39.07	0.00	38.84	0.00
	Life expectancy data unavailable (0-99)	40.56	0.00	40.51	0.00	40.32	0.00
	Top 75% life expectancy (0-99)	40.54	0.00	40.50	0.00	40.31	0.00
Poverty Status	<Poverty line (0-99)	40.26	0.00	40.22	0.00	40.03	0.00
	>Poverty line (0-99)	40.25	0.00	40.21	0.00	40.01	0.00
Redlined Areas	HOLC Grade D (0-99)	40.44	0.00	40.40	0.00	40.16	0.00
	HOLC Grades A-C (0-99)	41.18	0.00	41.14	0.00	40.89	0.00
	Not Graded by HOLC (0-99)	40.11	0.00	40.07	0.00	39.88	0.00
Tribal Land Designation	Not Tribal land (0-99)	40.24	0.00	40.20	0.00	40.00	0.00
	Tribal land (0-99)	41.64	0.00	41.58	0.00	41.24	0.00
Ages	Adults (18-64)	40.30	0.00	40.27	0.00	40.07	0.00
	Children (0-17)	40.47	0.00	40.43	0.00	40.23	0.00
	Older Adults (65-99)	39.85	0.00	39.81	0.00	39.63	0.00
Sex	Females (0-99)	40.24	0.00	40.20	0.00	40.00	0.00
	Males (0-99)	40.27	0.00	40.22	0.00	40.03	0.00

Figure 6-2 Heat Map of the National Average Ozone Concentrations in the Baseline and Reductions in Concentrations under the Final Rule Across Demographic Groups in 2028, 2030, and 2035 (ppb)

6.5.3.2 State Aggregated Results

We also provide ozone concentration reductions by state and demographic population in 2028, 2030, and 2035 for the 48 states in the contiguous U.S, for the final regulatory option

(Figure 6-3). In this heat map, dark blue indicates larger ozone reductions, with demographic groups shown as rows and each state as a column.

The magnitude of state-level ozone concentration changes under the final regulatory option is very small, with the vast majority of state-level ozone concentrations changes not discernable out to the hundredths digit. State-level average populations that are projected to experience reductions in ozone concentrations by up to 0.01 ppb are residents of HOLC Grade D (i.e., redlined) census tracts and Black individuals in Arkansas (AR), and most population groups in North Dakota (ND). Only state-level average reductions in ozone concentrations were observed for populations in 2028. The small magnitude of differential ozone exposure impacts expected by the final rule is not likely to exacerbate or mitigate EJ concerns within individual states.

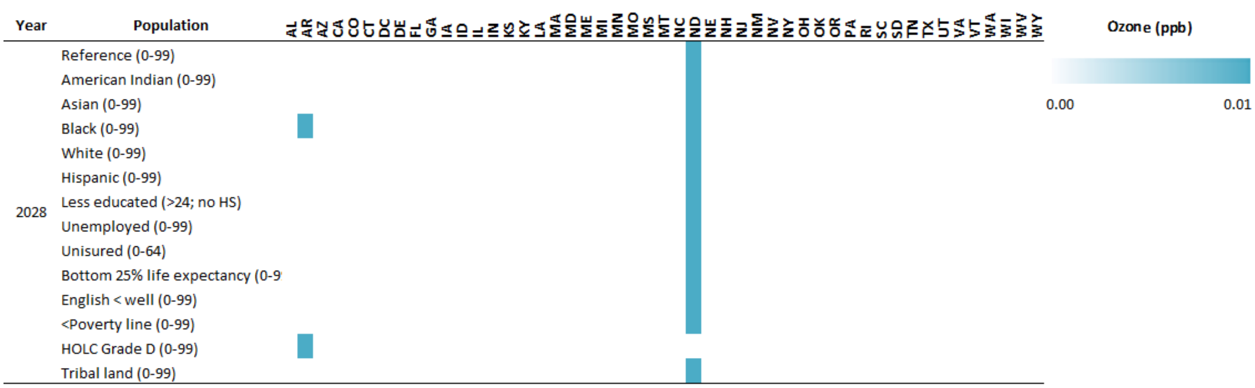

Figure 6-3 Heat Map of the State Average Ozone Concentrations Reductions (Green) and Increases (Red) under the Final Rule Across Demographic Groups in 2028 (ppb)

6.5.3.3 Distributional Results

We also assess the cumulative proportion of each population exposed to ascending levels of ozone concentration changes across the contiguous U.S. Results allow evaluation of what percentage of each subpopulation (e.g., Hispanic individuals) in the contiguous U.S. experience what change in ozone concentrations compared to what percentage of the overall reference group (i.e., the total population of contiguous U.S.) experiences similar concentration changes from EGU emission changes under the final regulatory option in 2028, 2030, and 2035.

This distributional EJ analysis is also subject to additional uncertainties related to more highly resolved input parameters and additional assumptions. For example, this analysis does not account for potential difference in underlying susceptibility, vulnerability, or risk factors across populations expected to experience post-policy ozone exposure changes. Nor could we include information about differences in other factors that could affect the likelihood of adverse impacts (e.g., exercise patterns) across groups. Therefore, this analysis should not be used to assert that there are meaningful differences in ozone exposures impacts in either the baseline or the rule across population groups.

As the baseline scenario is similar to that described by other RIAs, we focus on the ozone changes due to this final rulemaking. Distributions of 12-km gridded ozone concentration changes from EGU control strategies of affected facilities under the final rule were evaluated.

The vast majority of ozone concentration changes round to 0.00 ppb under the final regulatory option for all three future years analyzed. Therefore, there are no discernable differences in impacts in the distribution of ozone concentration changes across population demographics under the final regulatory option. This also provides additional evidence that the final rule is not likely to exacerbate or mitigate EJ ozone exposure concerns for population groups evaluated.

6.6 GHG Impacts on Environmental Justice and other Populations of Concern

In the 2009 Endangerment Finding, the Administrator considered how climate change threatens the health and welfare of the U.S. population. As part of that consideration, she also considered risks to people of color and low-income individuals and communities, finding that certain parts of the U.S. population may be especially vulnerable based on their characteristics or circumstances. These groups include economically and socially disadvantaged communities; individuals at vulnerable life stages, such as the elderly, the very young, and pregnant or nursing women; those already in poor health or with comorbidities; persons with disabilities; those experiencing homelessness, mental illness, or substance abuse; and Indigenous or other populations dependent on one or limited resources for subsistence due to factors including but not limited to geography, access, and mobility.

Scientific assessment reports produced over the past decade by the U.S. Global Change Research Program (USGCRP), the IPCC, the National Research Council, and the National Academies of Science, Engineering, and Medicine add more evidence that the impacts of climate change raise potential EJ concerns (IPCC, 2018; National Academies, 2017; National Research

Council, 2011; Oppenheimer et al., 2014; Porter et al., 2014; Smith et al., 2014; U.S. EPA, 2021; USGCRP, 2016, 2018). These reports conclude that less-affluent, traditionally marginalized, and predominantly non-White communities can be especially vulnerable to climate change impacts because they tend to have limited resources for adaptation, are more dependent on climate-sensitive resources such as local water and food supplies or have less access to social and information resources. Some communities of color, specifically populations defined jointly by ethnic/racial characteristics and geographic location (e.g., African-American, Black, and Hispanic/Latino communities; individuals who identify as Native American, particularly those living on tribal lands and Alaska Natives), may be uniquely vulnerable to climate change health impacts in the U.S., as discussed below. In particular, the 2016 scientific assessment on the *Impacts of Climate Change on Human Health* found with high confidence that vulnerabilities are place- and time-specific, lifestages and ages are linked to immediate and future health impacts, and social determinants of health are linked to greater extent and severity of climate change-related health impacts (USGCRP, 2016).

Per the Fourth National Climate Assessment (NCA4), "Climate change affects human health by altering exposures to heat waves, floods, droughts, and other extreme events; vector-, food- and waterborne infectious diseases; changes in the quality and safety of air, food, and water; and stresses to mental health and well-being" (Ebi et al., 2018). Many health conditions such as cardiopulmonary or respiratory illness and other health impacts are associated with and exacerbated by an increase in GHGs and climate change outcomes, which is problematic as these diseases occur at higher rates within vulnerable communities. Importantly, negative public health outcomes include those that are physical in nature, as well as mental, emotional, social, and economic.

The scientific assessment literature, including the aforementioned reports, demonstrates that there are myriad ways in which these populations may be affected at the individual and community levels. Individuals face differential exposure to criteria pollutants, in part due to the proximities of highways, trains, factories, and other major sources of pollutant-emitting sources to less-affluent residential areas. Outdoor workers, such as construction or utility crews and agricultural laborers, who frequently are comprised of already at-risk groups, are exposed to poor air quality and extreme temperatures without relief. Furthermore, people in communities with EJ concerns face greater housing, clean water, and food insecurity and bear disproportionate and adverse economic impacts and health burdens associated with climate change effects. They have less or limited access to healthcare and affordable, adequate health or homeowner insurance (USGCRP, 2016). Finally, resiliency and adaptation are more difficult for economically vulnerable communities; these communities have less liquidity, individually and collectively, to move or to make the types of infrastructure or policy changes to limit or reduce the hazards they face. They frequently are less able to self-advocate for resources that would otherwise aid in building resilience and hazard reduction and mitigation.

The assessment literature cited in EPA's 2009 and 2016 Endangerment and Cause or Contribute Findings, as well as *Impacts of Climate Change on Human Health,* also concluded that certain populations and life stages, including children, are most vulnerable to climate-related health effects (USGCRP, 2016). The assessment literature produced from 2016 to the present strengthens these conclusions by providing more detailed findings regarding related vulnerabilities and the projected impacts youth may experience. These assessments – including the Fourth National Climate Assessment (USGCRP, 2018) and *The Impacts of Climate Change on Human Health in the United States* (USGCRP, 2016) – describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events (USGCRP, 2016). In addition, children are among those especially susceptible to allergens, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households. More generally, these reports note that extreme weather and flooding can cause or exacerbate poor health outcomes by affecting mental health because of stress; contributing to or worsening existing conditions, again due to stress or also as a consequence of exposures to water and air pollutants; or by impacting hospital and emergency services operations (Ebi et al., 2018). Further, in urban areas in particular, flooding can have significant economic consequences due to effects on infrastructure, pollutant exposures, and drowning dangers. The ability to withstand and recover from flooding is dependent in part on the social vulnerability of the affected population and individuals experiencing an event (National Academy of Sciences, 2019). In addition, children are among those especially susceptible to allergens, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

The Impacts of Climate Change on Human Health also found that some communities of color, low-income groups, people with limited English proficiency, and certain immigrant groups (especially those who are undocumented) are subject to many factors that contribute to vulnerability to the health impacts of climate change (USGCRP, 2016). While difficult to isolate from related socioeconomic factors, race appears to be an important factor in vulnerability to climate-related stress, with elevated risks for mortality from high temperatures reported for Black or African American individuals compared to White individuals after controlling for factors such as air conditioning use. Moreover, people of color are disproportionately more exposed to air pollution based on where they live, and disproportionately vulnerable due to higher baseline prevalence of underlying diseases such as asthma. As explained earlier, climate change can exacerbate local air pollution conditions, so this increase in air pollution is expected to have disproportionate and adverse effects on these communities. Locations with greater health threats include urban areas (due to, among other factors, the "heat island" effect where built infrastructure and lack of green spaces increases local temperatures), areas where airborne allergens and other air pollutants already occur at higher levels, and communities that have experienced depleted water supplies or vulnerable energy and transportation infrastructure.

The 2021 EPA report on climate change and social vulnerability examined four socially vulnerable groups (individuals who are low income, minority, without high school diplomas, and/or 65 years and older) and their exposure to several different climate impacts (air quality, coastal flooding, extreme temperatures, and inland flooding) (U.S. EPA, 2021). This report found that Black and African-American individuals were 40 percent more likely to currently live in areas with the highest projected increases in mortality rates due to climate-driven changes in extreme temperatures, and 34 percent more likely to live in areas with the highest projected increases in childhood asthma diagnoses due to climate-driven changes in particulate air pollution. The report found that Hispanic and Latino individuals are 43 percent more likely to live in areas with the highest projected labor hour losses in weather-exposed industries due to climate-driven warming, and 50 percent more likely to live in coastal areas with the highest projected increases in traffic delays due to increases in high-tide flooding. The report found that

American Indian and Alaska Native individuals are 48 percent more likely to live in areas where the highest percentage of land is projected to be inundated due to sea level rise, and 37 percent more likely to live in areas with high projected labor hour losses. Asian individuals were found to be 23 percent more likely to live in coastal areas with projected increases in traffic delays from high-tide flooding. Persons with low income or no high school diploma are about 25 percent more likely to live in areas with high projected losses of labor hours, and 15 percent more likely to live in areas with the highest projected increases in asthma due to climate-driven increases in particulate air pollution, and in areas with high projected inundation due to sea level rise.

In a more recent 2023 report, *Climate Change Impacts on Children's Health and Well-Being in the U.S.,* EPA considered the degree to which children's health and well-being may be impacted by five climate-related environmental hazards—extreme heat, poor air quality, changes in seasonality, flooding, and different types of infectious diseases (U.S. EPA, 2023). The report found that children's academic achievement is projected to be reduced by 4–7 percent per child, as a result of moderate and higher levels of warming, impacting future income levels. The report also projects increases in the numbers of annual emergency department visits associated with asthma, and that the number of new asthma diagnoses increases by 4–11 percent due to climate-driven increases in air pollution relative to current levels. In addition, more than 1 million children in coastal regions are projected to be temporarily displaced from their homes annually due to climate-driven flooding, and infectious disease rates are similarly anticipated to rise, with the number of new Lyme disease cases in children living in 22 states in the eastern and midwestern U.S. increasing by approximately 3,000–23,000 per year compared to current levels. Overall, the report confirmed findings of broader climate science assessments that children are uniquely vulnerable to climate-related impacts and that in many situations, children in the U.S. who identify as Black, Indigenous, and People of Color, are limited English-speaking, do not have health insurance, or live in low-income communities may be disproportionately more exposed to the most severe adverse impacts of climate change.

Indigenous communities face disproportionate and adverse risks from the impacts of climate change, particularly those communities impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Indigenous communities whose health, economic well-being, and cultural traditions depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The IPCC indicates that losses of customs and historical knowledge may cause communities to be less resilient or adaptable (Porter et al., 2014). The NCA4 (2018) noted that while Indigenous peoples are diverse and will be impacted by the climate changes universal to all Americans, there are several ways in which climate change uniquely threatens Indigenous peoples' livelihoods and economies (Jantarasami et al., 2018; USGCRP, 2018). In addition, as noted in the following paragraph, there can be institutional barriers (including policy-based limitations and restrictions) to their management of water, land, and other natural resources that could impede adaptive measures.

For example, Indigenous agriculture in the Southwest is already being adversely affected by changing patterns of flooding, drought, dust storms, and rising temperatures leading to increased soil erosion, irrigation water demand, and decreased crop quality and herd sizes. The Confederated Tribes of the Umatilla Indian Reservation in the Northwest have identified climate risks to salmon, elk, deer, roots, and huckleberry habitat. Housing and sanitary water supply infrastructure are vulnerable to disruption from extreme precipitation events. Native Americans' ability to respond to these conditions is impeded by limitations imposed by statutes including the Dawes Act of 1887 and the Indian Reorganization Act of 1934, which ultimately restrict Indigenous peoples' autonomy regarding land-management decisions through Federal trusteeship of certain tribal lands and mandated Federal oversight of these peoples' management decisions. Additionally, NCA4 noted that Indigenous peoples generally are subjected to institutional racism effects, such as poor infrastructure, diminished access to quality healthcare, and greater risk of exposure to pollutants. Consequently, Native Americans often have disproportionately higher rates of asthma, cardiovascular disease, Alzheimer's disease, diabetes, and obesity. These health conditions and related effects (disorientation, heightened exposure to $PM_{2.5}$, etc.) can all contribute to increased vulnerability to climate-driven extreme heat and air pollution events, which also may be exacerbated by stressful situations, such as extreme weather events, wildfires, and other circumstances.

NCA4 and IPCC's Fifth Assessment Report also highlighted several impacts specific to Alaskan Indigenous Peoples (Porter et al., 2014). Coastal erosion and permafrost thaw will lead to more coastal erosion, rendering winter travel riskier and exacerbating damage to buildings, roads, and other infrastructure—impacts on archaeological sites, structures, and objects that will lead to a loss of cultural heritage for Alaska's Indigenous people. In terms of food security, the NCA4 discussed reductions in suitable ice conditions for hunting, warmer temperatures impairing the use of traditional ice cellars for food storage, and declining shellfish populations due to warming and acidification. While the NCA4 also noted that climate change provided more opportunity to hunt from boats later in the fall season or earlier in the spring, the assessment found that the net impact was an overall decrease in food security.

6.7 Summary

As with all EJ analyses, data limitations make it quite possible that disparities may exist that our analysis did not identify. This is especially relevant for potential EJ characteristics, environmental impacts, and more granular spatial resolutions that were not evaluated. For example, here we provide qualitative EJ assessment of ozone and $PM_{2.5}$ concentration changes from this rule but can only qualitatively discuss EJ impacts of CO_2 emission reductions. Therefore, this analysis is only a partial representation of the distributions of potential impacts. Additionally, EJ concerns for each rulemaking are unique and should be considered on a case-by-case basis, so results similar to those presented here should not be assumed for other rulemakings.

For the rule, we quantitatively evaluate the proximity of affected facilities populations of potential EJ concern (Section 6.4) and the potential for disproportionate pre- and policy-policy $PM_{2.5}$ and ozone exposures across different demographic groups (Section 6.5). As exposure results generated as part of the 2020 Residual Risk analysis were below both the presumptive acceptable cancer risk threshold and the noncancer health benchmarks, and this final regulation should still 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. Each of these analyses presented depend on mutually exclusive assumptions, was performed to answer separate questions, and is associated with unique limitations and uncertainties.

Baseline demographic proximity analyses provide information as to whether there may be potential EJ concerns associated with local environmental stressors such as local NO_2 and SO_2 emitted from sources affected by the regulatory action, traffic, or noise for certain population groups of concern in the baseline (Section 6.4). The baseline demographic proximity analyses examined the demographics of populations living within 10 km of the following sources: lignite-fired coal plants with units potentially impacted by the Hg standard revision and coal plants with units potentially impacted by the fPM standard revision. The proximity demographic analysis indicates that on average, the population living within 10 km of coal plants potentially impacted by the fPM standards shas 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-fired coal plants potentially impacted by Hg standard is higher than the national average. Relating these results to question 1 from Section 6.3, we conclude that there may be potential EJ concerns associated with directly emitted pollutants that are affected by the regulatory action (e.g., local NO_X or 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.

While the demographic proximity analyses may appear to parallel the baseline analysis of nationwide ozone and $PM_{2.5}$ exposures in certain ways, the two should not be directly compared. The baseline ozone and $PM_{2.5}$ exposure assessments are in effect an analysis of total burden in the contiguous U.S., and include various assumptions, such as the implementation of promulgated regulations. It serves as a starting point for both the estimated ozone and $PM_{2.5}$ changes due to this final rule as well as a snapshot of air pollution concentrations in the near future. This final 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.

The baseline ozone and $PM_{2.5}$ exposure analyses respond to question 1 from EPA's EJ Technical Guidance document more directly than the proximity analyses, as they evaluate a form of the environmental stressor primarily affected by the regulatory action (Section 6.5). Baseline $PM_{2.5}$ and ozone exposure analyses show that certain populations, such as residents of redlined census tracts, those linguistically isolated, Hispanic individuals, Asian individuals, those without a high school diploma, and the unemployed may experience disproportionately higher ozone and

$PM_{2.5}$ exposures as compared to the national average. American Indian individuals, residents of Tribal Lands, populations with higher life expectancy or with life expectancy data unavailable, children, and insured populations may also experience disproportionately higher ozone concentrations than the reference group. Hispanic individuals, Black individuals, those below the poverty line, and uninsured populations may also experience disproportionately higher PM2.5 concentrations than the reference group. Therefore, there likely are potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline.

Finally, we evaluate how the post-policy options of this final rulemaking are expected to differentially impact demographic populations, informing questions 2 and 3 from EPA's EJ Technical Guidance with regard to ozone and $PM_{2.5}$ exposure changes. 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 baseline disparities in ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the final regulatory option (question 2). Also, due to the very small differences in the magnitude of post-policy ozone and $PM_{2.5}$ exposure impacts across demographic populations, we do not find evidence that potential EJ concerns related to ozone or $PM_{2.5}$ exposures will be exacerbated or mitigated in the final regulatory option, compared to the baseline (question 3).

This EJ air quality analysis concludes that there are $PM_{2.5}$ and ozone exposure disparities across various populations in the pre-policy baseline scenario (EJ question 1) and infer that these disparities are likely to persist after promulgation of this final rulemaking (EJ question 2). This EJ assessment also suggests that this action will neither mitigate nor exacerbate $PM_{2.5}$ and ozone exposure disparities across populations of EJ concern analyzed (EJ question 3) at the national scale.

6.8 References

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COMPARISON OF BENEFITS AND COSTS

7.1 Introduction

This section presents the estimates of the projected benefits, costs, and net benefits associated with the final MATS review relative to baseline MATS requirements. There are potential benefits and costs that may result from this rule that have not been quantified or monetized. Due to current data and modeling limitations, quantified and monetized benefits from reducing Hg and non-Hg HAP metals emissions are not included in the monetized benefits presented here. We are also unable to quantify the potential benefits from the CEMS requirement. Due to data and modeling limitations, there are also still many categories of climate impacts and associated damages that are not reflected yet in the monetized climate benefits from reducing CO_2 emissions. For example, the modeling omits most of the consequences of changes in precipitation, damages from extreme weather events, the potential for nongradual damages from passing critical thresholds (e.g., tipping elements) in natural or socioeconomic systems, and non-climate mediated effects of GHG emissions (e.g., ocean acidification).

The projections indicate that the final rule results in 9,500 pounds of reductions in emissions of Hg as well as 5,400 tons of reductions in $PM_{2.5}$ across all run years. The final rule is projected to also reduce CO_2, SO_2, and NO_x by 650,000 tons, 770 tons, and 220 tons, respectively, and we estimate that the final rule will reduce at least 49 tons of non-Hg HAP metals. These reductions are composed of reductions in emissions of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.[108] Table 7-1 summarizes the total emissions reductions projected over the 2028 to 2037 analysis period.

[108] The estimates on non-mercury HAP metals reductions were obtained my multiplying the ratio of non-mercury HAP metals to fPM by estimates of PM_{10} reductions under the rule, as we do not have estimates of fPM reductions using IPM, only PM_{10}. The ratios of non-mercury HAP metals to fPM were based on analysis of 2010 MATS Information Collection Request (ICR) data. As there may be substantially more fPM than PM_{10} reduced by the control techniques projected to be used under this rule, these estimates of non-mercury HAP metals reductions are likely underestimates. More detail on the estimated reduction in non-mercury HAP metals can be found in the docketed memorandum *Estimating Non-Hg HAP Metals Reductions for the 2024 Technology Review for the Coal-Fired EGU Source Category*.

Table 7-1 Cumulative Projected Emissions Reductions for the Final Rule, 2028 to 2037[a,b]

Pollutant	Emissions Reductions
Hg (pounds)	9,500
$PM_{2.5}$ (tons)	5,400
CO_2 (thousand tons)	650
SO_2 (tons)	770
NO_x (tons)	220
Non-Hg HAP metals (tons)	49

[a] Values rounded to two significant figures.
[b] Estimated reductions from model year 2028 are applied to 2028 and 2029, those from model year 2030 are applied to 2031 and 2032, and those from model year 2035 are applied to 2032 through 2037. These values are summed to generate total reduction figures.

The compliance costs reported in this RIA are not social costs, although in this analysis we use compliance costs as a proxy for social costs. We do not account for changes in costs and benefits due to changes in economic welfare of suppliers to the electricity market or to non-electricity consumers from those suppliers. Furthermore, costs due to interactions with pre-existing market distortions outside the electricity sector are omitted.

7.2 Methods

EPA calculated the PV of benefits, costs, and net benefits for the years 2028 through 2037, using 2, 3, and 7 percent end-of-period discount rates from the perspective of 2023. All dollars are in 2019 dollars. In addition to the final rule, we assess a less stringent alternative to the final requirements.

This calculation of a PV requires an annual stream of values for each year of the 2028 to 2037 timeframe. EPA used IPM to estimate cost and emission changes for the projection years 2028, 2030, and 2035. The year 2028 approximates the compliance year for the final requirements. In the IPM modeling for this RIA, the 2028 projection year is representative of 2028 and 2029, the 2030 projection year is representative of 2030 and 2031, and the 2035 projection year is representative of 2032 to 2037. Estimates of costs and emission changes in other years are determined from the mapping of projection years to the calendar years that they represent. Consequently, the cost and emission estimates from IPM in each projection year are applied to the years which it represents.[109]

[109] Projected costs associated with the CEMS requirement are not based on IPM. For information on these cost estimates, see Section 3.

Health benefits are based on projection year emission estimates and also account for year-specific variables that influence the size and distribution of the benefits. These variables include population growth, income growth, and the baseline rate of death.[110] Climate benefits estimates are based on these projection year emission estimates, and also account for year-specific SC-CO_2 values.

EPA calculated the PV and EAV of costs, benefits, and net benefits over the 2028 through 2037 timeframe for the three regulatory options examined in this RIA. The EAV represents a flow of constant annual values that, had they occurred in each year from 2028 to 2037, would yield an equivalent present value. The EAV represents the value of a typical cost or benefit for each year of the analysis, in contrast to the year-specific estimates presented elsewhere for the snapshot years of 2028, 2030, and 2035.

7.3 Results

We first present net benefit analysis for the three years of detailed analysis, 2028, 2030, and 2035. Table 7-2, Table 7-3, and Table 7-4 present the estimates of the projected compliance costs, health benefits, climate benefits, and net benefits projected for the final rule. Table 7-5, Table 7-6, and Table 7-7 present results for the less stringent regulatory option.

The comparison of benefits and costs in PV and EAV terms for the final rule can be found in for the final regulatory option. Table 7-9 presents the results for the less stringent regulatory option. Estimates in the tables are presented as rounded values. Note the less stringent regulatory option only has unquantified benefits associated with requirements for PM CEMS. As a result, there are no quantified benefits associated with this regulatory option.

[110] As these variables differ by year, the health benefit estimates vary by year, including when different years are based on the same IPM projection year emission estimate.

Table 7-2 Projected Net Benefits of the Final Rule in 2028 (millions of 2019 dollars)[a,b]

		Final Rule, 2028	
Health Benefits[c]	42	and	87
Climate Benefits[d]		14	
Total Benefits[e]	57	and	100
Compliance Costs		110	
Net Benefits	**-58**	**and**	**-13**
		Non-Monetized Benefits[e]	
		Benefits from reductions of about 1000 pounds of Hg	
		Benefits from reductions of about 7 tons of non-Hg HAP metals	
		Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS	

[a] We focus results to provide a snapshot of projected benefits and costs in 2028, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.

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

[c] Monetized air quality related benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. For the presentational purposes of this table, the projected health benefits reported here are associated with several point estimates and are presented at a real discount rate of 2 percent. See Table 4-4 for the full range of monetized health benefit estimates.

[d] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of carbon dioxide (SC-CO_2) (under 1.5 percent, 2 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. See Table 4-10 for the full range of monetized climate benefit estimates.

[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 HAP metals emissions and from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring CEMS.

Table 7-3 Projected Net Benefits of the Final Rule in 2030 (millions of 2019 dollars)[a,b]

	Final Rule, 2030		
Health Benefits[c]	15	and	31
Climate Benefits[d]		-8.2	
Total Benefits[e]	7.3	and	22
Compliance Costs		120	
Net Benefits	**-110**	**and**	**-94**
	Non-Monetized Benefits[e]		
	Benefits from reductions of about 1000 pounds of Hg		
	Benefits from reductions of about 4 tons of non-Hg HAP metals		
	Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS		

[a] We focus results to provide a snapshot of projected benefits and costs in in 2030, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.

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

[c] Monetized air quality related health benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. For the presentational purposes of this table, the projected health benefits reported here are associated with several point estimates and are presented at a real discount rate of 2 percent. See Table 4-4 for the full range of monetized health benefit estimates.

[d] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of methane (SC-CO_2) (under 1.5 percent, 2 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. See Table 4-10 for the full range of monetized climate benefit estimates.

[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 HAP metals emissions and from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring CEMS.

Table 7-4 Projected Net Benefits of the Final Rule in 2035 (millions of 2019 dollars)[a,b]

		Final Rule, 2035	
Health Benefits[c]	10	and	18
Climate Benefits[d]		24	
Total Benefits[e]	34	and	42
Compliance Costs		95	
Net Benefits	**-61**	**and**	**-53**
		Non-Monetized Benefits[e]	
		Benefits from reductions of about 900 pounds of Hg	
		Benefits from reductions of about 4 tons of non-Hg HAP metals	
		Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS	

[a] We focus results to provide a snapshot of projected benefits and costs in 2035, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.

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

[c] Monetized air quality related health benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. For the presentational purposes of this table, the projected health benefits reported here are associated with several point estimates and are presented at a real discount rate of 2 percent. See Table 4-4 for the full range of monetized health benefit estimates.

[d] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of carbon dioxide (SC-CO_2) (under 1.5 percent, 2 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. See Table 4-10 for the full range of monetized climate benefit estimates.

[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 HAP metals emissions and from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring CEMS.

Table 7-5 Projected Monetized Benefits, Costs, and Net Benefits of the Less Stringent Option in 2028 (millions of 2019 dollars) [a,b]

		Final Rule, 2028	
Health Benefits[c]	0	and	0
Climate Benefits[d]		0	
Total Benefits[e]	0	and	0
Compliance Costs		2.3	
Net Benefits	**-2.3**	**and**	**-2.3**
Non-Monetized Benefits			
Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS			

[a] We focus results to provide a snapshot of projected benefits and costs in 2035, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.

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

Table 7-6 Projected Monetized Benefits, Costs, and Net Benefits of the Less Stringent Option in 2030 (millions of 2019 dollars) [a,b]

		Final Rule, 2030	
Health Benefits[c]	0	and	0
Climate Benefits[d]		0	
Total Benefits[e]	0	and	0
Compliance Costs		2.3	
Net Benefits	**-2.3**	**and**	**-2.3**
Non-Monetized Benefits			
Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS			

[a] We focus results to provide a snapshot of projected benefits and costs in 2035, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.

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

Table 7-7 Projected Monetized Benefits, Costs, and Net Benefits of the Less Stringent Option in 2035 (millions of 2019 dollars)[a,b]

		Final Rule, 2035	
Health Benefits[c]	0	and	0
Climate Benefits[d]		0	
Total Benefits[e]	0	and	0
Compliance Costs		2.3	
Net Benefits	**-2.3**	**and**	**-2.3**
Non-Monetized Benefits			
Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS			

[a] We focus results to provide a snapshot of projected benefits and costs in 2035, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.

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

Table 7-8 Stream of Projected Monetized Benefits, Costs, and Net Benefits of the Final Rule, 2028 to 2037 (discounted to 2023, millions of 2019 dollars)[a]

	Health Benefits[b]			Climate Benefits[c,d]	Compliance Costs			Net Benefits[e]		
Year	**2%**	**3%**	**7%**	**2%**	**2%**	**3%**	**7%**	**2%**	**3%**	**7%**
2028	79	71	52	13	100	99	82	-12	-15	-16
2029	79	71	50	13	100	96	77	-10	-13	-13
2030	27	24	16	-7.1	100	95	73	-82	-78	-64
2031	27	24	16	-7.1	100	92	68	-80	-76	-60
2032	14	13	8	19	79	73	52	-46	-41	-24
2033	14	13	8	19	78	71	48	-44	-39	-21
2034	14	12	7.3	19	76	69	45	-43	-37	-19
2035	14	12	7.0	19	75	67	42	-41	-35	-16
2036	14	12	6.7	19	73	65	39	-40	-33	-14
2037	14	12.0	6.4	19	72	63	37	-39	-32	-11
	Health Benefits[b]			**Climate Benefits[c,d]**	**Compliance Costs**			**Net Benefits[e]**		
	Discount Rate									
	2%	**3%**	**7%**	**2%**	**2%**	**3%**	**7%**	**2%**	**3%**	**7%**
PV	**300**	**260**	**180**	**130**	**860**	**790**	**560**	**-440**	**-400**	**-260**
EAV	**33**	**31**	**25**	**14**	**96**	**92**	**80**	**-49**	**-47**	**-41**
Non-Monetized Benefits[e]										
Benefits from reductions of about 900 to 1000 pounds of Hg annually										
Benefits from reductions of about 4 to 7 tons of non-Hg HAP metals annually										
Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS										

[a] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.
[b] The estimated value of the air quality-related health benefits reported here are from Table 4-5, Table 4-6, and Table 4-7. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. For discussions of the uncertainty associated with these health benefits estimates, see Section 4.3.8.
[c] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of carbon dioxide (SC-CO_2) (under 1.5 percent, 2 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. See Table 4-10 for the full range of monetized climate benefit estimates.
[d] The small increases and decreases in climate and health benefits and related EJ impacts result from very small changes in fossil dispatch and coal use relative to the baseline. For context, the projected increase in CO_2 emission of less than 40,000 tons in 2030 is roughly one percent of the emissions of a mid-size coal plant operating at availability (about 4 million tons).
[e] Several categories of benefits remain unmonetized and are thus not reflected in the table.

Table 7-9 Stream of Projected Monetized Benefits, Costs, and Net Benefits of the Less Stringent Option, 2028 to 2037 (millions of 2019 dollars, discounted to 2023)[a]

	Health Benefits			Climate Benefits	Compliance Costs			Net Benefits		
Year	**2%**	**3%**	**7%**	**2%**	**2%**	**3%**	**7%**	**2%**	**3%**	**7%**
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.0	0.0	2.1	2.0	1.7	-2.1	-2.0	-1.7
2029	0.0	0.0	0.0	0.0	2.1	2.0	1.6	-2.1	-2.0	-1.6
2030	0.0	0.0	0.0	0.0	2.0	1.9	1.5	-2.0	-1.9	-1.5
2031	0.0	0.0	0.0	0.0	2.0	1.9	1.4	-2.0	-1.9	-1.4
2032	0.0	0.0	0.0	0.0	2.0	1.8	1.3	-2.0	-1.8	-1.3
2033	0.0	0.0	0.0	0.0	1.9	1.7	1.2	-1.9	-1.7	-1.2
2034	0.0	0.0	0.0	0.0	1.9	1.7	1.1	-1.9	-1.7	-1.1
2035	0.0	0.0	0.0	0.0	1.9	1.6	1.0	-1.9	-1.6	-1.0
2036	0.0	0.0	0.0	0.0	1.8	1.6	1.0	-1.8	-1.6	-1.0
2037	0.0	0.0	0.0	0.0	1.8	1.6	0.9	-1.8	-1.6	-0.9

	Health Benefits			Climate Benefits	Compliance Costs			Net Benefits		
	Discount Rate									
	2%	**3%**	**7%**	**2%**	**2%**	**3%**	**7%**	**2%**	**3%**	**7%**
PV	**0.0**	**0.0**	**0.0**	**0.0**	**20**	**18**	**13**	**-20**	**-18**	**-13**
EAV	**0.0**	**0.0**	**0.0**	**0.0**	**2.2**	**2.1**	**1.8**	**-2.2**	**-2.1**	**-1.8**

Non-Monetized Benefits[b]
Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS

[a] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.
[b] Several categories of benefits remain unmonetized and are thus not reflected in the table.

The monetized estimates of benefits presented in this section are underestimated because important categories of benefits, including benefits from reducing Hg and non-Hg HAP metals emissions and the increased transparency, compliance assurance, and the potential emissions reductions from the accelerated identification of anomalous emissions anticipated from requiring PM CEMS, were not monetized in our analysis. Additionally, to the extent that the removal of the second definition of startup leads to actions that may otherwise not occur absent this final rule, there may be benefit and cost impacts we are unable to estimate. As a result, the estimates of compliance costs used in the net benefits analysis may provide an incomplete characterization of the true costs of the rule. We nonetheless consider these potential impacts in our evaluation of the net benefits of the rule.

7.4 Uncertainties and Limitations

Throughout the RIA, we considered several sources of uncertainty, both quantitatively and qualitatively, regarding the emissions reductions, benefits, and costs estimated for the final rule. We summarize the key elements of our discussions of uncertainty below.

Compliance costs: The IPM-projected annualized cost estimates of private compliance costs provided in this analysis are meant to show the increase in production (generating) costs to the power sector in response to the finalized requirements. As discussed in more detail in section 3.6, there are several key areas of uncertainty related to the electric power sector that are worth noting, including assumptions about electricity demand, natural gas supply and demand, longer-term planning by utilities, and assumptions about the cost and performance of controls. There are also uncertainties associated with the estimated costs for the CEMS requirement as well as associated with the potential costs of the removal of the startup definition if these amendments lead to actions by affected facilities that otherwise would not occur absent the finalized amendments.

Non-monetized benefits: Several categories of health, welfare, and climate benefits are not quantified in this RIA. These unquantified benefits are described in detail in Section 4. As noted above, EPA is unable to quantify and monetize the incremental potential benefits of requiring facilities to utilize CEMS rather than continuing to allow the use of quarterly testing, but the requirement has been considered qualitatively.

Monetized $PM_{2.5}$ and ozone-related benefits: The analysis of monetized $PM_{2.5}$ and ozone-related benefits described in Section 4.3 includes many data sources as inputs that are each subject to uncertainty. Input parameters include projected emissions inventories, projected compliance methods, air quality data from models (with their associated parameters and inputs), population data, population estimates, health effect estimates from epidemiology studies, economic data, and assumptions regarding the future state of the world (i.e., regulations, technology, and human behavior). When compounded, even small uncertainties can greatly influence the size of the total quantified benefits. Below are key uncertainties associated with estimating the number and value of $PM_{2.5}$ and ozone-related premature deaths. Additional detail regarding specific uncertainties associated with ozone health benefit estimates can be found in the Health Benefits TSD (U. S. EPA, 2023). A discussion of uncertainties and limitations related to the air quality modeling informing the $PM_{2.5}$ and ozone-related benefits analysis is presented in section 8.6

Monetized CO_2-related climate benefits: EPA considered the uncertainty associated with the SC-CO_2) estimates, which were used to calculate the monetized climate impacts of the changes in CO_2 emissions projected to result from this action. Section 4.4 provides a detailed discussion of the limitations and uncertainties associated with the SC-CO_2 estimates used in this analysis and describes ways in which the modeling addresses quantified sources of uncertainty.

7.5 References

U. S. EPA. (2023). *Air Quality Modeling Technical Support Document for Regulatory Impact Analysis of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*. (EPA-454/R-23-007). Research Triangle Park, NC: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards

APPENDIX A: AIR QUALITY MODELING

A.1 Introduction

As noted in Section 4, EPA used photochemical modeling to create air quality surfaces[111] that were then used in air pollution health benefits calculations of the final rule. The modeling-based surfaces captured air pollution impacts resulting from changes in NO_X, SO_2, and direct $PM_{2.5}$ emissions from EGUs. This appendix describes the source apportionment modeling and associated methods used to create air quality surfaces for the baseline scenario and the final rule scenario in three analytic years: 2028, 2030, and 2035. EPA created air quality surfaces for the following pollutants and metrics: annual average $PM_{2.5}$; April-September average of 8-hr daily maximum (MDA8) ozone (AS-MO3).

New ozone and PM source apportionment modeling outputs were created to support analyses in the RIAs for multiple final EGU rulemaking efforts. The basic methodology for determining air quality changes is the same as that used in the RIAs from multiple previous rules (U.S. EPA, 2019, 2020a, 2020b, 2021b, 2022a). EPA calculated baseline and final rule EGU emissions estimates of NO_X and SO_2 for all three analysis years using IPM (Section 3 of this RIA). EPA also used IPM outputs to estimate EGU emissions of $PM_{2.5}$ based on emission factors described in U.S. EPA (2021a). This appendix provides additional details on the source apportionment modeling simulations and the associated analysis used to create ozone and $PM_{2.5}$ air quality surfaces.

A.2 Air Quality Modeling Simulations

The air quality modeling utilized a 2016-based modeling platform which included meteorology and base year emissions from 2016 and projected future-year emissions for 2026 for all sectors other than EGUs and 2030 for EGUs. The air quality modeling included photochemical model simulations for a 2016 base year and a future year representing the combined 2026/2030 emissions described above to provide hourly concentrations of ozone and $PM_{2.5}$ component species nationwide. In addition, source apportionment modeling was performed for the future year to quantify the contributions to ozone from NO_X emissions and to $PM_{2.5}$ from NO_X, SO_2 and directly emitted $PM_{2.5}$ emissions from EGUs on a state-by-state and

[111] "Air quality surfaces" refers to continuous gridded spatial fields using a 12 km grid-cell resolution.

fuel-type basis. As described below, the modeling results for 2016 and the future year, in conjunction with EGU emissions data for the baseline and the final rule in 2028, 2030, and 2035 were used to construct the air quality surfaces that reflect the influence of emissions changes between the baseline and the final rule in each year.

The air quality model simulations (i.e., model runs) were performed using the Comprehensive Air Quality Model with Extensions (CAMx) version 7.10[112] (Ramboll Environ, 2021). The nationwide modeling domain (i.e., the geographic area included in the modeling) covers all lower 48 states plus adjacent portions of Canada and Mexico using a horizontal grid resolution of 12 km shown in Figure A-1. CAMx requires a variety of input files that contain information pertaining to the modeling domain and simulation period. These include gridded, hourly emissions estimates and meteorological data, and initial and boundary concentrations. The meteorological data and the initial and boundary concentrations were identical to those described in U.S. EPA (2023a). Separate emissions inventories were prepared for the 2016 base year and the projected future year. All other inputs (i.e., meteorological fields, initial concentrations, ozone column, photolysis rates, and boundary concentrations) were specified for the 2016 base year model application and remained unchanged for the projection-year model simulation.

2016 base year emissions are described in detail in U.S. EPA (2023b). The types of sources included in the emission inventory include stationary point sources such as EGUs and non-EGUs; non-point emissions sources including those from oil and gas production and distribution, agriculture, residential wood combustion, fugitive dust, and residential and commercial heating and cooking; mobile source emissions from onroad and nonroad vehicles, aircraft, commercial marine vessels, and locomotives; wild, prescribed, and agricultural fires; and biogenic emissions from vegetation and soils. Future year emissions from all sources other than EGUs were based on the 2026 emissions projections described in U.S. EPA (2023b). The Post-IRA 2022 Reference Case of EPA's Power Sector Platform v6 using Integrated Planning Model (IPM), which includes the Final GNP, was also reflected. The EGU projected inventory represents demand growth, fuel resource availability, generating technology cost and

[112] This CAMx simulation set the Rscale NH_3 dry deposition parameter to 0 which resulted in more realistic model predictions of $PM_{2.5}$ nitrate concentrations than using a default Rscale parameter of 1.

performance, and other economic factors affecting power sector behavior. It also reflects environmental rules and regulations, consent decrees and settlements, plant closures, and newly built units for the calendar year 2030. In this analysis, the projected EGU emissions include provisions of tax incentives impacting electricity supply in the Inflation Reduction Act of 2022 (IRA), Final GNP, 2021 Revised Cross-State Air Pollution Rule Update (RCU), the 2016 Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources, the Mercury and Air Toxics Rule (MATS) finalized in 2011, and other finalized rules. Documentation and results of the Post-IRA 2022 Reference Case, where the Final GNP was also included for EGUs, are available at (*https://www.epa.gov/power-sector-modeling/final-pm-naaqs*).

Model predictions of ozone and $PM_{2.5}$ concentrations were compared against ambient measurements (U.S. EPA, 2023a, 2024). Ozone and $PM_{2.5}$ model evaluations showed model performance that was adequate for applying these model simulations for the purpose of creating air quality surfaces to estimate ozone and $PM_{2.5}$ benefits.

Figure A-1 Air Quality Modeling Domain

The contributions to ozone and $PM_{2.5}$ component species (e.g., sulfate, nitrate, ammonium, elemental carbon (EC), organic aerosol (OA), and crustal material[113]) from EGU emissions in individual states and from each EGU-fuel type were modeled using the "source

[113] Crustal material refers to elements that are commonly found in the earth's crust such as Aluminum, Calcium, Iron, Magnesium, Manganese, Potassium, Silicon, Titanium, and the associated oxygen atoms.

apportionment" tool approach. In general, source apportionment modeling quantifies the air quality concentrations formed from individual, user-defined groups of emissions sources or "tags." These source tags are tracked through the transport, dispersion, chemical transformation, and deposition processes within the model to obtain hourly gridded[114] contributions from the emissions in each individual tag to hourly gridded modeled concentrations. For this RIA we used the source apportionment contribution data to provide a means to estimate of the effect of changes in emissions from each group of emissions sources (i.e., each tag) to changes in ozone and $PM_{2.5}$ concentrations. Specifically, we applied outputs from source apportionment modeling for ozone and $PM_{2.5}$ component species using the future year modeled case to obtain the contributions from EGUs emissions in each state and fuel-type to ozone and $PM_{2.5}$ component species concentrations in each 12 km model grid cell nationwide. Ozone contributions were modeled using the Anthropogenic Precursor Culpability Assessment (APCA) tool and $PM_{2.5}$ contributions were modeled using the Particulate Matter Source Apportionment Technology (PSAT) tool (Ramboll Environ, 2021). The ozone source apportionment modeling was performed for the period April through September to provide data for developing spatial fields for the April through September maximum daily eight-hour (MDA8) (i.e., AS-MO3) average ozone concentration exposure metric. The $PM_{2.5}$ source apportionment modeling was performed for a full year to provide data for developing annual average $PM_{2.5}$ spatial fields. Source apportionment simulations were set-up to separately track ozone and $PM_{2.5}$ contributions from coal EGU emissions in each contiguous U.S. state, natural gas EGU emissions in each contiguous U.S. state, and emissions from all other EGUs aggregated across all contiguous U.S. states. In cases where projected EGU emissions for a specific tag and pollutant were either 0 or very small, emissions were combined with nearby states to make multi-state tags. Tables A-1, A-2, and A-3 provide emissions that were tracked for each source apportionment tag.

[114] Hourly contribution information is provided for each grid cell to provide spatial patterns of the contributions from each tag.

Table A-1 Future-Year Emissions Allocated to Each Modeled Coal EGU State Source Apportionment Tag

State	Ozone Season NO_X (tons)	Annual NO_X (tons)	Annual SO_2 (tons)	Annual $PM_{2.5}$ (tons)
AL	2,537	5,046	1,929	700
AR[4]	NA	304	331	51
AZ	1,005	2,536	4,515	609
CA	222	511	99	27
CO	19	269	287	21
CT	0	0	0	0
DC	0	0	0	0
DE	0	0	0	0
FL	1,110	1,401	7,163	277
GA	1,654	2,534	3,247	159
IA	8,354	18,776	9,656	1,203
ID	0	0	0	0
IL	1,639	3,742	6,773	270
IN	4,886	18,146	26,584	2,252
KS[1]	NA	214	121	NA
KY	3,551	7,333	7,127	560
LA[2,4]	NA	47	NA	NA
MA	0	0	0	0
MD[3]	NA	139	272	31
MD + PA[3]	708	NA	NA	NA
ME	0	0	0	0
MI	1,532	4,071	12,478	380
MN	724	1,549	3,289	94
MO	2,947	23,480	38,989	853
MS[4]	NA	252	507	23
MT	3,771	8,842	4,056	1,252
NC	266	482	634	35
ND	8,583	19,562	25,398	1,923
NE[1]	7,817	17,507	43,858	NA
NE + KS[1]	NA	NA	NA	374
NH	0	0	0	0
NJ	0	0	0	0
NM	1,442	2,757	6,800	1,739
NV	0	1	1	0
NY	0	0	0	0
OH	3,152	10,485	21,721	901
OK[4]	NA	212	152	21
OR	0	0	0	0
PA[3]	NA	1,530	4,932	167
RI	0	0	0	0

SC	807	1,939	3,429	364
SD	418	1,100	1,022	27
TN	259	259	269	32
TX[2,4]	NA	7,031	NA	NA
TX + LA[2]	NA	NA	11,607	1,578
TX-reg[4]	2,698	NA	NA	NA
UT	2,702	4,236	7,625	232
VA	466	1,124	259	445
VT	0	0	0	0
WA	0	0	0	0
WI	866	2,137	838	90
WV	6,824	16,358	17,631	1,753
WY	6,066	13,222	11,754	1,024

[1]KS and NE emissions grouped into multi-state tag for direct $PM_{2.5}$
[2]LA and TX emissions grouped into multi-state tag for SO_2 and direct $PM_{2.5}$
[3]MD and PA emissions grouped into multi-state tag for ozone season NO_X
[4]AR, KS, LA, MS, OK and TX emissions grouped into multi-state tag ("TX-reg") for ozone season NO_X

Table A-2 Future-Year Emissions Allocated to Each Modeled Natural Gas EGU State Source Apportionment Tag

State	Ozone Season NO_X (tons)	Annual NO_X (tons)	Annual SO_2 (tons)	Annual $PM_{2.5}$ (tons)
AL	2,833	5,132	0	1,979
AR	1,651	2,957	0	632
AZ	1,759	3,146	0	686
CA	1,960	5,773	0	1,964
CO	957	1,825	0	461
CT	461	778	0	160
DC	6	11	0	7
DE	383	502	0	134
FL	7,550	14,372	0	4,996
GA	2,279	4,182	0	1,740
IA	875	1,106	0	327
ID	336	513	0	185
IL	1,624	2,705	0	825
IN	1,180	2,166	0	955
KS	329	621	0	54
KY	980	2,806	0	699
LA	3,771	8,706	0	2,158
MA	482	725	0	244
MD	402	710	0	435
ME	232	273	0	21
MI	6,523	11,372	0	1,508
MN	661	928	0	87
MO	587	875	0	342
MS	1,926	3,860	0	1,140
MT	11	19	0	7
NC	1,803	3,426	0	1,213
ND	25	41	0	3
NE	13	47	0	4
NH	120	136	0	34
NJ	1,024	1,910	0	608
NM	733	1,128	0	131
NV	1,693	2,471	0	648
NY	2,793	5,125	0	1,270
OH	1,838	3,824	0	1,617
OK	1,558	2,448	0	546
OR	5	188	0	87
PA	6,811	12,386	0	3,280
RI	115	153	0	73
SC	1,092	2,090	0	917

SD	93	105	0	11
TN	464	1,107	0	388
TX	7,652	14,715	0	3,567
UT	1,189	1,779	0	514
VA	1,836	3,409	0	1,087
VT	4	8	0	6
WA	485	1,311	0	464
WI	847	1,447	0	369
WV	109	180	0	50
WY	203	206	0	28

Table A-3 Future-Year Emissions Allocated to the Modeled Other EGU Source Apportionment Tag

State	Ozone Season NO_X (tons)	Annual NO_X (tons)	Annual SO_2 (tons)	Annual $PM_{2.5}$ (tons)
US[a]	20,611	48,619	9,631	7,915

[a] Only includes US emissions from the contiguous 48 states

Examples of the magnitude and spatial extent of ozone and $PM_{2.5}$ contributions are provided in through Figure A-5 for EGUs in California, Georgia, Iowa, and Ohio. These figures show how the magnitude and the spatial patterns of contributions of EGU emissions to ozone and $PM_{2.5}$ component species depend on multiple factors including the magnitude and location of emissions as well as the atmospheric conditions that influence the formation and transport of these pollutants. For instance, NO_X emissions are a precursor to both ozone and $PM_{2.5}$ nitrate. However, ozone and nitrate form under very different types of atmospheric conditions, with ozone formation occurring in locations with ample sunlight and ambient VOC concentrations while nitrate formation requires colder and drier conditions and the presence of gas-phase ammonia. California's complex terrain that tends to trap air and allow pollutant build-up combined with warm sunny summer and cooler dry winters and sources of both ammonia and VOCs make its atmosphere conducive to formation of both ozone and nitrate. While the magnitude of EGU NO_X emissions from gas plus coal EGUs is substantially larger in Iowa than in California (Table A-1 and Table A-2) the emissions from California lead to larger maximum contributions to the formation of those pollutants due to the conducive conditions in that state. Georgia and Ohio both had substantial NO_X emissions. While maximum ozone impacts shown for Georgia and Ohio EGUs are similar order of magnitude to maximum ozone impacts from

California EGUs, nitrate impacts are negligible in both Georgia and Ohio due to less conducive atmospheric conditions for nitrate formation in those locations. California EGU SO_2 emissions in the future year source apportionment modeling are several orders of magnitude smaller than SO_2 emissions in Ohio and Georgia (Table A-1) leading to much smaller sulfate contributions from California EGUs than from Ohio and Georgia EGUs. $PM_{2.5}$ organic aerosol EGU contributions in this modeling come from primary $PM_{2.5}$ emissions rather than secondary atmospheric formation. Consequently, the impacts of EGU emissions on this pollutant tend to occur closer to the EGU sources than impacts of secondary pollutants (ozone, nitrate, and sulfate) which have spatial patterns showing a broader regional impact. These patterns demonstrate how the model captures important atmospheric processes which impact pollutant formation and transport from emissions sources. Finally, Figures A-6 and A-7 show EGU ozone and $PM_{2.5}$ contributions from all contiguous U.S. EGUs split out by fuel type. The spatial differences between coal EGU, natural gas EGU, and other EGU contributions reflect the varying location and magnitude of emissions from each type of EGU.

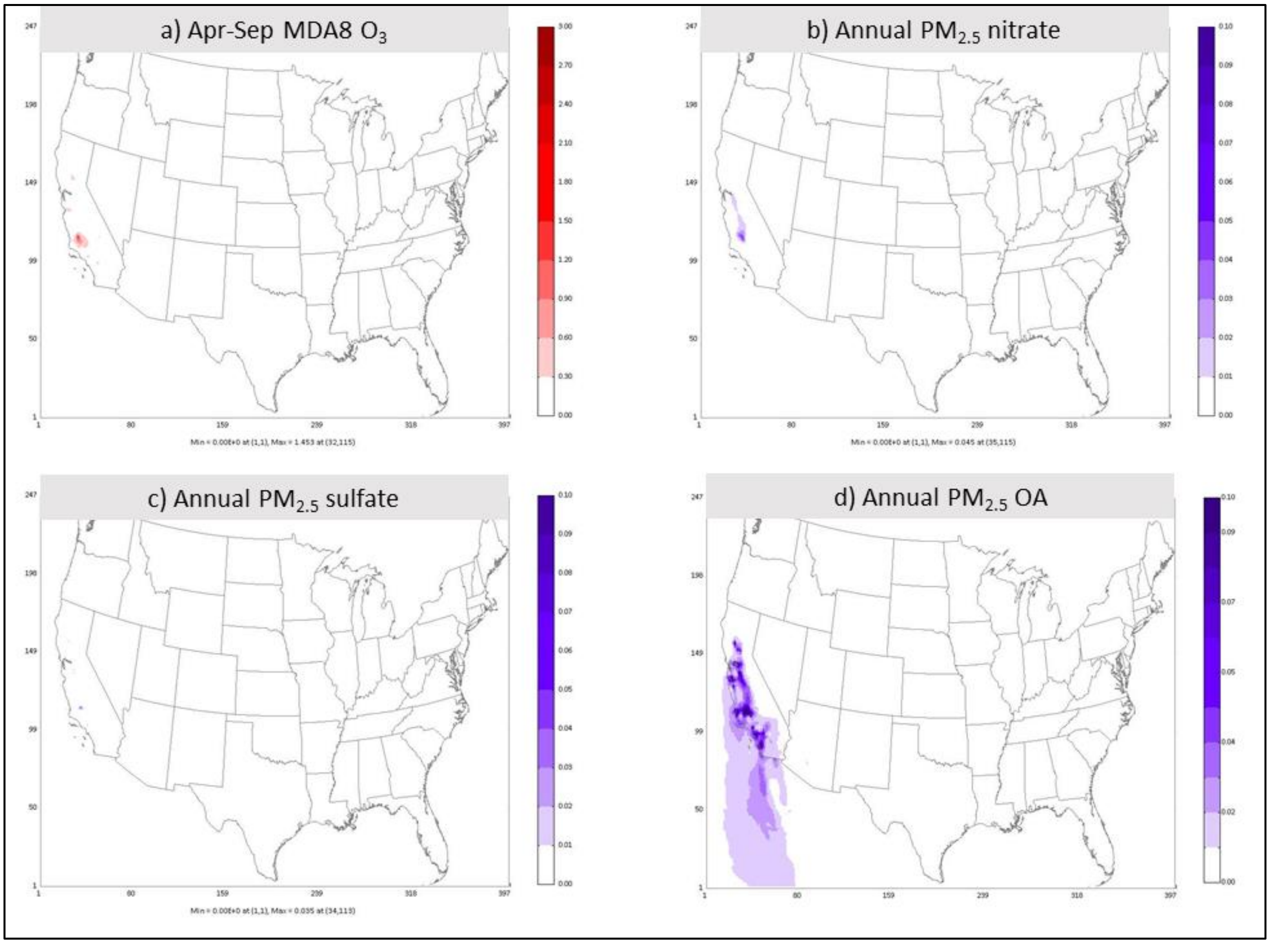

Figure A-2 Maps of California EGU Tag Contributions to a) April-September Seasonal Average MDA8 Ozone (ppb); b) Annual Average $PM_{2.5}$ Nitrate (µg/m3); c) Annual Average $PM_{2.5}$ Sulfate (µg/m3); d) Annual Average $PM_{2.5}$ Organic Aerosol (µg/m3)

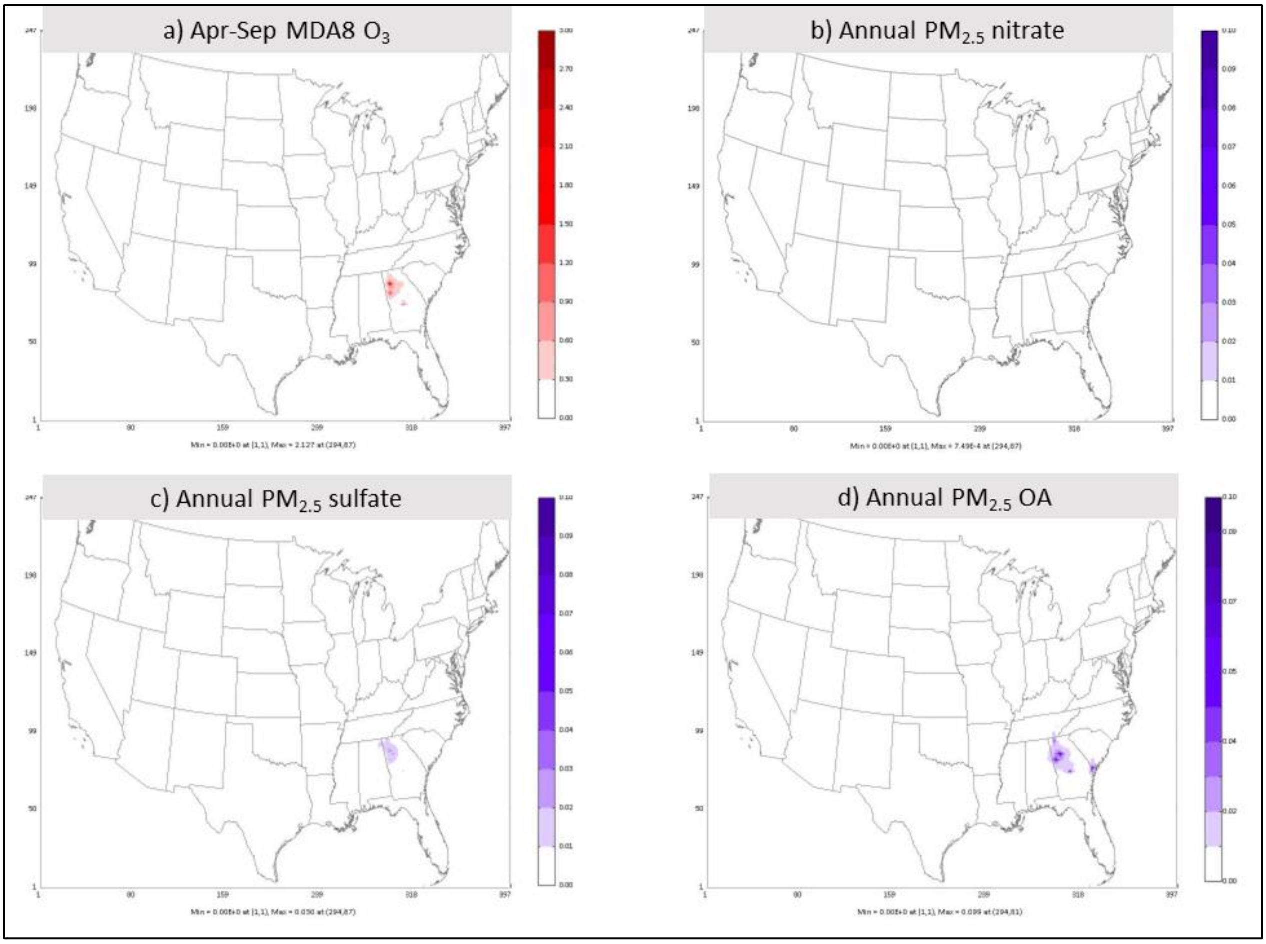

Figure A-3 Maps of Georgia EGU Tag Contributions to a) April-September Seasonal Average MDA8 Ozone (ppb); b) Annual Average $PM_{2.5}$ Nitrate µg/m^3); c) Annual Average $PM_{2.5}$, Sulfate (µg/m^3); d) Annual Average $PM_{2.5}$ Organic Aerosol (µg/m^3)

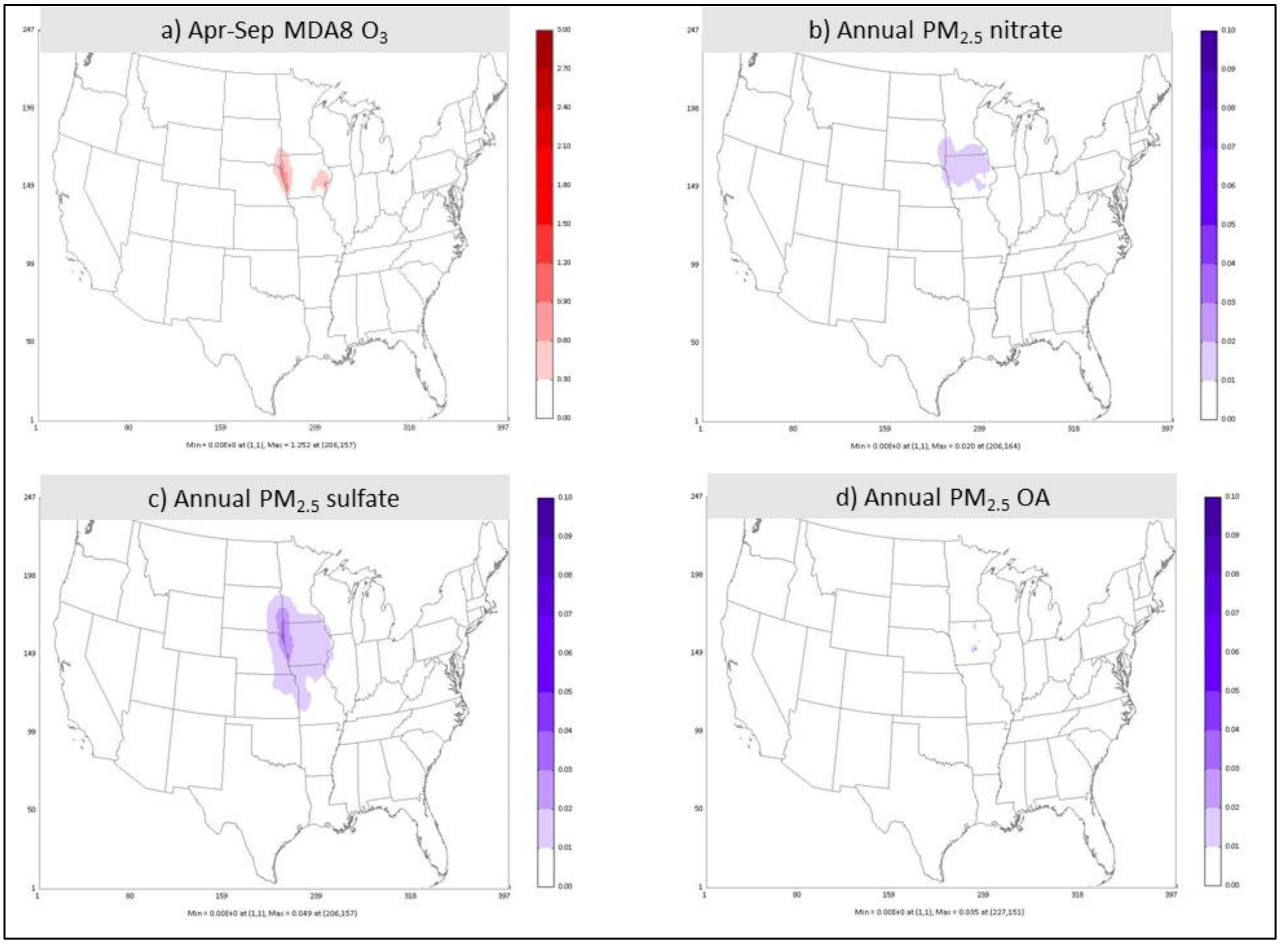

Figure A-4 Maps of Iowa EGU Tag contributions to a) April-September Seasonal Average MDA8 Ozone (ppb); b) Annual Average $PM_{2.5}$ Nitrate ($\mu g/m^3$); c) Annual Average $PM_{2.5}$ Sulfate ($\mu g/m^3$); d) Annual Average $PM_{2.5}$ Organic Aerosol ($\mu g/m^3$)

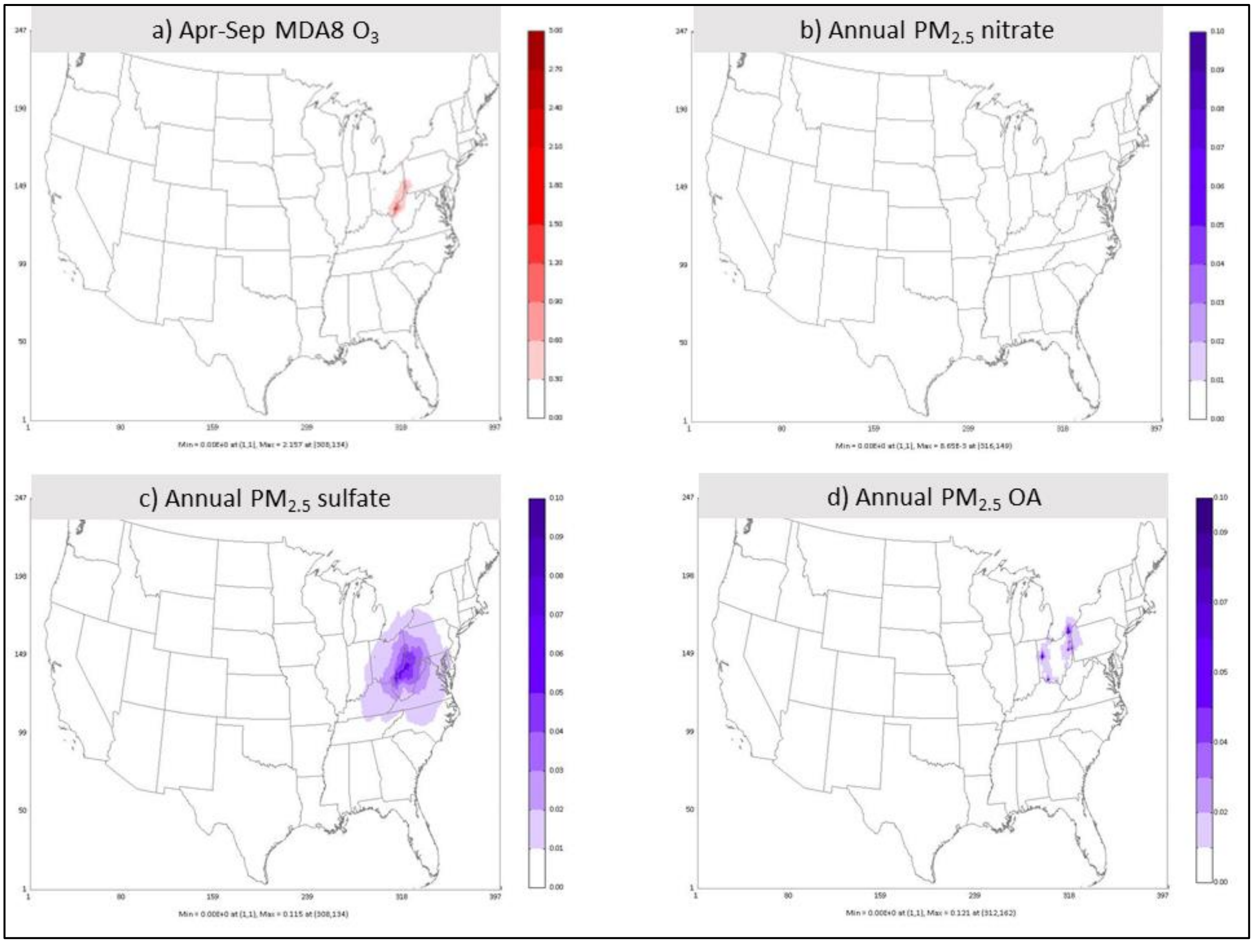

Figure A-5 Maps of Ohio EGU Tag Contributions to a) April-September Seasonal Average MDA8 Ozone (ppb); b) Annual Average $PM_{2.5}$ Nitrate ($\mu g/m^3$); c) Annual Average $PM_{2.5}$ Sulfate ($\mu g/m^3$); d) Annual Average $PM_{2.5}$ Organic Aerosol ($\mu g/m^3$)

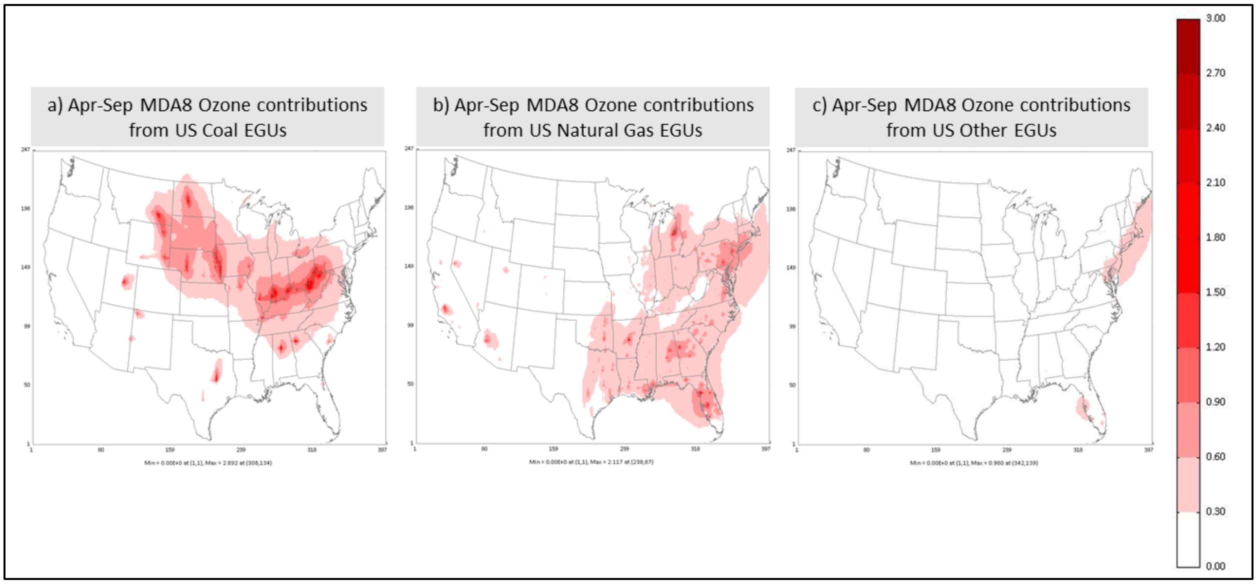

Figure A-6 Maps of national EGU Tag Contributions to April-September Seasonal Average MDA8 Ozone (ppb) by fuel for a) coal EGUs; b) natural gas EGUs; c) all other EGUs

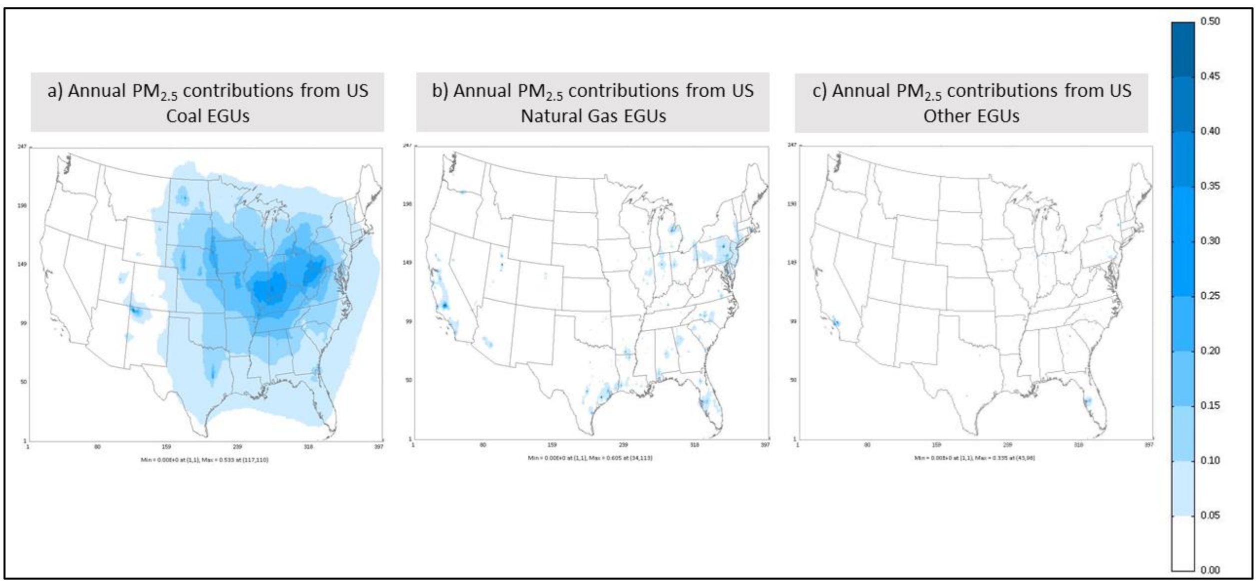

Figure A-7 Maps of national EGU Tag Contributions Annual Average $PM_{2.5}$ ($\mu g/m^3$) by fuel for a) coal EGUs; b) natural gas EGUs; c) all other EGUs

A.3 Applying Modeling Outputs to Create Spatial Fields

In this section we describe the method for creating spatial fields of AS-MO3 and annual average $PM_{2.5}$ based on the 2016 and future year modeling. The foundational data include (1) ozone and speciated $PM_{2.5}$ concentrations in each model grid cell from the 2016 and the future year modeling, (2) ozone and speciated $PM_{2.5}$ contributions in the future year of EGUs emissions from each state in each model grid cell,[115] (3) future year emissions from EGUs that were input to the contribution modeling (Table A-1, Table A-2, Table A-3), and (4) the EGU emissions from IPM for baseline and the final rule scenarios in each analytic year. The method to create spatial fields applies scaling factors to gridded source apportionment contributions based on emissions changes between future year projections and the baseline and the final rule options to the modeled contributions. This method is described in detail below.

Spatial fields of ozone and $PM_{2.5}$for the future year were created based on "fusing" modeled data with measured concentrations at air quality monitoring locations. To create the spatial fields for each future emissions scenario, these fused future year model fields are used in combination with the EGU source apportionment modeling and the EGU emissions for each scenario and analytic year. Contributions from each state and fuel EGU contribution "tag" were scaled based on the ratio of emissions in the year/scenario being evaluated to the emissions in the modeled scenario. Contributions from tags representing sources other than EGUs are held constant at 2026 levels for each of the scenarios and year. For each scenario and year analyzed, the scaled contributions from all sources were summed together to create a gridded surface of total modeled ozone and $PM_{2.5}$. The process is described in a step-by-step manner below starting with the methodology for creating AS-MO3 spatial fields followed by a description of the steps for creating annual $PM_{2.5}$ spatial fields.

Ozone:

1. Create fused spatial fields of future year AS-MO3 incorporating information from the air quality modeling and from ambient measured monitoring data. The enhanced Voronoi Neighbor Average (eVNA) technique (Ding et al., 2016; Gold et al., 1997; U.S. EPA, 2007) was applied to ozone model predictions in conjunction with measured data to create modeled/measured fused surfaces that leverage measured concentrations at air quality monitor locations and model predictions at locations with no monitoring data.
    1.1. The AS-MO3 eVNA spatial fields are created for the 2016 base year with EPA's software package, Software for the Modeled Attainment Test – Community Edition

[115] Contributions from EGUs were modeled using projected emissions for the modeled scenario. The resulting contributions were used to construct spatial fields in 2028, 2030, and 2035.

(SMAT-CE)[116] (U.S. EPA, 2022b) using three years of monitoring data (2015-2017) and the 2016 modeled data.

1.2. The model-predicted spatial fields (i.e., not the eVNA fields) of AS-MO3 in 2016 were paired with the corresponding model-predicted spatial fields in the future year to calculate the ratio of AS-MO3 between 2016 and the future year in each model grid cell.

1.3. To create a gridded future year eVNA surfaces, the spatial fields of 2016/future year ratios created in step 1.2 were multiplied by the corresponding eVNA spatial fields for 2016 created in step 1.1 to produce an eVNA AS-MO3 spatial field for future year using (Eq-1).

$$\mathrm{eVNA}_{\mathrm{g,future}} = \left(\mathrm{eVNA}_{\mathrm{g,2016}}\right) \times \frac{\mathrm{Model}_{\mathrm{g,future}}}{\mathrm{Model}_{\mathrm{g,2016}}} \qquad \text{Eq-1}$$

- $\mathrm{eVNA}_{\mathrm{g,future}}$ is the eVNA concentration of AS-MO3 or $PM_{2.5}$ component species in grid-cell, g, in the future year
- $\mathrm{eVNA}_{\mathrm{g,2016}}$ is the eVNA concentration of AS-MO3 or $PM_{2.5}$ component species in grid-cell, g, in 2016
- $\mathrm{Model}_{\mathrm{g,future}}$ is the CAMx modeled concentration of AS-MO3 or $PM_{2.5}$ component species in grid-cell, g, in the future year
- $\mathrm{Model}_{\mathrm{g,2016}}$ is the CAMx modeled concentration of AS-MO3 or $PM_{2.5}$ component in grid-cell, g, in 2016

2. Create gridded spatial fields of total EGU AS-MO3 contributions for each combination of scenario and analytic year evaluated.

2.1. Use the EGU ozone season NO_X emissions for the 2028 baseline and the corresponding future year modeled EGU ozone season emissions (Table A-1, Table A-2, and Table A-3) to calculate the ratio of 2028 baseline emissions to future year modeled emissions for

[116] SMAT-CE available for download at *https://www.epa.gov/scram/photochemical-modeling-tools*.

each EGU tag (i.e., an ozone scaling factor calculated for each state-fuel tag).[117] These scaling factors are provided in Table A-, A-5 and A-11.

2.2. Calculate adjusted gridded AS-MO3 EGU contributions that reflect differences in state-fuel EGU NO_X emissions between the modeled future year and the 2028 baseline by multiplying the ozone season NO_X scaling factors by the corresponding gridded AS-MO3 ozone contributions[118] from each state-fuel EGU tag.

2.3. Add together the adjusted AS-MO3 contributions for each state-fuel EGU tag to produce spatial fields of adjusted EGU totals for the 2028 baseline.[119]

2.4. Repeat steps 2.1 through 2.3 for the 2028 final rule scenario and for the baseline and final rule scenarios for each additional analytic year. All scaling factors for the baseline scenario and the regulatory control alternatives are provided in Tables A-4, A-5, and A-11.

3. Create a gridded spatial field of AS-MO3 associated with IPM emissions for the 2028 baseline by combining the EGU AS-MO3 contributions from step 2.3 with the corresponding contributions to AS-MO3 from all other sources. Repeat for each of the EGU contributions created in step 2.4 to create separate gridded spatial fields for the 2028 final rule scenario and the baseline and final rule scenario for the two other analytic years.

Steps 2 and 3 in combination can be represented by equation 2:

$$\text{AS-MO3}_{g,i,y} = \text{eVNA}_{g,\text{future}} \times \left(\frac{C_{g,BC}}{C_{g,Tot}} + \frac{C_{g,int}}{C_{g,Tot}} + \frac{C_{g,bio}}{C_{g,Tot}} + \frac{C_{g,fires}}{C_{g,Tot}} + \frac{C_{g,USanthro}}{C_{g,Tot}} + \sum_{t=1}^{T} \frac{C_{EGUVOC,g,t}}{C_{g,Tot}} + \sum_{t=1}^{T} \frac{C_{EGUNOx,g,t}\, S_{NOx,t,i,y}}{C_{g,Tot}} \right) \qquad \text{Eq-2}$$

[117] State-level tags were tracked for separately for coal EGUs and for natural gas EGUs. All other EGU emissions were tracked using a single national tag. In addition, preliminary testing of this methodology showed unstable results when very small magnitudes of emissions were tagged especially when being scaled by large factors. To mitigate this issue, in cases where state-fuel EGU tags were associated with no or very small emissions, tags were combined into multi-state regions.

[118] The source apportionment modeling provided separate ozone contributions for ozone formed in VOC-limited chemical regimes (O3V) and ozone formed in NO_X-limited chemical regimes (O3N). The emissions scaling factors are multiplied by the corresponding O3N gridded contributions to MDA8 concentrations. Since there are no predicted changes in VOC emissions in the control scenarios, the O3V contributions remain unchanged.

[119] The contributions from the unaltered O3V tags are added to the summed adjusted O3N EGU tags.

- $\text{AS-MO3}_{g,i,y}$ is the estimated fused model-obs AS-MO3 for grid-cell, “g,” scenario, “i,”[120] and year, “y;”[121]

- $\text{eVNA}_{g,future}$ is the future year eVNA future year AS-MO3 concentration for grid-cell “g” calculated using Eq-1;

- $C_{g,Tot}$ is the total modeled AS-MO3 for grid-cell “g” from all sources in the future year source apportionment modeling;

- $C_{g,BC}$ is the future year AS-MO3 modeled contribution from the modeled boundary inflow;

- $C_{g,int}$ is the future year AS-MO3 modeled contribution from international emissions within the modeling domain;

- $C_{g,bio}$ is the future year AS-MO3 modeled contribute/on from biogenic emissions;

- $C_{g,fires}$ is the future year AS-MO3 modeled contribution from fires;

- $C_{g,USanthro}$ is the total future year AS-MO3 modeled contribution from U.S. anthropogenic sources other than EGUs;

- $C_{EGUVOC,g,t}$ is the future year AS-MO3 modeled contribution from EGU emissions of VOCs from tag, “t”;

- $C_{EGUNOx,g,t}$ is the future year AS-MO3 modeled contribution from EGU emissions of NO_X from tag, “t”; and

- $S_{NOx,t,i,y}$ is the EGU NO_X scaling factor for tag, “t,” scenario, “i,” and year, “y.”

$PM_{2.5}$

4. Create fused spatial fields of future year annual $PM_{2.5}$ component species incorporating information from the air quality modeling and from ambient measured monitoring data. The eVNA technique was applied to $PM_{2.5}$ component species model predictions in conjunction with measured data to create modeled/measured fused surfaces that leverage measured concentrations at air quality monitor locations and model predictions at locations with no monitoring data.

[120] Scenario “i" can represent either the baseline or the final rule scenario.
[121] Year “y” can represent 2028, 2030, or 2035.

4.1. The quarterly average $PM_{2.5}$ component species eVNA spatial fields are created for the 2016 base year with EPA's SMAT-CE software package using three years of monitoring data (2015-2017) and the 2016 modeled data.

4.2. The model-predicted spatial fields (i.e., not the eVNA fields) of quarterly average $PM_{2.5}$ component species in 2016 were paired with the corresponding future year model-predicted spatial fields to calculate the ratio of $PM_{2.5}$ component species between 2016 and the future year in each model grid cell.

4.3. To create a gridded future year eVNA surfaces, the spatial fields of 2016/future year ratios created in step 4.2 were multiplied by the corresponding eVNA spatial fields for 2016 created in step 4.1 to produce an eVNA annual average $PM_{2.5}$ component species spatial field for the future year using Eq-1.

5. Create gridded spatial fields of total EGU speciated $PM_{2.5}$ contributions for each combination of scenario and analytic year evaluated.

5.1. Use the EGU annual total NO_X, SO_2, and $PM_{2.5}$ emissions for the 2028 baseline scenario and the corresponding future year modeled EGU NO_X, SO_2, and $PM_{2.5}$ emissions from Table A-1, Table A-2 and Table A-3 to calculate the ratio of 2028 baseline emissions to future year modeled emissions for each EGU state-fuel contribution tag (i.e., annual nitrate, sulfate and directly emitted $PM_{2.5}$ scaling factors calculated for each state-fuel tag).[122] These scaling factors are provided in Table A-6 through Table A-11.

5.2. Calculate adjusted gridded annual $PM_{2.5}$ component species EGU contributions that reflect differences in state-EGU NO_X, SO_2, and primary $PM_{2.5}$ emissions between the modeled future year and the 2028 baseline by multiplying the annual nitrate, sulfate and directly emitted $PM_{2.5}$ scaling factors by the corresponding annual gridded $PM_{2.5}$ component species contributions from each state-fuel EGU tag.[123]

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[122] State-level tags were tracked for separately for coal EGUs and for natural gas EGUs. All other EGU emissions were tracked using a single national tag. In addition, preliminary testing of this methodology showed unstable results when very small magnitudes of emissions were tagged especially when being scaled by large factors. To mitigate this issue, in cases where state-fuel EGU tags were associated with no or very small emissions, tags were combined into multi-state regions.

[123] Scaling factors for components that are formed through chemical reactions in the atmosphere were created as follows: scaling factors for sulfate were based on relative changes in annual SO_2 emissions; scaling factors for

5.3. Add together the adjusted $PM_{2.5}$ contributions of for each EGU state tag to produce spatial fields of adjusted EGU totals for each $PM_{2.5}$ component species.

5.4. Repeat steps 5.1 through 5.3 for the final rule scenario in 2028 and for the baseline and the final rule scenario for each additional analytic year. The scaling factors for all $PM_{2.5}$ component species for the baseline and final rule scenarios are provided in Table A-6 through Table A-11

6. Create gridded spatial fields of each $PM_{2.5}$ component species for the 2028 baseline by combining the EGU annual $PM_{2.5}$ component species contributions from step 5.3 with the corresponding contributions to annual $PM_{2.5}$ component species from all other sources. Repeat for each of the EGU contributions created in step 5.4 to create separate gridded spatial fields for the baseline and final rule scenarios for all other analytic years.

7. Create gridded spatial fields of total $PM_{2.5}$ mass by combining the component species surfaces for sulfate, nitrate, organic aerosol, elemental carbon, and crustal material with ammonium, and particle-bound water. Ammonium and particle-bound water concentrations are calculated for each scenario based on nitrate and sulfate concentrations along with the ammonium degree of neutralization in the base year modeling (2016) in accordance with equations from the SMAT-CE modeling software (U.S. EPA, 2022bfi).

Steps 5 and 6 result in Eq-3 for $PM_{2.5}$ component species: sulfate, nitrate, organic aerosol, elemental carbon, and crustal material.

$$\mathrm{PM}_{s,g,i,y} = \mathrm{eVNA}_{s,g,future} \times \left(\frac{C_{s,g,BC}}{C_{s,g,Tot}} + \frac{C_{s,g,int}}{C_{s,g,Tot}} + \frac{C_{s,g,bio}}{C_{s,g,Tot}} + \frac{C_{s,g,fires}}{C_{s,g,Tot}} + \frac{C_{s,g,USanthro}}{C_{s,g,Tot}} + \sum_{t=1}^{T} \frac{C_{EGUs,g,t}\, S_{s,t,i,y}}{C_{s,g,Tot}} \right) \qquad \text{Eq-3}$$

nitrate were based on relative changes in annual NO_X emissions. Scaling factors for $PM_{2.5}$ components that are emitted directly from the source (OA, EC, crustal) were based on the relative changes in annual primary $PM_{2.5}$ emissions between the future year modeled emissions and the baseline or the final rule scenario in each year.

- $PM_{s,g,i,y}$ is the estimated fused model-obs PM component species "s" for grid-cell, "g," scenario, "i,"[124] and year, "y;"[125]

- $eVNA_{s,g,future}$ is the future year eVNA PM concentration for component species "s" in grid-cell "g" calculated using Eq-1;

- $C_{s,g,Tot}$ is the total modeled PM component species "s" for grid-cell "g" from all sources in the 2026 source apportionment modeling;

- $C_{s,g,BC}$ is the future year PM component species "s" modeled contribution from the modeled boundary inflow;

- $C_{s,g,int}$ is the future year PM component species "s" modeled contribution from international emissions within the modeling domain;

- $C_{s,g,bio}$ is the future year PM component species "s" modeled contribution from biogenic emissions;

- $C_{s,g,fires}$ is the future year PM component species "s" modeled contribution from fires;

- $C_{s,g,USanthro}$ is the total future year PM component species "s" modeled contribution from U.S. anthropogenic sources other than EGUs;

- $C_{EGUs,g,t}$ is the future year PM component species "s" modeled contribution from EGU emissions of NO_X, SO_2, or primary $PM_{2.5}$ from tag, "t"; and

- $S_{s,t,i,y}$ is the EGU scaling factor for component species "s," tag "t," scenario "i," and year "y." Scaling factors for nitrate are based on annual NO_x emissions, scaling factors for sulfate are based on annual SO_2 emissions, scaling factors for primary $PM_{2.5}$ components are based on primary $PM_{2.5}$ emissions.

[124] Scenario "i" can represent either baseline or the final rule scenario.
[125] Year "y" can represent 2028, 2030, or 2035.

A.4 Scaling Factors Applied to Source Apportionment Tags

Table A-4 Ozone Seasonal NO_X Scaling Factors for Coal EGU Tags in the Baseline and the Final Rule

	Baseline			Final Rule		
State Tag	**2028**	**2030**	**2035**	**2028**	**2030**	**2035**
AL	1.20	1.40	1.47	1.20	1.40	1.47
AZ	0.01	1.43	1.13	0.01	1.43	1.17
CA	0.00	0.00	0.00	0.00	0.00	0.00
CO	139.01	1.28	1.98	139.01	1.28	1.98
CT	0.00	0.00	0.00	0.00	0.00	0.00
DC	0.00	0.00	0.00	0.00	0.00	0.00
DE	0.00	0.00	0.00	0.00	0.00	0.00
FL	0.47	1.24	0.10	0.47	1.24	0.10
GA	0.00	0.18	0.00	0.00	0.18	0.00
IA	1.17	1.18	0.77	1.17	1.18	0.77
ID	0.00	0.00	0.00	0.00	0.00	0.00
IL	0.97	0.96	0.81	0.97	0.96	0.81
IN	1.35	0.76	0.19	1.35	0.76	0.19
KY	0.79	0.95	0.97	0.79	0.95	0.98
MA	0.00	0.00	0.00	0.00	0.00	0.00
MDPA[a]	3.14	3.17	2.58	3.14	3.17	2.58
ME	0.00	0.00	0.00	0.00	0.00	0.00
MI	0.75	0.00	0.00	0.75	0.00	0.00
MN	2.41	2.25	0.00	2.41	2.25	0.00
MO	2.72	1.57	0.67	2.71	1.57	0.67
MT	1.07	1.12	1.11	1.07	1.12	1.09
NC	9.89	6.41	2.86	9.92	6.43	2.86
ND	1.09	1.08	0.25	1.06	1.08	0.25
NE	1.16	1.18	0.73	1.16	1.18	0.74
NH	0.00	0.00	0.00	0.00	0.00	0.00
NJ	0.00	0.00	0.00	0.00	0.00	0.00
NM	0.98	0.98	0.01	0.98	0.98	0.01
NV	0.00	0.00	0.00	0.00	0.00	0.00
NY	0.00	0.00	0.00	0.00	0.00	0.00
OH	0.58	1.07	0.00	0.58	1.07	0.00
OR	0.00	0.00	0.00	0.00	0.00	0.00
RI	0.00	0.00	0.00	0.00	0.00	0.00
SC	0.81	2.22	3.18	0.81	2.22	3.18
SD	0.87	1.33	0.00	0.87	1.33	0.00
TN	3.89	0.01	0.00	3.89	0.01	0.00
TX-reg[b]	4.69	4.26	1.64	4.70	4.26	1.64
UT	1.00	0.06	0.06	1.00	0.06	0.06

State Tag	Baseline			Final Rule		
	2028	2030	2035	2028	2030	2035
VA	0.65	0.45	0.00	0.65	0.45	0.00
VT	0.00	0.00	0.00	0.00	0.00	0.00
WA	0.00	0.00	0.00	0.00	0.00	0.00
WI	1.66	2.16	0.36	1.69	2.16	0.36
WV	0.92	1.16	0.92	0.92	1.16	0.91
WY	1.26	1.12	1.12	1.26	1.12	1.12

Note: Emissions from Maryland, Arkansas, Kansas, Louisiana, Oklahoma, and Mississippi are less than 10 tpy in the original source apportionment modeling. Air quality impacts and emissions from those states were combined with nearby states.

[a] MDPA: Maryland and Pennsylvania

[b] TX-reg: Arkansas, Kansas, Louisiana, Oklahoma, Mississippi, Texas

Table A-5 Ozone Seasonal NO_X Scaling Factors for Gas EGU Tags in the Baseline and the Final Rule

	Baseline			Final Rule		
State Tag	2028	2030	2035	2028	2030	2035
AL	0.53	0.61	0.49	0.53	0.61	0.49
AR	0.65	0.68	0.43	0.63	0.68	0.43
AZ	0.69	0.68	0.67	0.69	0.68	0.67
CA	0.92	0.94	0.85	0.92	0.94	0.85
CO	3.26	0.63	0.50	3.26	0.63	0.50
CT	1.04	0.98	0.89	1.04	0.98	0.89
DC	0.86	0.59	0.33	0.86	0.59	0.33
DE	0.79	0.80	0.38	0.79	0.80	0.38
FL	1.08	1.03	1.04	1.08	1.03	1.04
GA	0.58	0.54	0.52	0.58	0.54	0.52
IA	0.53	0.42	0.16	0.53	0.42	0.16
ID	0.60	0.90	0.90	0.59	0.91	0.89
IL	0.69	0.61	0.42	0.68	0.61	0.42
IN	0.75	0.63	0.38	0.75	0.63	0.38
KS	1.38	1.32	0.25	1.38	1.32	0.24
KY	0.87	0.81	0.69	0.86	0.81	0.69
LA	1.04	1.00	0.72	1.04	1.00	0.72
MA	0.60	0.67	0.66	0.60	0.67	0.66
MD	1.51	1.33	1.12	1.51	1.33	1.12
ME	1.16	1.15	0.59	1.16	1.15	0.59
MI	0.68	0.70	0.55	0.68	0.70	0.55
MN	0.92	0.84	0.34	0.92	0.84	0.34
MO	0.59	0.59	0.20	0.58	0.59	0.20
MS	0.64	0.62	0.50	0.64	0.62	0.50
MT	0.95	1.10	0.08	0.95	1.10	0.09
NC	0.77	0.59	0.68	0.77	0.59	0.68
ND	0.85	1.85	0.34	0.82	1.85	0.34
NE	5.91	5.92	0.28	5.91	5.92	0.29
NH	0.67	0.51	0.41	0.67	0.51	0.41
NJ	0.81	0.85	0.61	0.81	0.85	0.62
NM	1.00	0.84	0.77	1.00	0.84	0.77
NV	0.33	0.25	0.19	0.33	0.25	0.19
NY	1.03	0.99	0.65	1.03	0.99	0.64
OH	1.02	0.97	0.84	1.03	0.97	0.84
OK	1.69	1.57	0.48	1.69	1.57	0.47
OR	63.29	0.00	0.00	63.55	0.00	0.00
PA	0.79	0.69	0.34	0.79	0.69	0.34
RI	0.69	0.75	0.71	0.69	0.75	0.71

State Tag	Baseline			Final Rule		
	2028	2030	2035	2028	2030	2035
SC	0.93	0.96	0.59	0.93	0.96	0.59
SD	0.59	0.59	0.17	0.59	0.59	0.17
TN	1.12	1.09	1.07	1.12	1.09	1.07
TX	0.99	0.89	0.47	0.99	0.89	0.47
UT	0.50	0.43	0.34	0.50	0.43	0.34
VA	0.89	0.85	0.54	0.88	0.85	0.54
VT	0.00	0.37	3.53	0.00	0.37	3.53
WA	0.08	0.23	0.79	0.08	0.23	0.79
WI	0.74	0.70	0.58	0.74	0.70	0.57
WV	1.19	1.12	0.33	1.19	1.12	0.33
WY	0.01	0.04	0.06	0.01	0.04	0.07

Table A-6 Nitrate Scaling Factors for Coal EGU Tags in the Baseline and the Final Rule

	Baseline			Final Rule		
State Tag	**2028**	**2030**	**2035**	**2028**	**2030**	**2035**
AL	1.33	1.45	1.65	1.33	1.45	1.65
AR	39.93	8.30	3.83	39.92	8.32	3.83
AZ	0.47	0.97	0.59	0.47	0.97	0.61
CA	0.24	0.36	0.16	0.24	0.36	0.16
CO	25.56	0.97	0.37	25.57	0.97	0.37
CT	0.00	0.00	0.00	0.00	0.00	0.00
DC	0.00	0.00	0.00	0.00	0.00	0.00
DE	0.00	0.00	0.00	0.00	0.00	0.00
FL	0.89	1.20	0.26	0.89	1.20	0.26
GA	0.23	0.12	0.00	0.23	0.12	0.00
IA	1.20	1.16	0.68	1.20	1.16	0.68
ID	0.00	0.00	0.00	0.00	0.00	0.00
IL	0.98	0.92	0.62	0.98	0.92	0.62
IN	1.29	0.64	0.11	1.28	0.65	0.11
KS	45.15	46.03	3.08	45.15	46.03	3.08
KY	1.38	1.12	1.15	1.38	1.12	1.16
LA	24.63	16.33	25.37	24.63	16.33	25.37
MA	0.00	0.00	0.00	0.00	0.00	0.00
MD	3.54	3.54	3.54	3.54	3.54	3.54
ME	0.00	0.00	0.00	0.00	0.00	0.00
MI	0.74	0.00	0.00	0.74	0.00	0.00
MN	2.97	2.31	0.00	2.97	2.31	0.00
MO	1.41	1.06	0.43	1.40	1.06	0.43
MS	4.02	3.60	1.06	4.01	3.60	1.06
MT	1.07	1.09	1.08	1.07	1.09	1.07
NC	19.19	11.95	3.66	19.22	11.95	3.67
ND	1.03	1.03	0.25	1.02	1.03	0.25
NE	1.14	1.13	0.61	1.14	1.13	0.62
NH	0.00	0.00	0.00	0.00	0.00	0.00
NJ	0.00	0.00	0.00	0.00	0.00	0.00
NM	0.99	0.99	0.01	0.99	0.99	0.01
NV	0.00	0.00	0.00	0.00	0.00	0.00
NY	0.00	0.00	0.00	0.00	0.00	0.00
OH	0.90	0.94	0.19	0.90	0.94	0.19
OK	12.10	5.08	3.11	12.08	5.07	3.11
OR	0.00	0.00	0.00	0.00	0.00	0.00
PA	3.05	2.94	2.61	3.05	2.94	2.61
RI	0.00	0.00	0.00	0.00	0.00	0.00

	Baseline			Final Rule		
State Tag	2028	2030	2035	2028	2030	2035
SC	1.15	1.92	2.98	1.14	1.92	2.98
SD	0.93	1.11	0.00	0.93	1.11	0.00
TN	7.49	1.00	0.00	7.49	1.00	0.00
TX	1.02	1.13	0.87	1.02	1.13	0.87
UT	3.50	0.09	0.09	3.50	0.09	0.09
VA	0.67	0.41	0.12	0.67	0.41	0.12
VT	0.00	0.00	0.00	0.00	0.00	0.00
WA	0.00	0.00	0.00	0.00	0.00	0.00
WI	1.84	2.07	0.38	1.85	2.07	0.38
WV	1.25	1.30	0.97	1.25	1.30	0.97
WY	1.32	1.15	1.14	1.32	1.15	1.14

Table A-7 Nitrate Scaling Factors for Gas EGU Tags in the Baseline and the Final Rule

	Baseline			Final Rule		
State Tag	**2028**	**2030**	**2035**	**2028**	**2030**	**2035**
AL	0.59	0.60	0.45	0.59	0.60	0.45
AR	0.56	0.68	0.38	0.55	0.68	0.38
AZ	0.73	0.85	0.83	0.73	0.85	0.83
CA	0.76	0.88	0.97	0.76	0.88	0.97
CO	2.02	0.71	0.72	2.02	0.71	0.72
CT	0.92	0.81	0.66	0.92	0.81	0.66
DC	0.63	0.47	0.26	0.63	0.47	0.26
DE	0.79	0.76	0.33	0.79	0.76	0.33
FL	1.11	1.06	1.01	1.10	1.06	1.01
GA	0.68	0.63	0.54	0.68	0.63	0.54
IA	0.49	0.42	0.13	0.49	0.42	0.13
ID	1.02	1.36	1.39	1.01	1.36	1.38
IL	0.54	0.54	0.29	0.53	0.54	0.29
IN	0.67	0.59	0.34	0.66	0.59	0.34
KS	0.96	0.87	0.20	0.96	0.88	0.20
KY	0.81	0.76	0.46	0.81	0.76	0.46
LA	0.96	0.94	0.61	0.96	0.94	0.61
MA	0.64	0.66	0.54	0.64	0.66	0.54
MD	1.47	1.35	1.05	1.47	1.35	1.05
ME	1.64	1.34	0.63	1.64	1.34	0.63
MI	0.65	0.71	0.43	0.65	0.71	0.43
MN	1.02	0.95	0.36	1.02	0.95	0.36
MO	0.52	0.52	0.19	0.52	0.52	0.19
MS	0.61	0.56	0.36	0.61	0.56	0.36
MT	0.66	0.80	0.05	0.66	0.80	0.06
NC	0.89	0.67	0.72	0.89	0.67	0.72
ND	0.66	1.32	0.26	0.65	1.31	0.26
NE	2.05	1.80	0.13	2.05	1.80	0.13
NH	0.78	0.59	0.44	0.78	0.59	0.44
NJ	0.82	0.83	0.51	0.82	0.83	0.52
NM	0.74	0.66	0.64	0.74	0.66	0.64
NV	0.50	0.39	0.44	0.50	0.39	0.44
NY	0.91	0.89	0.55	0.91	0.89	0.55
OH	1.00	0.98	0.87	1.00	0.98	0.87
OK	1.43	1.20	0.34	1.44	1.20	0.34
OR	5.58	0.96	0.50	5.59	0.96	0.49
PA	0.69	0.61	0.35	0.69	0.61	0.35
RI	0.76	0.76	0.64	0.77	0.76	0.64
SC	0.94	0.96	0.67	0.94	0.96	0.67
SD	0.55	0.55	0.16	0.55	0.55	0.16

State Tag	Baseline			Final Rule		
	2028	2030	2035	2028	2030	2035
TN	1.02	0.97	0.79	1.02	0.97	0.80
TX	0.97	0.88	0.42	0.97	0.89	0.42
UT	0.52	0.62	0.56	0.52	0.62	0.56
VA	0.84	0.80	0.43	0.84	0.80	0.43
VT	0.10	0.16	1.53	0.10	0.16	1.53
WA	0.43	0.36	0.72	0.43	0.36	0.72
WI	0.66	0.67	0.45	0.66	0.67	0.44
WV	1.02	0.89	0.22	1.02	0.89	0.22
WY	0.01	0.04	0.06	0.01	0.04	0.06

Table A-8 Sulfate Scaling Factors for Coal EGU Tags in the Baseline and the Final Rule

	Baseline			Final Rule		
State Tag	2028	2030	2035	2028	2030	2035
AL	4.96	5.39	7.07	4.96	5.39	7.07
AR	118.10	7.02	4.45	118.07	7.04	4.45
AZ	0.48	1.42	1.16	0.48	1.42	1.16
CA	0.33	0.50	0.26	0.33	0.50	0.26
CO	14.31	0.98	0.20	14.31	0.98	0.20
CT	0.00	0.00	0.00	0.00	0.00	0.00
DC	0.00	0.00	0.00	0.00	0.00	0.00
DE	0.00	0.00	0.00	0.00	0.00	0.00
FL	0.98	1.16	0.50	0.98	1.16	0.50
GA	0.04	0.09	0.00	0.04	0.09	0.00
IA	1.31	1.25	0.78	1.31	1.25	0.78
ID	0.00	0.00	0.00	0.00	0.00	0.00
IL	1.01	0.73	0.48	1.01	0.73	0.48
IN	0.89	0.56	0.12	0.89	0.56	0.12
KS	52.35	51.92	11.39	52.35	51.92	11.39
KY	2.68	2.12	1.88	2.68	2.11	1.88
MA	0.00	0.00	0.00	0.00	0.00	0.00
MD	3.54	3.54	3.54	3.54	3.54	3.54
ME	0.00	0.00	0.00	0.00	0.00	0.00
MI	0.85	0.00	0.00	0.85	0.00	0.00
MN	1.68	1.47	0.00	1.68	1.47	0.00
MO	2.20	1.08	0.71	2.20	1.08	0.71
MS	4.02	3.60	1.06	4.01	3.60	1.06
MT	1.85	2.06	1.92	1.85	2.06	1.86
NC	7.31	5.14	1.88	7.32	5.14	1.88
ND	0.94	1.00	0.94	0.94	1.00	0.94
NE	0.96	0.95	0.58	0.96	0.95	0.58
NH	0.00	0.00	0.00	0.00	0.00	0.00
NJ	0.00	0.00	0.00	0.00	0.00	0.00
NM	1.00	1.00	0.01	1.00	1.00	0.01
NV	0.00	0.00	0.00	0.00	0.00	0.00
NY	0.00	0.00	0.00	0.00	0.00	0.00
OH	0.78	0.61	0.29	0.78	0.60	0.29
OK	37.84	4.77	2.54	37.83	4.77	2.54
OR	0.00	0.00	0.00	0.00	0.00	0.00
PA	4.25	4.06	3.94	4.25	4.06	3.94
RI	0.00	0.00	0.00	0.00	0.00	0.00
SC	0.73	1.22	1.76	0.73	1.22	1.76
SD	1.05	1.27	0.00	1.06	1.27	0.00
TN	20.55	1.57	0.00	20.55	1.57	0.00

State Tag	Baseline			Final Rule		
	2028	**2030**	**2035**	**2028**	**2030**	**2035**
TXLA[a]	1.86	2.39	2.25	1.86	2.39	2.25
UT	0.93	0.06	0.06	0.93	0.06	0.06
VA	0.11	0.07	0.02	0.11	0.07	0.02
VT	0.00	0.00	0.00	0.00	0.00	0.00
WA	0.00	0.00	0.00	0.00	0.00	0.00
WI	3.50	3.83	1.15	3.51	3.83	1.14
WV	1.40	1.39	1.08	1.40	1.39	1.08
WY	1.26	0.98	0.97	1.26	0.98	0.97

Note: Emissions from Louisiana are less than 10 tpy in the original source apportionment modeling. Air quality impacts and emissions from Texas and Louisiana were combined.

[a] TXLA: Louisiana and Texas

Table A-9 Primary $PM_{2.5}$ Scaling Factors for Coal EGU Tags in the Baseline and the Final Rule

	Baseline			Final Rule		
State Tag	2028	2030	2035	2028	2030	2035
AL	1.20	1.31	1.43	1.20	1.31	1.43
AR	20.02	7.10	3.14	19.96	7.12	3.14
AZ	0.38	1.17	0.61	0.38	1.17	0.61
CA	0.24	0.36	0.16	0.24	0.36	0.16
CO	13.37	1.19	0.51	13.38	1.19	0.51
CT	0.00	0.00	0.00	0.00	0.00	0.00
DC	0.00	0.00	0.00	0.00	0.00	0.00
DE	0.00	0.00	0.00	0.00	0.00	0.00
FL	1.40	1.84	0.25	1.38	1.82	0.25
GA	0.03	0.06	0.00	0.03	0.06	0.00
IA	1.17	1.14	0.67	1.17	1.14	0.67
ID	0.00	0.00	0.00	0.00	0.00	0.00
IL	1.17	0.95	0.57	1.15	0.95	0.57
IN	1.28	0.60	0.20	1.28	0.60	0.20
KY	1.30	1.19	0.77	1.28	1.17	0.75
MA	0.00	0.00	0.00	0.00	0.00	0.00
MD	3.54	3.54	3.54	3.54	3.54	3.54
ME	0.00	0.00	0.00	0.00	0.00	0.00
MI	0.83	0.00	0.00	0.83	0.00	0.00
MN	3.50	2.70	0.00	3.51	2.70	0.00
MO	3.04	1.33	0.54	2.78	1.33	0.54
MS	4.02	3.60	1.06	3.33	2.99	0.88
MT	0.98	0.98	0.98	0.71	0.71	0.72
NC	21.57	17.32	6.08	21.44	17.30	6.09
ND	0.94	0.98	0.78	0.94	0.98	0.78
NEKS[a]	3.70	3.68	0.80	3.70	3.68	0.80
NH	0.00	0.00	0.00	0.00	0.00	0.00
NJ	0.00	0.00	0.00	0.00	0.00	0.00
NM	0.98	0.99	0.01	0.98	0.99	0.01
NV	0.00	0.00	0.00	0.00	0.00	0.00
NY	0.00	0.00	0.00	0.00	0.00	0.00
OH	0.83	1.08	0.19	0.83	1.08	0.19
OK	14.75	8.14	8.94	14.74	8.12	8.94
OR	0.00	0.00	0.00	0.00	0.00	0.00
PA	3.12	3.04	2.28	2.98	2.91	2.15
RI	0.00	0.00	0.00	0.00	0.00	0.00
SC	1.03	2.17	3.78	1.03	2.17	3.78
SD	0.93	1.11	0.00	0.93	1.11	0.00

State Tag	Baseline			Final Rule		
	2028	2030	2035	2028	2030	2035
TN	16.88	1.00	0.00	16.88	1.00	0.00
TXLA[b]	1.10	1.30	1.15	1.10	1.30	1.15
UT	2.92	0.06	0.06	2.92	0.06	0.06
VA	0.46	0.29	0.08	0.46	0.29	0.08
VT	0.00	0.00	0.00	0.00	0.00	0.00
WA	0.00	0.00	0.00	0.00	0.00	0.00
WI	2.11	2.36	0.46	2.13	2.36	0.46
WV	1.29	1.45	1.23	1.22	1.38	1.17
WY	1.03	1.10	1.08	1.02	1.09	1.07

Note: Emissions from Louisiana and Kansas are less than 10 tpy in the original source apportionment modeling. Air quality impacts and emissions from those states were combined with nearby states.

[a] NEKS: Nebraska and Kansas

[b] TXLA: Louisiana and Texas

Table A-10 Primary $PM_{2.5}$ Scaling Factors for Gas EGU Tags in the Baseline and the Final Rule

	Baseline			Final Rule		
State Tag	2028	2030	2035	2028	2030	2035
AL	0.85	0.84	0.71	0.85	0.84	0.71
AR	0.63	0.82	0.43	0.63	0.82	0.43
AZ	0.70	0.85	0.86	0.70	0.85	0.86
CA	0.96	1.06	0.98	0.96	1.06	0.98
CO	1.23	0.74	0.77	1.23	0.74	0.77
CT	0.78	0.67	0.60	0.78	0.67	0.60
DC	0.15	0.13	0.11	0.15	0.13	0.11
DE	0.62	0.64	0.31	0.62	0.64	0.31
FL	0.97	0.98	0.95	0.97	0.98	0.95
GA	0.84	0.81	0.72	0.84	0.81	0.72
IA	0.50	0.48	0.20	0.51	0.47	0.20
ID	1.22	1.65	1.68	1.22	1.65	1.67
IL	0.49	0.55	0.28	0.49	0.55	0.28
IN	0.67	0.67	0.44	0.67	0.67	0.44
KS	1.12	1.02	0.19	1.12	1.02	0.19
KY	0.75	0.72	0.49	0.74	0.72	0.49
LA	0.79	0.80	0.64	0.79	0.80	0.64
MA	0.48	0.46	0.34	0.48	0.46	0.34
MD	1.05	1.08	0.85	1.05	1.09	0.85
ME	1.75	1.44	0.51	1.75	1.44	0.52
MI	0.75	0.87	0.63	0.75	0.87	0.63
MN	0.57	0.52	0.21	0.57	0.52	0.21
MO	0.30	0.33	0.10	0.30	0.33	0.10
MS	0.88	0.84	0.51	0.88	0.85	0.51
MT	0.17	0.21	0.03	0.17	0.21	0.04
NC	0.87	0.70	0.76	0.87	0.69	0.76
ND	0.47	0.92	0.19	0.46	0.91	0.19
NE	2.17	2.04	0.27	2.17	2.04	0.28
NH	0.59	0.43	0.31	0.59	0.43	0.31
NJ	0.82	0.84	0.52	0.82	0.84	0.52
NM	0.52	0.52	0.89	0.52	0.52	0.89
NV	0.72	0.84	0.83	0.72	0.84	0.83
NY	0.86	0.85	0.59	0.86	0.85	0.59
OH	0.95	0.95	0.89	0.95	0.95	0.89
OK	1.00	0.79	0.22	1.01	0.79	0.22
OR	3.29	0.74	0.39	3.30	0.74	0.39
PA	0.83	0.80	0.60	0.83	0.80	0.60

State Tag	Baseline			Final Rule		
	2028	2030	2035	2028	2030	2035
RI	0.83	0.78	0.65	0.83	0.78	0.65
SC	0.80	0.86	0.64	0.80	0.86	0.64
SD	0.73	0.73	0.25	0.73	0.73	0.25
TN	1.08	1.05	0.88	1.08	1.05	0.88
TX	0.90	0.83	0.45	0.90	0.83	0.45
UT	0.66	0.87	0.84	0.66	0.87	0.84
VA	0.81	0.73	0.47	0.81	0.73	0.48
VT	0.00	0.00	0.03	0.00	0.00	0.03
WA	0.44	0.48	0.58	0.44	0.48	0.58
WI	0.56	0.66	0.43	0.56	0.66	0.42
WV	0.51	0.38	0.10	0.51	0.38	0.10
WY	0.01	0.04	0.03	0.01	0.04	0.04

Table A-11 Scaling Factors for Other EGU Tags in the Baseline and the Final Rule

	Baseline			Final Rule		
Pollutants	2028	2030	2035	2028	2030	2035
Seasonal NO_X	1.16	1.16	1.10	1.16	1.16	1.10
Annual NO_X	1.17	1.17	1.11	1.17	1.17	1.11
Annual SO_2	1.00	1.01	1.00	1.00	1.01	1.00
Annual $PM_{2.5}$	1.37	1.37	1.32	1.37	1.37	1.32

A.5 Air Quality Surface Results

The spatial fields of model-predicted air quality changes between the baseline and the two regulatory options in 2028, 2030, and 2035 for AS-MO3 are presented in Figure A-8. It is important to recognize that ozone is a secondary pollutant, meaning that it is formed through chemical reactions of precursor emissions in the atmosphere. As a result of the time necessary for precursors to mix in the atmosphere and for these reactions to occur, ozone can either be highest at the location of the precursor emissions or peak at some distance downwind of those emissions sources. The spatial gradients of ozone depend on a multitude of factors including the spatial patterns of NO_X and VOC emissions and the meteorological conditions on a particular day. Thus, on any individual day, high ozone concentrations may be found in narrow plumes downwind of specific point sources, may appear as urban outflow with large concentrations downwind of urban source locations or may have a more regional signal. However, in general, because the AS-MO3 metric is based on the average of concentrations over more than 180 days in the spring and summer, the resulting spatial fields are rather smooth without sharp gradients, compared to what might be expected when looking at the spatial patterns of MDA8 ozone concentrations on specific high ozone episode days. Air quality changes in these figures are calculated as the final rule minus the baseline. The spatial patterns shown in the figures are a result of (1) the spatial distribution of EGU sources that are predicted to have changes in emissions and (2) the physical or chemical processing that the model simulates in the atmosphere. The spatial fields used to create these maps serve as an input to the benefits analysis and the EJ analysis. While total U.S. NO_X emissions are predicted to decrease in the final rule scenario for 2028 and 2030 when compared to the baseline, predicted NO_X emissions changes are heterogeneous across the country with increases predicted in some states. In 2035, NO_x

emissions across the contiguous 48 states included in this analysis are predicted to increase compared to the baseline. In Figure A-8[126] there are small predicted ozone decreases from the final rule compared to the baseline evident in North Dakota in 2028 and Montana in 2035. There are also small predicted ozone increases from the final rule compared to the baseline evident near the border of Arizona and New Mexico in 2035.

Figure A-9 presents the model-predicted air quality changes between the baseline and the final regulatory option in 2028, 2030, and 2035 for $PM_{2.5}$.[127] Secondary $PM_{2.5}$ species sulfate and nitrate often demonstrate regional signals without large local gradients while primary $PM_{2.5}$ components often have heterogenous spatial patterns with larger gradients near emissions sources. Air quality changes in these figures are calculated as the final rule minus the baseline. The spatial patterns shown are a result of (1) the spatial distribution of EGU sources that are predicted to have changes in emissions and (2) the physical or chemical processing that the model simulates in the atmosphere. The spatial fields used to create these maps serve as an input to the benefits analysis and the EJ analysis. Both secondary and primary $PM_{2.5}$ contribute to the spatial patterns shown in Figure A-9. In 2028, there are predicted $PM_{2.5}$ decreases from the final rule evident in Montana, North Dakota, Missouri, West Virginia, and Pennsylvania. In Montana, West Virginia, and Pennsylvania, these $PM_{2.5}$ changes coincide with predicted decreases in direct $PM_{2.5}$ emissions. In North Dakota and Missouri, emissions of NO_X, SO_2 and direct $PM_{2.5}$ are all predicted to decrease compared to the baseline in 2028. In 2030 and 2035, there are predicted $PM_{2.5}$ decreases from the final rule evident in Montana, West Virginia, and Pennsylvania. In 2030 those predicted $PM_{2.5}$ concentration decreases coincide with direct $PM_{2.5}$ emissions decreases from all three states. In 2035 the predicted $PM_{2.5}$ concentration decreases coincide with SO_2, NO_X, and direct $PM_{2.5}$ decreases from Montana and West Virginia and direct $PM_{2.5}$ decreases from Pennsylvania in 2035.

[126] Note scale change on maps compared to similar figures from the proposal RIA. Color scale presented in figure 8-8 has a range of -0.11 ppb to 0.11 ppb. Maps in the proposal used a scale range from -0.2 ppb to 0.2 ppb.
[127] Note scale change on maps compared to similar figures from the proposal RIA. Color scale presented in figure 8-9 has a range of -0.011 $\mu g/m^3$ to 0.011 $\mu g/m^3$. Maps in the proposal used a scale range from -0.05 $\mu g/m^3$ to 0.05 $\mu g/m^3$.

Figure A-8 Maps of change in ASM-O3 for the final rule compared to baseline values (ppb) shown in 2028 (right panel), 2030 (middle panel) and 2035 (right panel)

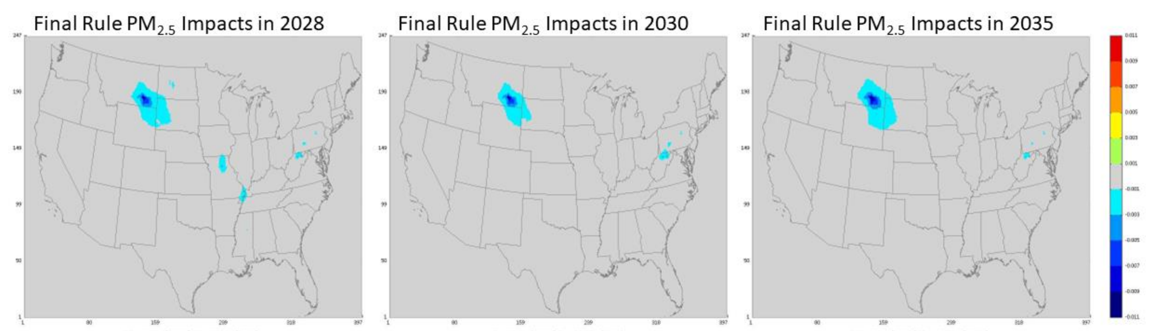

Figure A-9 Maps of change in $PM_{2.5}$ for the final rule compared to baseline values (µg/m3) shown in 2028 (right panel), 2030 (middle panel) and 2035 (right panel)

A.6 Uncertainties and Limitations of the Air Quality Methodology

One limitation of the scaling methodology for creating ozone and $PM_{2.5}$ surfaces associated with the baseline or regulatory control alternatives described above is that the methodology treats air quality changes from the tagged sources as linear and additive. It therefore does not account for nonlinear atmospheric chemistry and does not account for interactions between emissions of different pollutants and between emissions from different tagged sources. The method applied in this analysis is consistent with how air quality estimations have been made in several prior regulatory analyses (U.S. EPA, 2012, 2019, 2020a). We note that air quality is calculated in the same manner for the baseline and for the final rule, so any uncertainties associated with these assumptions are propagated through results for both the baseline and the final rule in the same manner. In addition, emissions changes between baseline and the final rule are relatively small compared to modeled future year emissions that form the basis of the source apportionment approach described in this appendix. Previous studies have shown that air pollutant concentrations generally respond linearly to small emissions changes of up to 30 percent (Cohan et al., 2005; Cohan and Napelenok, 2011; Dunker et al., 2002; Koo et al., 2007; Napelenok et al., 2006; Zavala et al., 2009). A second limitation is that the source apportionment contributions are informed by the spatial and temporal distribution of the emissions from each source tag as they occur in the future year modeled case. Thus, the contribution modeling results do not allow us to consider the effects of any changes to spatial distribution of EGU emissions within a state between the future year modeled case and the baseline and final rule scenarios analyzed in this RIA. Finally, the CAMx-modeled concentrations themselves have some uncertainty. While all models have some level of inherent uncertainty in their formulation and inputs, the base-year 2016 model outputs have been evaluated against ambient measurements and have been shown to adequately reproduce spatially and temporally varying concentrations (U.S. EPA, 2023a, 2024).

A.7 References

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APPENDIX B: CLIMATE BENEFITS APPENDIX

B.1 Climate Benefits Estimated using the Interim SC-CO_2 values used in the Proposal

This appendix presents the climate benefits of the final standards using the interim SC-CO_2 values used in the proposal of this rulemaking. The interim SC-CO_2 values are presented in Table B-1 and the climate benefits using these values are presented in Table B-2.

Table B-1 Interim SC-CO_2 Values, 2028 to 2037 (2019 dollars per metric ton)

Emissions Year	Discount Rate and Statistic			
	5%	3%	2.50%	3%
	Average	Average	Average	95th Percentile
2028	$16	$54	$79	$160
2029	$16	$55	$81	$160
2030	$17	$56	$82	$170
2031	$17	$57	$83	$170
2032	$18	$58	$85	$170
2033	$18	$59	$86	$180
2034	$19	$60	$87	$180
2035	$19	$61	$88	$180
2036	$20	$62	$90	$190
2037	$20	$63	$91	$190

Note: These SC-CO_2 values are identical to those reported in the 2016 SC-GHG TSD (IWG, 2016) adjusted for inflation to 2019 dollars using the annual GDP Implicit Price Deflator values in the U.S. Bureau of Economic Analysis' (BEA) NIPA Table 1.1.9 (U.S. BEA, 2021). The values are stated in $/metric ton CO_2 (1 metric ton equals 1.102 short tons) and vary depending on the year of CO_2 emissions. This table displays the values rounded to the nearest dollar; the annual unrounded values used in the calculations in this RIA are available on OMB's website: *https://www.whitehouse.gov/omb/information-regulatory-affairs/regulatory-matters/#scghgs*.
Source: Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under E.O. 13990 (IWG, 2021).

Table B-2 Stream of Projected Climate Benefits under the Final Rule from 2028 to 2037 (millions of 2019 dollars, discounted to 2023)

Emissions Year	SC-CO_2 Discount Rate and Statistic			
	5%	3%	2.50%	3%
	Average	Average	Average	95th Percentile
2028*	$0.9	$3.3	$5.0	$10
2029	$0.9	$3.3	$4.9	$9.9
2030*	-$0.49	-$1.8	-$2.7	-$5.4
2031	-$0.48	-$1.8	-$2.7	-$5.4
2032	$1.3	$4.8	$7.2	$15
2033	$1.3	$4.7	$7.1	$14
2034	$1.2	$4.7	$7.1	$14
2035*	$1.2	$4.6	$7.0	$14
2036	$1.2	$4.6	$6.9	$14
2037	$1.2	$4.5	$6.9	$14
PV	**$8.2**	**$31**	**$47**	**$94**
EAV	**$1.1**	**$3.6**	**$5.3**	**$11**

Note: Climate benefits are based on reductions in CO_2 emissions and are calculated using the IWG interim SC-CO_2 estimates from IWG (2021).

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June 23, 2023

Michael S. Regan, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.0 20460
Email To: Regan.Michael@epa.gov

Submitted To: Docket No. EPA–HQ–OAR–2018–0794

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

Dear Administrator Regan:

The Midwest Ozone Group ("MOG")[1] is pleased to offer these comments on the proposal by the U.S. Environmental Protection Agency ("EPA") 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). The comment period on this proposal closes June 23, 2023.

MOG is an affiliation of companies and associations that draws upon its collective resources to seek solutions to the development of legally and technically sound air quality programs that may impact on their facilities, their employees, their communities, their contractors, and the consumers of their products. MOG's primary efforts are to work with policy makers in evaluating air quality policies by encouraging the use of sound science. MOG has been actively engaged in a variety of issues and initiatives related to the development and implementation of air quality policy, including the revision of the ozone and particulate matter NAAQS, development of transport rules (including the Revised CSAPR Update and the 2015 ozone NAAQS federal implementation plan), nonattainment designations, petitions under Sections 126, 176A and 184(c) of the Clean Air Act ("CAA"), NAAQS implementation guidance, the development of Good Neighbor State Implementation Plans ("SIPs") and related regional haze and climate change and environmental justice issues. MOG Members and Participants own and operate numerous stationary sources that are affected by air quality requirements including the MATS.

[1] The members of and participants in the Midwest Ozone Group include: Alcoa, Ameren, American Electric Power, American Forest & Paper Association, American Iron and Steel Institute, American Wood Council, Appalachian Region Independent Power Producers Association, Associated Electric Cooperative, Berkshire Hathaway Energy, Big Rivers Electric Corp., Buckeye Power, Inc., Citizens Energy Group, City Water, Light & Power (Springfield IL), Cleveland Cliffs, Council of Industrial Boiler Owners, Duke Energy Corp., East Kentucky Power Cooperative, ExxonMobil, FirstEnergy Corp., Indiana Energy Association, Indiana-Kentucky Electric Corporation, Indiana Municipal Power Agency, Indiana Utility Group, LGE/ KU, Marathon Petroleum Company, National Lime Association, North American Stainless, Nucor Corporation, Ohio Utility Group, Ohio Valley Electric Corporation, Olympus Power, Steel Manufacturers Association, and Wabash Valley Power Alliance.

Specifically, EPA proposes 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. EPA states that these proposed amendments are the result of its review of the May 22, 2020, residual risk and technology review (RTR) of MATS.

For reasons set out below, MOG believes that the MATS proposal is fatally flawed both technically and legally and should be withdrawn.

1. **A standard of 0.006 lb/MMBtu or lower does not represent a better balancing of the statutory factors.**

   The EPA proposal notes that the proposed standard of 0.010 lb/MMBtu "appropriately balances CAA section 112's direction to achieve the maximum degree of emissions reductions while taking into account the statutory factors, including cost." (88 Fed Reg 24871) Inexplicably, though, 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." *Id*

   The proposed standard of 0.010 lb/MMBtu doesn't appropriately balance the statutory factors and, accordingly, any standard that is more stringent is clearly inappropriate given the cost of compliance. CAA Section 112(n)(1)(A) as a statutory factor must be considered when doing a reconsideration of an already completed RTR given EPA's cost effectiveness numbers in the range of $80,000 - $100,000/ton of fPM.

   Remarkably, the Regulatory Impact Analysis[2] (RIA) of the proposed rule, in discussing benefits, concedes that "[t]he results presented in this section [Comparison of Benefits and Costs] provide an incomplete overview of the effects of the proposal, because important categories of benefits, including health and environmental benefits from reducing mercury and non-mercury metal HAP emissions and the increased transparency and accelerated identification of anomalous emission anticipated from requiring CEMS, were not monetized and are therefore not directly reflected in the quantified benefit-cost comparisons." (RIA at page 26).

   Based on the RIA quote cited above, EPA has failed to justify its claim that this proposed rule "appropriately balances CAA Section 112's direction to achieve the maximum degree of emissions reductions while taking into account the statutory factors, including cost," when EPA cites no benefits provided by this proposed rule, which is being proposed under the guise of Section 112, for the reduction of Hg and non-Hg metals. With no estimated Hg or non-Hg metal benefits, whatever the estimated compliance cost renders the statutory factors, especially cost, *inappropriately* balanced.

2. **EPA has not accurately assessed the variability of fPM emissions.**

EPA requests comment in the proposed rule 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

[2] https://www.epa.gov/system/files/documents/2023-01/naaqs-pm_ria_proposed_2022-12.pdf

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." (88 Fed Reg 24872). Because available public data demonstrate that imposition of the proposed standard of 0.010 lb/MMBtu is not cost effective, no standard that is more stringent than the proposed standard can be considered cost effective. The benefits simply do not come close to exceeding the costs.

A significant factor regarding the reduction in the proposed fPM surrogate emission limit to 0.010 lb/MMBtu or the more stringent 0.006 lb/MMBtu is that EPA is not just revising the numerical value, it is changing both the compliance determination technique and the averaging period. Further, EPA is essentially punishing the sources that have met the low emitting EGU (LEE) limit of the MATS rule (0.015 lb/MMBtu) by eliminating the reward of testing once every three years after a lengthy demonstration of the ability to meet that limit.

From a technical standpoint, changing the numerical limit, averaging period and the compliance demonstration techniques amounts to a massive increase in the stringency of the standard compared with either revising the numerical limit without changing the compliance demonstration method or the compliance averaging period, or revising the compliance demonstration method while retaining the same numerical limit and compliance averaging period.

If there are to be changes to the numerical emission limit, then there should not be a change to the compliance demonstration method or to the frequency of testing to meet a numerical limit that is only 2/3rds of the fPM emission rate that defined a LEE under the previous rule. For context, to qualify as a fPM LEE, the source had to consistently meet a limit that was only 50% of the fPM limit finalized in the rule. Consequently, implementation of the proposed rule will reduce the fPM limit by 67% rather than the implied 33%, misrepresenting the reality of the proposal. Moreover, a change in the fPM emission limit from 0.030 to 0.010 (or lower) lb/MMBtu would likely disqualify a source from realizing "low-emitting source" status[3] without any change in source operating practices, procedures, or emission control device performance. Sources that are not "low-emitting sources" and required to install a PM CEMS are subject to more stringent requirements associated with the development of the PM CEMS correlation curve (see Performance Standard 11, Section 13.2), which are exceptionally challenging to develop irrespective of the source emitting status.

This is especially true for EGUs that are equipped with fabric filter particulate control devices (baghouses) or equipped with an electrostatic precipitator (ESP) and a flue gas desulfurization system (FGD). Baghouses are the most effective filterable particulate matter control devices available and typically an FGD will control an additional 70% of the filterable particulate matter remaining after the exhaust gas passes through the ESP, which alone removes 98-99% of the fPM. So long as there is not a physical or permitted capability to allow discretionary[4] bypass of the baghouse or ESP/FGD combination, there is no need to require continuous fPM monitoring. With these control equipment devices, which result in extremely low fPM emissions, in place, a requirement to site, procure, install, certify, operate and maintain, quality assure and maintain a data acquisition and handling system to record and maintain records is unnecessary and only serves to increase the cost of the demonstration of compliance with no demonstrated monetized benefit. There is no need to either

[3] 40 CFR 60, Appendix B, Performance Specification 11, Section 3.16 "Low-Emitting Source" means a source that operated at no more than 50 percent of the emission limit during the most recent performance test, and, based on the PM CEMS correlation, the daily average emissions for the source, measured in the units of the applicable emission limit, have not exceeded 50 percent of the emission limit for any day since the most recent performance test. (https://www.epa.gov/sites/default/files/2019-06/documents/performance_specification_11.pdf)

[4] Discretionary excluding emergency bypasses that are required by National Fire Protection Association Codes or American Society of Mechanical Engineers Codes for Boilers and Pressure Vessels.

require emissions measurement more frequently than the current fPM LEE schedule or require the use emissions measurement methods for units equipped with these fPM emissions control equipment devices. Units with these devices would be required to meet a fPM limit that is 33% lower than the current fPM LEE limit of 0.015 lb./MMBtu. In practice, other currently installed monitoring devices are used as an indicator of fPM emissions control performance (e.g., opacity monitor for units installed with a baghouse or dry FGD, mist eliminator pressure drop for units installed with a wet FGD), which also reduces the efficacy of the proposed requirements.

Because these new limits represent limits that have already been achieved, there are no environmental benefits gained except if these very costly additional requirements force additional facilities, particularly facilities that operate in restructured electric markets, to permanently cease operations, reducing grid reliability. EPA does not claim any benefit relating to air toxics, which is appropriate because there are no air toxics benefits resulting from implementation of the proposed rule. The benefits EPA claims are co-benefits. It's also worth noting that the original MATS claimed direct health benefits only for one air toxic, mercury, and that the direct benefit claimed was a very small $4-6 million per year as opposed to the total cost of $37-90 billion dollars per year. Even monetizing the benefits from air toxics reductions, purportedly the reason for the rule, doesn't make benefits of the rule exceed cost of compliance. The MATS was and is the backstop for the Clean Power Plan and it worked. The proposed rule is both unnecessary and overreaching.

The effect of this rule is to add additional costs of operations, forcing merchant coal-fired generators out of business and putting rate-based coal-fired generation at risk. Moreover, the RIA demonstrates that implementation of the proposed rule doesn't result in any meaningful environmental benefits achieved by reduction in Hg and non-Hg metals.

3. **EPA has overestimated the need for continued quarterly testing of units with binding schedules for retirement.**

EPA concedes in the preamble to the proposed rule that it 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." (88 Fed Reg 24874) As a result, it "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." (88 Fed Reg 24874) In addition to seeking comments with respect to allowance of testing for compliance, EPA also "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." (88 Fed Reg 24874)

Any EGU that is on an enforceable schedule for ceasing coal or oil-fired operation and that has not demonstrated qualification as a fPM LEE should be allowed to continue to use its emissions testing schedule past the proposed compliance date, and units that are complying by means of this emissions testing schedule should not be required to install CEMS. Those enforceable schedules were negotiated and established in arm's length transactions, presumably including consideration of operational details such as the cost of stack testing versus being required to install additional equipment. Changing the emissions testing requirement, both the test method and frequency of emission measurement, after the fact is both unreasonable and possibly illegal.

In addition, if a unit is on an enforceable schedule for ceasing coal or oil-fired operations and is qualified as an LEE, already having demonstrated emissions of fPM at a rate below 0.015 lb/MMBtu using quarterly emissions testing over a three year period, then that currently qualified fPM LEE should be allowed to test at the current LEE schedule or annually at most. Quarterly testing of this class of unit provides no environmental benefit and simply adds cost.

Accordingly, MOG urges EPA to allow use of the aforementioned testing schedules for these units with enforceable schedules for ceasing coal or oil-fired operations until such time as they cease coal or oil-fired operations as set forth in the applicable enforceable schedule.

4. **Whether there are any areas where EPA has overestimated costs, including some of the generation and storage technologies discussed in the rule as well as the cost of PM controls themselves.**

Based upon publicly available data, EPA has grossly underestimated the cost of installing and operating a PM CEMS, grossly overestimated the cost of stack testing, and has failed to provide the true additional costs of the proposal. For example, according to a June 2023 report styled "Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology"[5], of three categories of ESP upgrades considered by EPA, the cost for the most extensive – a complete rebuild to add collecting plate area – is inadequate. Four such major ESP rebuild projects have been implemented for which costs are reported in the public domain – and not acknowledged by EPA. Incorporating these results elevates the range of cost from EPA's estimate of $75-100/kW to $57-213/kW. Consequently, the "average" cost for this action used in the cost per ton ($/ton) evaluation increases from $87/kW to $133/kW.[5]

As a consequence of under-predicting capital required for ESP "rebuild", and not recognizing the need for a design and operating margin, EPA under-predicts the number of units requiring retrofit or upgrade by half (20 vs 37). As a result, EPA's estimate of incurred cost of $12,200-$14,700/ton to comply with a PM rate of 0.010 lb/MMBtu is only one quarter of the $47,371/ton average cost projected by units for which there is publicly available data.[5]

Another example of EPA underestimating PM CEMS cost is that EPA has estimated the cost of installed PM CEMS ranging from $35,000 (citing the Institute of Clean Air Companies (ICAC)) to $234,070 (citing EPA MCAT Extractive figures) (88 Fed Reg 24873, Table 4). A more reasonable assumption based on ongoing supply chain challenges, requirements for specialized installation and significantly higher cost of project management labor may result in an estimated installation cost as high as $350,000 for a PM CEMS based on information from ICAC.

EPA also appears to have averaged the cost estimates of dry and wet stack installations, which ignores the added cost and operations and maintenance issues for a PM CEMS in a wet, or scrubbed, stack. EPA also

[5] Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology, Prepared for National Rural Electric Cooperative Association American Public Power Association, America's Power, Midwest Ozone Group, NAACO,
National Mining Association, Power Generators Air Coalition, prepared by Cichanowicz, Marchetti, and Hein, June 19, 2023

overstates the cost of individual M5 tests at $15,522, when typical costs can run between $5,000 to $10,000. EPA has thus grossly underestimated the costs of compliance regarding installation, maintenance, and operation of a PM CEMs and grossly overestimated the cost of quarterly testing. EPA must recalculate the Equivalent Uniform Annual Cost using accurate costs and that recalculation will most likely show that quarterly stack testing is the most cost-effective option. Therefore, EPA should not require PM CEMS for compliance because it is not cost effective. Installation of a PM CEMS should remain an option for the EGU sector but not be mandated.

A final point regarding cost is that regarding cost, by eliminating the LEE provisions which allow once per three year emissions testing as an incentive to be a low emitter, EPA is forcing massive cost increases on the lowest emitting affected EGUs by requiring continuous emissions monitoring, record keeping, and reporting.

In summary, EPA has grossly overestimated costs of stack testing for compliance and grossly underestimated the cost of installation, maintenance, and operation of PM CEMs for compliance.

5. **IPM model data for PM does not agree with EPA's alleged 0.010 lb/MMBtu operating rate for units subject to the MATS.**

EPA assumed a very unrealistic implementation of the Inflation Reduction Act and the implementation of renewable assets. Future operating scenarios modeled by IPM do not project adequate replacement capacity to offset the capacity of coal projected to be retired in 2030. This shortcoming appears prompted by EPA not fully considering the grid reliability issues confronting the Electric Power Sector. Consequently, IPM created a flawed Baseline scenario, which does not adequately measure the impacts of the proposed rule. Most notably, IPM predicts only 500 MW of coal capacity will retire in response to the proposed rule.[5] Grid operators predict significantly more retirements based on the suite of EGU focused rules EPA has proposed in 2023.

6. **The CAA does not authorize EPA to promulgate a rule based 100% on co-benefits as EPA has done with this rule.**

EPA has failed to economically justify the proposed rule. The cost of compliance with the proposed rule far outweighs the benefits attributable to the stated purpose of the rule of reducing emissions of Hg and non-Hg metal HAP. EPA discusses the cost and benefits of the proposed rule at length, noting that "[t]his proposed rule is projected to reduce PM2.5 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–CO2 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." (88 Fed Reg 24891) Incredibly, EPA adds in this proposal to reduce Hg and non-Hg metal HAP that <u>"[t]he potential benefits from reducing Hg and non-Hg metal HAP</u> <u>were not monetized and are therefore not directly reflected in the monetized benefit-cost estimates associated with this proposal.</u> 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." (88 Fed Reg 24891) (emphasis supplied)

EPA has provided no estimated benefits for the reductions of Hg and non-Hg metal HAP from EGUs. MACT standards such as the proposed standards must be supported by clear economic benefits. Based on the benefits of the proposed rule claimed by EPA, EPA is essentially using MACT controls to drive reductions of PM2.5 and ozone, which are criteria pollutants, but with no analysis of whether implementation of the rule will result in attainment in non-attainment areas or even whether these reductions are necessary to meet a NAAQS. The CAA is quite clear in establishing an orderly process by which delegated states attain criteria pollutant NAAQS and the use of MACT controls is not appropriate for that purpose.

CAA §110 establishes the process for state implementation plans for national primary and secondary ambient air quality standards. Section 110(a) requires, in pertinent part, that

> (1) Each State shall, after reasonable notice and public hearings, adopt and submit to the Administrator, within 3 years (or such shorter period as the Administrator may prescribe) after the promulgation of a national primary ambient air quality standard (or any revision thereof) under section 7409 of this title for any air pollutant, a plan which provides for implementation, maintenance, and enforcement of such primary standard in each air quality control region (or portion thereof) within such State. In addition, such State shall adopt and submit to the Administrator (either as a part of a plan submitted under the preceding sentence or separately) within 3 years (or such shorter period as the Administrator may prescribe) after the promulgation of a national ambient air quality secondary standard (or revision thereof), a plan which provides for implementation, maintenance, and enforcement of such secondary standard in each air quality control region (or portion thereof) within such State...

The CAA §110 process described above has been the anchor of air quality management since the promulgation of the CAA Amendments of 1970 and, based on the dramatic improvement in air quality since 1970, has worked well for more than 40 years. The proposed rule is inconsistent with the CAA §110 process since it would utilize CAA §112 MACT controls for the purpose of reducing emissions of PM2.5, which is a criteria pollutant.

Because EPA has failed to economically justify the proposed rule and the cost of compliance with the proposed rule far outweighs the benefits attributable to the stated purpose of the rule of reducing emissions of HG and non-HG metal HAP, the proposed rule should be withdrawn.

7. **The CAA does not authorize EPA to assign benefits to a PM rule that include benefits in areas attaining the PM or ozone NAAQS.**

Clean Air Act Section 109(b)(1) requires that NAAQS established by EPA "shall be ambient air quality standards the attainment and maintenance of which in the judgment of the Administrator, based on such criteria and allowing an adequate margin of safety, are requisite to protect the public health." (emphasis supplied) EPA has established PM NAAQS and the majority of the monitors in the United States are in attainment with the current PM NAAQS. EPA explained its benefits calculation in the RIA for the proposed rule as follows:
"To assess economic value in a damage-function framework, the changes in environmental quality must be translated into effects on people or on the things that people value. In some cases, the changes in environmental quality can be directly valued. In other cases, such as for changes in ozone and PM, a

health and welfare impact analysis must first be conducted to convert air quality changes into effects that can be assigned dollar values.

We note at the outset that EPA rarely has the time or resources to perform extensive new research to measure directly either the health outcomes or their values for regulatory analyses. Thus, similar to work by Künzli et al. (2000) and co-authors and other, more recent health impact analyses, our estimates are based on the best available methods of benefits transfer. Benefits transfer is the science and art of adapting primary research from similar contexts to obtain the most accurate measure of benefits for the environmental quality change under analysis. Adjustments are made for the level of environmental quality change, the socio-demographic and economic characteristics of the affected population, and other factors to improve the accuracy and robustness of benefits estimates." (RIA at 93)

EPA has failed to provide an accurate estimate of health benefits, in part because of a lack of time. In addition, the RIA states that "[t]he benefit of the reduction in each health risk is based on the exposed individual's willingness to pay (WTP) for the risk change…" (RIA at 87) rather than on the air quality improvements in specific areas resulting from implementation of the proposed rule. Since much of the country is in attainment with the current PM and ozone NAAQS, which by law are established at levels required to protect human health with an adequate margin of safety, it is not appropriate to include as benefits the monetization of health improvements resulting from implementation of the proposed rule that might occur due to possible reductions in criteria pollutants (e.g., ozone and PM) in areas that are already attaining the PM or ozone NAAQS. In addition, EPA makes the erroneous assumption that all PM is the same when, in fact, it is well documented that different species of PM are more deleterious to human health than others.

8. **EPA's choice of only two quarters and a portion of a third quarter in which the quarter selected includes lowest unit PM emissions from its data base of quarterly data between 2017 and 2021 is arbitrary and capricious.**

The Cichanowicz, Marchetti, Hein report[5] concludes that "EPA's database of PM emissions is inadequate. EPA attempts to capture typical PM emissions by acquiring samples from 3 years – 2017, 2019, and 2021. For the vast majority of the units – 80% - EPA uses only 2 of the potentially available 12 quarters of data to construct the PM database. Further, of these limited samples EPA, cites the lowest - thus for most 1 of 2 samples – to reflect a reasoned target PM emissions rate. EPA cites the use of the '99th percentile' PM rate in lieu of the average compensates for variability; but this approach fails to account for long-term changes in fuel and process conditions."

EPA does not explain the rationale for using minimal data to characterize "typical" PM emissions from facilities expected to be subject to the proposed rule when it had years of data points available. The resulting analysis of projected impacts of the proposed rule is inevitably biased by the failure to use all available data, and the data used by EPA is not representative. Accordingly, MOG urges EPA to, at a minimum, revise the rule based on sound science and use of all available data before publishing a final rule and, preferably, because there are no environmental benefits with respect to Hg and non-Hg meatal emissions reductions, withdraw the proposal.

9. **CAA Section 112 does not require EPA to reduce emissions for a category for which there is no or very low residual risk identified.**

The preamble to the proposed rule states that “[t]he 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. (88 Fed Reg 24866) (emphasis supplied)

> EPA cites the case of *La. Envtl. Action Network v. Envtl. Prot. Agency*, (955 F.3d 1088, D.C. Cir. 2020) (LEAN) in support of its position that MACT standards may be revised even though the mandatory residual risk review finds no residual risk for the source sector being reviewed. LEAN states in pertinent part that
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>> The provision at issue here, section 112(d)(6), requires EPA, on an ongoing periodic basis, to revisit and update emission standards that it has already set for each source. No less than every eight years, EPA must "review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards promulgated under this section." *Id.* § 7412(d)(6). That review ensures that, over time, EPA maintains source standards compliant with the law and on pace with emerging developments that create opportunities to do even better.
>>
>> In addition to its section 112(d)(6) review, EPA under section 112(f)(2) must conduct a one-time review within 8 years of promulgating an emission standard to, among other things, evaluate the residual risk to the public from each source category’s emissions and promulgate more stringent limits as necessary "to provide an ample margin of safety to protect public health." *Id.* § 7412(f)(2)(A)” La. Envtl. Action Network v. Envtl. Prot. Agency, 955 F.3d 1088 at 1093 (D.C. Cir. 2020)
>
> However, LEAN stands only for the proposition that, when conducting an RTR, EPA is obligated to revise the standard to include pollutants listed under Section 112(b) that were not included in the original Section 112(d)(3) limits. Significantly, LEAN cites another case, "Surface Finishing" (Nat’l Ass’n for Surface Finishing v. EPA, 795 F.3d 1, 4 (D.C. Cir. 2015), which allows for ratcheting down of standards as a result of "developments," but does not require it. Surface Finishing seems to be more on point than LEAN, and provides EPA options. It does not say that EPA can revise limits when it determines those limits are achievable. In fact, 112(d)(6) requires that EPA revise standards "as necessary" taking into account developments in practices, processes and control technologies. In the proposed rule, EPA finds only that the 0.010 lb/MMBTu limits are achievable, *not* that they are necessary. Moreover, EPA points to no “developments” to support the proposal; rather EPA only notes that the proposed emission limits are achievable.

EPA has based the proposed rule on an incorrect proposition. The proposed revised standards are not necessary under Section 112(d)(6) because EPA has failed to demonstrate that developments require updates. Indeed, EPA concedes that the proposed rule will provide no public health benefits for reduction in Hg and non-Hg metals, and Section 112(n)(1)(A) requires EPA to regulate EGUs only if there is a public health hazard after imposition of the requirements of the Act. Here, EPA has found no public health hazard and therefore it cannot find that it is "necessary" under Section 112(d)(6) to revise the standards, even if it does find reduced limits achievable.

Congress clearly expressed its intent in the Clean Air Act in Section 112(f) that EPA should not lower standards when risks are acceptable.

Clean Air Act Section 112(f)(2)(A) states

> (2)Emission standards
> (A) If Congress does not act on any recommendation submitted under paragraph (1), the Administrator shall, within 8 years after promulgation of standards for each category or subcategory of sources pursuant to subsection (d), promulgate standards for such category or subcategory if promulgation of such standards is required in order to provide an ample margin of safety to protect public health in accordance with this section (as in effect before November 15, 1990) or to prevent, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect. <u>Emission standards promulgated under this subsection shall provide an ample margin of safety to protect public health in accordance with this section (as in effect before November 15, 1990), unless the Administrator determines that a more stringent standard is necessary to prevent, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect.</u> If standards promulgated pursuant to subsection (d) and applicable to a category or subcategory of sources emitting a pollutant (or pollutants) classified as a known, probable or possible human carcinogen do not reduce lifetime excess cancer risks to the individual most exposed to emissions from a source in the category or subcategory to less than one in one million, the Administrator shall promulgate standards under this subsection for such source category. (emphasis supplied)

The statutory language itself only directs EPA to revise a standard if it determines that a revision is *necessary* to prevent an adverse environmental impact. In the case of the proposed rule, EPA points to no additional adverse environmental impacts caused by emission of Hg or non-Hg HAP. Indeed, in this case, EPA can only point to benefits of additional reductions of ozone and PM, which are criteria pollutants, and not HAPS which are the purported subject of the proposed rule. In a case such as the proposed rule, when the agency knows that the residual risk of the constituent it purportedly is attempting to address is acceptable with an ample margin of safety, EPA should not be issuing new standards.

10. EPA continues to ignore grid reliability concerns in its EGU focused rulemaking processes.

EPA has proposed several EGU-focused rules in 2023, including a Federal Good Neighbor transport rule, a greenhouse gas reduction rule, and this proposed Hg and non-Hg metals rule. In each proposal, EPA asserts that it has worked with grid operators and that the proposed rule poses no grid reliability issues. With respect to the Good Neighbor rule, Principal Deputy Assistant Administrator for the Office of Air and Radiation Joe Goffman spoke at an April 2023 meeting of The Association of Air Pollution Control Agencies (AAPCA) and stated to the AAPCA attendees that EPA had revised the proposed Good Neighbor rule, working with grid operators, such that grid reliability is not an issue in the final rule. More recently, Office of Air and Radiation Deputy Assistant Administrator for Stationary Sources Dr. Tomas Carbonell, in remarks to participants at a virtual annual meeting of the OTC/MANEVU Commissioners, made multiple refences to the recently proposed EGU carbon rule, noting that its offers plant and grid operators the ability to provide reliable power.

These assertions by EPA regarding reliability fly in the face of warnings regarding grid reliability by multiple grid operators. The issue is captured most succinctly and most recently in testimony of PJM Interconnection President and CEO Manu Asthana who, in testimony before the United States Senate Committee on Energy & Natural Resources on June 1, 2023, said that "[c]urrently, the nation is developing environmental and reliability policy in separate silos with limited and not very transparent coordination between the environmental and reliability regulators. Increased coordination and synchronization

of the nation's environmental and reliability needs may require discrete changes to the statutes governing each agency's mission to embrace this effort. But the time may be ripe to initiate these statutory changes so that each regulator has both the authority and ability to develop policies that harmonize and meet both the nation's reliability and environmental goals." This sentiment is consistent with comments filed by multiple grid operators regarding the Federal Good Neighbor rule and EPA continues to ignore the issue in proposing this rule.

Conclusion

For all of the aforementioned reason, MOG urges EPA to withdraw the MATS proposal because it is fatally flawed both technically and legally.

Very truly yours,

/s/ *Edward "Skipp" Kropp*

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Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology

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1. Summary of Flaws in EPA's Approach

The following is a summary of flaws in EPA's analysis, further described in detail in this report.

Particulate Matter (PM) Database

EPA's database of PM emissions is inadequate. EPA attempts to capture typical PM emissions by acquiring samples from 3 years – 2017, 2019, and 2021. For the vast majority of the units – 80% - EPA uses only 2 of the potentially available 12 quarters (in those 3 years; up to 20 quarters from 2017 to 2021) of data to construct the PM database. Further, of these limited samples. EPA cites the lowest to reflect a target PM emissions rate. EPA cites the use of the "99th percentile" PM rate in lieu of the average compensates for variability; but this approach accounts for variability within a single ("the lowest") quarter. It fails to account for long-term variability, which is affected by changes in fuel and process conditions, among others.

Lack of Design and Compliance Margin

EPA recognizes the need for margin in both design and operation (for compliance) of environmental control equipment, but ignores this concept in developing this proposed rule. The need for design margin is recognized in a 2012 OAQPS memo[1] addressing the initial developments of this very same rule, while margin for operation is considered in evaluating CEMS calibration[2] for this proposed rule. Neither design nor operating margin is considered in setting target PM standards, resulting in underestimation of number of units affected and total costs to deploy control technology. For some owners of fabric filter-equipped units, the revised rate of 0.010 lbs/MBtu eliminates any operating margin.

Inadequate Cost for ESP Rebuild

Of three categories of ESP upgrades considered by EPA, the cost for the most extensive – a complete rebuild to add collecting plate area – is inadequate. Four such major ESP rebuild projects have been implemented for which costs are reported in the public domain – and not acknowledged by EPA. Incorporating these results elevates the range of cost from EPA's estimate of $75-100/kW to $57-213/kW. Consequently, the "average" cost for this action used in the cost per ton ($/ton) evaluation increases from $87/kW to $133/kW.

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[1] Hutson, N., National Emission Standards for Hazardous Air Pollutants (NESHAP) Analysis of Control Technology Needs for Revised Proposed Emission Standards for New Source Coal-fired Electric Utility Steam Generating Units, Memo to Docket No. EPA-HQ-OAR—2009-0234, November 16, 2012. Hereafter Hutson 2012.

[2] Parker, B., PM CEMS Random Error Contribution by Emission Limit, Memo to Docket ID No. EPA-HQ-OAR-2018-0794, March 22, 2023. Hereafter Parker 2023.

Inadequate $/ton Removal Cost

As a consequence of under-predicting capital required for ESP "rebuild," and not recognizing the need for a design and operating margin, EPA under-predicts the number of units requiring retrofit and incurred cost. As a result, in contrast to the annual cost of $169.7 M projected by the Industry Study described in this report, EPA estimates a range from $77.3 to $93.2 M. Further, the Industry Study estimates the cost per ton ($/ton) of fPM to be $67,400, 50% more than the maximum cost estimated by EPA - $44,900 /ton.

Faulty Lignite Hg Rate Revision

EPA's proposal to lower the Hg emission rate for lignite-fired units to 1.2 lbs/TBtu is based on improper interpretation of Hg emissions data – both in terms of the mean rate and variability. EPA's projection that 85 and 90% Hg removal would be required for the proposed rate is incorrect, with up to 95% Hg removal required for some units – a level of Hg reduction not feasible in commercial systems. In addition to the variability of Hg content in lignite, EPA ignores the deleterious role of flue gas SO_3 in lignite-fired units, which compromises sorbent performance and effectiveness – even though this latter barrier is recognized and cited by EPA's contractor for the IPM model.[3]

Faults in IPM Modeling

IPM creates a flawed Baseline scenario that does not adequately measure the impacts of the proposed rule. Most notably, IPM err in the number of coal units that would be retired in both 2028 and 2030; as a consequence, EPA underestimates the number of units subject to the proposed rule. Also, IPM unrealistically retrofitted 27 coal units with carbon capture and storage (CCS) in 2030. Consequently, IPM modeling results of the Baseline likely understate the compliance impacts of the proposed rule.

[3] IPM Model – Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology, Prepared by Sargent & Lundy, Project 12847-002, March 2013.

2. Introduction

The Environmental Protection Agency (EPA) is proposing to amend the National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Coal- and Oil-fired Electric Utility Steam Generating Units (EGUs), otherwise known as the Mercury and Air Toxics Standards (MATS). The specific emissions limits being revised address the filterable particulate matter (fPM) standard (which is the surrogate standard for non-mercury (Hg) metal HAPs); the Hg standard for lignite-fired units; fPM measurement methods for compliance; and the definition of startup. This report provides a review and evaluation of EPA's approach to selecting the revised fPM standard, the capital and annual costs for achieving the proposed revised standard, and the cost per ton ($/ton) to control non-Hg metal HAPs; and a critique of EPA's basis for proposing an Hg limit of 1.2 lbs/TBtu for lignite-fired units. This document also provides information supporting EPA's decision to retain the present Hg limit for bituminous and subbituminous coal.

The proposal to lower fPM and Hg limits is premised on EPA's interpretation of data related to the cost and capabilities of PM and Hg emission control technologies. EPA reports to have conducted realistic assessments of PM and Hg emissions and control technology capabilities in support of their analysis. EPA's assumptions are reported in the MATS_RTR_Proposal_Technology Review Memo[4] where EPA describes the PM database they developed, the cost and control capabilities of upgrades to electrostatic precipitators (ESPs) and fabric filters, and their understanding of the key factors that affect Hg emissions in bituminous, subbituminous, and lignite coal - and how the latter are alike or differ.

Many of EPA's assumptions are contrary to data in their possession or strategies previously adopted by EPA, but not considered. EGUs have been reporting fPM compliance data to EPA since MATS became applicable to them – i.e., for the vast majority of EGU, April 2015 or April 2016 for units that obtained a one-year extension. However, EPA's effort to "mine" fPM emissions data from prior years provides a sparse, inadequate database that does not reflect operating duty nor account for inevitable variability; further EPA misinterprets this information. No design or operating margins are considered in setting fPM (the same is true for lignite Hg emission rates). The cost to upgrade ESPs to meet the proposed limits is inadequate for the most significant modification EPA envisions – the complete ESP Rebuild. The cost to deploy enhanced operating and maintenance (O&M) actions on existing fabric filers is inadequate. Regarding revised Hg limits for lignite coal, EPA does not recognize the differences in lignite versus Powder River Basin (PRB) subbituminous coal that effect Hg control. EPA draws an incorrect analogy between PRB and lignite, improperly assuming the Hg removal by carbon sorbent observed with PRB can be replicated on lignite.

[4] Benish, S. et. al., 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, Memo to Docket ID No. EPA-HQ-OAR-2018-0794. January 2023. Hereafter RTR Tech Memo.

The remaining sections of this report detail the findings summarized in Section 1, and are as follows:

- Section 3 describes EPA's approach to assembling their fPM database, and the flaws and weaknesses in their approach.
- Section 4 evaluates the fPM rates assigned by the database for the EPA analysis.
- Section 5 evaluates EPA's cost bases for the proposed fPM revised standard, and compares these to the realistic assumptions used in the Industry Study described in the paper.
- Section 6 addresses EPA's proposal to lower Hg from lignite-fired units to 1.2 lbs/TBtu, delineating the shortcomings in EPA's approach and assumptions.
- Section 7 provides historical data for Hg emission from non-low rank fuels, showcasing the inherent variability in the 30-day rolling average.
- Section 8 reviews the IPM modeling analysis conducted by EPA to support this rule.
- Appendix B presents examples of PM emission timelines for a limited number of units[5] that show how EPA's sparse database does not capture the authentic "PM signature" of the units.

[5] We reviewed data for a limited number of units because the comment period was very short and did not allow adequate time to undertake a more thorough review. EPA has all the data and in our opinion should have conducted such an analysis for every unit at issue.

3. Description of EPA Reference PM Database

Section 3 describes the PM database assembled by EPA which serves as the basis for the proposed NESHAP rule. Section 3 first describes the coal fleet inventory reflected, and then identifies shortcomings of this database concerning (a) selection of the sample year and quarter, (b) number of samples considered, and (c) data analysis.

3.1 Coal Fleet Inventory

EPA projects that a total of 275 generating units will be operating at the compliance date of January 1, 2028, representing a reduction from the present (2023) operating inventory of approximately 450 units. EPA identified the 275 units based on their estimate of unit retirements and units planning to switch to natural gas by the compliance date. EPA accounted for these assets not as individual units, but in terms of the number of reporting monitors to the Clean Air Markets Division. As 27 units employ common stack reporting, the data presented by EPA in the draft rule and RTR Tech Memo consider 248 discrete data points that reflect the 275 units. This analysis will adopt the same reporting methodology.

EPA's selection of 275 units contains 22 units that have publicly disclosed plans to retire or switch to natural gas by the compliance date of January 1, 2028. For the purposes of this analysis, these units are retained in the database so the results can be more readily compared.

Figure 3-1 depicts the installed inventory projected by EPA, presented according to the suite of control technology. The first two bars (from the left) report units equipped with ESPs as the primary PM control device in the following configurations: a total of 54,116 MW for an ESP followed by a wet FGD; and a total of 16,346 MW with an ESP only. The next 3 bars describe the total inventory equipped with a fabric filter in the following three configurations: 12,194 MW with the fabric filer as the sole device; 20,206 MW with a fabric filter followed by a wet FGD, and 19,995 MW where the fabric filter is preceded by a dry FGD process. Consequently, the bulk of the inventory (70,462 MW) will employ an ESP as part of the control scheme, with 52,395 MW employing a fabric filter for PM. Given the role of wet FGD in PM emissions – in most cases such devices will reduce PM by approximately 50% - more than half (74,322 MW) employ wet FGD as the last control step.

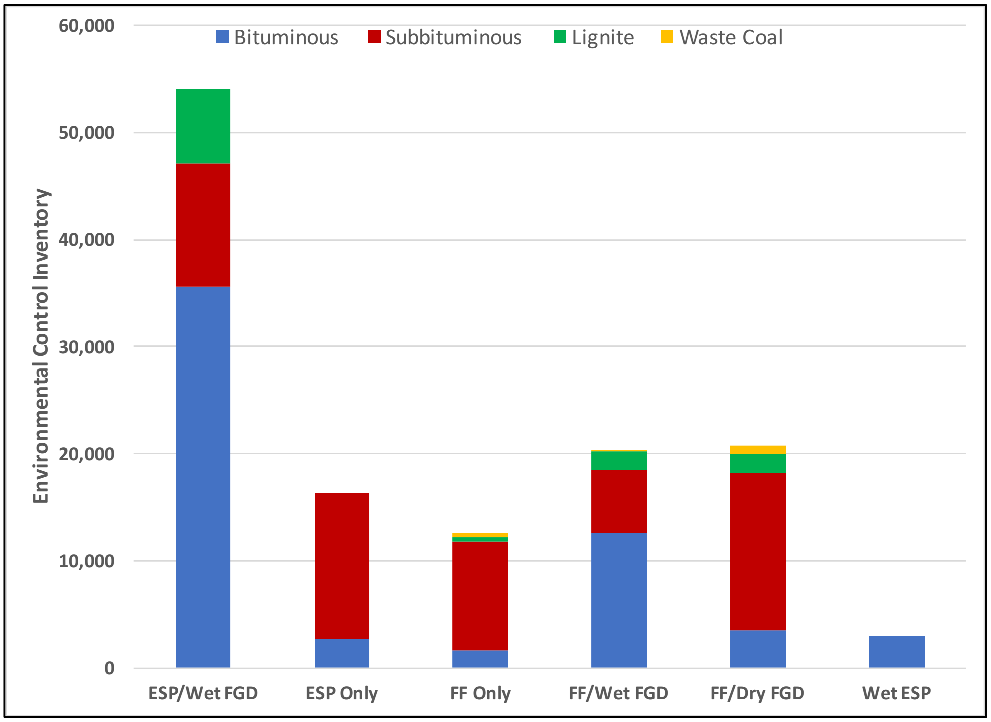

Figure 3-1. Inventory of EPA-Project 2028 Fleet by Control Technology Suite

3.2 Database Characteristics

Several characteristics of EPA's database severely compromise the quality of the analysis. These are the (a) selection of sampling year and quarter and (b) number of samples used.

3.2.1 Selection of Sample Year and Quarter

EPA does not describe the rationale for the limited data selected. The selection of three reference years (2017, 2019, and 2021) from at least 5-6 years of data readily available to EPA, and the sampling periods within each year (typically the 1st or the 3rd quarter even though all quarters are generally available) are not discussed. EPA extracts data from the year 2021 using a different approach from the years 2019 and 2017 without explanation. EPA states for 2021 that 2 quarters of data are utilized (always the 1st and the 3rd). For 2019, EPA reports utilizing data from "quarters three and occasionally four" while for 2017 EPA reports data acquired from "variable quarters."[6]

The rationale for the irregular selection of quarters is not stated. For 2021, the first and third quarters are selected with no technical basis. For 2019, the selection of quarters three and "occasionally" four does not replicate the time periods selected for 2021. For 2017, there is no description of the quarters or selection criteria.

EPA ignores a rich field of data that could support a much more robust and reasonable analysis.

[6] RTR Tech Memo, page 2.

3.2.2 Number of Samples

The number of discrete data points in EPA's Reference Database – defined by the number of operating quarters – is extremely limited. EPA's description of the sampling approach[7] is as follows:

Quarterly data from 2017 (variable quarters) and 2019 (quarters three and occasionally four) were first reviewed because data for all affected EGUs subject to numeric emission limits had been previously extracted from CEDRI. In addition, the EPA obtained first and third quarter data for calendar year 2021 for a subset of EGUs with larger fPM rates (generally greater than 1.0E-02 lb/MMBtu for either 2017 or 2019).

Figure 3-2 shows most monitor locations — 193 of the 245 — are characterized by only 2 quarters of data, which is inadequate compared to the 16 or 20 EPA has access to. The distribution of quarters selected by EPA according to either CEMS or stack test measurement for all 245 locations is shown. The second largest category is 33 units characterized by 4 quarters.

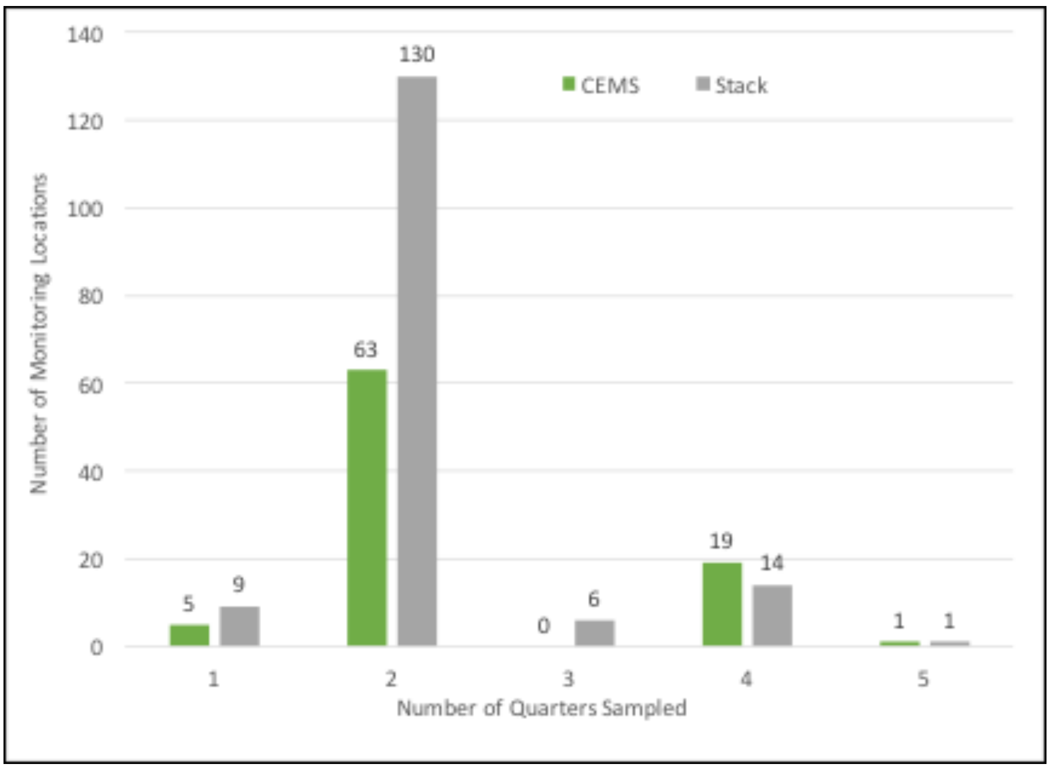

Figure 3-2. Numbers of Quarters Sampled by EPA for Use in PM Database

[7] RTR Tech Memo, page 2.

Additional depictions of the data (not shown) reveal that only nine units are described by data in 2017, and 187 units by data from 2019. Only 41 units are described by data in 2021; the lack of data in 2021 was intentional as EPA considered this year only if data from 2017 or 2019 showed the unit exceeding the 0.010 lbs/MBtu proposed limit.[8] In other words, EPA looked at 2021 only when it was trying to find an emission rate less than 0.010 lbs/MBtu for a unit.

3.2.3 PM Data Selection and Analysis

EPA does not explain the methodology chosen to reflect each quarters' emission rate, using at least two methods, depending on the year. EPA followed a four-step process to construct its database to select the "base rate" for each unit. The process is described as follows:

Step 1: Quarter Selection. EPA looked at 2-4 (usually 2) quarters for each unit. EPA states: "Quarterly data from 2017 (variable quarters) and 2019 (quarters three and occasionally four) were first reviewed …. In addition, the EPA obtained first and third quarter data for calendar year 2021 for a subset of EGUs with larger fPM rates (generally greater than 1.0E-02 lb/MMBtu for either 2017 or 2019)."[9]

As noted previously, EPA considered Q1 and Q3 2021 data solely to find a PM rate lower than 0.010 lb/MMBtu, and further explained: "The quarterly 2021 data summarizes recent emissions and also reflect the time of year where electricity demand is typically higher and when EGUs tend to operate more and with higher loads."[10]

Step 2. Select Single Quarter. From the candidate quarters identified in Step 1, EPA selected a single value, using criteria specific for each tests methodology:

- *PM CEMS*: for quarters in 2017 and 2019, EPA selected the 30-day average observed on the last day of the quarter; for quarters in 2021, EPA determined the average of the 30-day rolling averages observed in that quarter.
- *Stack Tests*: EPA took the average of the multiple (usually 3) test runs.

Step 3. Select Lowest Quarter. EPA selected the "lowest quarter" PM rate from the quarters selected in Step 2.

Step 4. Determine PM of 99th Percentile. For this lowest quarter per Step 3, EPA calculated the statistical percentile values as observed over the entire quarter. The methodology varied on whether PM CEMS or stack test data was provided. For PM CEMS, the percentiles were calculated for all 30-day rolling averages in the quarter. For stack tests, the percentiles were calculated for the typically 3 test runs.

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[8] Personal communication: Sarah Benish to Liz Williams, April 28, 2023. "*Data for 2021 was mined only for the EGUs that showed 2017 or 2019 fPM data above 1.0E-02 lb/MMBtu. We did not mine 2021 PM data for EGUs not expected to be impacted by the proposed fPM limit.*"
[9] RTR Memo, page 2.
[10] Ibid.

The results are reported in Appendix B of the Technology Review Memo. The 99th percentile rate was chosen as the "base rate," supposedly to account for variability within the "lowest quarter."

EPA does not describe why data selected was restricted to the years 2017, 2019, and 2021. EPA does not explain why 2021 data was limited to the 1st and 3rd quarters, 2019 data was limited to the 3rd and occasionally the 4th quarter, while 2017 data from variable quarters could be utilized.

Of concern is the limited subset of data used for this analysis – Figure 3-2 showed that for 80% of the units the lowest is selected from only two samples. EPA states "By using the lowest quarter's 99th percentile as the baseline, the analyses account for actions individual EGUs have already taken to improve and maintain PM emissions."[11] EPA states employing the PM rate at the 99th percentile –reflecting approximately the highest data within that quarter – remedies any bias.[12]

There is no basis for this statement. EPA is assuming that because a unit emitted fPM during a single quarter at a particular level, the lowest such level must necessarily reflect "actions individual EGUs have already taken to improve and maintain PM emissions," and therefore each EGU must be able to replicate that rate in every quarter going forward, indefinitely. Also, EPA ignores the unavoidable variability in emission rates: the "actions individual EGUs have already taken to improve and maintain PM emissions" are not the only factor that determines fPM emissions rate. The factors that affect fPM rates are numerous and include but are not limited to the following: coal quality (e.g., chemical composition and ash content) which varies within a single mine; variation in temperature within an ESP; content of SO_3 and trace constituents that determine ash electrical resistivity; physical conditions (spacing) of collecting plates and emitting electrodes; effectiveness of the rapping "hammers" that dislodge collected ash from the collecting plates; and physical properties of the collected ash layer that define ash re-entrainment. Further, boiler operation will influence ESP performance, most notably unit duty (i.e., relatively stable operating level for a "baseload" unit versus more load changes for an intermediate unit or a unit operating in peaking mode), operating level, and load "ramp" rate. Achieving the "least emission" rate observed during a quarter that EPA selected is not necessarily feasible at other times and under other conditions.

3.2.4 Example Cases

Figure 3-3 presents an example that demonstrate the shortcomings of EPA's approach. Figure 3-3 presents PM data from Coronado Generating Station Units 1 and 2 reflecting all operating quarters from 2017 through 2021. Both the average PM rate and the 99th percentile from each quarter are presented for 20 quarters of operation over the 4-year period. Figure 3-3 also identifies the two samples EPA selected from 2017 Q3 and 2019 Q3 as representative of low fPM rate, with the latter as the "least" – and the 99th-percentile reporting 0.0086 lbs/MBtu. Figure 3-3 shows EPA's two samples do not capture the full character of Coronado operating duty (with the red dotted line denoting the PM rate selected as representative of the units'

[11] RTR Tech Memo, page 4.
[12] Ibid.

capabilities to control PM). These quarters as selected by EPA are far from representative of unit operations or capabilities: among 20 quarters for which data are available, the units' 90th percentile fPM rates exceed the 0.0086 lbs/MBtu rate EPA selected for 16 quarters. Ten out of 20 quarters showed 90th percentile fPM rates exceeded the proposed standard of 0.010 lb/MBtu.

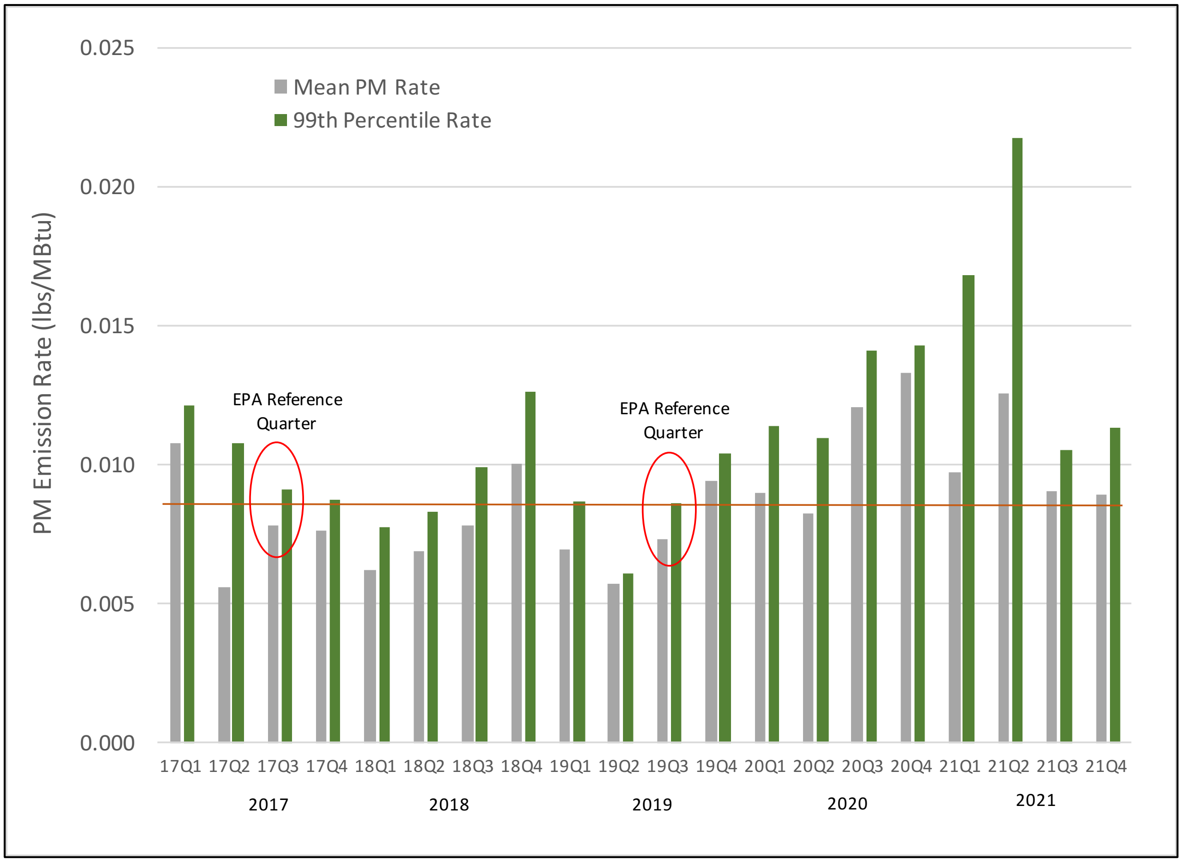

Figure 3-3. Coronado Generating Station: 20 Operating Quarters

Coronado Units 1/2 show how selecting the least PM rate of any quarter, and adopting the 99th percentile PM rate within that quarter, does not capture the variability in fPM emission rates, which are affected by the variability of coal and operating conditions, among others. These examples demonstrate that EPA used best-case fPM data from both compliance measures (continuous monitor and performance test data).

Additional examples are presented in the Appendix B to this report.

3.3 Conclusions

- EPA's database is sparse and does not fully capture operating duty. Of the 275 units and approximately 250 monitoring locations, the vast majority – 80% - are characterized by only two samples.
- Selecting the lowest quarter - "one" of what in most cases are "two" samples - fails to capture the operating profile of the unit, and presents a serious deficiency in representing

operations. EPA's approach of considering the 99th percentile within a quarter is inadequate to assess variability, particularly that induced by fuel composition, as such fuel changes are observed over a characteristic time of years and not several months.

- The use of statistical means within one quarter does not capture the multi-month variances in coal composition, seasonal load, and process conditions that are not constrained to 3-month events.

- An improved, robust database would allow observing variation between– as opposed to within – operating quarters, to better reflect variations and uncertainties in operating duty and fuel supply.

4. Coal Fleet PM Emissions Characteristics

Section 4 characterizes the coal-fired fleet selected to represent the PM emissions

The emission control technologies on the 275 units projected by EPA to be operating in 2028 present a variety of approaches to lower fPM emission limits – with implications for upgrades and actions that would be required to meet a revised standard for fPM. This subsection presents the distribution of control technology by ability to operate below the revised PM limits for the units in EPA's database. By necessity, this analysis uses EPA's database (both for a discussion of expected or achievable fPM emission rates and the units projected to operate in 2028 and later), and such use does not represent an endorsement or acceptance of EPA's approach. As discussed above, EPA's analysis of expected/achievable fPM emission rates is inadequate. And as discussed later in this report, EPA's selection of units that would continue to operate after 2028 is flawed: it contains multiple errors; and EPA's post-IRA IPM analysis is inaccurate.

Figure 4-1 is used to present our analysis.

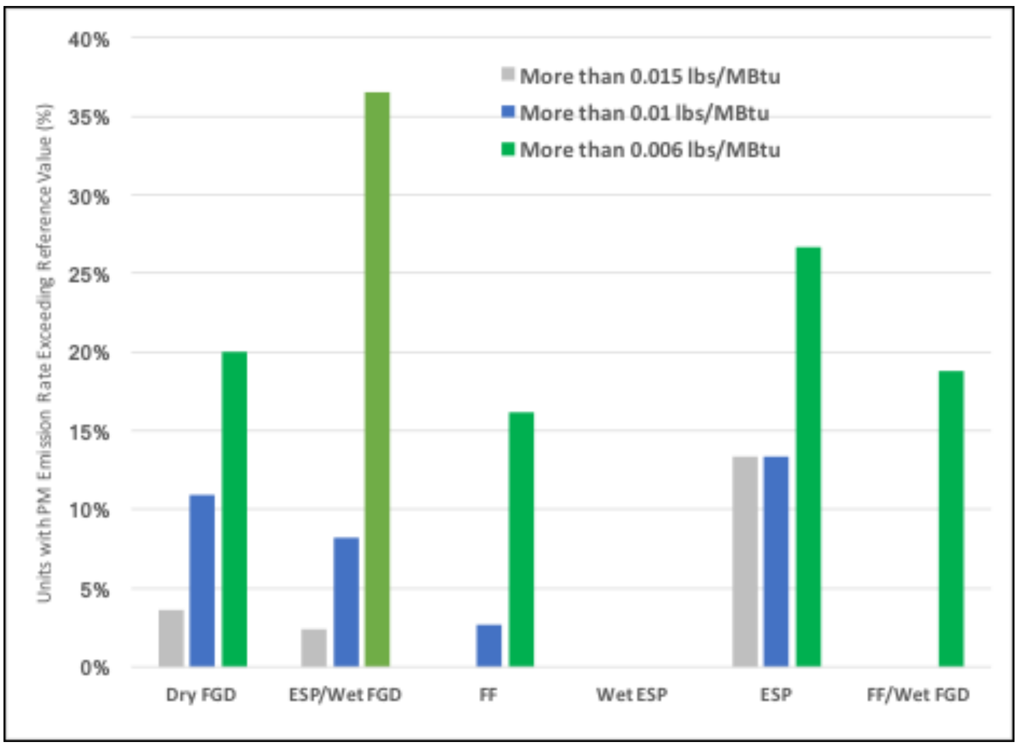

Figure 4-1. Fraction of Units Exceeding Three PM Rates: By Control Technology

Figure 4-1 presents for five control technology configurations the percentage of units that emit (according to EPA's chosen "base rate") above the following PM emission limits: 0.015 lbs/MBtu, 0.010 lbs/MBtu, and 0.006 lbs/MBtu. The control technologies are (a) dry FGD with a fabric filter, (b) ESP followed by a wet FGD, (c) fabric filter alone (employing low sulfur coal or multi-unit station-averaging to meet an SO_2 limit), (d) wet ESP as the last control device, (e) ESP alone (employing low sulfur coal or multi-unit station-averaging to meet an SO_2 limit), and (f) fabric filter followed by a wet FGD.

In Figure 4-1, the proportion of units in the inventory that exceed the contemplated fPM rate is proportional to the height of the bar; a higher bar implies a greater fraction of units in the inventory exceed the contemplated fPM rate. Thus:

4.1.1 PM Rate of 0.015 lbs/MBtu

Units in three categories exceed this highest contemplated rate – those with an ESP alone, a dry FGD followed by a fabric filter, and an ESP followed by a wet FGD. The latter category of ESP/wet FGD benefits in that actions within the absorber tower – although not designed to removed fPM – can under some conditions remove fPM. Data describing PM removal via wet FGD is sparse but suggests 50% removal can be observed.

4.1.2 PM Rate of 0.010 lbs/MBtu

The number of units in each of the three preceding categories exceeding this rate increases – there is no change for the category of ESP-alone, but the number of units exceeding this rate more than triple for dry FGD/fabric filter and ESP/wet FGD. No units with fabric filter/wet FGD or a wet ESP emit at greater than this rate.

4.1.3 PM Rate of 0.006 lbs/MBtu

The number of units exceeding a rate of 0.006 lbs/MBtu increases with this most stringent contemplated rate. More than 1/3 of the units with ESP/wet FGD and ¼ of ESP- only cannot meet this rate, with fabric filters either operating with dry FGD (20%) or alone (16%) not achieving this target. Almost 20% of those with fabric filter/wet FGD units emit greater than this value.

In conclusion, within six major categories of control technology, units equipped with fabric filters achieve the lowest PM rates. Units with ESPs – either operating alone or with a wet FGD- represent the highest fraction of their population that exceed the strictest contemplated rate. Units with fabric filters – operating alone, or as part of a wet or dry FGD arrangement – are among the lowest exceeding the strictest contemplated PM rate. As noted previously, this analysis used EPA's database (as reflected in Appendix B of the RTR Tech Memo) out of necessity, and such use does not represent an endorsement or acceptance of EPA's approach.

5. CRITIQUE OF COST-EFFECTIVENESS CALCULATIONS

Section 5 addresses the cost effectiveness ($/ton basis) estimated to reduce the PM emission rate to EPA's proposed limit of 0.010 lbs/MBtu, and the alternative limit of 0.006 lbs/MBtu. EPA has conducted this calculation with inputs based on analysis by Sargent & Lundy (S&L)[13] and Andover Technology Partners (ATP).[14] EPA's results are presented in both Table 3 of the proposed rule and in Table 7 of the RTR Tech Memo.

This section reviews EPA's calculation methodology, critiques inputs of the EPA Study, and presents results of an Industry Study that utilizes realistic costs. Results from EPA's evaluation and the Industry Study addressing the 0.010 lbs/MBtu and 0.006 lbs/MBtu PM rates are compared.

5.1 EPA Evaluation

5.1.1 EPA Study Inputs

The EPA study used both the PM database described in Section 3 and cost and technology assumptions derived by the above-mentioned S&L and ATP references. As noted in Section 2, EPA's sparsely-populated database is inadequate from which to base a revised PM rate that represents a significant reduction in PM emissions but is achievable in long-term duty.

The analyses by S&L and ATP provide capital cost for three categories of ESP upgrades, improvements to fabric filter operating and maintenance (O&M) and associated costs, capital requirement for fabric filter retrofit and associated O&M cost. Most of the analysis is premised on the costs and PM removal performance of ESP upgrades as defined by S&L. It should be noted S&L did not provide specific projects with publicly available data as the basis of their assumptions.

The most significant shortcoming of EPA's assumptions is low capital estimates for the most significant ESP upgrade - the "ESP Rebuild" scenario. In contrast to the generalizations of the S&L memo, Table 5-2 reports publicly documented costs incurred for "ESP Rebuild." Equally significant, EPA ignores the inherent variability of fPM and FGD process equipment by not utilizing a design or operating margin in selecting the value of fPM rates that would require operator action. This is counter to EPA's prior acknowledgement of the use of margin in the initial rulemaking for MATS[15] and recent observations as to CEMS calibration.[16] It is also contrary to basic operation goals: no source operates at the applicable standard; a compliance

[13] PM Incremental Improvement Memo, Project 13527-002, Prepared by Sargent & Lundy, March 2023. Hereafter S&L PM Improvement Memo.

[14] Analysis of PM Emission Control Costs and Capabilities, Memo from Jim Staudt (Andover Technology Partners) to Erich Eschmann, March 22, 2023. Hereafter ATP 2023.

[15] Hutson 2012.

[16] Parker 2023.

margin is always necessary, at least to account for unavoidable variability of performance in the real world. By ignoring the need for margin, EPA's evaluation under-predicts the number of units that would be retrofit with new or upgraded control technology to meet the target rate.

These and other critiques of EPA's approach are discussed subsequently.

Shortcomings in EPA inputs compromise the results of their analysis. These shortcomings, as well as other observations, are summarized as follows:

ESP Upgrade. Three categories of ESP upgrade are proposed by EPA. The most significant shortcoming relates to the "ESP Rebuild" category in which - as described by S&L – additional plate area is added to the ESP. The addition of collecting surface area will require major changes to – or demolition and complete rebuilding of – the gas flow confinement that houses the existing collecting plates. Also, these process changes require specialized labor for fabrication and installation that may be limited in availability. The costs suggested by S&L (without citation of references) - $75-100/kW –are low when compared to publicly disclosed costs from similar projects.

Fabric Filter O&M. Fabric-filter-equipped units that emit greater than 0.010 lbs/MBtu are assumed to adopt enhanced O&M practices. These enhanced practices consist of (a) upgrading filter material to higher quality fabrics, such PTFE, and (b) increasing the replacement frequency so that filters are replaced on a 3-year basis. The cost premium for this action, based on analysis by ATP, does not consider the additional manpower costs for the more frequent replacement.

Fabric Filter Construction. EPA's range of capital cost for retrofit of fabric filter technology is consistent with industry experience.

Design/Compliance Margin. A premise of environmental control system design is accounting for variability due to many factors, including, for example, variations in fuel composition, operating load, and process conditions. Such variability is generally addressed by a design/compliance margin – selecting a target emission rate less than mandated by a standard. The concept of design/compliance margin is broadly applied in the industry, and was acknowledged in a 2012 EPA memo summarizing the range of margin adopted by various process suppliers, with a minimum cited as 20-30%.[17] EPA did not adopt a design/compliance or operating margin in selecting fPM emission rates for a revised fPM standard in this evaluation, despite the fact that elsewhere in the record of this proposal EPA acknowledges a typical "operational target" of 50% of the limit.[18] Because of its assumption of no design/compliance margin whatsoever, EPA presumes that units that report an operating fPM of 0.010 lbs/MBtu – based on EPA's sparse database - require no investment to meet the proposed standard of 0.010 lb/MBtu.

[17] Hutson, N., National Emission Standards for Hazardous Air Pollutants (NESHAP) Analysis of Control Technology Needs for Revised Proposed Emission Standards for New Source Coal-fired Electric Utility Steam Generating Units, Memo to Docket No. EPA-HQ-OAR—2009-0234, November 16, 2012.

[18] Parker 2023.

Separate from the preceding issues, EPA did not disclose the capacity factors assumed in the analysis. The capacity factor can be inferred from the tons of PM removed as reported in Appendix B of the RTR Tech Memo; this requires acquiring heat input and net plant heat rate from AMPD and EIA data.

5.1.2 EPA Results

Table 5-1 presents results of EPA's evaluation.

Table 5-1. Summary of EPA Results

EPA Study					
Unit Affected	Tons fPM Removed	Annual Cost ($M/y)	$/ton fPM (average)	Non-Hg metallic HAPS Removed (tons)	$/ton non-Hg metallic HAP ($000s)
Target: 0.010 lbs/MBtu					
20	2,074	77.3-93.2	37,300-44,900	6.34	12,200-14,700
Target: 0.006 lbs/MBtu					
65	6,163	633	103	24.7	25,600

<u>Proposed Limit: 0.010 lbs/MBtu</u>. EPA estimates 20 units in the entire inventory are required to retrofit some form of ESP upgrade. The number of units with existing fabric filters required to enhance O&M is not identified, nor is their cost. EPA estimates a range in annual cost to implement the ESP and fabric filter O&M enhancement of $77.3 to 93.2 M/yr, with the range determined by the range in cost and performance of each option as described by S&L.[19] This total annualized cost translates into an average fPM removal cost effectiveness of $37,300 - $44,900 per ton of fPM and $12.2M -$14.7 M per ton of total non-Hg metallic HAPs. These steps remove a total of 2,074 tons of fPM (6.34 tons of total non-Hg metallic HAPs) annually.

EPA did not consider in its analysis the potential impact of the capital cost of major controls construction or upgrades (i.e., ESP rebuilds for most of the 20 units; new Fabric Filters for the two Colstrip units) on the viability of the units at which such rebuilds would occur. Appendix Figure A-1 presents the capital required for each unit as designated by EPA for upgrade – requiring an investment likely prohibitive for continued operation.

<u>Potential Limit: 0.006 lbs/MBtu</u>. EPA estimates 65 units in the entire inventory are required to retrofit a fabric filter or deploy enhanced O&M to an existing fabric filter. EPA estimate an annual cost of $633 M/yr will be incurred, at an average cost effectiveness of $103,000 per ton

[19] S&L PM Improvement Memo.

of fPM and $25.6 M per ton of total non-Hg metallic HAPs. These steps remove a total of 6,163 tons of fPM (24.7 tons of total non-Hg metallic HAPs) annually.

5.2 Industry Study

The Industry Study alters several assumptions to reflect actual, documented cost data and the necessity of a design/compliance margin. Table 5-2 presents these results.

5.2.1 Revised Cost Inputs

The modified cost inputs necessary to reflect authentic conditions ESP upgrade and fabric filter operation are discussed as follows.

ESP Upgrades. The three categories of ESP upgrades are assessed as follows.

Minor Upgrades (Low Cost). Both the cost range and PM removal efficiency for this activity as estimated by S&L are adopted for this analysis. ESPs requiring Minor Upgrade are assigned a $17/kW cost to derive an average of 7.5% removal of fPM.

Typical Upgrades (Average Cost). Both the cost range and PM removal efficiency for this activity as estimated by S&L are adopted for this analysis. ESPs requiring Typical Upgrade are assigned a $55/kW cost to derive an average of 15% fPM removal.

ESP Rebuild (High Cost). The cost range for this activity as estimated by S&L does not reflect that reported publicly for four projects that represent the "ESP Rebuild" category. Two projects were completed at the AES Petersburg station – the complete renovation of the ESPs on Units 1 and 4[20] for which S&L provided engineering services. The cost for this work has been publicly reported in 2016-dollar basis. Two additional major ESP upgrades were implemented by Ameren at the Labadie station unit in 2014 – with costs publicly reported.[21]

Table 5-2 summarizes the cost incurred for the four major ESP retrofits, including costs in the year incurred and escalated (using the Chemical Engineering Process Cost Index)[22] to 2021. Table 5-1 shows a cost range of $57-209/kW, with 3 of the 4 units incurring a cost exceeding $100/kW. These costs significantly exceed EPA's maximum for this range.

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[20] State of Indiana – Indian Public Utility Commission, Cause No. 44242, August 14, 2013. See Appendix, electronic page 50 of 51.

[21] Ameren Missouri Installs Clean Air Equipment at its Labadie Energy Center; https://ameren.mediaroom.com/news-releases?item=1351

[22] https://www.chemengonline.com/pci-home#:~:text=Since%20its%20introduction%20in%201963,from%20one%20period%20to%20another.

Table 5-2. ESP Rebuild Costs: Four Documented Cases

Owner/Station	Unit	Basis Year	2021 ($/kW)
AES/Petersburg	1	2016	117
AES/Petersburg	4	2016	57
Ameren Labadie	1	2014	192
Ameren Labadie	2	2014	209

Consequently, the range of ESP rebuild costs is adjusted to $57-209/kW, and the mean value of $133/kW (2021 basis) selected to represent this category of upgrade.[23]

FF O&M. A fabric filter O&M cost was derived for existing units, based on the assumption by S&L that filter material will be upgraded, as well as the frequency of filter replacement. An increase in cost – reflected as fixed O&M – of $515,000 is estimated for a 500 MW unit. This cost premium is comprised of higher material cost of $425,000 to upgrade filter material to PTFE fabric and an additional $90,000 for installation labor. This cost premium as is assigned to existing units based on generating capacity, and using a conventional "6/10th" power law.

The revised Industry Study costs are based on (a) gas flow volume treated, (b) surface area of filter required based on the unit design, (c) unit cost of filter (e.g. $ per ft^2 of cleaning surface), and (d) replacement rate of filter material. Gas flow treated for each unit was determined using the quantitative relationships derived by S&L for fabric filter cost evaluation developed for the IPM model.[24] Filter surface area was not defined for each unit as dependent on the specific air/cloth ratio; rather a fleet air/cloth ratio of 5 – a mean value between conventional and pulse-jet design concepts – is selected. The unit cost for fabric was selected (at $4.00/ft^2) per ATP analysis. Per S&L's IPM fabric filter costing procedure[25] and the EPA-sponsored review of filter material cost,[26] the increase in cost for enhanced O&M is derived. The cost to upgrade material, accelerate filter replacement (from 5 to 3 years) and supporting cages (from 9 to 6 year) intervals is estimated as $425K per year for a reference 500 MW unit.

Fabric Filter Capital Cost. EPA proposed a capital cost to retrofit a fabric filter as $150-$360/kW. The cost range offered by EPA is consistent with industry experience and is used in this study.

EPA did not share the incremental operating cost incurred by the retrofit fabric filters. The Industry Study adopted fixed and variable operating costs from the previously cited S&L fabric filter cost estimating procedure. For the assigned inputs, the S&L evaluation projects a fixed

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[23] Colstrip Units 3 and 4 are equipped with legacy FGD that combine removal of SO2 and PM in a wet venturi; there is not an ESP option to upgrade. Fabric filer retrofit is the only option; as Colstrip represents an atypical case the costs are reported in the category of Major ESP upgrade.

[24] IPM Model – Updates to Cost and Performance for APC Technologies: Particulate Control Cost Development Methodology, Project 13527-001, Sargent & Lundy, April 2017. Hereafter S&L Fabric Filter 2017.

[25] Ibid.

[26] ATP report.

O&M of $0.27/kW-yr and a variable operating cost of 0.48 $/MWh. The variable O&M cost is mostly comprised of filter replacement at the accelerated rate described, and auxiliary power.

Design/Compliance Margin. EPA in two public documents address – and apparently recognize – the need for design/compliance margin.[27] The use of design/compliance margin was acknowledged in a 2012 EPA memo summarizing the range adopted by various suppliers, citing a minimum of 20-30%.[28] For the proposed limit of 0.010 lbs/MBtu, the minimum of 20% is used as a design target for ESP upgrades. Thus, the Industry Study applied ESP upgrade and fabric filter O&M enhancements to attain 0.008 lbs/MBtu, in lieu of EPA's target of 0.010 lbs/MBtu. It should be noted this 20% margin is the least of those considered; if the highest operating margin of 50% suggested by EPA in the record of this rule was used the units requiring upgrade and the cost would have been even higher.

As noted by EPA, the sole reliable compliance means for a 0.006 lbs/MBtu PM rate is a fabric filter. Fabric filters historically exhibit low variability due to their inherent design; thus, the operating margin is slightly relaxed to 0.005 lbs/MBtu. Consequently, the Industry Study assumed ESP-equipped units emitting greater than 0.005 lbs/MBtu will retrofit a fabric filter to insure 0.006 lbs/MBtu is attained. Units with existing fabric filters operating at greater than 0.005 lbs/MBtu will adopt improved operation and maintenance, as previously described.

5.2.2 Cost Effectiveness Results

Revised costs from the Industry Study are projected for the proposed fPM limit of 0.010 lbs/MBtu, and the alternative rate of 0.006 lbs/MBtu. Table 5-4 presents these results.

Proposed Limit: 0.010 lbs/MBtu. Results derived in the Industry Study are reported for all three categories of ESP upgrade in Table 5-1. A total of 26 units are required to upgrade ESPs – 11 deploying *Minor*, 7 deploying *Typical*, and 8 deploying *Major* upgrades.[29] In addition, 11 units equipped with fabric filters are required to enhance O&M activities. The totality of these actions each year incur an operating cost of $169.7 M/yr, and remove 2,523 tons of PM.

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[27] Hutson, 2012 and Parker, 2023.

[28] Hutson, N., National Emission Standards for Hazardous Air Pollutants (NESHAP) Analysis of Control Technology Needs for Revised Proposed Emission Standards for New Source Coal-fired Electric Utility Steam Generating Units, Memo to Docket No. EPA-HQ-OAR—2009-0234, November 16, 2012. at 1 (discussing mercury); 2 (discussing PM).

[29] The two Colstrip units are equipped with an early generation FGD process which does not include an ESP, thus the concept of an ESP upgrade is irrelevant. Consistent with EPA's assumption, the Colstrip units are assumed to retrofit a fabric filter as the only option to meet a limit of 0.010 lbs/MBtu.

Table 5-3. Summary of Results: Industry Study

Technology (Units Affected)	Annual Cost ($M/y)	Tons fPM Removed	$/ton fPM average	Non-Hg metallic HAPS Removed (tons)	$/ton non-Hg metallic HAP ($000s)
Target: 0.010 lbs/MBtu					
ESP Minor (11)	20.9	100	209,340	0.31	67,470
ESP Typical (7)	34.7	282	122,926	0.86	40,216
ESP Major † (8)	113.6	1,665	68,228	5.1	21,662
FF O&M (11)	0.4	475	869	1.45	284
Total or Average	169.7	2,523	67.3	7.71	22,000
Target: 0.006 lbs/MBtu					
FF O&M (23)	1.23	652	1,887	2.61	617
FF Retrofit (52)	1,955.4	6,269	311,900	25.13	102,000
Total or Average	1,956.6	6,921	282,715	27.74	92,470

† Includes 2 fabric filters retrofit to Colstrip Units 3 and 4. See footnote #23.

The incurred cost per ton varies significantly by ESP upgrade category. For the ESP *Minor* upgrade, the average cost effectiveness is approximately $67,470,000 per ton of non-Hg metal HAP for 0.31 of tons removed ($209,340 per ton of fPM for 100 tons of fPM removed). The cost-effectiveness cost effectiveness for the ESP *Typical* upgrade average $40,216,000 per ton of non-Hg metal HAP for 0.86 tons removed ($122,956 tons of fPM for 282 tons of fPM removed). The *Major* upgrade removes the most non-Hg metal HAP – 5.1 tons – (1,665 tons of fPM) for an average cost effectiveness of $21,662,000 per ton of non-Hg metal HAP ($68,228 per ton of fPM). The most cost-effective control evaluated is enhanced fabric filter O&M, which removes 1.45 tons of non-Hg metal HAP at a cost-effectiveness of $284,230/ton (475 tons of fPM at a cost-effectiveness of $869/ton).

These actions cumulatively remove a total of 2,523 tons of PM for an average cost effectiveness of 22,000,000 per ton of non-Hg metal HAP ($67,262 per ton of fPM) removed, a 50% increase compared to the cost estimated by EPA.

Appendix Table A-1 reports the units to which the Industry Study assigned ESP upgrades, and defines the category of upgrade to meet the proposed fPM limit of 0.010 lbs/MBtu.

Possible Lower Limit: 0.006 lbs/MBtu. The Industry Study projects 52 ESP-equipped units would be required to retrofit a fabric filter, removing 25.13 tons of non-Hg metal HAP (6,269 tons of fPM) for an average cost effectiveness of $102,000,000 per ton of non-Hg metal HAP ($311,900 per ton of fPM). In addition, 23 existing units equipped with fabric filters would have to adopt enhanced O&M, removing an additional 2.61 tons of non-Hg metal HAP (652 tons of fPM) for an average of cost of $617,195/ton of non-Hg metal HAP ($1,887/ton of fPM). These actions cumulatively remove a total of 27.74 tons of non-Hg metal HAP (6,921 tons of fPM) for an average cost effectiveness of $92,470,000/ton non-Hg metal HAP ($282,715/ton of fPM) removed. These costs are a factor of almost three times that projected by EPA.

Appendix Table A-2 reports the units to which the Industry Study assigned fabric filter retrofits and enhancements of operating and maintenance procedures, to meet the alternative fPM limit of 0.006 lbs/MBtu.

5.3 Conclusions

- EPA's cost study is deficient in terms of the number of ESP-equipped units required to retrofit improvements, the capital cost assigned for the most significant *Major* ESP improvement, and estimates of $/ton cost-effectiveness incurred. EPA, by ignoring the need for a design and operating margin cited in at least two of their publications (Hutson, 2012 and Parker, 2023) under-predicts the number of units that would require retrofits.

- This study – using the minimum margin cited by EPA in previous publications – projects a much higher annual cost for capital equipment to meet the proposed 0.010 lbs/MBtu - $169.7 M versus EPA's maximum estimate of $93.3 M. To meet the alternative PM rate of 0.006 lbs/MBtu, this study projects 50% more units (87 versus 65) must be retrofit with fabric filters or implement enhanced O&M to an existing fabric filter, incurring an annual cost of $1.96 B versus EPA's estimate of 633 M/yr – a three-fold increase.

- As a consequence, this study predicts the cost effectiveness to meet 0.010 lbs/MBtu will average $22,000,000 per ton of non-Hg metal HAP removed ($67,262 per ton of fPM), a 50% premium to EPA's estimate of $12,200,000 - $14,700,000/ton of non-Hg metal HAP ($37,300 – $44,900/ton of fPM) removed. This study projects the cost to meet the alternative rate of 0.006 lbs/MBtu will average $92,470,000/ton non-Hg metal HAP ($282,715/ton fPM) removed, almost a factor of three higher than EPA's estimate of $103,000/ton.

6. Mercury Emissions: Lignite Coals

Section 6 addresses EPA's proposed action to reduce the limit for Hg for lignite-fired units to 1.2 lbs/TBtu. (the following Section 7 addresses EPA's proposal to retain the present emission limit of 1.2 lbs/TBtu for units firing bituminous and subbituminous coals (i.e., non-low rank fuels).) This section critiques EPA's basis for proposing the lignite Hg emission rate of 1.2 lbs/MBtu, while supporting the proposal to retain the existing rate for non-low rank coals.

EPA states the following in support of their proposal regarding lignite:

".....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.

Both lignite and subbituminous coal do contain less sulfur than bituminous coal, but other major differences in composition exist that EPA does not recognize. These are Hg content and its variability, the sulfur content, and the alkalinity of inorganic matter. EPA's failure to recognize these differences manifests itself as (a) assuming activated carbon sorbent effectiveness observed on subbituminous coal (specifically PRB) extends to lignite, and (b) ignoring variability in Hg content, as well as the role of sulfur trioxide (SO_3), which compromises achieving 90%+ Hg removal as required to attain 1.2 lbs/TBtu.

Fuel properties are described separately for the North Dakota and Gulf Coast (Texas and Mississippi) lignite mines.

6.1 North Dakota Mines and Generating Units

Figures 6-1 to 6-4 present data provided by lignite suppliers from North Dakota mines that describe the variability for Hg and other constituents key to Hg removal. These figures present data as a "box and whisker" plot, which portrays the mean value, the 25th and 75th percentile of the observed data, and the near-minimum (5%) and near-maximum (95%) extremities. Figure 6-1 shows the variability of Hg and Figure 6-2 the variability of sulfur content. Figure 6-3 shows variability of fuel alkalinity compared to sulfur content – specifically, the ratio of calcium (Ca) and sodium (Na) to sulfur – i.e., the (Ca + Na)/S metric.

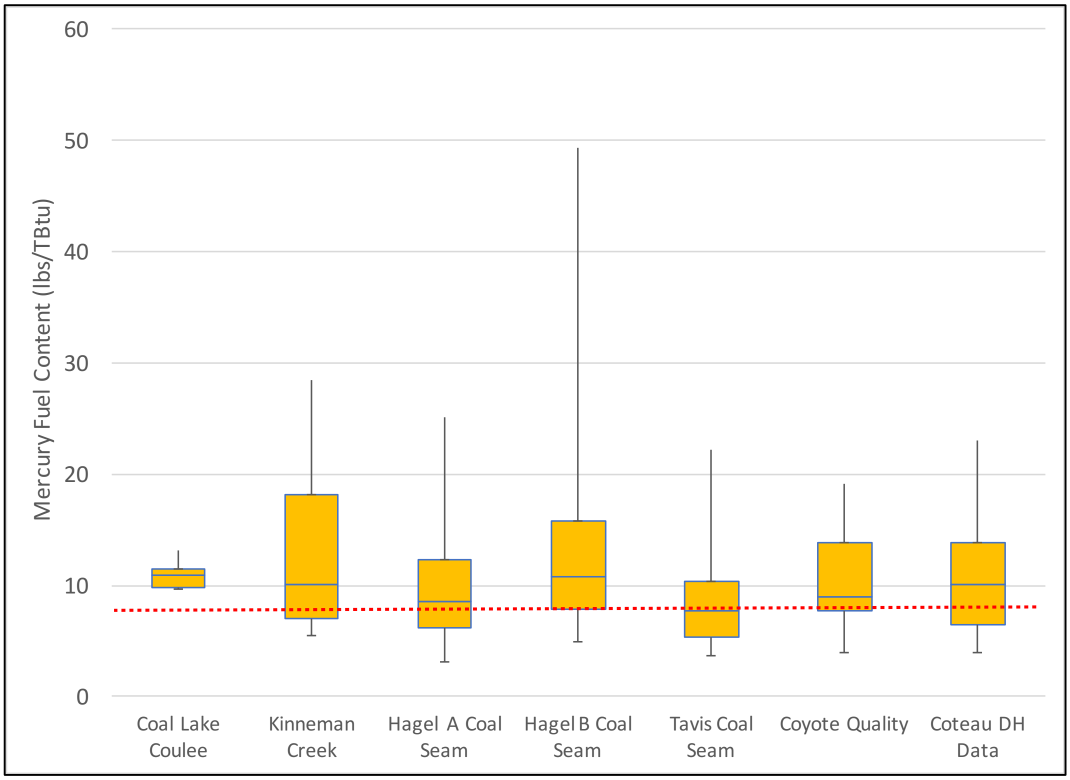

Figure 6-1. Mercury Content Variability for Eight North Dakota Lignite Mines

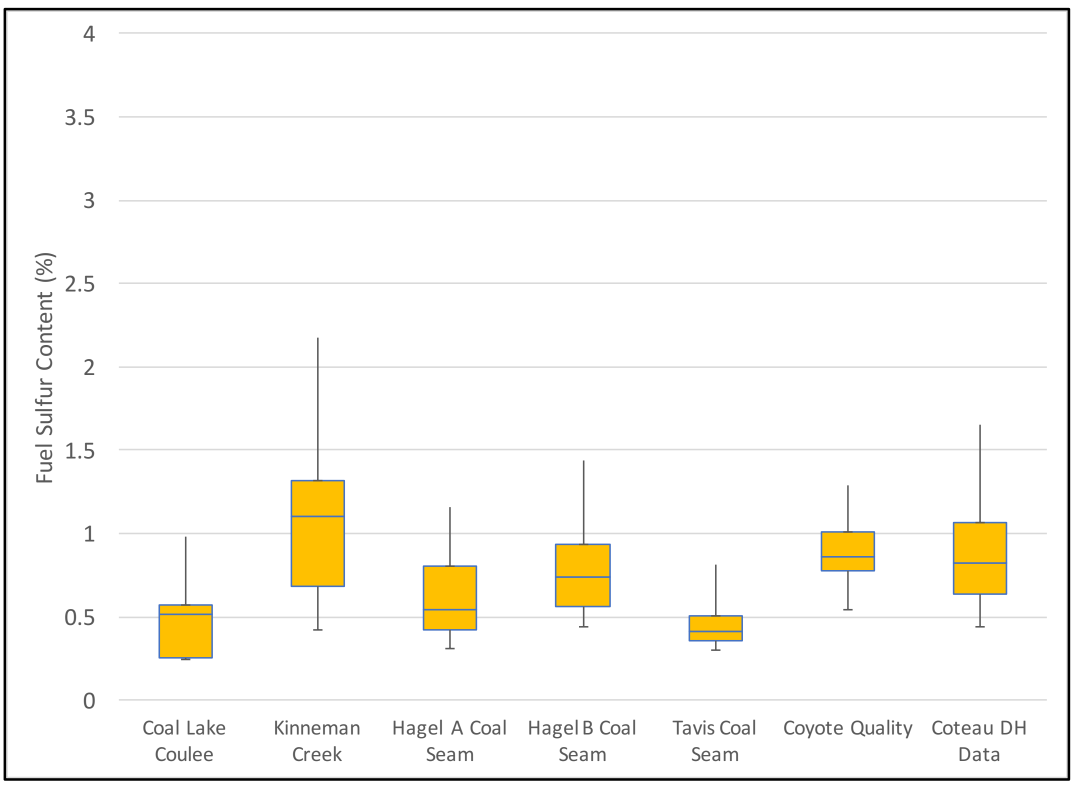

Figure 6-2. Fuel Sulfur Content Variability for Eight North Dakota Lignite Mines

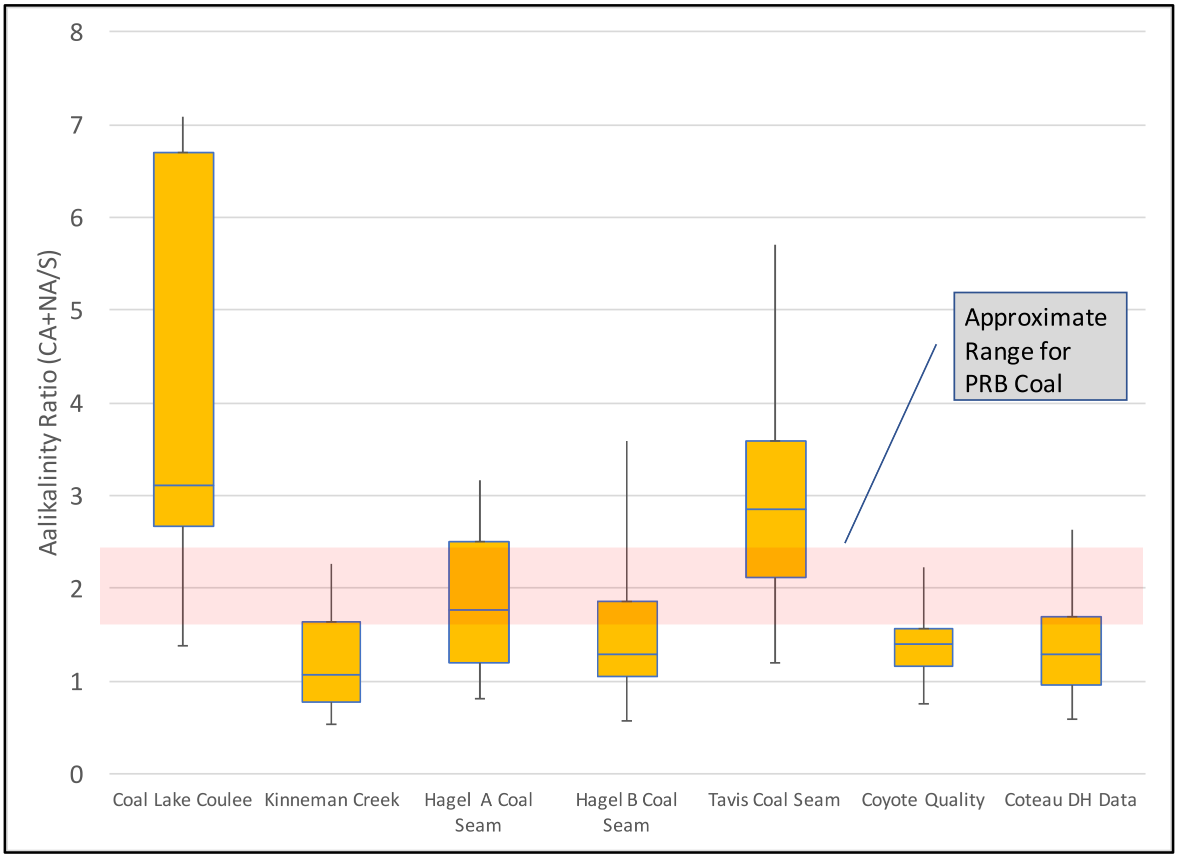

Figure 6-3. Fuel Alkalinity/Sulfur Ratio for Eight North Dakota Mines

Figure 6-1 compares the Hg content and variability to the fixed value of 7.7-7.8 lbs/TBu, assumed by EPA as representing North Dakota lignite, as summarized in Table 11 of the Tech Memo. Figure 6-1 shows – with the exception of the Tavis seam – all mean values of Hg content exceed EPA's assumed value that serves as the basis of EPA's evaluation. More notably, the 75th percentile value of Hg for each seam - slightly more than one standard deviation variance from the mean – in all cases significantly exceeds the value assumed by EPA.

Of note is that the variability of Hg depicted in Figure 6-1 is not necessarily observed only over extended periods of time – such as months or quarters – it can be witnessed over period of days or weeks. This is attributable to the sharp contrast in Hg content of seams that are geographically proximate and thus are mined within an abbreviated time period. Figure 6-4 presents a physical map showing the location of "boreholes" in a lignite field with imbedded text describing (in addition to the borehole code) the Hg content as ppm. The text boxes report this Hg content in terms of lbs/TBtu. These example boreholes – separated by typically 660 feet- and the factor of 3 to 6 variation of Hg content present a meaningful visualization of Hg variability in a lignite mine, and the consequences for the delivered fuel.

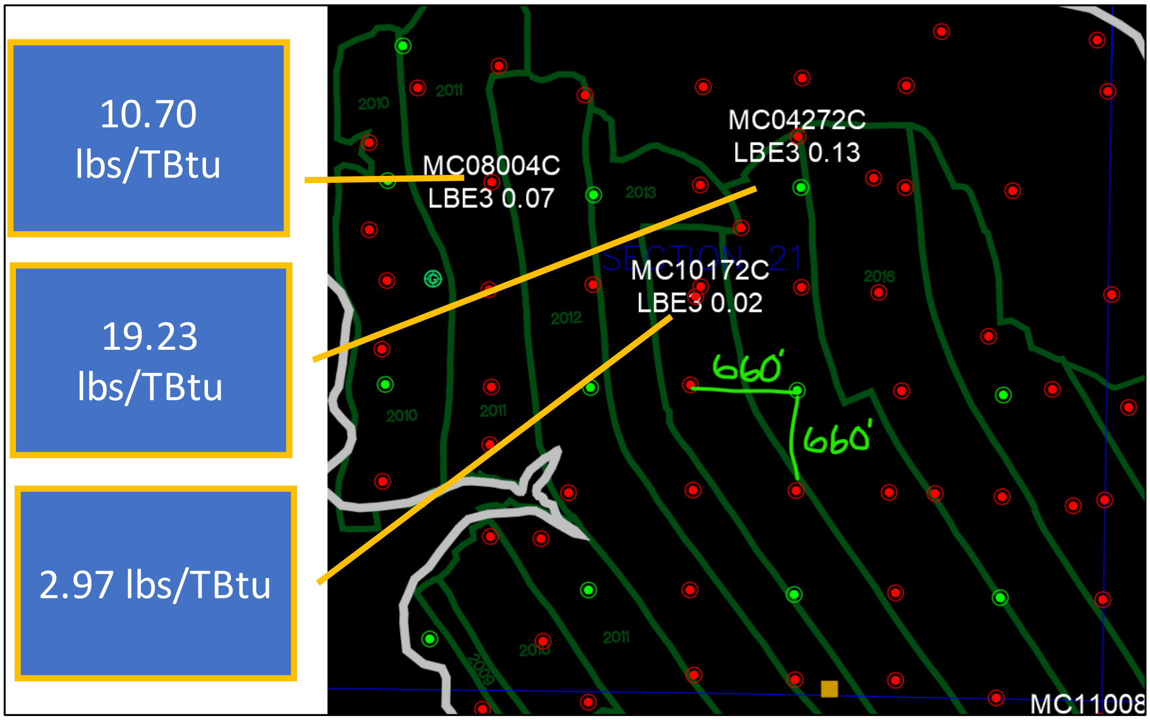

Figure 6-4. Spatial Variation of Hg in a Lignite Mine

Data from Figure 6-1 is summarized in Table 6-1 for units at four stations in North Dakota – Coal Creek, Antelope Valley, Coyote, and Leland Olds. Both Figures 6-1 and Table 6-1 show Hg variability exceed that assumed by EPA in their evaluation. Table 6-1 shows that achieving a 1.2 lbs/TBu requires an Hg removal rate of approximately 93-95% for unavoidable instances where coal Hg content is at the 95th percentile of observed value. The approximate 93-95% Hg removal requirements well exceed the 85% Hg removal based on the IPM-assigned Hg content.

Table 6-1. Hg Variability for Select North Dakota Reference Stations

Station	Mine	Seams	IPM Designated Hg Rate (lbs/TBtu)	Inferred EIA 2021 Hg Rate (lbs/TBtu)	Hg Fuel Content at 95th Percentile (lbs/TBtu)	Hg Removal (%) for 1.2 lbs/TBtu at 95th Percentile
Coal Creek	Falkirk	UTAV, HGB1 and HGA1/HGA2 (Mostly Haga A seam)	7.81	7.80	25.1	95.2
Antelope Valley	Freedom	Freedom Mine Belauh Seam	7.81	7.76	23.0	94.8
Coyote	Coyote Creek	Coyote Upper Belauh	7.81	7.79	19.2	93.8
Leland Olds	Freedom	Kinneman Creek, Hagel A, Hagel B	7.81	7.79	23.0	94.8

6.2 Texas Gulf Coast Mines and Generating Units

Figures 6-5 to 6-7 present data from Texas and Mississippi lignite mines describing the content and variability for Hg, sulfur, and the (Ca + Na)/S metric, as delivered to generating units in Texas. Analogous to the data cited for North Dakota, the "box and whisker" depiction represents the same metrics.

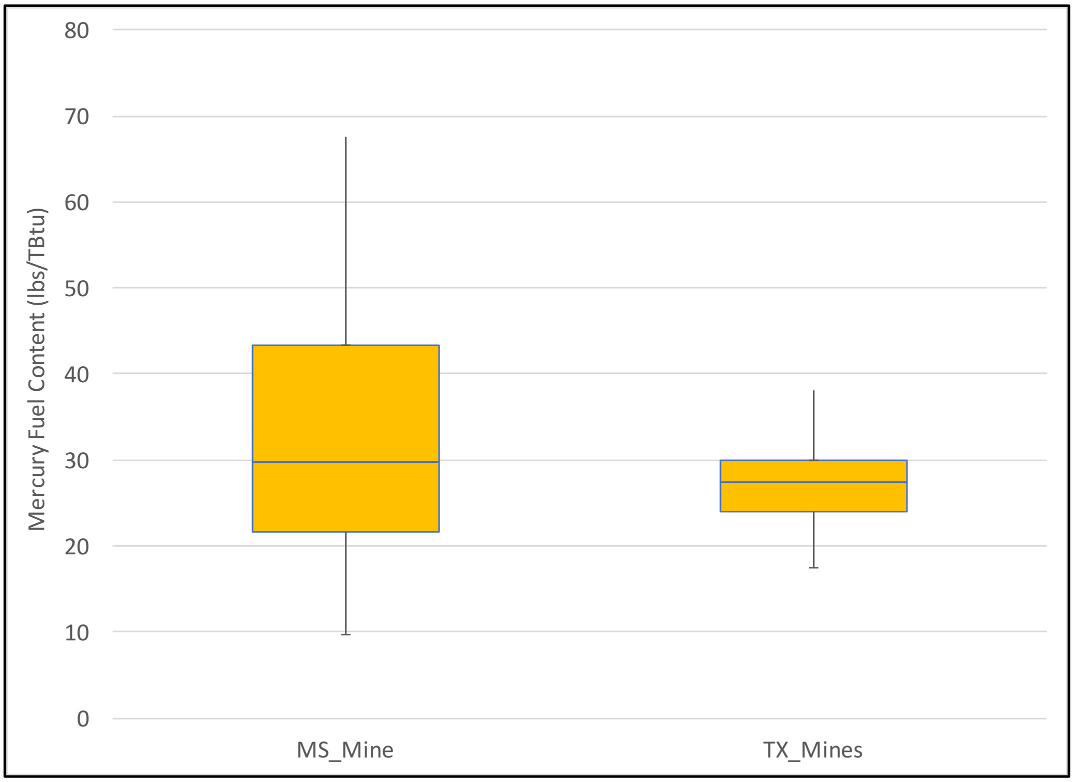

Figure 6-5. Mercury Variability for Two Gulf Coast Sources: Mississippi, Texas

Table 6-2 compares the Hg removal required to meet the proposed 1.2 lbs/TBtu rate considering the variability of Hg in Texas and Mississippi coals, instead of the IPM-assigned Hg coal content. For three Texas plants that fired 100% lignite – Major Oak Units 1 and 2, Oak Grove Units 1 and 2, and San Miguel – EPA assigned inlet Hg values from 12.44 to 14.88 lbs/TBtu, implying Hg removal of 90-92% to achieve 1.2 lbs/TBtu. However, based on the 95th percentile value of the Texas lignite Hg values from Figure 6-5, the required Hg removal would be 96-97%.

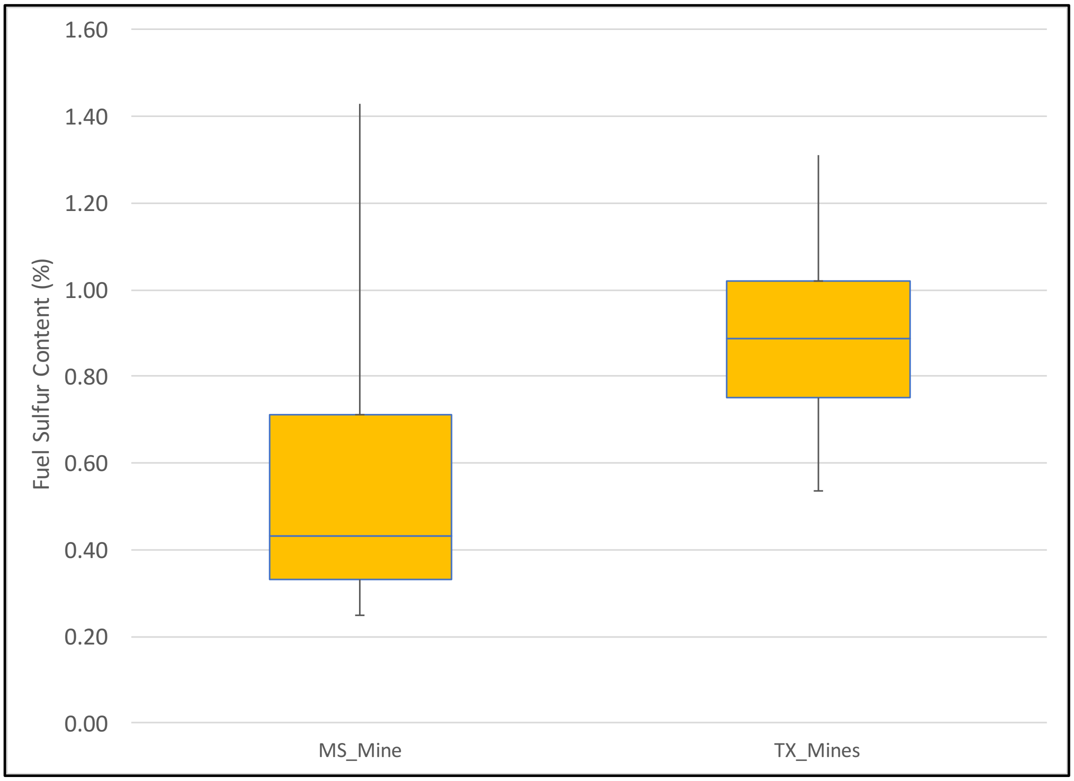

Figure 6-6. Sulfur Variability for Mississippi, Texas Lignite Mines19.1

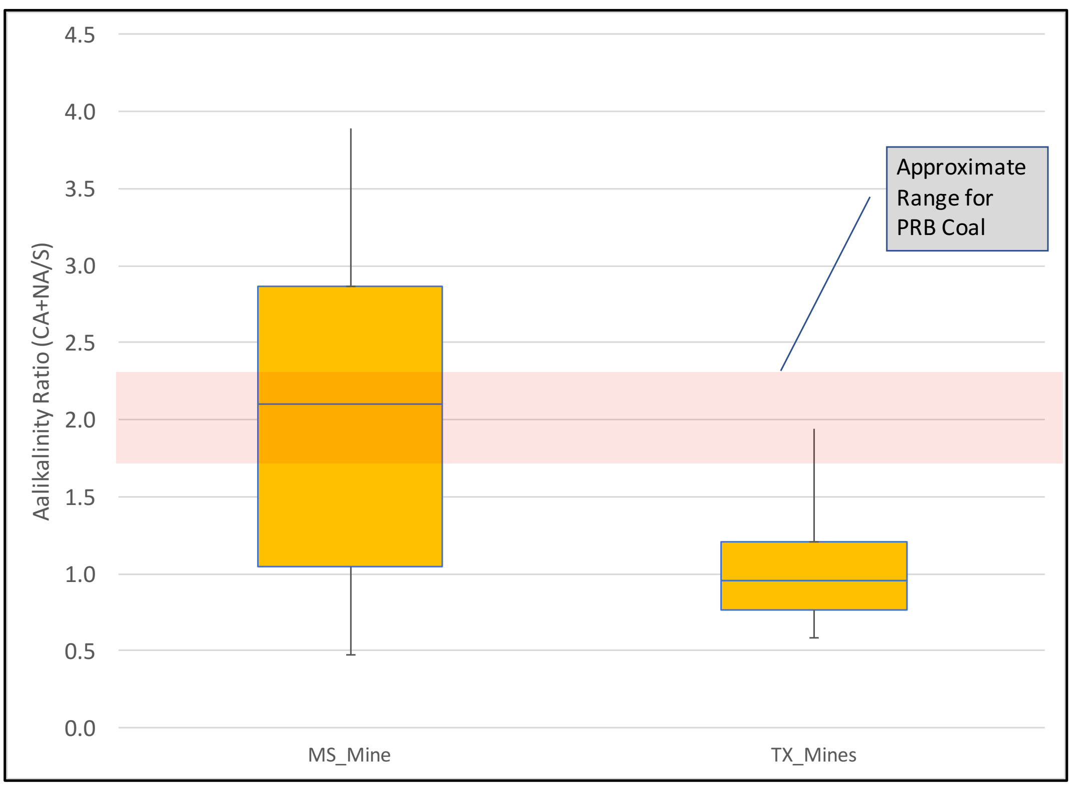

Figure 6-7. Fuel Alkalinity/Sulfur Ratio for Mississippi, Texas Lignite Mines

Table 6-2. Hg Variability for Select Texas Reference Stations

Station	Mines	IPM Designated Hg Rate (lbs/TBtu)	Inferred EIA 2021 Hg Rate (lbs/TBtu)	Hg Fuel Content at 95th Percentile (lbs/TBtu)	Hg Removal (%) for 1.2 lbs/TBtu at 95th Percentile
Major Oak 1,2	Calvert	14.65	14.62	38.12	96.9
Oak Grove 1, 2	Kosse Strip	14.88	14.6	38.12	96.9
Red Hills 1, 2	Red Hills	12.44	12.4	67.6	98.2
San Miguel	San Miguel Lignite	14.65	14.62	38.1	96.9

6.3 Role of Flue Gas SO3

EPA equates PRB and lignite coal in terms of constituents that affect Hg capture by carbon sorbent. Data from North Dakota and Gulf Coast mines, displayed in the previous Figures 6-1 to 6-7, show these fuels also contain higher sulfur content than PRB - by a factor or two or more. This relationship is verified by data acquired from EIA Form 960, as provided by power station owners. These fuel data, combined with inherent alkalinity, identifies the problematic role of flue gas SO_3 content.

6.3.1 EIA Hg-Sulfur Relationship

Figure 6-8 compares the seam-by-seam Hg and sulfur content from various power stations firing lignite coals, representing approximately 60 lignite mines and 40 PRB mines. Figure 6-8 shows, even excluding the outlier values of Hg (approximating 50 lbs/TBtu), lignite presents significantly greater variability in Hg and sulfur than PRB. Moreover, lignite coals have a much higher sulfur content than PRB and in many instances have twice the Hg content. The higher sulfur content of lignite equates to greater production rates of sulfur SO_3.

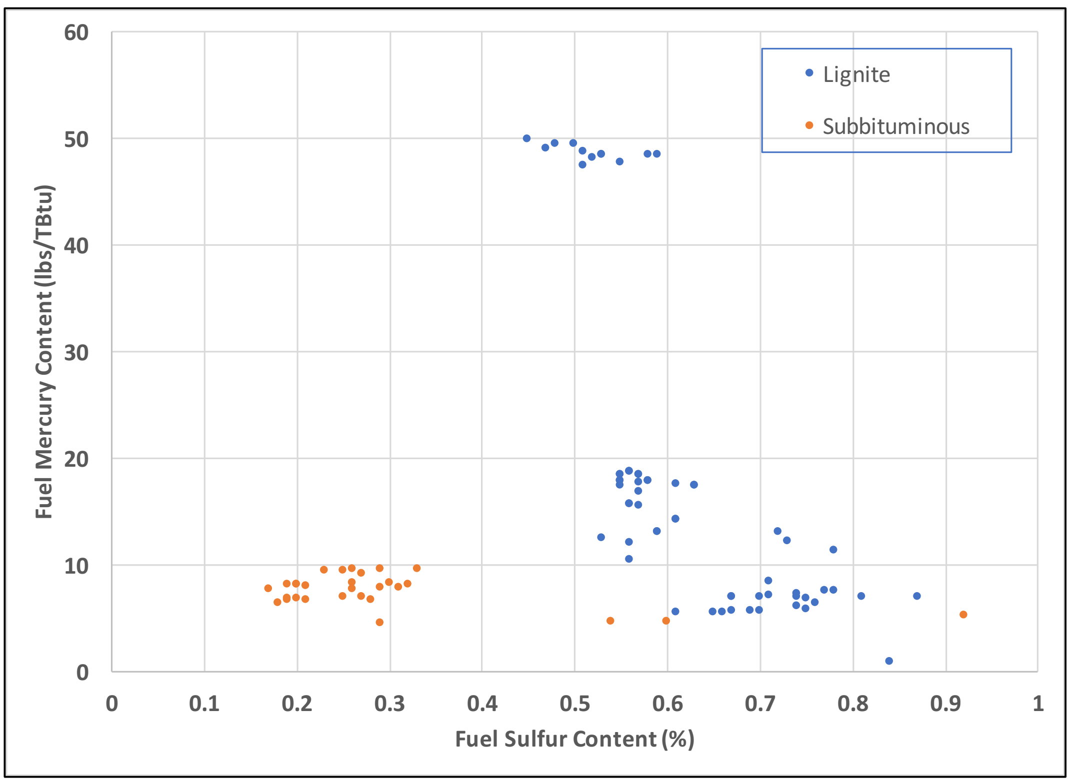

Figure 6-8. Lignite Hg and Sulfur Content Variability: 2021 EIA Submission

An additional factor is the amount of "inherent" alkalinity compared to sulfur – with higher value surpassing the SO_3 content in flue gas. As introduced previously, one metric of this feature is the ratio of Na and Ca to sulfur – on a mole basis.

Figures 6-3 and 6-7 show North Dakota and Gulf Coast lignite present a similar ratio of alkalinity to sulfur content as does PRB – approximating a value of 2. By this metric, lignite fuels in Figure 6-3 present similar means to "buffer" SO_3 as PRB. Notably, Texas lignite in Figure 6-7 is disadvantaged in this metric as the alkalinity to sulfur ratio is half that of PRB – reducing the buffering" effect of inherent ash.

Consequently, the higher sulfur content of lignite combined with equal or lower total alkali relative to sulfur allows measurable levels of SO_3 in lignite-generated flue gas, as evidenced by field measurements. EPA does not recognize this distinguishing difference, and states the following regarding lignite and subbituminous coal:[30]

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 demonstrate compliance with 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.

This passage contains two major flaws – that the effectiveness of Hg removal techniques with PRB-generated flue gas can be replicated with lignite, and that average annual Hg emission rates are the metric for comparison. EPA fails to recognize that Hg removal in PRB is in the presence of very little (essentially unmeasurable) SO_3, and 30-day rolling averages exhibit variability not captured by the annual average.

6.3.2 SO_3: Inhibitor to Hg Removal

The ability of SO_3 to interfere with sorbent Hg removal is well-known.[31] Most notably, EPA's contractor for the technology assessments used in the IPM[32] – Sargent & Lundy –for EPA issued assessment on Hg control technology. This document states[33]

With flue gas SO3 concentrations greater than 5 - 7 ppmv, the sorbent feed rate may be increased significantly to meet a high Hg removal and 90% or greater mercury removal may not be feasible in some cases. Based on commercial testing, capacity of activated carbon can be cut by as much as one half with an SO3 increase from just 5 ppmv to 10 ppmv.

This passage from the S&L technology assessment – funded by EPA to support the IPM model - describes that Hg absorption capacity of carbon can be cut in half by an increase in SO_3 from 5 to 10 ppm. In addition, the presence of SO_3 asserts a secondary role in terms of gas temperature – units with measurable SO_3 are designed with higher gas temperature at the air heater exit – typically where sorbent is injected – to avoid corrosion. Special-purpose tests on a fabric filter

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[30] Tech Memo page 21
[31] Sjostrom 2019. See graphics 21-25
[32] Documentation for EPA's Power Sector Modeling Platform v6: Using the Integrated Planning Model, May 2018.
[33] IPM Model – Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology, Prepared by Sargent & Lundy, Project 12847-002, March 2013.

pilot plant showed an increase in gas temperature from 310ºF to 340ºF lowered sorbent Hg removal from 81% to 68%.[34] The role of SO_3 is not considered in assumed carbon injection rates for EPA's economic analysis in Tables 12 and 13 of the Tech Memo.

Publicly available field test data demonstrate the role of SO_3 on carbon sorbent effectiveness. Figure 6-9 presents results from a lignite-fired plant describing Hg removal across the ESP with sorbent injection.[35] This 900 MW unit is reported to fire a higher sulfur lignite in which more than 20 ppm of SO_3 in flue gas is observed preceding the air heater, subsequently decreasing to 10 ppm SO_3 existing the air heater.

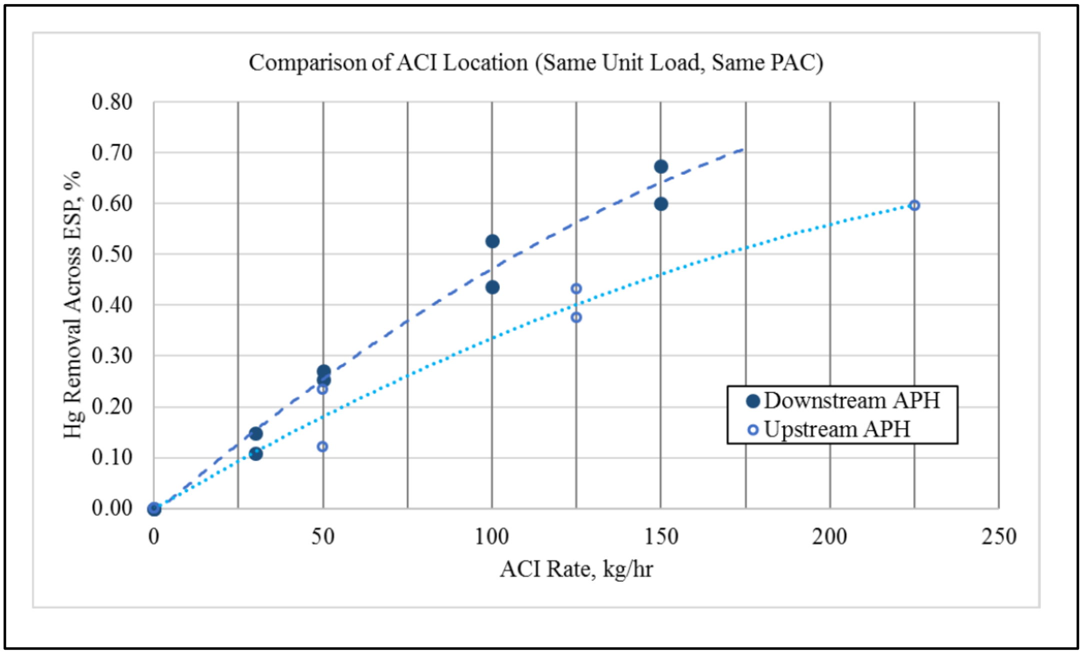

Figure 6-9. Sorbent Hg Removal in ESP in Lignite-Fired Unit: Effect of Injection Location

Data in Figure 6-9 show the role of SO_3 in compromising sorbent performance - highest Hg removal is attained with lower SO_3 (downstream APH) with 60-68% Hg removal achieved (at an injection rate corresponding to 0.6 lbs/MACF).

Attaining a total system 92% Hg removal – the target as described by EPA – is likely not achievable given the trajectory of the curves as shown in Figure 6-9.

6.4 EPA Cost Calculations Ignore FGD

EPA ignores the major role of wet or dry FGD in removing Hg – a fundamental flaw in their analysis. EPA's premise that sorbent addition is the sole compliance technology is incorrect – 18 of 22 units in the lignite fleet listed in Table 9 of the RTR Tech Memo are equipped with FGD.

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[34] Sjostrom 2016. See graphic 16.

[35] Satterfield, J., Optimizing ACI Usage to Reduce Costs, Increase Fly Ash Quality, and Avoid Corrosion, presentation to the Powerplant Pollutant and Effluent Control Mega Symposium, August, 2018.

Of these 18 units, 4 are equipped with dry FGD and 14 with wet FGD. This process equipment asserts a major role in Hg removal as discussed in the next section.

The calculation of cost-effectiveness for the model plant as presented in Section (e)(i) of the RTR Tech memo addresses only sorbent addition, thus does not reflect the Hg compliance strategy of 18 units in the lignite fleet. EPA assumes (a) upgrade of sorbent from "conventional" activated carbon to the halogenated form, and (b) increasing sorbent injection from 2.5 to 5.0 lbs/MAFH elevates Hg reduction from 73% to 92%.[36] This assumption is not relevant – at least in this specific form – to 18 of 22 units in the lignite fleet, as wet or dry FGD will contribute to Hg removal. EPA's approach could underestimate the cost per ton incurred, as tons of Hg removed by the FGD could be credited to sorbent injection (the denominator of the $/ton calculation is larger than it should be).

The variable of FGD Hg removal cannot be ignored, and undermines the legitimacy of the cost estimates as Hg removed by FGD cannot be ascribed to sorbent injection. Thus, depending on how or if the sorbent injection rate changes, costs could increase beyond EPA's estimate (as the denominator in the $/ton calculation is reduced.

6.5 Conclusions

- EPA's proposal that Hg emissions of 1.2 lbs/TBtu can be attained for lignite-fired units by increasing sorbent injection rate and adding halogens (to compensate for loss of refined coal) is incorrect, as it assumes sorbent injection Hg removal observed with PRB is achievable on lignite.

- Flue gas generated from lignite exhibits measurable SO_3 in quantities that– as summarized by EPA's contractor for IPM model inputs - reduce the effectiveness of sorbent by 50% and in some cases presents a barrier to 90% Hg removal.

- Accounting for the variability of Hg content in lignite for most North Dakota and Texas lignite fuels, more than 90% Hg removal is required to meet 1.2 lbs/MBtu, exceeding the nominally 80% removal estimated by EPA, and over a 30-day rolling average basis is unlikely to be attained.

- EPA's calculation of cost–effectiveness for lignite fuels ignores the role of FGD, present in 18 of the 22 reference stations, in removing Hg. The result of this erroneous assumption could be an under-estimation of the cost for additional Hg removal.

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[36] EPA uses the incorrect constant in the calculation of gas flow rate to translate sorbent injection from a mass per time basis (lb//hr) to mass per unit volume of gas (lbs/MACF). The calculation on page 24 uses the value of 9,860 scf/MBtu to quantify flue gas generated from lignite coal. Per EPA-454/R-95-015 (Procedure for Preparing Emission Factor Documents, OAQPS, November 1997) this value reflects the dry volume of gas produced from lignite coal, per MBtu. The flue gas rate that is processed by the environmental controls is the authentic "wet" basis and about 20% higher per MBtu (12,000 scf/MBtu). Use of the correct, latter constant lowers the value of sorbent per MACF by the same magnitude.

7. Mercury Emissions: Non-Low Rank Fuels

Section 7 addresses EPA's proposal to retain the present Hg limit of 1.2 lbs/TBtu for units firing bituminous and subbituminous coals.

EPA recognizes that Hg emission rates - as determined on an annual average basis - have decreased significantly since the initial MATS rule was issued, with bituminous–fired units averaging 0.4 lbs/TBtu (and ranging between 0.2 and 1.2 lbs/TBtu) and subbituminous-fired units averaging 0.6 lbs/TBtu (ranging between 0.1 to 1.2 lbs/TBtu).[37] EPA states these Hg emission rates represent between a 77 and 98% Hg removal from an assumed Hg inlet value of 5.5 lbs/TBtu. EPA notes they did not acquire detailed information on compliance steps such as the type of sorbent injected, the rate of sorbent injection, and the role of SCR NOx control and wet FGD and the myriad factors that determine Hg removal "co-benefits."

This section addresses the reported Hg removal and basis for EPA's position.

7.1 Hg Removal

EPA's discussion of the annual average of Hg removal does not consider the 30-day rolling average, the more challenging metric to attain – and the metric mandated for compliance. The 30-day rolling average reflects variability in Hg coal content and process conditions, both of which can experience daily or hourly changes, which obviously is not captured in annual averages.

Figures 7-1 and 7-2 report two metrics of Hg emission rate variability.[38] Figure 7-1 presents the mean and standard deviation of Hg annual average emissions for eleven categories of control technology and fuel rank. For six of these eleven categories, the sum of the mean and the standard deviation approach the Hg limit of 1.2 lbs/TBtu.

Figure 7-2 describes for six categories of control technology and 2 or 3 fuel ranks (depending on the technology) the number of units that for at least one operating day exceed 1.2 lbs/TBtu on a 30-day rolling average. Figure 7-2 shows for all categories of control technology and fuel rank experience 10% to 20% of units exceed this 30-day average.

In summary, EPA's report of annual Hg emission rate - significantly reduced compared from 2012 – does not provide a basis for further reductions as annual data does not account for variability.

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[37] Prepublication Version, page 85

[38] Cichanowicz, J. E. et. al., Mercury Emissions Rate: The Evolution of Control Technology Effectiveness, Presented at the Power Plant Pollutant and Effluent Control MEGA Symposium: Best Practices and Trends, August 20-23, 2018, Baltimore, MD.

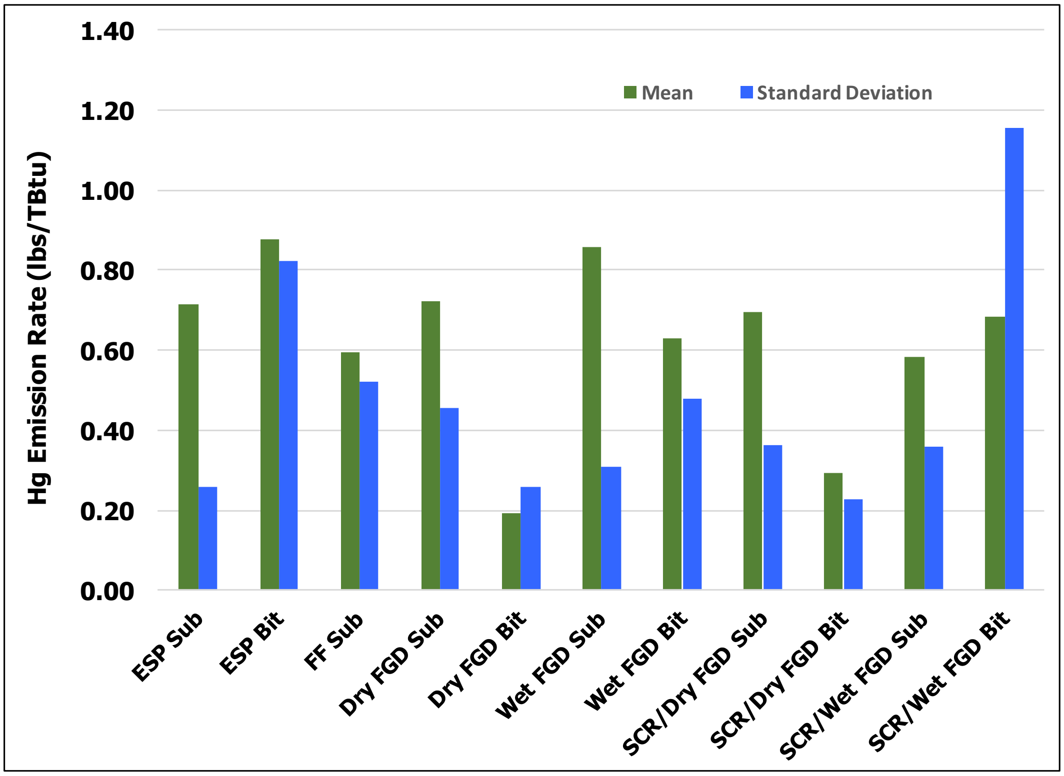

Figure 7-1. Mean, Standard Deviation of Annual Hg Emissions: 2018

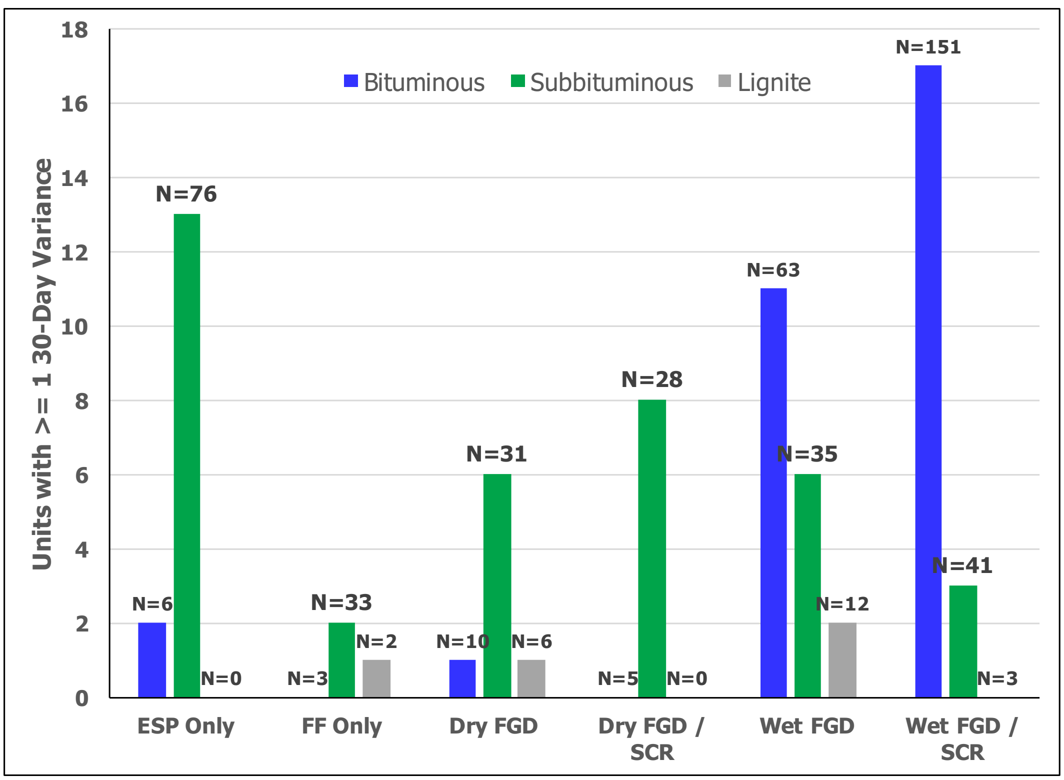

Figure 7-2. Mean, Standard Deviation of Annual Hg Emissions: 2018

7.2 Role of Fuel Composition and Process Conditions

Hg emissions are defined by variability in coal composition and process conditions, the latter including sorbent type, and injection rate, and the "co-benefit" Hg removal imparted by SCR NOx control and wet or dry FGD.

Although EPA did not elicit detailed process information from owners via Section 114, several key insights are presented in a 2018 survey conducted by ADA.[39]

7.2.1 Coal Variability

EPA cites observing for Hg emissions "a control range of 98 to 77 percent (assuming an average inlet concentration of 5.5 lb/TBtu)."[40] It is not clear if EPA assigns the average Hg content value of 5.5 lbs/TBtu to both bituminous and subbituminous coal, or solely the latter.

Figure 7-3 shows an average value of 5.5 lbs/TBtu does not represent either coal rank well. Figure 7-3 presents – on an annual average basis – data from more than 70 units reporting Hg content to the EIA. Numerous units report up to 10 lbs/TBtu - almost twice the average value EPA assigns, with 10 additional units reporting Hg content exceeding 10 lbs/TBtu. Northern Appalachian bituminous coals appear to contain higher Hg content than coals from other regions.

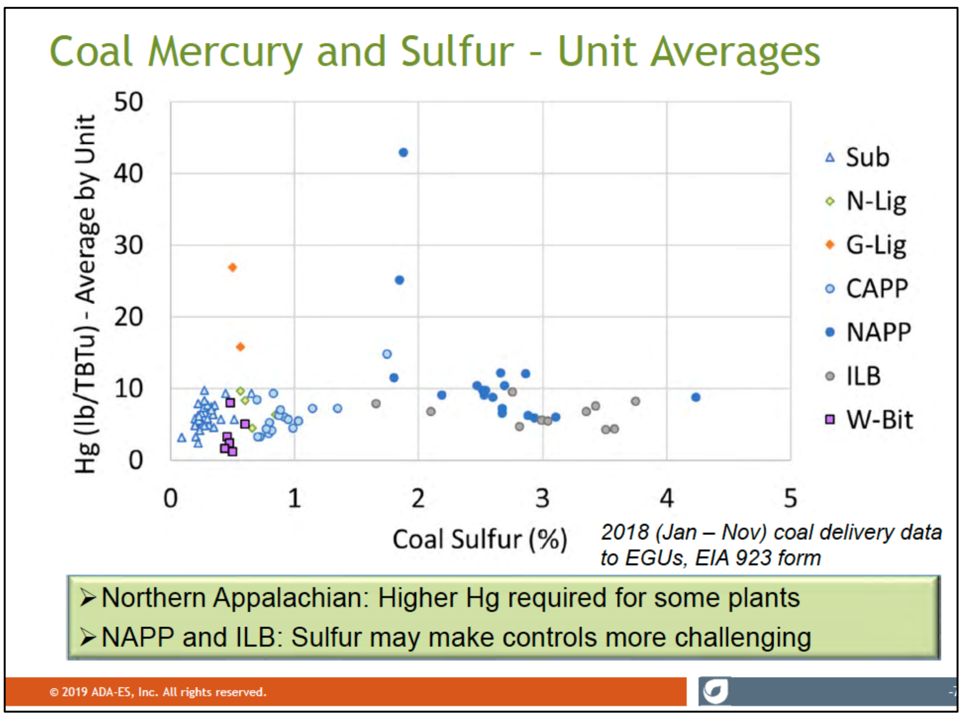

Figure 7-3. Annual Average of Fuel Hg, Sulfur Content in Coal

[39] Sjostrom, S. et. al., Mercury Control in the U.S.: 2018 Year in Review
[40] RTR Tech Memo, page 19.

Consequently, EPA's calculation of 98 to 77% Hg removal is likely inaccurate as the assumed coal Hg content is too low.

7.2.2 Process Conditions

The process conditions for Hg removal: sorbent composition, sorbent injection rate, and the "co-benefits" of SCR NOx control and wet FGD are highly variable, due to a combination of factors. The following provides several examples.

Refined Coal. The absence of Refined Coal – no longer a viable option - complicates projecting future Hg emissions. A survey of Hg compliance activities for 2018 reported Refined Coal as a compliance step;[41] EIA fuel records show this trend persisted through 2021. EPA's assumption that adding halogens to the fuel or flue gas compensates for the unavailability of Refined Coal is speculative and without basis. *Without assurances of the benefits from the halogen content of Refined Coal, it is not possible to assess the viability of lowering Hg emissions.*

Sorbent Injection. Sorbent injection is a key compliance step for 70% of subbituminous-fired units, for some augmented with coal additives and Refined Coal. For bituminous-fired units, 18% of coal use is treated by some combination of sorbent injection and coal additives.

As described by EPA, increasing the rate of sorbent injection increases Hg removal – but with diminishing returns as sorbent mass is added. An example of this relationship is provided by full-scale tests at Ameren's PRB-fired Labadie Unit 3. These tests explored the effectiveness of both conventional and brominated activated carbon. These tests, purposely conducted in PRB-generated flue gas to define sorbent performance in the absence of SO_3, show Hg removal of 90% or more is feasible and that halogen addition can lower sorbent rate.[42]

This relationship is complicated by the role of Refined Coal, coal additives, and (as described below) the contribution of "co-benefits". *Devising a reasoned prediction of Hg removal under variable conditions, including coal composition and the impact of changing sorbents is not possible with current available information.*

SCR, FGD Co-Benefits. The capture of Hg by wet FGD – in many cases prompted by the role of SCR catalysts to oxidize elemental Hg – can be a primary mean for Hg capture. However, such co-benefits are highly variable, and depend on the ratio of elemental to oxidized Hg in the flue gas, and the consequential Hg "re-emission" by a wet FGD. There are means to remedy this variability in some instances, but broad success cannot be assured. *Without the specifics of FGD design and operation, Hg removal via wet FGD cannot be predicted.*

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[41] Sjostrom, S. et. al., Mercury Control in the U.S.: 2018 Year in Review. Hereafter Sjostrom 2019.
[42] Senior, C. et. al., *Reducing Operating Costs and Risks of Hg Control with Fuel Additives*, Presentation to the Power Plant Pollutant Control and Carbon Management Mega Symposium, August 16-18, 2016.

Hg Re-Emission. The fate of Hg entering a wet FGD is uncertain.[43] If in the oxidized state, Hg upon entering the FGD solution can (a) remain in solution and be discharged with the FGD-cleansing step of "blowdown" (b) precipitate as a solid and be removed with the byproduct (typically gypsum), or (c) be reduced from the oxidized to the elemental state, thus re-emitted in the flue gas. Several means to minimize Hg re-emission exist, including injection of sulfite and controlling the scrubber liquor oxidation/reduction potential (ORP). These means can limit Hg remission but are additional process steps that are superimposed upon the task of achieving high efficiency SO_2 removal. *The extent these means can be universally applied without compromising SO_2 removal is uncertain.*

Role of Variability Due to Load Changes. An in-plant study showed that increasing load for a wet FGD-equipped unit can elevate Hg re-emission, eventually exceeding 1.2 lbs/TBtu.[44] This observation can be due to loss of the control over the ORP, defined in the previous paragraph as a key factor in FGD Hg removal. Chemical additives can adjust ORP but complete and autonomous control may not be available. For example, in a systematic evaluation of FGD operating variables conducted at a commercial power station, factors such as limestone composition and the extent to which units must operate in zero-water discharge – as perhaps mandated by the pending Effluent Limitation Guideline – can affect ORP and thus Hg-re-emission.[45]

Upsets in wet FGD process conditions can prompt Hg re-emission. Specifically, one observer noted two units that "….experienced a scrubber reemission event causing the mercury stack emissions to increase dramatically above the MATS limit and significantly higher than the incoming mercury in the coal and the event lasting for several days."[46] This high Hg event was eventually remedied over the short-term operation, but long-term performance is not available.

7.3 Conclusions: Mercury Emissions - Non-Low Rank Coals

There is inadequate basis to further lower the Hg emissions rate below the present limit of 1.2 lbs/TBtu, as variability in fuel and process operations outside the control of the operator can elevate emissions to approach or in some cases exceed that rate.

[43] Gadgil, M., 20 Years of Mercury Re-emission – What do we Know?, Presentation to the Power Plant Pollutant Control and Carbon Management Mega Symposium, August 16-18, 2016.
[44] Blythe, G. et. al., Maximizing Co-Benefit Mercury Capture for MATS Compliance on Multiple Coal-Fired Units, Presentation to the Power Plant Pollutant Control and Carbon Management Conference Mega Symposium, August 16-18, 2016.
[45] Blyte, G. et. al., Investigation of Toxics Control by Wet FGD Systems, Presentation to the Power Plant Pollutant Control and Carbon Management Conference Mega Symposium, August 16-18, 2016.
[46] Pavlisch, J. et. al., Managing Mercury Reemission and Managing MATS compliance Using a sorbent Approach, Presentation to the Power Plant Pollutant Control and Carbon Management Conference Mega Symposium, August 16-18, 2016.

8. EPA IPM RESULTS: EVALUATION AND CRITIQUE

EPA used the Integrated Planning Model (IPM) to establish a Baseline Scenario from which to measure compliance impacts of the proposed rule. This Baseline Scenario is premised upon IPM's Post-IRA 2022 Reference Case. In this Post-IRA simulation, IPM evaluated a number of tax credit provisions of the Inflation Reduction Act of 2022 (IRA), which address application of Carbon Capture and Storage (CCS) and other means to mitigate carbon dioxide (CO_2). These are the (i) New Clean Electricity Production Tax Credit (45Y); (ii) New Clean Electricity Investment Credit (48E); Manufacturing Production Credit (45X); CCS Credit (45Q); Nuclear Production Credit (45U); and Production of Clean Hydrogen (45V). Also, the Post-IRA 2022 Reference Case includes compliance with the proposed Good Neighbor Policy (Transport Rule).[47]

A critique of EPA's methodology and findings is described subsequently.

8.1 IPM 2030 Post-IRA 2022 Reference Case: A Flawed Baseline

The IPM Post-IRA 2022 Reference Case for the years 2028 and 2030 comprises a flawed baseline to measure compliance impacts of the proposed rule. This flawed baseline centers around IPM projected coal retirements in both 2028 and 2030 as well as units projected to deploy CCS in 2030. Specifically, IPM has erroneously retired numerous coal units expected to operate beyond 2028 and 2030 based upon current announced retirement plans; consequently, these units are subject to the proposed rule beginning in 2028. There are numerous challenges and limitations to deploying CCS as EPA has projected on 27 coal units in 2030. These units would also be subject to the proposed. Consequently, IPM's compliance impacts of the proposed rule is likely understated.

8.1.1 Analytical Approach

This analysis identifies those units IPM modeled as coal retirements, CCS retrofits and coal to gas (C2G) conversions in both 2028 and 2030, and compares them to announced plans for unit retirements, technology retrofits and C2G conversions. To identify errors for 2028, the parsed file for the 2028 Post-IRA 2022 Reference Case was used. Since EPA did not provide a parsed

[47] In addition to the IRA and GNP, the Post-IRA 2022 Reference Case takes into account compliance with the following: (i) Revised Cross-State Air Pollution Rule (CSAPR) Update Rule; (ii) Standards of Performance for Greenhouse Gas Emissions from New, Modified and Reconstructed Stationary Sources: Electric Utility Generating Units; (iii) MATS Rule which was finalized in 2011; (iv) Various current and existing state regulations; (v) Current and existing RPS and Current Energy Standards; (vi) Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART); and, (vii) Platform reflects California AB 32 and RGGI. Three non-air federal rules affecting EGUs: (i) Cooling Water Intakes (316(b) Rule; (ii) Coal Combustion Residuals (CCR), which reflects EPA's July 29, 2020 position on retrofitting or closure of surface impoundments; and, (iii) Effluent Limitation Guidelines, which includes the 2020 Steam Electric Reconsideration Rule (cost adders were applied starting in 2025).

file of the 2030 Post-IRA 2022 Reference Case, an abbreviated parsed file was created using four different IPM files. These are: (i) 2028 parsed file of the Post-IRA 2022 Reference Case; (ii) Post-IRA 2022 Reference Case RPE File for the year 2030; (iii) Post-IRA 2022 Reference Case RPT Capacity Retrofits File for the year 2030; and, (iv) National Electrical Energy Data System (NEEDS) file for the Post-IRA 2022 Reference Case. These parsed files allow identifying IPM modeled retirements in 2028 and 2030, CCS retrofits in 2030 and C2G in both 2028 and 2030. These modeled retirements and conversions were compared to announced information in the James Marchetti Inc ZEEMS Data Base.

8.1.2 Coal Retirements

The 2028 IPM modeling run retired 112 coal units (53.6 GW) from 2023 to 2028. In the 2030 analysis, IPM retired an additional 52 coal units (25.5 GW). The total number of retirements for the two modeling run years is 164 coal units (79.1 GW).

Table 8-1 summarizes the IPM retirement errors in the 2028 and 2030 modeling runs. Specifically, IPM incorrectly retired 29 coal units (14.0 GW) by 2028 and an additional 23 coal units (14.1 GW) in 2030. In addition, there are 3 coal units (1.6 GW) that EPA listed in the NEEDS file as being retired before 2028 that will operate beyond 2030. In total, there are 55 coal units that IPM erroneously retired in the 2028 and 2030 modeling runs that will be operating and subject to some aspect of the proposed rule beginning in 2028.

Table 8-1. Coal Retirement Errors

Year	Description	Number
2028	Retiring after 2028	29
2030	Retiring after 2030	23
2030	NEEDS retirements that should be in the 2030 modeling platform	3
Total		55

Tables 8-2 to 8-6 lists each of the coal units IPM has incorrectly retired, incorrectly deployed CCS, or switched to natural gas.

Table 8-2. IPM Coal Retirement Errors: 2028 Post-IRA 2022 Reference Case Run

No.	RegionName	StateName	ORISCode	UnitID	PlantName	Capacity	Observation
1	WECC_Arizona	Arizona	6177	U1B	Coronado	380	To be retired by 2032 and continued seasonal curtailemts,
2	SPP West	Arkansas	6138	1	Flint Creek	528	Retire January 1, 2039 - Entergy LL 2023 IRP (March 31, 2023).
3	MISO_Arkansas	Arkansas	6641	1	Independence	809	Agreement with Sierra Club and NPCA to cease coal by Dec 31, 2030.
4	MISO_Arkansas	Arkansas	6641	2	Independence	842	Agreement with Sierra Club and NPCA to cease coal by Dec 31, 2030.
5	SERC_Central_TVA	Kentucky	1379	2	Shawnee	134	TVA planning assumption retirement (5/21) - December 31, 2033
6	SERC_Central_TVA	Kentucky	1379	3	Shawnee	134	TVA planning assumption retirement (5/21) - December 31, 2033
7	SERC_Central_TVA	Kentucky	1379	5	Shawnee	134	TVA planning assumption retirement (5/21) - December 31, 2033
8	SERC_Central_TVA	Kentucky	1379	6	Shawnee	134	TVA planning assumption retirement (5/21) - December 31, 2033
9	SERC_Central_TVA	Kentucky	1379	7	Shawnee	134	TVA planning assumption retirement (5/21) - December 31, 2033
10	SERC_Central_TVA	Kentucky	1379	8	Shawnee	134	TVA planning assumption retirement (5/21) - December 31, 2033
11	SERC_Central_TVA	Kentucky	1379	9	Shawnee	134	TVA planning assumption retirement (5/21) - December 31, 2033
12	MISO_Minn/Wisconsin	Minnesota	6090	3	Sherburne County	876	PSC approved closure (2/8/22). Upper Midwest Resource Plan (6/25/21) for 2030.
13	MISO_Missouri	Missouri	2103	1	Labadie	593	2022 IRP Update retire in 2042 (6/24/22).
14	MISO_Missouri	Missouri	2103	2	Labadie	593	2022 IRP Update retire in 2042 (6/24/22).
15	MISO_Missouri	Missouri	2103	3	Labadie	593	2022 IRP Update (6/24/22) retirement in 2036
16	MISO_Missouri	Missouri	2103	4	Labadie	593	2022 IRP Update (6/24/22) retirement in 2036
17	MISO_Missouri	Missouri	2107	1	Sioux	487	2022 IRP Update (6/24/22) - To be retired in 2030
18	MISO_Missouri	Missouri	2107	2	Sioux	487	2022 IRP Update (6/24/22) - To be retired in 2030
19	SERC_VACAR	North Carolina	2712	3A.3B	Roxboro	694	2022 Carbon Reduction Plan per PSC retirement Jan. 1, 2028-34 (12/30/22).
20	SERC_VACAR	North Carolina	2712	4A, 4B	Roxboro	698	2023 Carbon Reduction Plan per PSC retirement Jan. 1, 2028-34 (12/30/22).
21	ERCOT_Rest	Texas	298	LIM1	Limestone	831	EIA 860 has retirement December 2029
22	ERCOT_Rest	Texas	298	LIM2	Limestone	858	EIA 860 has retirement December 2029
23	WECC_Utah	Utah	7790	1-1	Bonanza	458	Unit is planned to retire in 2030,
24	WECC_Utah	Utah	8069	2	Huntington	450	Retire in 2032 - 2023 IRP (3/31/23)
25	PJM_Dominion	Virginia	7213	1	Clover	440	Dominion 2023 IRP - Retirement Date 2040 (5/1/23)
26	PJM_Dominion	Virginia	7213	2	Clover	437	Dominion 2023 IRP - Retirement Date 2040 (5/1/23)
27	PJM_AP	West Virginia	3943	1	Fort Martin	552	EPA Settlement on wastewater upgrades (8/9/22). 2020 IRP through 2035
28	PJM_AP	West Virginia	3943	2	Fort Martin	546	EPA Settlement on wastewater upgrades (8/9/22). 2020 IRP through 2036
29	WECC_Wyoming	Wyoming	6101	BW91	Wyodak	332	Retire in 2039 - IRP (3/31/23)

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Table 8-3. IPM Coal Retirement Errors: 2030 Post IRA 2022 Reference Case Modeling Run

No.	RegionName	StateName	ORISCode	UnitID	PlantName	Capacity	Observations
1	WECC_Arizona	Arizona	6177	U2B	Coronado	382	To be retired by 2032 and contined seasonal curtailments
2	FRCC	Florida	628	4	Crystal River	712	To be retired in 2034 (2020 Sustainability Report)
3	FRCC	Florida	628	5	Crystal River	710	To be retired in 2034 (2020 Sustainability Report)
4	SERC_Southeastern	Georgia	6257	1	Scherer	860	ELG Compliance - Wastewater Treatment - No Announced Retirement
5	SERC_Southeastern	Georgia	6257	2	Scherer	860	ELG Compliance - Wastewater Treatment - No Announced Retirement
6	PJM West	Indiana	1040	1	Whitewater Valley	35	Biased to peak load duty. 2020 IRP Base Case has retirement May 31, 2034
7	MISO_Iowa	Iowa	1167	9	Muscatine Plant #1	163	ELG compliance options for FGDW and BATW, possible 2028 retirement
8	SPP North	Kansas	6068	1	Jeffrey Energy Center	728	To be retired at the end of 2039 (2021 IRP)
9	SPP North	Kansas	1241	2	La Cygne	662	To be retired at the end of 2039 (2021 IRP)
10	SERC_Central_Kentucky	Kentucky	1356	1	Ghent	474	To be retired 2034
11	SERC_Central_Kentucky	Kentucky	1356	3	Ghent	485	To be retired 2037.
12	SERC_Central_Kentucky	Kentucky	1356	4	Ghent	465	To be retired 2037.
13	SPP North	Missouri	6065	1	Iatan	700	To be retired at the end of 2039 (2021 IRP)
14	SPP North	Missouri	6195	1	John Twitty	184	Beyond 2030 retirement date - new 2022 IRP
15	SERC_VACAR	North Carolina	8042	1	Belews Creek	1110	1/1/2036 retirement per 2022 Carbon Reduction Plan
16	SERC_VACAR	North Carolina	8042	2	Belews Creek	1110	1/1/2036 retirement per 2022 Carbon Reduction Plan
17	SERC_VACAR	North Carolina	2727	3	Marshall (NC)	658	2022 Carbon Reduction Plan accepted by PSC retirement Jan. 1, 2033 (12/30/22)
18	SERC_VACAR	North Carolina	2727	4	Marshall (NC)	660	2022 Carbon Reduction Plan accepted by PSC retirement Jan. 1, 2033 (12/30/22)
19	MISO_MT, SD, ND	North Dakota	8222	B1	Coyote	429	Active perl reliablity concerns in MISO. End of depreciable life - 2041
20	SERC_VACAR	South Carolina	6249	1	Winyah	275	2023 IRP: operate unit through 2030 for reliability (4/19/23)
21	SERC_VACAR	South Carolina	6249	2	Winyah	285	2024 IRP: operate unit through 2030 for reliability (4/19/23)
22	SERC_VACAR	South Carolina	6249	3	Winyah	285	2025 IRP: operate unit through 2030 for reliability (4/19/23)
23	SERC_VACAR	South Carolina	6249	4	Winyah	285	2026 IRP: operate unit through 2030 for reliability (4/19/23)
24	PJM West	West Virginia	3935	1	John E Amos	800	Approved ELG upgrades to keep plant open until 2040.
25	PJM West	West Virginia	3935	2	John E Amos	800	Approved ELG upgrades to keep plant open until 2040.
26	PJM_AP	West Virginia	3954	1	Mt Storm	554	Dominion 2023 IRP - Retirement Date 2044 (5/1/23)
27	PJM_AP	West Virginia	3954	2	Mt Storm	555	Dominion 2023 IRP - Retirement Date 2044 (5/1/23)

Table 8-4 Units in the NEEDS to Be Operating in 2028

No.	Region Name	State Name	ORIS Plant	Unit ID	Plant Name	Capacity (MW)	NEEDS Retirement Year	Observations
1	SPP_N	Kansas	1241	1	La Cygne	736	2025	2022 IRP Update to be retired in 2032
2	MIS_LA	Louisiana	6190	3-1, 3-2	Brame Energy Center	626	2027	No plans to retire. Evaluating CCS
3	WECC_WY	Wyoming	4158	BW44	Dave Johnston	330	2027	Retire in 2039 - 2023 IRP (3/31/23).

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Table 8-5 Units IPM Predicts CCS By 2030

No.	Region Name	StateName	ORISCode	UnitID	PlantName	Capacity	Observations
1	ERCOT_Rest	Texas	6179	3	Fayette Power Project	286.05	
2	ERCOT_Rest	Texas	7097	BLR2	J K Spruce	537.93	Board voted to convert to natural gas by 2027 (1/23/23)
3	ERCOT_Rest	Texas	6180	1	Oak Grove (TX)	572.77	
4	ERCOT_Rest	Texas	6180	2	Oak Grove (TX)	570.97	
5	ERCOT_Rest	Texas	6183	SM-1	San Miguel	237.74	
6	FRCC	Florida	645	BB04	Big Bend	292.27	
7	MISO_Indiana	Indiana	6113	1	Gibson	594.24	
8	PJM West	Kentucky	6018	2	East Bend	399.00	
9	PJM West	West Virginia	3948	1	Mitchell (WV)	537.77	
10	PJM West	West Virginia	3948	2	Mitchell (WV)	537.77	
11	SERC_Southeastern	Alabama	6002	4	James H Miller Jr	477.05	
12	SPP_WAUE	North Dakota	6469	B1	Antelope Valley	289.22	
13	SPP_WAUE	North Dakota	6469	B2	Antelope Valley	288.38	
14	SPP_WAUE	North Dakota	2817	2	Leland Olds	279.16	
15	WECC_Arizona	Arizona	8223	3	Springerville	281.05	
16	WECC_Arizona	Arizona	8223	4	Springerville	281.05	
17	WECC_Colorado	Colorado	470	3	Comanche (CO)	501.15	To be retired Dec 31 2030 (10/31/22)
18	WECC_Colorado	Colorado	6021	C3	Craig (CO)	305.66	To be retired Dec 2029 - Electric Resource Plan (12/1/20)
19	WECC_Utah	Utah	6165	1	Hunter	319.80	Retire in 2031- 2023 IRP (3/31/23)
20	WECC_Utah	Utah	6165	2	Hunter	292.44	Retire in 2032 - 2023 IRP (3/31/23).
21	WECC_Utah	Utah	6165	3	Hunter	314.06	Retire in 2032 - 2023 IRP (3/31/23).
22	WECC_Utah	Utah	8069	1	Huntington	311.54	Retire in 2032 - 2023 IRP (3/31/23).
23	WECC_Wyoming	Wyoming	8066	BW73	Jim Bridger	354.02	Convert to natural gas in 2030 - 2023 IRP (3/31/23)
24	WECC_Wyoming	Wyoming	8066	BW74	Jim Bridger	349.78	Convert to natural gas in 2030 - 2023 IRP (3/31/23)
25	WECC_Wyoming	Wyoming	6204	1	Laramie River Station	385.22	
26	WECC_Wyoming	Wyoming	6204	2	Laramie River Station	382.92	
27	WECC_Wyoming	Wyoming	6204	3	Laramie River Station	383.45	

Table 8-6 Units IPM Erroneously Predicts Switch to Natural Gas

No.	RegionName	StateName	ORISCode	UnitID	PlantName	Year	Capacity	Observations
1	SPP West (Oklahoma,	Arkansas	56564	1	John W Turk Jr Power Plant	2030	609	Retire Jan 1, 2068 - SWEPCO 2023 IRP (March 29, 2023)
2	PJM West	Kentucky	6041	2	H L Spurlock	2028	510	No announced C2G or co-firing
3	ERCOT_Rest	Texas	56611	S01	Sandy Creek Energy Station	2030	933	No announced conversion

8.1.3 Coal CCS

Table 8-5 identifies the 27 units IPM projected to retrofit CCS by 2030; none of these have been involved in any Front-End Engineering and Design (FEED) Studies. However, 9 of the units identified by IPM will be either be retired or converted to natural gas in and around 2030. There are major questions addressing infrastructure and project implementation that present challenges to IPM's CCS projection for 2030. Indeed, it is next to impossible for these units to be in position to retrofit CCS by 2030.

8.1.4 Coal to Gas Conversions (C2G)

The 2028 IPM modeling run converted 36 coal units to gas (14.3 GW). In the 2030 IPM modeling run an additional 2 coal units (1.5 GW) were converted to gas (Turk and Sandy Creek). As shown in Table 8.6, three of these units have no announced plans to convert to gas by 2028 or 2030 and will be subject to the proposed rule.

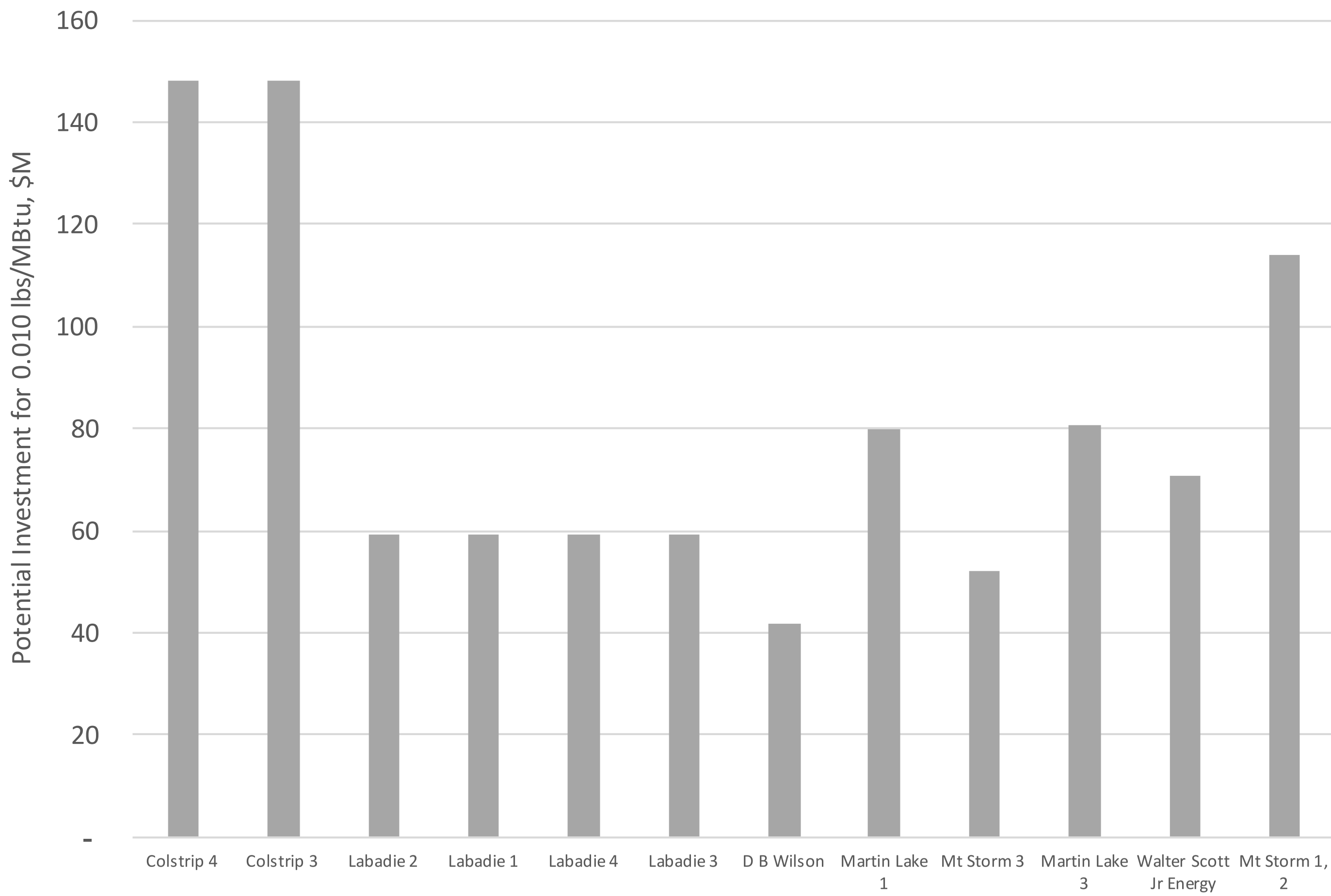
8.2 Summary

The major issues associated with EPA's IPM modeling of the 2028 and 2030 Post-IRA 2022 Reference Case are summarized as follows:

- The 2028 and 2030 Baseline (Post-IRA 2022 Reference Case) used to measure the compliance impacts of proposed rule is flawed and needs to be revised
- Most notably, IPM erred in retiring 55 coal units that will be subject to the proposed rule beginning in 2028.
- IPM retrofitted 27 units with CCS in 2030, 19 of which will be subject to the proposed rule. It is next to impossible for these units to retrofit CCS by 2030.
- The IPM modeled compliance impacts for the proposed rule in 2028 and 2030 is very likely understated.

Appendix A: Additional Cost Study Data

Figure A-1. Unit ESP Investment (per EPA's Cost Assumptions): PM of 0.010 lbs/MBtu



Note: Colstrip costs reflect EPA's approch of retrofitting a fabric filter, as an ESP is not installed at that site.

Table A-1. Technology Assignment for 0.010 lbs/MBtu PM Rate: Industry Study

ESP Minor	ESP Typical	ESP Major Upgrade	FF Cleaning	FF Retrofit
Alcoa/Warrick	East Bend	D B Wilson	Boswell Energy Center	Colstrip 3, 4
Big Bend	General James M Gavin	Labadie	Clover Power Project	
Coronado	Gibson	Labadie	Ghent	
Coronado	Martin Lake 2	Labadie	Gilberton Power/John B Rich	
Crystal River	Milton R Young	Labadie	H L Spurlock	
Crystal River	Mt Storm	Martin Lake 1	Iatan	
Jeffrey Energy Center	Mt Storm		Marion	
Laramie River Station			Mt Carmel Cogen	
Martin Lake			St Nicholas Cogen Project	
San Miguel			Walter Scott Jr Energy Center	
Seminole			WPS Westwood Generation LLC	

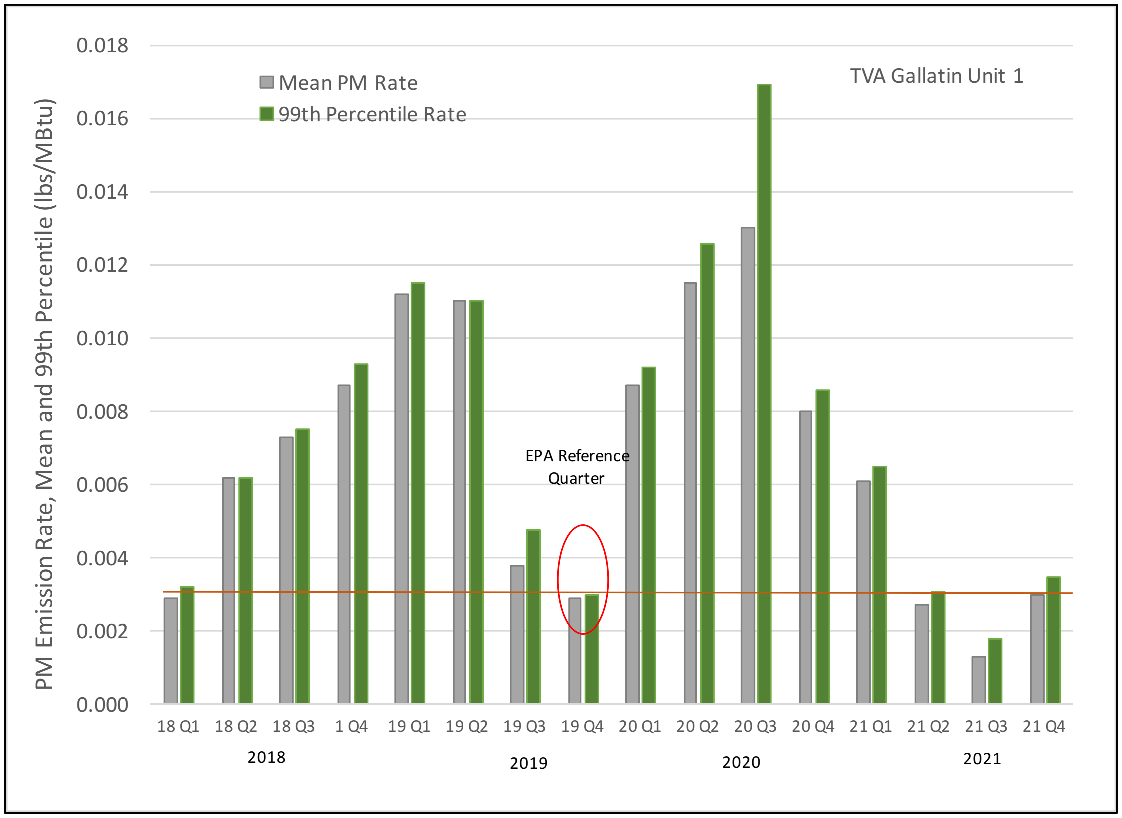
Table A-2 Technology Assignment for 0.006 lbs/MBtu PM Rate: Industry Study

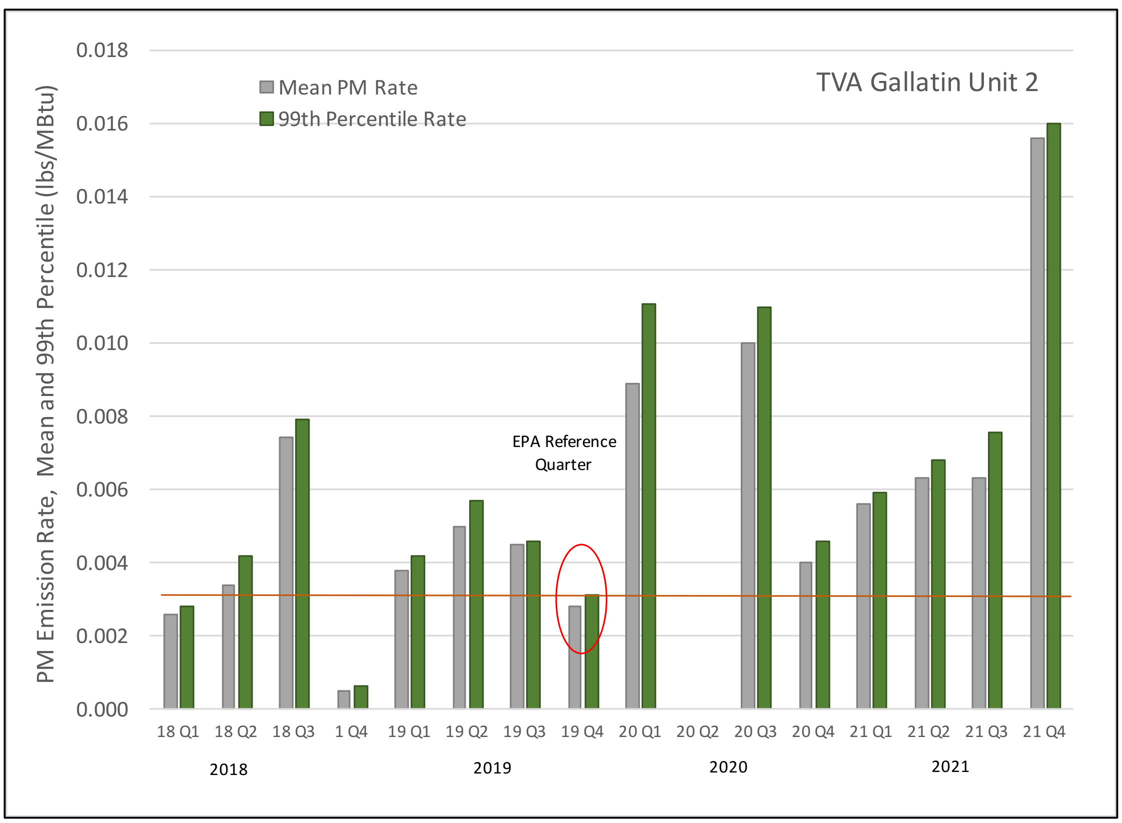
FF O&M Enhancement	FF Retrofit	FF Retrofit
Antelope Valley	Alcoa/Warrick	Laramie River Station
Bonanza	Belews Creek	Leland Olds 1, 2
Boswell Energy Center Clay Boswell	Big Bend	Martin Lake 1-3
Clover Power Project	Cardinal	Merrimack
Comanche	Colstrip 3, 4	Milton R Young
Ghent	Coronado 1, 2	Monroe 1, 2
Gilberton Power/John B Rich	Crystal River 4, 5	Mt Storm 1, 2
H L Spurlock	D B Wilson	Naughton
Huntington	East Bend	Nebraska City
Iatan	General James M Gavin	R D Green
Louisa	Gibson 1, 3	R S Nelson
Marion	Gibson	Sam Seymour Fayette 1, 2
Mt Carmel Cogen	Independence	San Miguel
Oak Grove 1	IPL - AES Petersburg	Schiller
Sandy Creek Energy Station	James H Miller Jr	Seminole
Scrubgrass Generating 1, 2	Jeffrey Energy Center 1, 2, 3	Trimble County
St Nicholas Cogen Project	Jim Bridger 3, 4	Whelan Energy Center
Twin Oaks Power 1, 2	Labadie 1 -4	White Bluff 1, 2
Walter Scott Jr Energy Center		
Weston		
WPS Westwood Generation LLC		

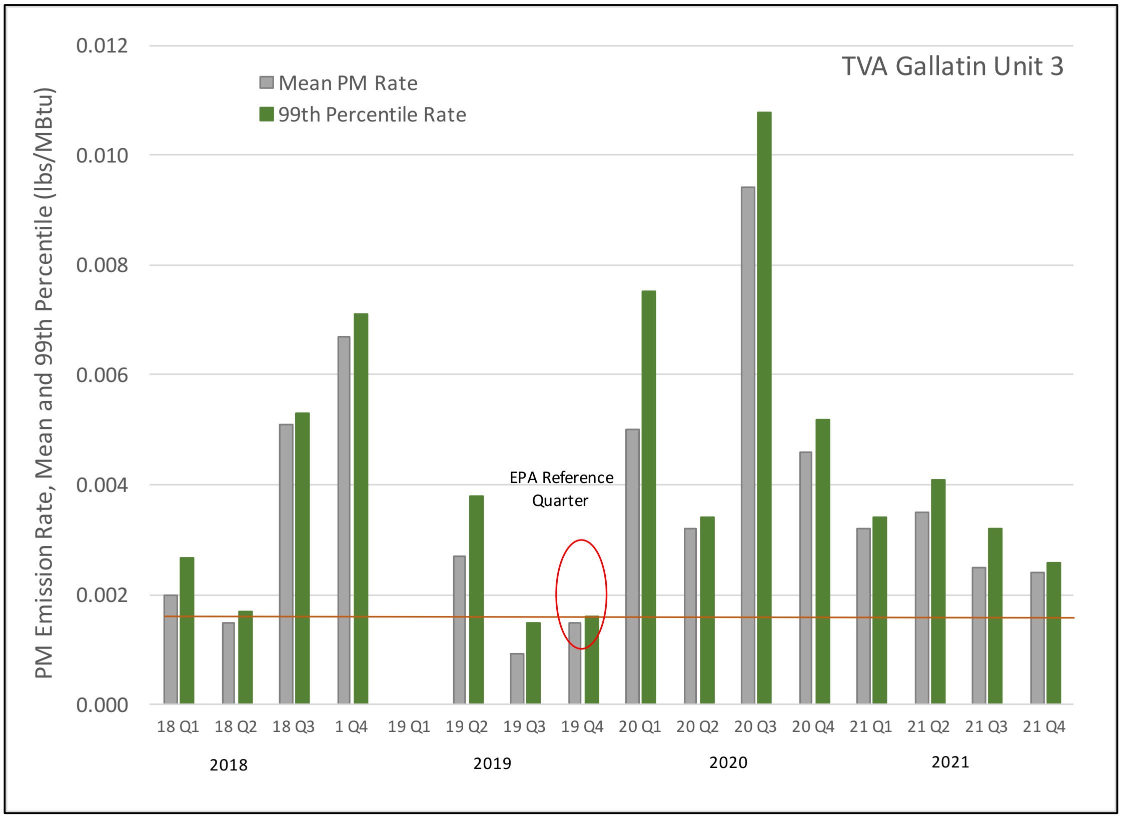
Appendix B: Example Data Chart

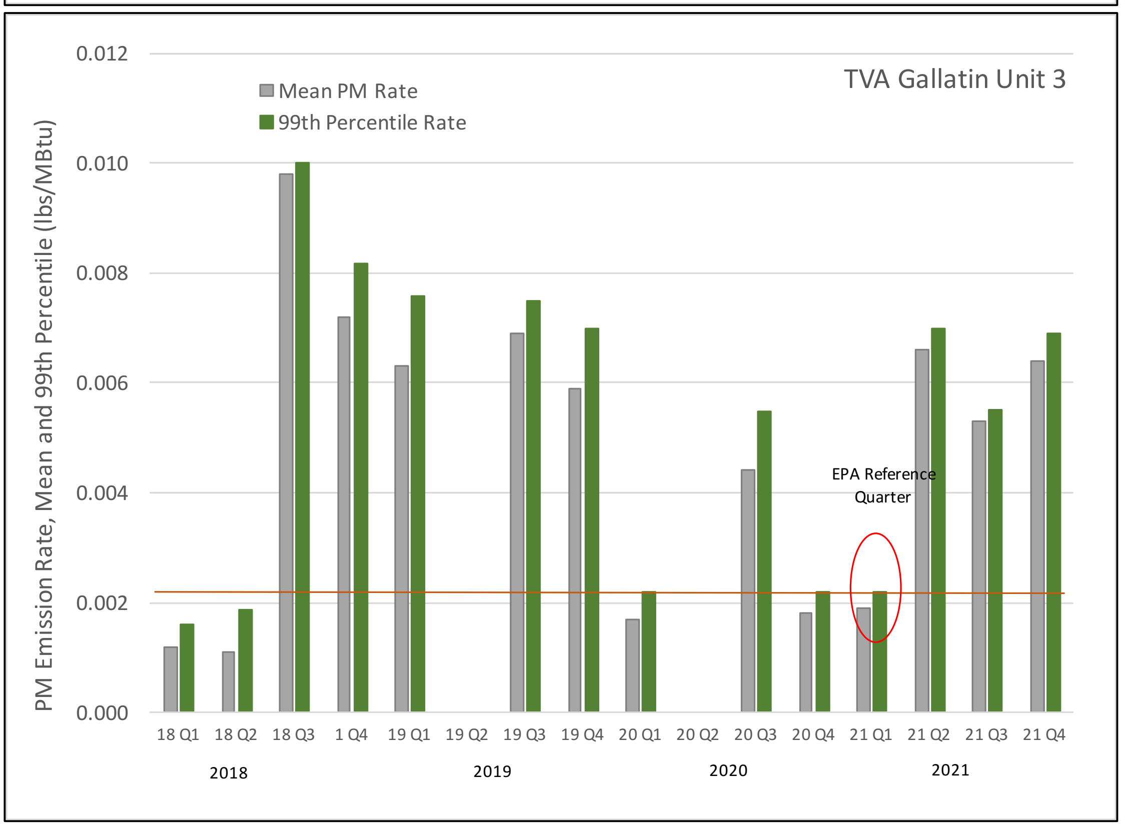
Appendix A presents additional examples of units for which EPA's PM sampling and evaluation approach distorted results. These charts contain both mean and 99th percentile data. Data is presented for the following units, for which observations are offered as follows:

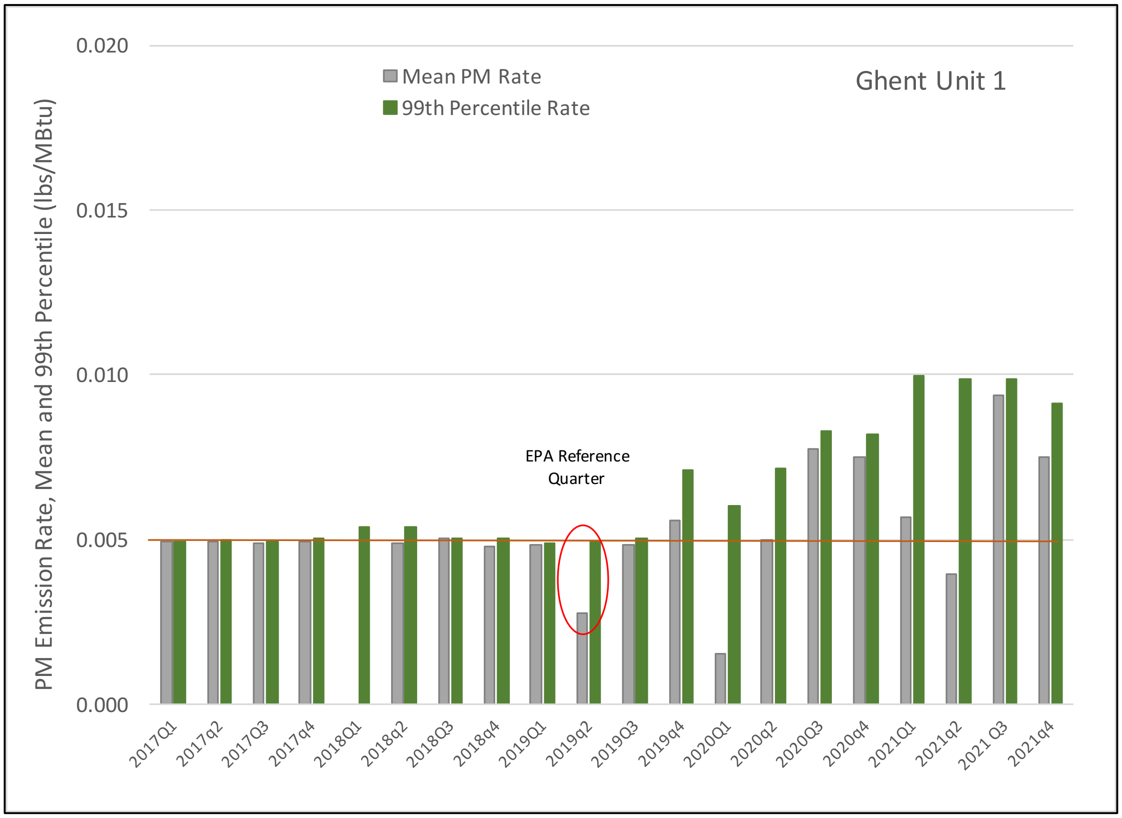
- TVA Gallatin Unit 1. EPA selected 0.0030 lbs/MBtu as the reference PM rate, using Q4 of 2019. Few of the 16 quarters that report lower PM emissions.
- TVA Gallatin Unit 2. EPA selected 0.0031 lbs/MBtu as the reference PM rate, also using Q4 of 2019. Few of the 16 quarters that report lower PM, similar to Unit 1.
- TVA Gallatin Unit 3. EPA selected 0.0016 lbs/MBtu as the reference PM rate, again using Q4 of 2019. Only one quarter (Q3 of 2019) reports lower PM rate.
- TVA Gallatin Unit 4. EPA selected 0.0022 lbs/MBtu as the reference PM rate, using Q1 of 2021. Of the 14 quarters reporting data, two quarters report PM rates equal to this rate, while two are below this rate.
- LG&E/KU Ghent 1. EPA selected 0.005 lbs/MBtu as the reference PM rate, using Q2 of 2019. This PM rate represents that reported in previous quarters, but with one exception all subsequent quarters through 2021 report higher PM.
- LG&E/KU Mill Creek Unit 4. EPA selected 0.0035 lbs/MBtu as the reference PM rate, using Q4 of 2021. With the exception of the previous quarter, this value is the lowest of any reported since 2017 by a significant margin.
- Alabama Power Gaston Unit 5. EPA selected 0.005 lbs/MBtu as the reference PM rate, using Q1 of 2021. Data for this unit is displayed from Q1 2017 through Q4 2022. Of the 24 reporting quarters (1Q 2017 through 4QW 2022) only 6 quarters have lower PM rates.
- Alabama Power Miller Unit 1. EPA selected 0.004 lbs/MBtu as the reference PM rate, using Q3 of 2017. Data for this unit is displayed from Q1 2017 through Q4 2022. The designated rate represents a significant reduction from approximately half of the reporting quarters since Q1 2020.

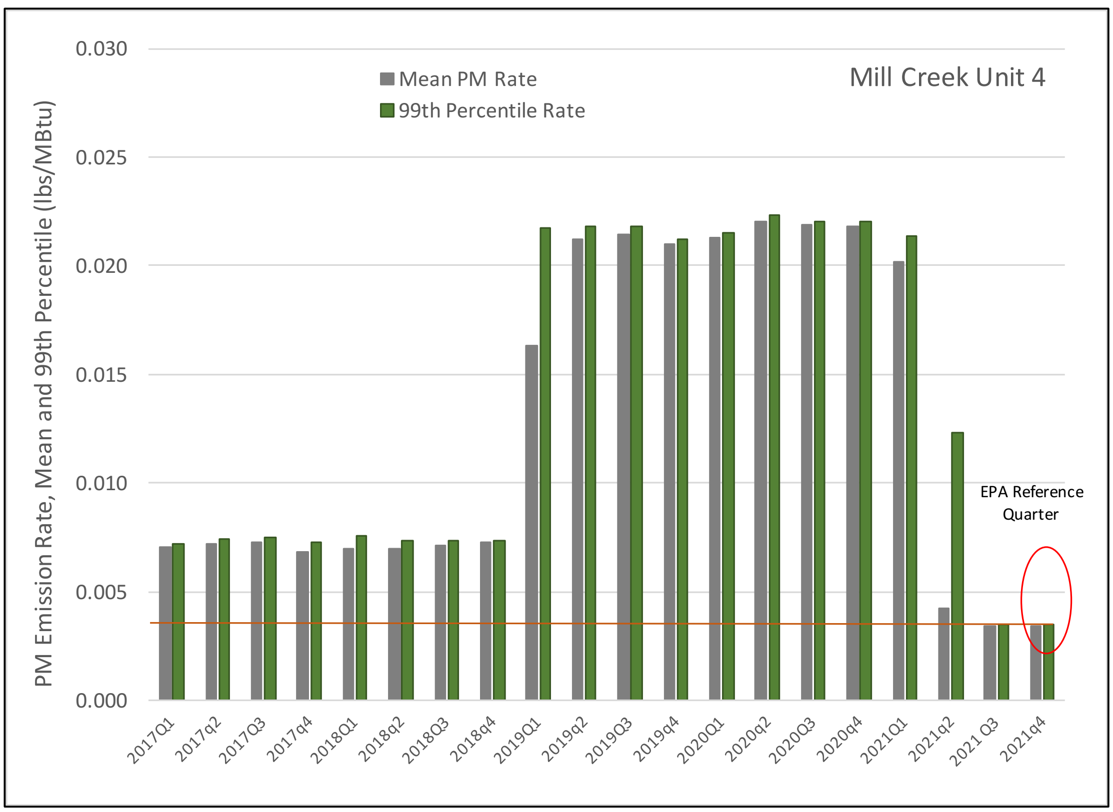

TVA Gallatin Unit 1
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.018
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.000
EPA Reference Quarter
18 Q1 18 Q2 18 Q3 1 Q4 19 Q1 19 Q2 19 Q3 19 Q4 20 Q1 20 Q2 20 Q3 20 Q4 21 Q1 21 Q2 21 Q3 21 Q4
2018
2019
2020
2021

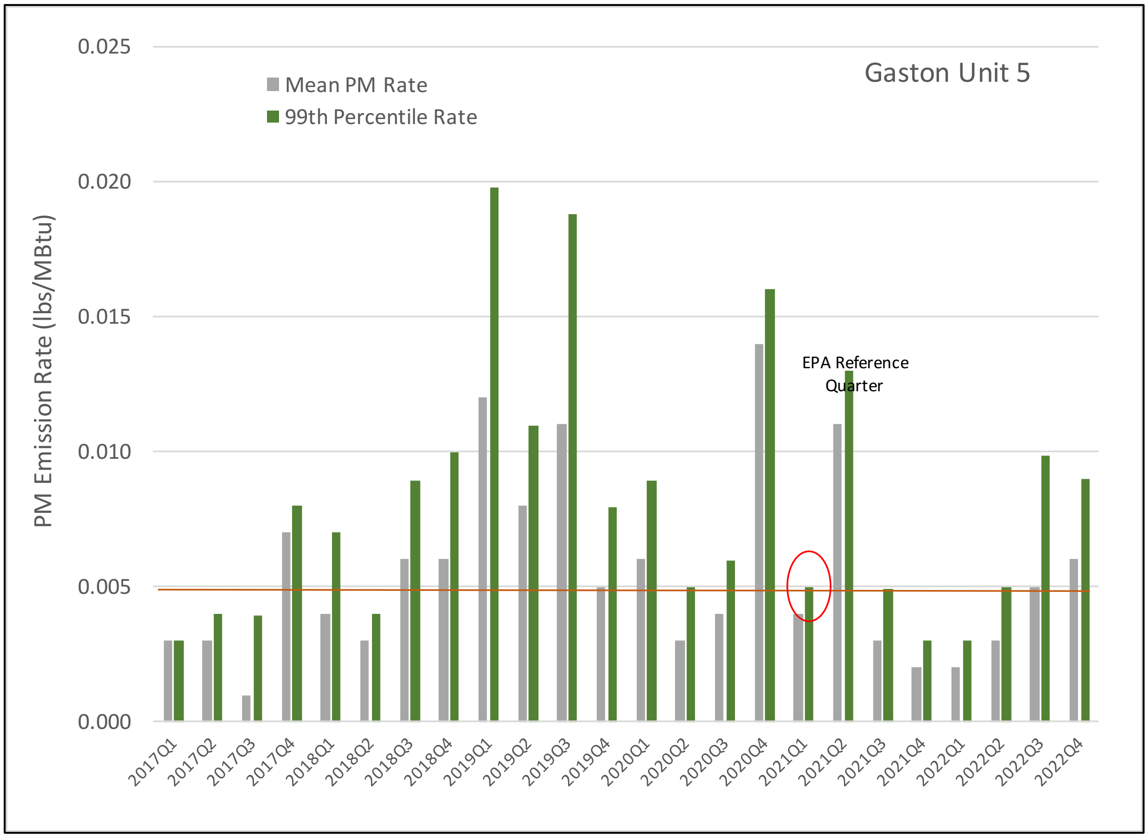

TVA Gallatin Unit 2
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.018
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.000
EPA Reference Quarter
18 Q1 18 Q2 18 Q3 1 Q4 19 Q1 19 Q2 19 Q3 19 Q4 20 Q1 20 Q2 20 Q3 20 Q4 21 Q1 21 Q2 21 Q3 21 Q4
2018
2019
2020
2021

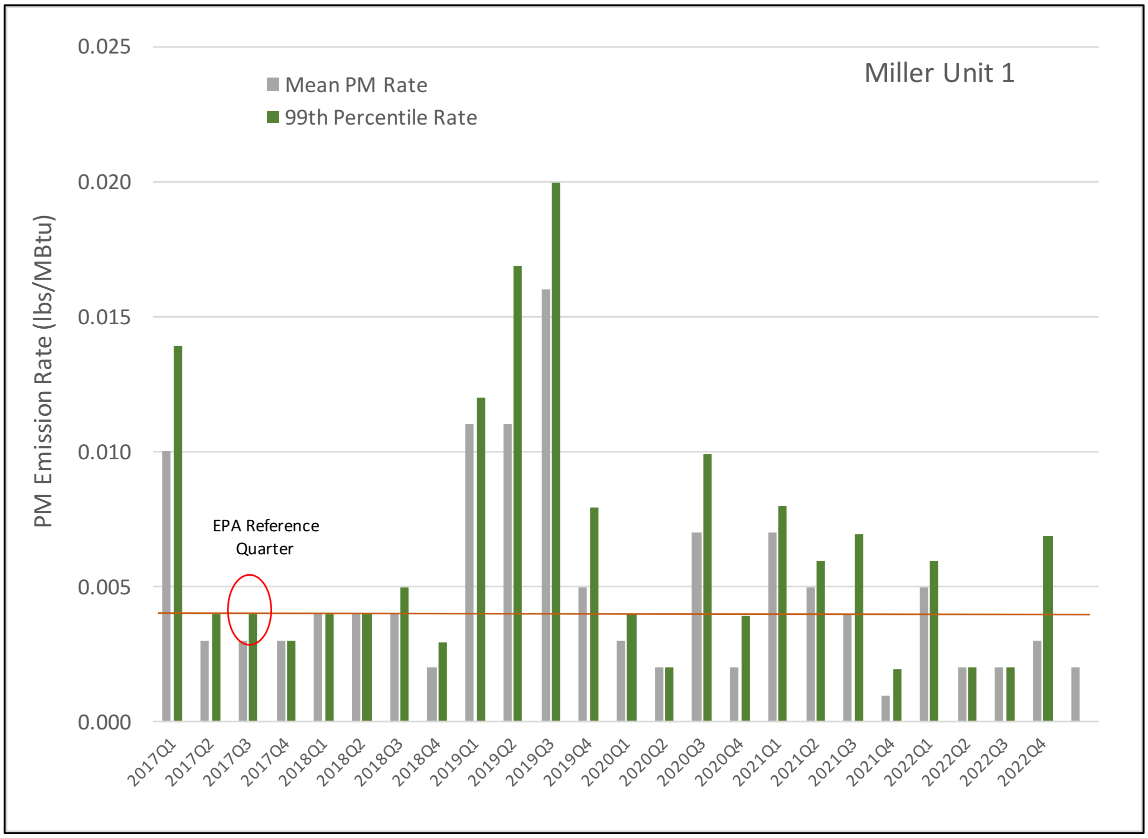

TVA Gallatin Unit 3
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.012
0.010
0.008
0.006
0.004
0.002
0.000
EPA Reference Quarter
18 Q1 18 Q2 18 Q3 1 Q4 19 Q1 19 Q2 19 Q3 19 Q4 20 Q1 20 Q2 20 Q3 20 Q4 21 Q1 21 Q2 21 Q3 21 Q4
2018
2019
2020
2021

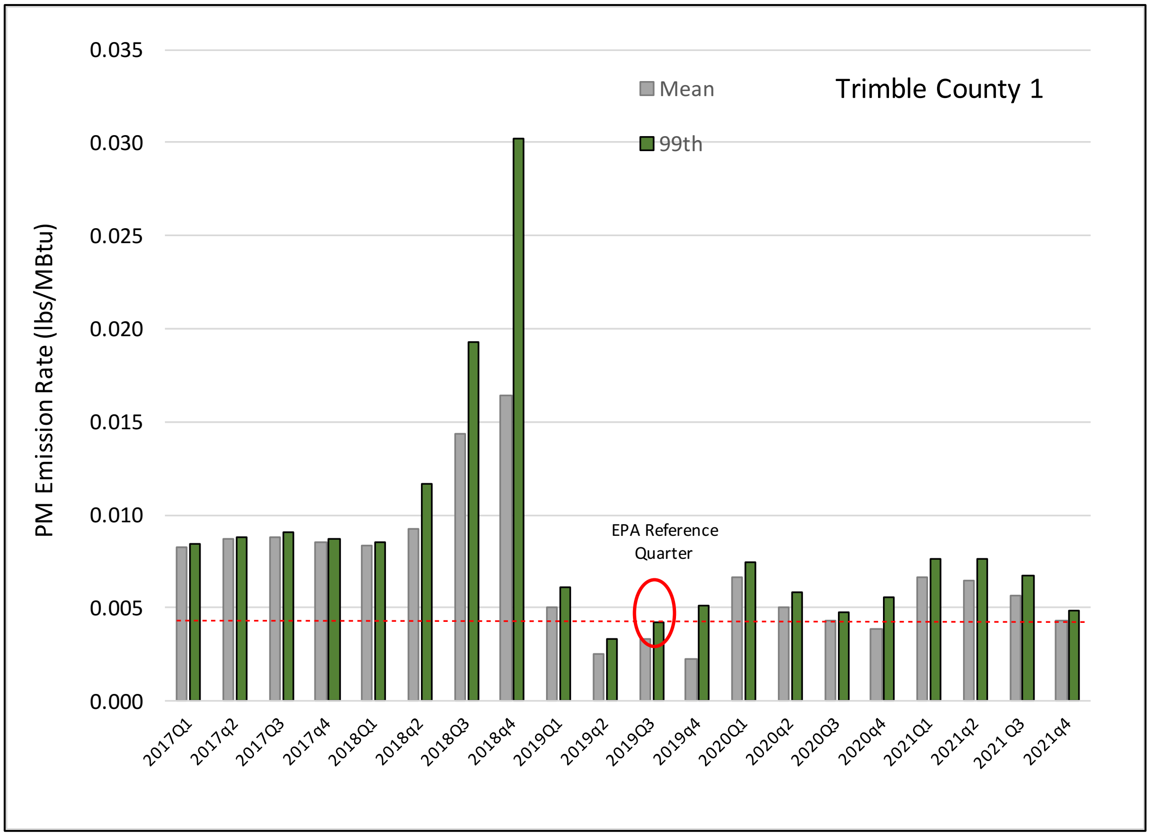

TVA Gallatin Unit 3
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.012
0.010
0.008
0.006
0.004
0.002
0.000
EPA Reference Quarter
18 Q1 18 Q2 18 Q3 1 Q4 19 Q1 19 Q2 19 Q3 19 Q4 20 Q1 20 Q2 20 Q3 20 Q4 21 Q1 21 Q2 21 Q3 21 Q4
2018
2019
2020
2021


Ghent Unit 1
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.020
0.015
0.010
0.005
0.000
EPA Reference Quarter
2017Q1
2017q2
2017Q3
2017q4
2018Q1
2018q2
2018Q3
2018q4
2019Q1
2019q2
2019Q3
2019q4
2020Q1
2020q2
2020Q3
2020q4
2021Q1
2021q2
2021 Q3
2021q4


Mill Creek Unit 4
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.030
0.025
0.020
0.015
0.010
0.005
0.000
EPA Reference Quarter
2017Q1
2017q2
2017Q3
2017q4
2018Q1
2018q2
2018Q3
2018q4
2019Q1
2019q2
2019Q3
2019q4
2020Q1
2020q2
2020Q3
2020q4
2021Q1
2021q2
2021 Q3
2021q4


0.025
0.020
0.015
0.010
0.005
0.000
PM Emission Rate (lbs/MBtu)
Mean PM Rate
99th Percentile Rate
Gaston Unit 5
EPA Reference Quarter
2017Q1
2017Q2
2017Q3
2017Q4
2018Q1
2018Q2
2018Q3
2018Q4
2019Q1
2019Q2
2019Q3
2019Q4
2020Q1
2020Q2
2020Q3
2020Q4
2021Q1
2021Q2
2021Q3
2021Q4
2022Q1
2022Q2
2022Q3
2022Q4


0.025
0.020
0.015
0.010
0.005
0.000
PM Emission Rate (lbs/MBtu)
Mean PM Rate
99th Percentile Rate
Miller Unit 1
EPA Reference Quarter
2017Q1
2017Q2
2017Q3
2017Q4
2018Q1
2018Q2
2018Q3
2018Q4
2019Q1
2019Q2
2019Q3
2019Q4
2020Q1
2020Q2
2020Q3
2020Q4
2021Q1
2021Q2
2021Q3
2021Q4
2022Q1
2022Q2
2022Q3
2022Q4


Trimble County 1
Mean
99th
PM Emission Rate (lbs/MBtu)
0.035
0.030
0.025
0.020
0.015
0.010
0.005
0.000
EPA Reference Quarter
2017Q1
2017q2
2017Q3
2017q4
2018Q1
2018q2
2018Q3
2018q4
2019Q1
2019q2
2019Q3
2019q4
2020Q1
2020q2
2020Q3
2020q4
2021Q1
2021q2
2021 Q3
2021q4

GAVIN A. MCCOLLAM
DECLARATION OF HARM IN SUPPORT OF MOTION FOR A STAY PENDING REVIEW

1. My name is Gavin A. McCollam. I am the Senior Vice President and Chief Operating Officer of Basin Electric Power Cooperative ("Basin Electric"). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. I have more than 35 years of experience in electricity generation. I have been employed at Basin Electric since 1989. I hold an associate's degree from Bismarck (North Dakota) State College, a bachelor's degree in mechanical engineering from North Dakota State University, and a master's degree in systems management from the University of Southern California. I am also a registered professional engineer. As the Senior Vice President and Chief Operating Officer at Basin Electric, my responsibilities include ensuring access to safe, reliable, affordable and sustainable electricity for Basin Electric's member-owner cooperatives. This includes oversight of Basin Electric's coal-fired electric generating units in North Dakota and Wyoming.

3. I am providing this Declaration in support of the motions to stay challenging the U.S. Environmental Protection Agency's ("EPA") National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38508 (May 7, 2024), known as the Mercury and Air Toxics Standards Risk and Technology Review ("Final Rule" or "MATS RTR").

4. Basin Electric is a not-for-profit generation and transmission cooperative incorporated in 1961 to provide supplemental power to a consortium of rural electric cooperatives. Those member cooperatives—140 of them—are Basin Electric's owners. Through them, Basin Electric serves approximately three million consumer members in an area that covers roughly 500,000 square miles across nine states: Colorado, Iowa, Minnesota, Montana, Nebraska, New Mexico, North Dakota, South Dakota, and Wyoming. Basin Electric's end-use consumer members across these nine states include residential, farm, commercial, industrial, and irrigation electric consumers. As of the end of 2023, Basin Electric had an asset base of $8 billion and operated 5,219 megawatts ("MW") of wholesale electric generating capability and had 8,112 MW of generating

capacity within its portfolio. Those owned electric generation facilities are located in the states of Iowa, Montana, North Dakota, South Dakota, and Wyoming. Three of Basin's electric generation facilities are expected to be significantly impacted by the MATS RTR: Antelope Valley Station, Leland Olds Station, and Laramie River Station.

5. Basin Electric is one of the few utilities that supplies electricity on both sides of the national electric system separation. In the Eastern Interconnection, Basin Electric's system is part of two assessment areas overseen by two System Operators: the Southwest Power Pool ("SPP") and the Midcontinent Independent System Operator ("MISO"). In the Western Interconnection, Basin Electric's system is overseen by the Northwest Power Pool ("NWPP") and the Rocky Mountain Reserve Group ("RMRG"). These System Operators regulate the multiple energy and capacity markets that exist within each regional grid. They also require utilities like Basin Electric to maintain a certain amount of capacity to ensure reliability during periods of high demand.

6. Basin Electric, which has two North Dakota facilities that are fueled by lignite coal, is a member of the Lignite Energy Council ("LEC"). LEC represents the regional lignite industry in North Dakota, an $18

billion industry critical to the economy of the Upper Midwest and the reliability of its electrical grid. The primary objective of LEC is to maintain a viable lignite coal industry and enhance development of the region's lignite resources. Members of LEC include mining companies, utilities that use lignite to generate electricity, synthetic natural gas, and other valuable byproducts, and businesses that provide goods and services to the lignite industry. LEC has advocated for its members since 1974 to protect, maintain, and enhance development of our region's abundant lignite resources. LEC is committed to environmental stewardship and understands the importance of protecting North Dakota's natural beauty.

7. Basin Electric is also member of the National Rural Electric Cooperative Association ("NRECA"). NRECA represents the interests of rural electric cooperatives across the country.

8. Lignite is frequently utilized at mine-mouth power generation facilities, which are coal-fired power plants built near a coal mine that use coal from that mine as fuel.

9. The MATS RTR threatens the viability of lignite-powered plants. It also threatens the reliability of the entire grid across the region,

places burdens on the power sector as a whole, and causes harm to industries dependent on a reliable electric grid.

ANTELOPE VALLEY STATION

10. Basin Electric is the operator and part owner of the Antelope Valley Station ("Antelope Valley"), a two-unit power plant located in Mercer County, North Dakota. Each EGU is rated at 450 MW. Antelope Valley began commercial operation in 1984. Antelope Valley Station is fueled by lignite coal from the nearby Freedom Mine.

11. At Antelope Valley, sulfur dioxide ("SO2") emissions from the Combustion Engineering tangentially fired boiler are controlled by a dry scrubber. Nitrogen oxide ("NOx") emissions were originally controlled by low NOx burners and close-coupled-over-fired air. Then, in spring 2016, an additional separated over fired air system was installed and reduced NOx emissions lower. Other pollution control equipment installed at Antelope Valley includes a fabric-filter system for particulate control and sorbent injection for mercury control.

LELAND OLDS STATION

12. Basin Electric is the operator and owner of the Leland Olds Station ("Leland Olds"), a two-unit power plant located in Mercer County,

North Dakota. The two units together generate 660 MW. Unit 1 began commercial operation in 1966 and Unit 2 began commercial operation in 1975. Leland Olds is fueled by lignite coal delivered by rail from the Freedom Mine.

13. At Leland Olds Unit 1, SO2 emissions from the Babcock & Wilcox wall-fired boiler are controlled by a wet scrubber. NOx emissions were originally controlled by low NOx burners. Then, in spring 2017, a selective non-catalytic reduction ("SNCR") system was installed and reduced NOx emissions lower. Other pollution control equipment installed at Unit 1 includes an electrostatic precipitator ("ESP") system for particulate control and activated carbon (sorbent) injection for mercury control.

14. At Leland Olds Unit 2, NOx emissions from the boiler are controlled by low-NOx burners, separated over-fired air, and SNCR. A wet scrubber is used to control SO2 emissions and an ESP is used for control of particulate matter ("PM") emissions. An activated carbon injection system is used to control mercury emissions.

LARAMIE RIVER STATION

15. Basin Electric is the operator and a minority co-owner of the Laramie River Station ("Laramie River"), a three-unit power plant located in Wheatland, Wyoming. The three units together generate approximately 1,700 MW, of which Basin Electric owns about 42%, for a total of roughly 714 MW. Unit 1 began commercial operation in 1980, Unit 2 began commercial operation in 1981, and Unit 3 began commercial operation in 1982. Laramie River is fueled by subbituminous coal from the Powder River Basin in Wyoming.

16. At Laramie River Unit 1, the NOx emissions from the boiler are controlled by low-NOx burners and separated over-fired air. A wet scrubber is used to control SO2 emissions and an ESP is used for control of PM emissions. An activated carbon injection system is used to control mercury emissions.

17. At Laramie River Unit 2, the NOx emissions from the boiler are controlled by low-NOx burners and separated over-fired air. In 2019, Unit 2 began operation of a SNCR. A wet scrubber is used to control SO2 emissions and an ESP is used for control of PM emissions. An activated carbon injection system is used to control mercury emissions.

18. At Laramie River Unit 3, the NOx emissions from the boiler are controlled by low-NOx burners and separated over-fired air. A dry scrubber is used to control SO2 emissions and an ESP is used for control of PM emissions. An activated carbon injection system is used to control mercury emissions.

MATS RTR RULE REVISIONS

19. The MATS RTR eliminates the low rank coal subcategory for lignite-powered facilities and changes the limit for mercury from lignite-fired power plants from 4.0 lb/TBtu to 1.2 lb/TBtu (the "New Mercury Limitation").

20. The MATS RTR decreases the limit for filterable particulate matter ("fPM") to 0.010 lbs/MMBtu (the "New fPM Limitation").

21. Compliance with the New Mercury and New fPM Limitations is required on or before three years after the Final Rule's effective date.

22. The MATS RTR provides that Continuous Emission Monitoring Systems ("CEMS") are the only method to demonstrate compliance with the fPM limit.

LIGNITE COMBUSTION

23. It is well-known and consistent with Basin Electric's experience that lignite deposits vary significantly in quality, including fuel combustion performance and mineral content. Mercury content in the lignite varies because different seams within the mine yield lignite with diverse attributes (including mercury) on a day-to-day basis. A compliance margin is critical to allow for continuous compliance with the Final Rule especially considering coal quality variability.

24. Lignite varies in composition and the distribution of mercury within individual coal samples is not uniform, unlike other types of coals. The amount of mercury within one seam of coal can vary drastically, not to mention mercury content fluctuations between seams at the same mine.

25. An important difference between mine-mouth coal plants and typical coal-fired power plants is the control over fuel composition. Non-mine-mouth facilities purchase coal of a specified quality to be delivered to the facility. Unlike other types of facilities that may be able to blend coals to achieve greater consistency in the character of their fuel, many North Dakota lignite units are located at mine-mouth facilities without

access to other coal types. Antelope Valley cannot use bituminous coal or other types of coal because the boilers were designed specifically for burning high moisture coal such as lignite. If Antelope Valley were to burn coal with lower moisture content, it would cause severe maintenance issues with heat transfer to the rear pendants and could result in a loss of produced electricity. Because Antelope Valley is a mine-mouth facility, having to rail in coal would significantly change the fuel cost and therefore significantly increase the cost that Basin Electric bids Antelope Valley into the market.

26. Leland Olds uses lignite coal from the nearby Freedom Mine, which is loaded at Antelope Valley and delivered via rail. If Leland Olds were to change coal types, it would need to be transported much further and would not be cost effective.

27. When high mercury batches of coal are combusted, the original MATS mercury emission limitation from 2012 provided lignite power plants enough leeway to account for higher mercury emissions due to the mercury content in the coal.

ELIMINATION OF THE MERCURY SUBCATEGORY FOR LIGNITE CAUSES IMMEDIATE AND IRREPARABLE HARM TO THE NORTH DAKOTA LIGNITE INDUSTRY AND TO BASIN ELECTRIC

28. EPA established the lignite subcategory for mercury because lignite units and lignite coal are markedly different than bituminous and subbituminous coals. Lignite has a higher mercury content in many instances and presents greater variability than other coals. The higher sulfur content found in lignite fuels inhibits the ability of injected sorbents to reduce mercury emissions at lignite plants. The mercury content also results in higher levels of SO_3 formed, which significantly limits the mercury emission reduction potential of emission controls at lignite plants.

29. Basin Electric has used the same technology (combination of sorbent injection plus a chemical additive (oxidizing agent)) as its primary mercury control strategy since the MATS rule came into effect and is not aware of more effective control technology.

30. There is no evidence that the units at Antelope Valley and Leland Olds could achieve compliance with the New Mercury Limitation on a sustained basis with the currently installed equipment as is required to meet a 30-day rolling basis while operating at full load.

31. The MATS RTR sets a mercury limitation for lignite units without any technical basis that it can be met on a continuous basis, in general, and provides no compliance margin to account for the variability in unit performance and emissions control capabilities from unit to unit.

32. Basin Electric is irreparably harmed by the final MATS RTR because it is unknown if Antelope Valley and Leland Olds' existing mercury controls can achieve the New Mercury Limitation of 1.2 lb/Tbtu on a sustained basis at full load.

33. The Final Rule places Basin Electric in an impossible position, given the Rule's impending compliance date. Noncompliance with the Clean Air Act is not an option.

34. To have any possibility of meeting the New Mercury Limitation, Basin Electric must modify the existing system at both Antelope Valley and Leland Olds to produce a higher injection rate and make the systems more robust. Even though EPA has not demonstrated that the New Mercury Limitation will provide any health benefits, Basin Electric must complete this modification project to lower the emission rate. The modification costs and ongoing operation expenses are significant. Specifically, these technologies will require over

$4,000,000.00 in capital expenditures upfront for the four units collectively, as well as increased labor costs for installation, operation, and maintenance of the technology and equipment and associated training, along with additional sorbent injection, will result in increased operating costs over the long term. We must begin expending these dollars immediately, and certainly before the resolution of this case, in order to meet the deadlines set out in the Final Rule.

35. Costs to comply with the New Mercury Limitation are exorbitant and damage Basin Electric. Costs will be passed along to its member cooperatives and end users who are harmed via higher electricity prices. The capital and operational costs to Basin Electric, its member cooperatives, and end users cannot be recouped.

THE NEW FPM LIMITATION WILL CAUSE IMMEDIATE AND IRREPARABLE HARM TO THE ELECTRIC COOPERATIVES AND TO BASIN ELECTRIC

36. EPA's New fPM limit of 0.010 lb/MMBtu will require upgrades at Leland Olds and Laramie River.

37. Basin Electric's harm is immediate. Basin Electric would need to begin engineering and constructing, at a minimum, ESP upgrades at Leland Olds and Laramie River as soon as possible to have any

opportunity to meet the new compliance date for the MATS RTR. If ESP upgrades are required, Basin Electric would need 36 months to complete. It is likely that the 36-month estimate will be further protracted due to the lack of contractors available to perform the work.

38. If ESP upgrades were not sufficient, baghouse technology would be required. If a baghouse is required, Basin Electric would need approximately 48 months to convert to baghouse technology.

39. Costs of compliance with the New fPM Limitation are overly burdensome, for the following reasons.

40. ESP retrofits are expensive. They may cost an estimated $67,262 per fPM ton removed. *See* Cichanowicz Technical Report.

41. Baghouse installation is extremely costly. It is estimated to cost $282,715 per fPM ton removed. *See* Cichanowicz Technical Report.

42. Electric cooperatives have limited financial resources to undertake projects of this magnitude coincident with other environmental compliance projects.

43. To comply with the MATS RTR, Basin Electric is forced to take measures that immediately increase compliance and operational costs. The MATS RTR impacts Basin Electric's ability to supply

affordable, reliable energy to its customers. Added costs will place upward pressure on rates for rural customers, particularly when combined with the effects of EPA's other recent electric utility sector-focused rules.

THE MATS RTR CREATES GRID RELIABILITY CONCERNS

44. Lignite power plants, which provide a significant source of electric power in North Dakota, are important to the regional economy.

45. Thus, the Final Rule, with its reversal of EPA's position on lignite-fired sources, impacts North Dakota more profoundly than other areas of the country. These concentrated impacts affect the ability of the North Dakota utilities to maintain adequate generation resources.

46. Most (if not all) of the lignite plants in North Dakota must make some changes as result of the Final Rule. These changes will require an immense amount of coordination between different regulated facilities and likely involve serious risks to the reliability of electric grids providing power to the region while the removal equipment at each of the impacted facilities are taken offline to undergo the additions and upgrades required by the Final Rule.

47. The North American Electric Reliability Corporation has predicted continued future shortfalls in North Dakota.[1] The MATS RTR intensifies an already tenuous, overburdened grid in transition.

SUMMARY OF HARM TO BASIN ELECTRIC

48. Basin Electric is harmed because it must immediately commence costly compliance testing and project development to evaluate whether it can meet the MATS RTR emissions limits and applicable compliance deadline.

49. The MATS RTR could potentially cause Antelope Valley, Leland Olds and Laramie River which are dispatchable, reliable generating resources, to operate differently at a substantial cost and permanent loss to Basin Electric.

50. Even if the MATS RTR is overturned, the direct costs to Basin Electric, its member cooperatives, and end users cannot be recouped once spent. These damages are permanent.

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[1] NERC, 2024 Summer Reliability Assessment (May 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

I declare under penalty of perjury that the foregoing is true and correct.

Gavin A. McCollam

Dated: 6/5/2024

DECLARATION OF TAWNY BRIDGEFORD IN SUPPORT OF MOTION TO STAY FINAL RULE

I, Tawny Bridgeford, declare as follows:

1. My name is Tawny Bridgeford. I am the General Counsel & Senior Vice President, Regulatory Affairs for the National Mining Association ("NMA"). I make this declaration in support of NMA's motion to stay the U.S. Environmental Protection Agency's ("EPA") Final Rule titled "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," 89 Fed. Reg. 38,508 (May 7, 2024) (hereinafter, the "Final Rule"). I am over the age of eighteen and have personal knowledge of the facts set forth below.

2. I have been employed by the NMA for over 19 years and have held my current position of General Counsel and Senior Vice President, Regulatory Affairs for 17 months. Since 2004, I have represented the NMA on legal, regulatory, and policy issues related to air, waste, and chemicals. I am currently responsible for managing the NMA's entire regulatory and litigation portfolio, including matters under the Clean Air Act.

3. The NMA is the national trade association that represents the interests of the mining industry, including every major coal company operating in the United States. In 2023, our member companies represented 75 percent of U.S. coal production in 18 states. The NMA has over 250 members, whose interests it represents before Congress, the administration, federal agencies, the courts, and the media. The NMA works to ensure America has secure and reliable supply chains, abundant and affordable energy, and the American-sourced materials necessary for U.S. manufacturing, national security, and economic security, all delivered under world-leading environmental, safety, and labor standards. As part of its core mission and purpose of representing NMA members' interests, the NMA advocates for sound regulatory policy decisions by the EPA and regularly participates in court cases challenging rules that harm the mining industry, such as the Final Rule.

4. Mining occupies a critical place in America's economy and energy infrastructure. In 2023, the coal mining industry fueled 16 percent of the Nation's electricity,[1] providing the fuel needed to generate

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[1] *See* Energy Information Administration (EIA), *Annual Energy Outlook 2023* (2023) (Table 7.2a: Electricity Net Generation: Total (All Sectors)), https://www.eia.gov/totalenergy/data/monthly/pdf/sec7_5.pdf.

affordable and reliable baseload power for households, businesses, manufacturing facilities, transportation and communications systems, and services throughout our economy. Likewise, the coal mining industry directly employs 100,000 people with 224,000 indirect coal mining jobs, and provides high-paying jobs to American workers. For example, the average annual wage for all U.S. coal miners is $102,855—46 percent above the average wage for all U.S. workers, which is $70,343. Millions of dollars in federal, state, and local taxes can be attributed to mining jobs, and coal mining directly contributed over $31 billion to GDP in 2023.[2] While coal mining often takes place in locations with per capita incomes well below and poverty rates well above national and state averages, coal mining jobs are among the best-paying blue collar jobs in the entire country and regularly exceed the average salary in coal mining areas.

5. Coal is America's most abundant energy resource—making up 85 percent of U.S. fossil energy reserves on a Btu basis. With increased electrification and surging power demand, and as our economy

[2] U.S. Dep't Interior., U.S. Geological Survey, *Mineral Commodity Summaries 2024* 9 tbl.1 (2024), https://pubs.usgs.gov/periodicals/mcs2024/mcs2024.pdf.

and population expand, our need for electricity will continue to grow. Coal is a workhorse fuel for power generation, providing 670.7 billion kilowatt hours of electricity, which calculates to nearly 17 percent of the Nation's electricity net power sector generation, in 2023.[3] Coal provides affordable and reliable baseload power to households, businesses, manufacturing facilities, transportation and communication systems, and services throughout our economy. Coal will continue to be called upon to meet the Nation's power needs even assuming ambitious growth scenarios are met for electricity generation from renewables and natural gas energy sources. Coal is also an affordable source of energy. Electricity costs are generally lower in States that rely upon coal for their electricity generation versus States that rely on other fuels. In 2020, 34 million Americans—27 percent of the population—were considered energy insecure. Dispatchable baseload power from coal that is reliable and affordable is critical to maintaining a healthy, safe, and modern standard of living.

[3] EIA, *Monthly Energy Review* (Apr. 2024) (Table 7.2b: Electricity Net Generation: Electric Power Sector), https://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.

6. I am familiar with the preparation and submission of the NMA's comments on EPA's Proposed Rule and the impacts the Final Rule will have on NMA members.[4] Nothing in the Final Rule alleviates the NMA's concern that EPA has failed to demonstrate that its new standards for filterable particulate matter ("fPM") and mercury are achievable, particularly by lignite-powered electric generating units ("EGUs").

7. I am familiar with the declarations filed by NACCO NR Natural Resources Corporation ("NACCO NR"), Lignite Energy Council ("LEC"), and Mike Holmes. NACCO NR and LEC are members of the NMA, and Mike Holmes is LEC's Vice President. As NACCO NR explained, the changes required by MATS, both in the fPM and mercury standards, are likely not technologically feasible for lignite-based power generation facilities. NACCO NR Decl. ¶ 5; *see also* NMA Comments, *supra*, at 10–12 (fPM standard) and 14–16 (mercury standard). LEC also demonstrates the technological and practical difficulties of achieving compliance. LEC Decl. ¶¶ 21–23. EPA has also significantly

[4] *See, e.g.*, Comment from Tawny A. Bridgeford, National Mining Association (June 23, 2023), Doc. ID No. EPA-HQ-OAR-2018-0794-5986 (comments on Proposed Rule) (hereinafter, "NMA Comments").

underestimated the costs and timeframe necessary even to attempt comply, as well as impacts to the power grid. *See* NACCO NR Decl. ¶¶ 29–30; *id.* Attach. A at 24–27, 31–37; Mike Holmes Decl. ¶¶ 5, 8(a), 10; LEC Decl. ¶¶ 19–27; NMA Comments at 9.[5] The only alternative to compliance is to prematurely retire coal plants. *See* NACCO NR Decl. Attach. A at 3, 25, 31–33; LEC Decl. ¶ 24.

8. Accordingly, unless it is stayed, the Final Rule will inflict immediate and irreparable harm on coal-fired generators, some of which will be forced to retire prematurely due to their inability to achieve compliance. *See* NACCO NR Decl. ¶¶ 5 & 30 & Attach. A at 3, 25, 31–33. They will not be able to unwind this decision if the Court finds the Final Rule unlawful, nor recover the resulting hundreds of millions of dollars of stranded assets. *See id.* ¶¶ 5, 9, 17, & 28. By extension, these harms on generating facilities will inevitably harm NMA members—namely, coal producers that supply coal-fired EGUs—whose fates are inextricably

[5] Citing J. Edward Cichanowicz, *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, at 16-21 (June 2023) (prepared on behalf of the National Rural Electric Cooperative Association, American Public Power Association, America's Power, Midwest Ozone Group, NAACO, National Mining Association, and Power Generators Air Coalition) ("Cichanowicz Report").

linked to the coal-fired power sector and who depend on a stable and continued domestic coal market.

9. As NMA member LEC explains, North Dakota lignite mining operations will be particularly hard-hit. In North Dakota, lignite coal is mined on a mine-to-mouth model, with each EGU contracting with a nearby lignite mine for its supply of lignite. LEC Decl. ¶ 10. The closure of a lignite EGU as a result of the Final Rule would mean the closure of the mine that supplies it, which will have no reasonable or viable market alternative. *Id.*

10. Similarly, NMA member NACCO NR has attested that the Final Rule will significantly affect several lignite-fired EGUs, including the Red Hills Generating Facility, Antelope Valley Station, Coal Creek Station, Coyote Station, Leland Olds, and Spiritwood Station, and EPA's own estimates confirm this conclusion. NACCO NR Decl. ¶ 5. Because these facilities all purchase lignite coal from NACCO NR, the closure of these facilities would force the closure of the mines that supply them, at a loss of tens of millions of investment dollars and a substantial number of jobs. *Id.*

11. Moreover, nothing in the Final Rule alleviates NMA's concerns, articulated during the comment period, about the Rule's impact on grid reliability. *See* NMA Comments, *supra*, at 18–24. With the Final Rule, EPA has continued its pattern of ignoring the alarms raised by grid experts concerning the threats to grid reliability resulting from rapid early retirement of dispatchable resources. EPA's Final Rule will accelerate the forced retirement of needed coal plants and exacerbate the reliability crisis. *See* NACCO NR Decl. ¶¶ 5; *id.* Attach. A at 3, 24–25, 27–32; LEC Decl. ¶¶ 7. Absent a stay, the EGU and mine closures necessitated by the Final Rule will be irreversible by the time the Court can rule on the Final Rule's lawfulness, leaving power-vulnerable communities that rely on lignite-fueled energy at even greater risk of being left in the dark.

12. I, Tawny Bridgeford, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

Executed on June 11, 2024, in Washington, DC.

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Tawny Bridgeford

JERRY PURVIS
DECLARATION OF HARM IN SUPPORT OF MOTION FOR A STAY PENDING REVIEW

1. My name is Jerry Purvis. I am Vice President of Environmental Affairs at East Kentucky Power Cooperative, Inc. (East Kentucky). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. I have 30 years of experience in electrical power generation. I have been employed at East Kentucky since 1994. I hold a bachelor's degree in Chemistry from Morehead State University and a bachelor's degree in Chemical Engineering from the University of Kentucky. I have a Master of Business Administration from Morehead State University. As Vice President, I am responsible for promoting proactive environmental policies, implementing comprehensive compliance strategies, and supporting East Kentucky's sustainability goals. I manage East Kentucky's staff and outside consultants in pursuit of these goals.

3. I am providing this Declaration in support of the motions to stay challenging the U.S. Environmental Protection Agency's (EPA) National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38508 (May 7, 2024), known as the Mercury and Air Toxics Standards Risk and Technology Review (the Final Rule or the MATS RTR).

4. East Kentucky is a not-for-profit electric generation and transmission cooperative headquartered in Winchester, Kentucky. East Kentucky is owned, operated, and governed by its members, who use the energy and services East Kentucky provides. These owner-member cooperatives provide energy to 520,000 homes, farms, and businesses across 87 counties in Kentucky. East Kentucky's purpose is to generate electricity and transmit it to 16 Owner-Member cooperatives that distribute it to retail, end-use consumers (Owner-Members). East Kentucky provides wholesale energy and services to Owner-Member distribution cooperatives through baseload units, peaking units, hydroelectric power, solar panels,

landfill gas to energy units and distributed generation resource power purchases – transmitting power across the rural Kentucky areas via more than 2,900 miles of transmission lines. East Kentucky's Owner-Members' collective customer base is comprised largely of residential customers (93%). And, in 2019, 57% of East Kentucky's owner-member retail sales were to the residential class. Electricity is the primary method for water heating and home heating for this class of customers.

5. East Kentucky is a member of PJM Interconnection (PJM). PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in 13 states and the District of Columbia.

6. East Kentucky is a member of the National Rural Electric Cooperative Association (NRECA). NRECA represents the interests of rural electric cooperatives across the country.

7. Demand for electricity is increasing in Kentucky. East Kentucky predicts increased demand during the time span in which this Final Rule would impact. East Kentucky forecasts net total energy requirements to increase from 13.5 to 16.7 million MWh (megawatt hours), an average of 1.5

percent per year over the 2021 through 2035 period.[1] Residential sales will increase by 0.7 percent per year, and small commercial sales (customers with ≤1000 KVA (kilo-volt-amperes)) will increase by 0.9 percent per year. The greatest area of growth will be for large commercial and industrial sales (customers with >1000 KVA), projected to increase by 3.3 percent per year.

8. East Kentucky is the voice for a substantial number of end users of electricity in its service territory that live in impoverished communities. These communities place a high value on affordable energy costs. East Kentucky's service territory includes rural areas with some of the lowest economic demographics in the United States. In these areas, families are literally faced with a daily choice between food, electricity, and medicine. Of the 87 counties that East Kentucky's Owner-Member cooperatives serve, 40 counties experience persistent poverty, as reported by the USDA.

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[1] East Kentucky Integrated Resource Plan, Load Forecast 2021-2035 (Dec. 2020) (IRP 2020).

9. Many of these hardworking Americans have been plagued by unemployment from mines, trucking companies, restaurants and other businesses. The unemployment rate is 60% higher than the national average. They rely on government assistance to survive; anywhere from 30% to 54% of total income in most of the counties that East Kentucky serves comes from governmental assistance programs. Forty-two percent of these electricity users are elderly (65 years or older). Many are on fixed incomes and reside in energy-leaking mobile homes. Recent brutal cold weather has caused their monthly electric bills to skyrocket. East Kentucky has a strong interest in keeping energy affordable to assist its 16 Owner-Member cooperatives in serving people facing the harsh realities of today's economy.

10. The MATS RTR threatens the viability of one of East Kentucky's essential coal-fired assets. It places burdens on the power sector, as a whole, and causes harm to our customers, including rural families, dependent on affordable, reliable electricity.

EAST KENTUCKY'S IMPACTED ELECTRIC GENERATING UNITS

11. East Kentucky owns electric generating units (affected EGUs) that fall within the Final Rule's scope of coverage and thus must comply with the Final Rule's stringent new filterable particulate matter (fPM) standard for coal-fired units. The Final Rule requires East Kentucky to expend substantial costs to comply with the fPM portion of the Rule that, ultimately, the rural ratepayers in East Kentucky's service area, must bear. Moreover, the Final Rule is so stringent that the margin between compliance and non-compliance is so thin that even a minor glitch would very likely cause a forced outage that would otherwise unnecessarily expose East Kentucky and its ratepayers to performance penalties in PJM and substantial exposure in the energy markets. Given the rapid growth in demand for electricity from large data centers and other new and expanding loads – coupled with the EPA's other chorus of new rules that target greenhouse gas emissions, coal combustion residuals, effluents,

ozone and particulates – the cumulative impact of the Final Rule will be to further jeopardize grid stability and reliability.

12. Spurlock Station, East Kentucky's flagship plant, is located near Maysville, Kentucky on the Ohio River. All four units at Spurlock have state-of-the-art NOx, SO_2, PM, and Hg controls. Spurlock Station combusts bituminous coal.

13. Spurlock Unit 3 is a coal-fired circulating fluidized bed boiler (CFB) unit (278 MW), which is designed to emit less NOx and SO_2 in the combustion process. Unit 3 has a SNCR to control NOx, a dry FGD to control SO_2/SO_3, and a filter fabric baghouse to control fPM. In essence, as fPM passes out of the Unit 3 boiler, it passes through a structure filled with 8,256 fabric bags that collect the fPM for later disposal. The limits for this type of emission are measured in hundredths of a pound of material per million British Thermal Units of energy produced (lb./mmBtu). Unit 3 is adversely affected by the Final Rule.

14. Spurlock Unit 3 has a stellar MATS compliance record with no historical exceedances of MATS Rule requirements. The Final Rule

confirms that the existing fPM and other MATS limits, are sufficiently protective of human health and the environment. Therefore, East Kentucky's existing fPM controls provide ample protection to ensure the communities surrounding Spurlock Station enjoy clean air.

15. East Kentucky has made substantial investments in Spurlock Station due to recent EPA environmental rules, including a conversion to dry bottom ash, ash pond clean closure by removal, and a new waste water treatment system with evaporation to ensure the plant is fully compliant with Effluent Limitation Guidelines (ELGs) and the 2015 Coal Combustion Residuals (CCR) rule. Altogether, EKPC has invested $1.8 billion in environmental control equipment.

16. EKPC is presently evaluating the need for further extraordinary expenditures due to the EPA Rules released on April 25, 2024.[2] Collectively,

[2] New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39798 (May 9, 2024) (Greenhouse Gas Power Sector Rule); Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR

these rules impose egregious financial impacts on EKPC, its members, and end users. This Final Rule's costs must be considered as cumulative environmental costs that will detrimentally impact the cost to heat and cool the homes of rural ratepayers in disadvantaged communities and to power the job-creating businesses that provide employment to these individuals.

MATS RTR RULE REVISIONS

17. The MATS RTR decreases the limit for fPM from 0.030 lb/mmBtu to 0.010 lb/mmBtu (the New fPM Limitation) – an unprecedented 67% reduction that imposes substantial risks to unit performance in PJM with little to no environmental benefit. The Final Rule

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Surface Impoundments, 89 Fed. Reg. 38950 (May 8, 2024); Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 89 Fed. Reg. 40198 (May 9, 2024); National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38508 (May 7, 2024).

exceeds the point where the law of diminishing returns suggests that the additional limitations are not warranted.

18. The Final Rule also requires adoption of continuous emission monitoring systems (CEMS) as the only method to demonstrate compliance with the New fPM Limitation, eliminating the option to use quarterly stack testing and also eliminating the Low Emitting EGU (LEE) program. These requirements will increase the costs associated with program compliance without offering any substantial benefit beyond what the current measurement and verification procedures already afford.

19. Compliance with the New fPM Limitation and installation of PM CEMS are required on or before three years after the effective date of the Final Rule. To be able to meet these deadlines, East Kentucky and other utilities must begin work now to be in a position to comply.

20. The MATS RTR also eliminates the low rank coal subcategory for lignite-powered facilities and revises the limit for mercury from lignite-fired power plants from 4.0 lb/TBtu to 1.2 lb/TBtu (the New Mercury

Limitation). The New Mercury Limitation does not affect East Kentucky because the cooperative's coal-fired plants do not combust lignite fuels.

THE NEW fPM LIMITATION WILL CAUSE IMMEDIATE AND IRREPARABLE HARM TO EAST KENTUCKY

21. Spurlock Unit 3 is not presently capable of meeting the New fPM Limitation of 0.010 lb/mmBtu on a sustained basis. Although no data exists to confirm that compliance can in fact be achieved, East Kentucky has devised an initial strategy to improve fPM removal performance of the Spurlock Unit 3 baghouse.

22. To attempt to meet the New fPM Limitation, Spurlock Unit 3 must expeditiously begin a study and upgrades to its baghouse (the Baghouse Upgrade Project). The cost of the Baghouse Upgrade Project causes additional financial harm to East Kentucky and its owner-members.

23. Given the requirements associated with designing, permitting, financing and securing state regulatory approval for the Baghouse Upgrade Project, work must begin during the early pendency of this litigation due to the compliance date for the Final Rule.

24. It is unknown to what extent the Baghouse Upgrade Project will improve Unit 3's fPM emission rates. Regardless of the potential improvements of the Project, the 2005-vintage baghouse installed at Unit 3 was not designed to meet 0.010 lb/mmBtu. The baghouse is undersized to achieve the fPM Limitation and must operate flawlessly to attain compliance. In East Kentucky's experience with baghouse operation at CFB units, the Unit 3 baghouse will certainly fail, despite best engineering and maintenance practices, due to the lack of any margin to meet the aggressively low new fPM Limitation.

25. Therefore, East Kentucky anticipates being harmed by increased Unit 3 forced outages, resulting in potential penalties and exposure to market volatility in the PJM market. Lower fPM emission limitations, in general, put environmental control equipment under more stress in the summer and winter on peak days. Since the limit for fPM was reduced immensely (67%), there is little margin for error. **To put the effect of the Final Rule in context, a single hole the size of a human pinky finger in one of over 8,000 fabric filter bags within the baghouse can**

cause an exceedance of the new standard and, thereby, force the unit offline. It is simply unreasonable to think that a baghouse will perform perfectly under every operating condition in every period of the year. Even if Unit 3 and its upgraded baghouse achieve initial compliance with the Final Rule, the new and stricter fPM limitations on peak demand days – when PJM is calling for all available generators to produce power in order to avoid blackouts - stress the fPM controls to the point of a forced outage. Forced outages in PJM are unforgiving and highly penalized with the added injury of having to pay market prices for power during periods when it is least available and, therefore, most expensive. East Kentucky estimated, as an example, the penalty and damages caused by one forced outage event on Spurlock Unit 3 could easily exceed $31 million per seven-day outage. For a non-profit cooperative such as EKPC, an entire year's worth of margins could be wiped out in a single weekend of extreme weather.

Cost of Spurlock Unit 3 Seven Day Outage

PJM Market Pricing Conditions	Cost of Replacement Power for Unit 3	Lost Capacity Payment	PJM PAI Non-Performance Penalty	Total
Winter Average Cost	$1,640,785	$232,066	0	$1,872,851
Summer Average Cost	$1,600,361	$232,066	0	$1,832,427
Winter High Cost	$3,371,164	$232,066	0	$3,503,230
Winter Storm Event	$13,203,225	$232,066	$17,595,000	$31,030,291

Note 1: Winter Average Cost is based on replacement power at an average day-ahead price for January 2023
Note 2: Winter High Cost is based on replacement power at an average 168 highest hours of real-time LMP in January 2024
Note 3: Winter Storm Event is based on replacement power at an average 168 highest hours of real-time LMP in December 2022 around and including Winter Storm Elliott
Note 4: All prices include 7-days of power
Note 5: PJM Performance Assessment Interval (PAI) Non-Performance Penalty is assessed during a reliability event due to certain triggering events identified in the PJM Tariff, such as during a manual load shed event. The cost calculation assumes a 23 Hour PAI event.

26. The table above illustrates that, for an unplanned forced outage in PJM, EKPC could experience up to a $31,030,291 dollar penalty for not showing up as a result from a hole in the baghouse the size of a pinky finger. This illustrates the dissonance between the very marginal environmental impact of the Final Rule and the very real, tangible and irreparable harm that would result from a forced outage coming at an inopportune moment.

27. Of course, the foregoing analysis assumes that replacement power is even available for purchase from the PJM market during a Final

Rule-induced forced outage. PJM has signaled that EPA's new environmental regulations – particularly the Greenhouse Gas Power Sector Rule – will reduce the dispatchable capacity in the PJM system. PJM states, "[I]n the very years when we are projecting significant increases in the demand for electricity, the [Greenhouse Gas Power Sector] Rule may work to drive premature retirement of coal units that provide essential reliability services . . ." Plainly, any unit downtime exacerbates an already precarious reliability situation, especially considering the increasing demand for electricity in Kentucky and elsewhere in the PJM region.

28. East Kentucky, as a non-profit electric cooperative, has limited financial resources to risk PJM penalties of this magnitude, especially when layered with other environmental compliance projects due to EPA's recent rulemaking agenda. All of these projects must take place during the same time period. These costs will place upward pressure on rates for rural customers and impact East Kentucky's ability to supply affordable, reliable energy to customers.

THE MATS RTR CREATES GRID RELIABILITY CONCERNS

29. Compliance costs and increased maintenance needs associated with the Final Rule create a significant risk of energy reliability and economic hardship.

30. Spurlock Unit 3 would not be available during forced outage time periods because the baghouse is not designed to provide sufficient margin for compliance with the New fPM Limitation, such that even a pinky-sized hole in one of the baghouse bags would cause an exceedance. During these time periods, existing generation resources may not be adequate in Kentucky to sustain the grid. Multiple new EPA environmental regulations directly and profoundly impact generation resources in Kentucky, causing multiple unit retirements in a short time frame. This Final Rule makes it more likely that Spurlock Unit 3 will be forced off-line when PJM depends upon it the most, contributing to cumulative reliability concerns.

31. If the interruption of power delivery from a grid failure occurs, East Kentucky, its members, the economy, and the public health of end

users in its service territory would be immediately harmed. Kentuckians rely on electricity to heat and cool their homes. Affordable and consistent power supports essential health services to the elderly, infirm, and to vulnerable individuals with chronic health conditions. Evidence from the grid failure during winter storm Elliott in the PJM area shows the documented health impacts and morbidity caused by those events. Other concrete damages would occur such as business shutdowns, food spoilage, property damage, and lost labor productivity.

32. Further economic development in Kentucky is at risk without the ability to provide sufficient energy to support new factories, data centers, and other infrastructure necessary to attract industry, and, in turn, create new jobs. Energy powers the economy from which the government derives tax revenues. The MATS RTR imposes tremendous new risks on East Kentucky and the power grid while offering benefits that are, at best, marginal.

SUMMARY OF HARM TO EAST KENTUCKY

33. At this time, Spurlock Unit 3 cannot currently meet the New fPM Limitation on a sustained basis.

34. East Kentucky must immediately expend several million dollars to determine how Spurlock Unit 3's fPM performance can be improved. Irrespective of the Project improvements, the Unit 3 baghouse's design provides virtually no compliance margin. However, the reality of the current state-of-the-art dictates that there will be failures from time to time. A very small hole in a single bag is the margin of error between compliance and enormous risk of exposure to PJM performance penalties and energy market exposures.

35. East Kentucky is harmed by the MATS RTR because it must expend financial resources to commence the Baghouse Upgrade Project sooner than later to lower its fPM emissions and to meet the MATS RTR compliance deadline. The Final Rule's unyielding mandates will result in less reliability and greater costs with no significant improvement in air quality.

36. These costs cannot be deferred or delayed until the courts reach a final determination on the merits of the Petition for Review and all appeals are exhausted. East Kentucky expects that could take several years. If the Final Rule remains in effect while challenges are pending, East Kentucky will have no choice but to incur significant non-refundable compliance costs as well as to shoulder the many other substantial, immediate, and irreparable harms described above. The consumers who rely on power generated by East Kentucky might find themselves with less reliable power or without the means to pay for it or both.

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[Signature Follows on Next Page]

I declare under penalty of perjury that the foregoing is true and correct.

Jerry Purvis

Jerry Purvis

Dated: 6/5/2024

[redacted]

Analysis of

Proposed EPA MATS Residual Risk and Technology Review and

Potential Effects on Grid Reliability in North Dakota

Claire Vigesaa, Director

North Dakota Transmission Authority

April 3, 2024

Assisted by:

Isaac Orr and Mitch Rolling

Center of the American Experiment

Contents

Executive Summary

On behalf of the North Dakota Transmission Authority (NDTA), the Center of the American Experiment prepared this study to analyze the potential impacts of EPA's proposed revisions to the Mercury and Air Toxics Standards (MATS) Rule on North Dakota's power generation and power grid reliability.

Our primary finding, which is drawn substantially from the Rule's administrative record, is that the proposed changes are likely not technologically feasible for lignite-based power generation facilities, will foreseeably result in the retirement of lignite power generation units, and will negatively impact consumers of electricity in the Midcontinent Independent Systems Operator (MISO) system by reducing the reliability of the electric grid and increasing costs for ratepayers.

Our analysis builds upon grid reliability data and forecasts from the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC), and it assesses what is likely to happen to grid reliability if the MATS Rule forces some or all of North Dakota's lignite power generation units to retire. We determined that the closure of lignite-fired powered power plants in the MISO footprint would increase the severity of projected future capacity shortfalls, i.e. rolling blackouts, in the MISO system even if these resources are replaced with wind, solar, battery storage, and natural gas plants. In reaching that determination, we have accepted EPA's estimates for capacity values of intermittent and thermal resources.

Moreover, building such replacement resources would come at a great cost to MISO ratepayers. The existing lignite facilities are largely depreciated assets that generate large quantities of dispatchable, low-cost electricity. Replacing these lignite facilities with new wind, solar, natural gas, and battery storage facilities would cost an additional $1.9 billion to $3.8 billion through 2035, compared to operating the current lignite facilities under status quo conditions.

MISO residents would also suffer economic damages from the increased severity of rolling blackouts. Accounting for projected increases in demand for electricity, we assess that if the MATS Rule goes into effect in the near future, by 2035, the MISO grid will experience up to an additional 73,699 megawatt hours (MWh) of unserved load, with an economic cost of up to $1.05 billion based on the Value of Lost Load (VoLL) criteria, which can be thought of as the Social Cost of Blackouts.

Section A: North Dakota's Power Environment

North Dakota Transmission Authority (NDTA)

The North Dakota Transmission Authority (NDTA) was established in 2005 by the North Dakota Legislative Assembly at the behest of the North Dakota Industrial Commission. Its primary mandate is to facilitate the growth of transmission infrastructure in North Dakota. The Authority serves as a pivotal force in encouraging new investments in transmission by aiding in facilitation, financing, development, and acquisition of transmission assets necessary to support the expansion of both lignite and wind energy projects in the state.

Operating as a 'builder of last resort,' the NDTA intervenes when private enterprises are unable or unwilling to undertake transmission projects on their own. Its membership, as stipulated by statute, comprises the members of the North Dakota Industrial Commission, including Governor, Attorney General, and Agriculture Commissioner.

Statutory authority for the North Dakota Transmission Authority (NDTA) is enshrined in Chapter 17-05 of the North Dakota Century Code. Specifically, Section 17-05-05 N.D.C.C. outlines the powers vested in the Authority, which include:

1. Granting or loaning money.
2. Issuing revenue bonds, with an upper limit of $800 million.
3. Entering into lease-sale contracts.
4. Owning, leasing, renting, and disposing of transmission facilities.
5. Entering contracts for the construction, maintenance, and operation of transmission facilities.
6. Conducting investigations, planning, prioritizing, and proposing transmission corridors.
7. Participating in regional transmission organizations.

In both project development and legislative initiatives, the North Dakota Transmission Authority (NDTA) plays an active role in enhancing the state's energy export capabilities and expanding transmission infrastructure to meet growing demand within North Dakota. Key to its success is a deep understanding of the technical and political complexities associated with energy transmission from generation sources to end-users. The Authority conducts outreach to existing transmission system owners, operators, and potential developers to grasp the intricacies of successful transmission infrastructure development. Additionally, collaboration with state and federal officials is essential to ensure that legislation and public policies support the efficient movement of electricity generated from North Dakota's abundant energy resources to local, regional, and national markets.

As the energy landscape evolves with a greater emphasis on intermittent generation resources, transmission planning becomes increasingly intricate. Changes in the generation mix and the redistribution of generation resource locations impose strains on existing transmission networks, potentially altering flow directions within the network. A significant aspect of the Authority's responsibilities involves closely monitoring regional transmission planning efforts. This includes observing the activities of regional transmission organizations (RTOs) recognized by the Federal Energy Regulatory Commission (FERC), which oversee the efficient and reliable operation of the transmission grid. While RTOs do not own transmission assets, they facilitate non-discriminatory access to the electric grid, manage congestion, ensure reliability, and oversee planning, expansion, and interregional coordination of electric transmission.

Many North Dakota service providers are participants in the Midcontinent Independent System Operator (MISO), covering the territories of several utilities and transmission developers. Additionally, some entities are part of the Southwest Power Pool (SPP), broadening the scope of transmission planning. Together, North Dakota utilities and transmission developers contribute to a complex system overseeing the transmission of over 200,000 megawatts of electricity across 100,000 miles of transmission lines, serving homes and businesses in multiple states.

MISO and SPP also operate power markets within their respective territories, managing pricing for electricity sales and purchases. This process determines which generating units supply electricity and provide ancillary services to maintain voltage and reliability. Overall, the NDTA's involvement in regional transmission planning and coordination is crucial for ensuring the reliability, efficiency, and affordability of electricity transmission across North Dakota and beyond.

FERC-Recognized Regional Transmission Organizations and Independent System Operators

(www.ferc.gov)

Generation Adequacy, Transmission Capacity & Load Forecast Studies

The North Dakota Transmission Authority (NDTA) conducts periodic independent evaluations to assess the adequacy of transmission infrastructure in the state. In 2023, the NDTA commissioned two generation resource adequacy studies, one for the Midcontinent Independent System Operator (MISO) and another for the Southwest Power Pool (SPP). Additionally, the NDTA recently completed a generation resource adequacy study examining the impact of the EPA's proposed Mercury and Air Toxics Standards (MATS) Rule. A transmission capacity study commissioned by the NDTA is scheduled for completion in the summer of 2024.

Regular load forecast studies are also commissioned by the NDTA, with the most recent study completed in 2021. This study, conducted by Barr Engineering, provided an update to the Power Forecast 2019, projecting energy demand growth over the next 20 years. The 2021 update incorporates factors such as industries expressing interest in locating in North Dakota, abundant natural gas availability from the Bakken wells, and the potential for carbon capture and sequestration from various sources. The 2021 update and the full study can be obtained from the North Dakota Industrial Commission website: Power Forecast Study – 2021 Update, https://www.ndic.nd.gov/sites/www/files/documents/Transmission-Authority/Publications/ta-annualreport-21.pdf

The Power Forecast 2021 Update projects a 10,000 GWhr increase in energy demand over the next two decades under the consensus scenario, requiring approximately 2200 to 2500 MW of additional capacity to meet demand. These projections are closely tied to industrial development forecasts and are coordinated with forecasts used by the North Dakota Pipeline Authority. These projections were highly dependent on industrial development and are premised on new federal regulations not forcing the early retirement of even more electric generation units.

Meeting this growing demand poses significant challenges for utilities responsible for providing reliable service. While there is considerable interest in increasing wind and solar generation, natural gas generation is also essential to provide stability to weather-dependent renewable sources. Importantly, load growth across the United States is driven by the electrification of transportation, heating/cooling systems, data centers, and manufacturing initiatives.

Studies consistently highlight the critical importance of maintaining existing dispatchable generation to prevent grid reliability failures. Ensuring uninterrupted power supply is paramount for national security, public safety, food supply, and overall economic stability. The NDTA's ongoing assessments and proactive planning are crucial for meeting the evolving energy needs of North Dakota while maintaining grid reliability and resilience.

The timing and implementation of resources to meet this growing demand is a significant challenge for the utilities. Importantly, electric demand growth across the United States over the next several decades is projected to be dramatic due to the electrification of transportation, home heating/conditioning, data center and artificial intelligence centers, as well as the effort to bring manufacturing back to the USA. Studies by NDTA and others all point to the critical need to keep all existing dispatchable generation online to avoid catastrophic grid reliability failures, and have been warning that the push to force the retirement of reliable, dispatchable fossil fuel generation units is occurring before it is projected there will be sufficient intermittent units in place to cover the anticipated increase in demand. And when demand for electricity exceeds the dispatchable supply, the foreseeable result will be blackouts or energy rationing.

Current North Dakota Generation Resources

Here is the current breakdown of North Dakota's generation resources:

1. Renewable Generation:
    - Wind Generation: North Dakota has 4,250 MW of wind generation capacity in service, making it a significant contributor to the state's renewable energy portfolio. The average capacity factor for these generating facilities is 40% to 42%.
    - The 4,000 MW of wind generation receives a reduced capacity accreditation in the ISO of approximately 600 MW since it is intermittent. This is representative of the

amount that is estimated to be available for the peak demand in the summer.
- Solar Generation: Although North Dakota currently lacks utility-scale solar generation facilities in operation, some projects are in the queues of regional transmission organizations like MISO and SPP, indicating potential future development in this area.

2. Thermal Coal Generation:
    - North Dakota currently operates thermal coal generation at six locations, comprising a total of 10 generating units with a combined capacity of approximately 4,048 MW.
    - The average capacity factor for these generating plants ranged from 65% to 91% in 2021, excluding the retired Heskett Station.
    - Rainbow Energy operates the Coal Creek Station and the DC transmission line that transports ND produced energy to the Minneapolis region. Rainbow Energy is assessing a CO2 capture project for the facility. In addition, approximately 400 MW of wind generation is planned for that area of McLean County to utilize the capacity on the DC line.
3. Hydro Generation:
    - North Dakota has one hydro generation site equipped with 5 units, boasting a total capacity of 614 MW.
    - However, the average capacity factor declined to approximately 43% in 2021 due to limitations imposed by water flow in the river, particularly during drought years.
4. Natural Gas Generation:
    - North Dakota operates three sites for electric generation utilizing natural gas, comprising 21 generating units with a total capacity of 596.3 MW.
    - These units include reciprocating engines and gas turbines, with variation in summer capacity influenced by the performance of gas generators in hot weather.
    - Total natural gas generation in North Dakota remained steady from 2019 through 2021, amounting to 1.445 GWhr in 2021.
5. Total Generation:
    - The combined total capacity of all types of utility-scale generation in North Dakota is approximately 8,863 MW.
    - Wind generation receives a reduced capacity accreditation in the ISO of approximately 600 MW due to its intermittent nature, down from 4,250MW of installed capacity, representing the estimated amount available during peak summer demand. However, newer installations have demonstrated slightly higher capacity for accreditation.

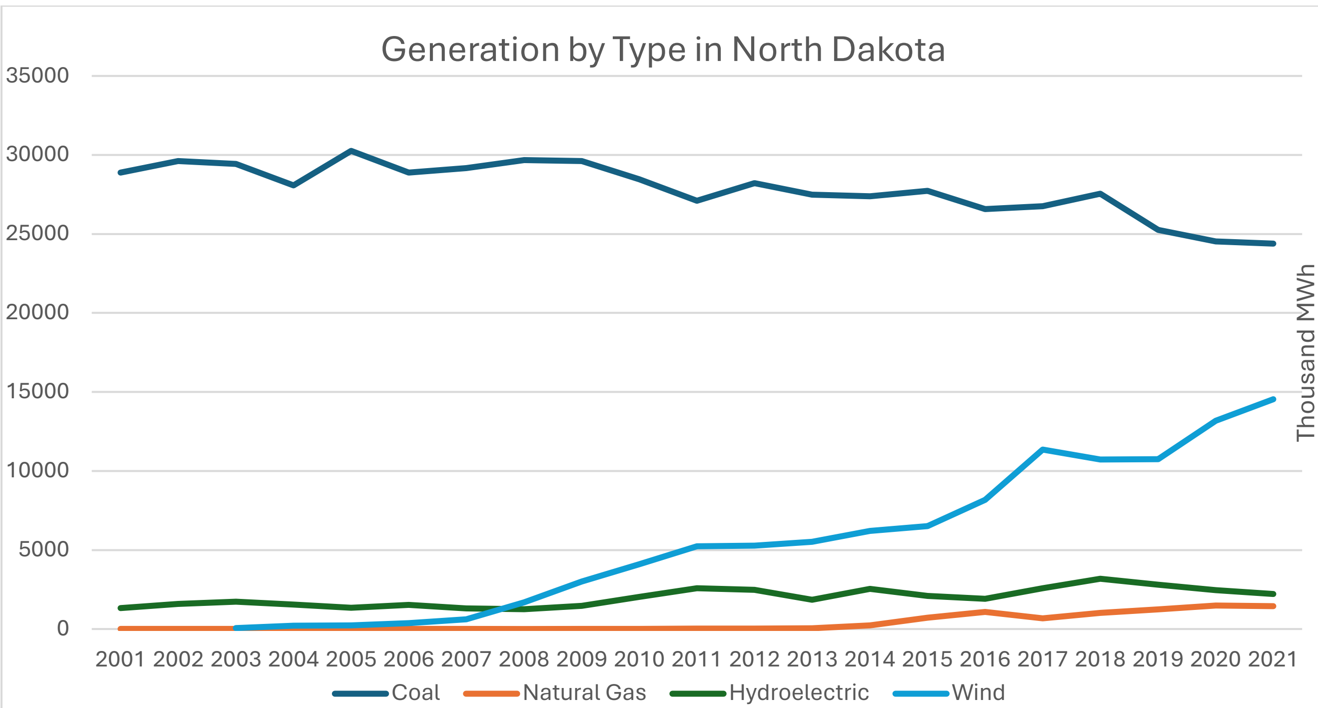
This comprehensive overview underscores the diverse mix of generation resources in North Dakota, with significant contributions from wind, coal, hydro, and natural gas. Continued assessment and adaptation to evolving energy needs and market dynamics are essential for ensuring a reliable and sustainable energy future for the state.

Electric Generation Market & Utilization

In recent decades, North Dakota has emerged as a significant exporter of electricity, primarily fueled by the development of thermal lignite generation in the western part of the state since the 1960s. Concurrently, transmission infrastructure has been expanded to facilitate the export of electricity to markets predominantly situated to the east. Moreover, North Dakota has garnered recognition as an excellent source of wind generation, leading to additional transmission development to accommodate the transmission of this renewable energy to markets.

According to data from the Energy Information Administration, in 2020, North Dakota generated a total of 42,705 MWh of electricity from all sources, with 46% of this total being exported beyond the state's borders over two large high voltage direct current lines (HVDC), which serve load in the neighboring state of Minnesota and multiple 345kv and 230kv alternating current (AC) transmission lines serving surrounding states. Wind generation accounted for 31% of North Dakota's total electricity generation in 2020, highlighting the growing significance of renewable energy in the state's energy portfolio. Notably, industrial demand in North Dakota experienced substantial growth, expanding by nearly 11% in 2020.

While demand for electricity in markets outside of North Dakota, and in most areas within the state, has remained relatively stable in recent years, the Bakken region has witnessed notable demand growth. Over the past 16 years, total electricity generation in North Dakota has increased from 29,936 MWh to 42,705 MWh, with retail sales climbing from 10,516 MWh to 22,975 MWh. This growth is primarily attributed to the burgeoning development of the Bakken oil fields. Industrial consumption in North Dakota also witnessed a robust increase of over 11% in 2020, with power forecasts projecting a continued upward trajectory in demand.



Grid Resource Adequacy and Threats to Growth Opportunities

In 2023, both the MISO and SPP grid operators issued warnings about the adequacy of generation resources to meet peak demand situations. This highlights a growing concern that the desired pace of change towards a more sustainable energy future is outpacing the achievable pace of transformation. This concern is underscored by the stark increase in grid events necessitating the activation of emergency procedures. **For instance, prior to 2016, MISO had no instances requiring the use of emergency procedures, but since then, there have been 48 Maximum Generation events.**

Many experts in the industry project that, despite ambitious goals, realistic scenarios still foresee a substantial dependence on fossil fuel energy—potentially up to 50%—even by 2050. While efforts to decarbonize fossil fuel resources are underway, achieving complete carbon neutrality or a fully renewable energy grid by 2050 appears increasingly unlikely. The scalability and affordability of storage technology, particularly for renewable energy sources, remain significant challenges.

In response to these challenges, Governor Burgum has issued a visionary goal for North Dakota to achieve carbon neutrality in its combined energy and agriculture sectors by 2030. Governor Burgum's approach emphasizes innovation over mandates, aiming to attract industries and technologies that support this goal to the state. The initiative seeks to leverage advancements in carbon capture and sequestration technologies to retain conventional generation in North Dakota while also promoting sustainable agricultural practices and other innovative solutions, such as CO2 sequestration from ethanol production and enhanced oil recovery. These efforts demonstrate a commitment to proactive and pragmatic solutions to address the complexities of achieving carbon neutrality in the energy and agriculture sectors.

The state's vision for a decarbonized energy generation future faces significant challenges due to the individual and cumulative impact of expansive federal rulemakings. These regulations would curtail the flexibility to achieve the 2030 goal through the deployment of carbon capture and sequestration (CCS) technologies. Furthermore, they would impose financial burdens on electric cooperatives and utilities with limited resources, diverting investment away from future growth options toward retrofitting existing facilities with costly emissions technologies to comply with new federal requirements.

This regulatory burden not only impedes progress towards decarbonization but also introduces opportunity costs for utilities and cooperatives. The funds that would otherwise be allocated for future growth and innovation in clean energy solutions are instead diverted to compliance measures, hindering the state's ability to transition to a more sustainable energy future efficiently and effectively.

Ultimately, the restrictive nature of these federal rulemakings poses a significant obstacle to North Dakota's efforts to achieve its decarbonization goals and undermines the state's vision for a cleaner and more sustainable energy generation landscape. It highlights the need for a balanced approach to regulation that supports innovation and investment in carbon reduction technologies while also allowing for continued economic growth and development in the energy sector.

Grid Reliability Is Already Vulnerable

The fragility of grid reliability is already evident as warnings have been issued due to the declining ratio of dispatchable and intermittent generation supplies. This concerning trend poses significant threats to public safety, economic stability, and national security. Grid reliability is vital for ensuring continuous access to essential services, such as food production and military operations. Dispatchable reliable generation forms the backbone of grid stability, enabling the balancing of supply and demand fluctuations. Failure to address these reliability concerns will compromise critical infrastructure and expose society to substantial risks. Urgent action is required to safeguard grid reliability and mitigate the potential consequences for public safety and national security.

NERC's 2023 Reliability Risk Assessment

The North American Electric Reliability Council's 2023 Reliability Risk Assessment[1] are concerning as demonstrated in the slides below. The electrification of the US economy, data & AI center growth and the build it at home initiatives will substantially increase the demand for electricity generation and transmission.

NERC's 2023 Summer Reliability Assessment warns that two-thirds of North America is at risk of energy shortfalls this summer during periods of extreme demand. While there are no high-risk areas in this year's assessment, the number of areas identified as being at elevated risk has increased. The assessment finds that, while resources are adequate for normal summer peak demand, if summer temperatures spike, seven areas — the U.S. West, SPP and MISO, ERCOT, SERC Central, New England and Ontario — may face supply shortages during higher demand levels.

"Increased, rapid deployment of wind, solar and batteries have made a positive impact," said Mark Olson, NERC's manager of Reliability Assessments. "However, generator retirements continue to increase the risks associated with extreme summer temperatures, which factors into potential supply shortages in the western two-thirds of North America if summer temperatures spike."

The North American Electric Reliability Corporation (NERC) recently released its 2023 Long-Term Reliability Assessment (LTRA), which found MISO is the region most at risk of capacity shortfalls in the years spanning from 2024 to 2028 due to the retirement of thermal resources with inadequate reliable generation coming online to replace them.[2]

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[1] NERC. "North American Reliability Assessment." North American Electric Reliability Corporation, May 2023, https://www.nerc.com/news/Headlines%20DL/Summer%20Reliability%20Assessment%20Announcement%20May%202023.pdf.

[2] North American Electric Reliability Corporation, "2023 Long-Term Reliability Assessment," December, 2023, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

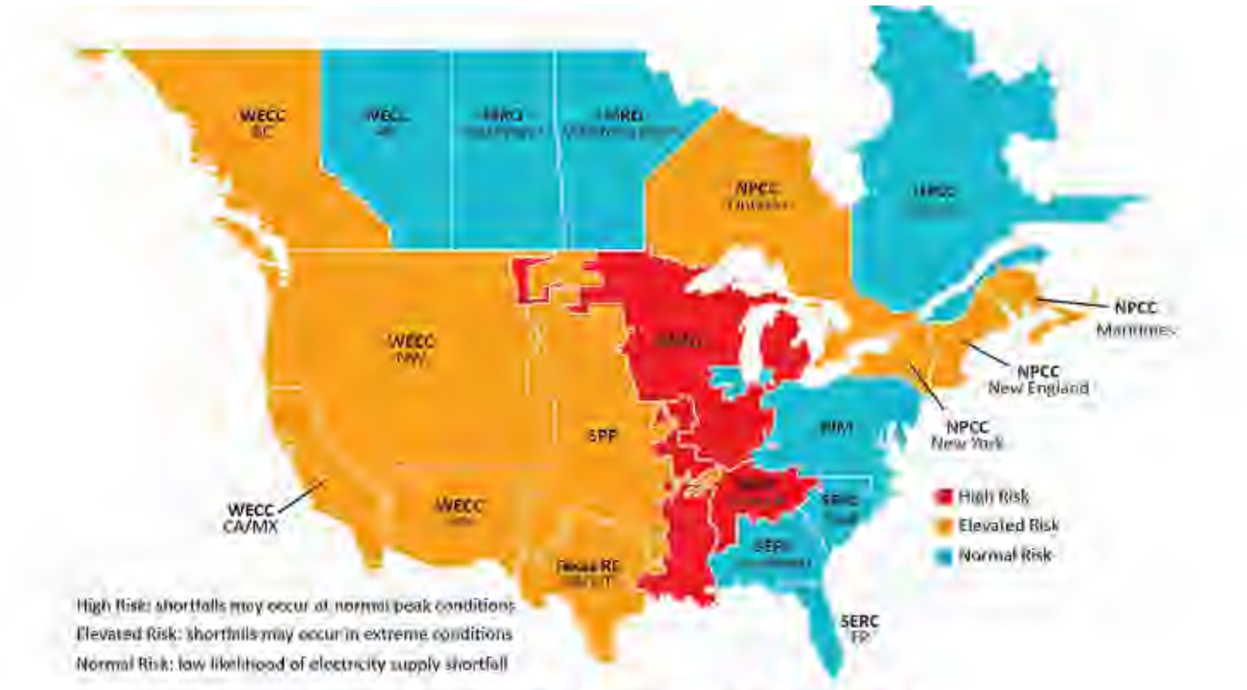

Figure 1: Risk Area Summary 2024–2028[8]

MISO is the region most at risk of rolling blackouts in the near future.

In 2028, MISO is projected to have a 4.7 GW capacity shortfall if expected generator retirements occur despite the addition of new resources that total over 12 GW, leaving MISO at risk of load shedding during normal peak conditions. This is because the new wind and solar resources that are being built have significantly lower accreditation values than the older coal, natural gas, and nuclear resources that are retiring.[3]

MISO's Response to the Reliability Imperative (2024)

On February 26, 2024, the Midcontinent Independent System Operator (MISO) released "MISO's Response to the Reliability Imperative[4]," a report which is updated periodically to reflect changing conditions in the 15-state MISO region that extends through the middle of the U.S. and into Canada. MISO's new report explains the disturbing outlook for electric reliability in its footprint unless urgent action is taken. The main reasons for this warning are the pace of premature retirements of dispatchable fossil generation and the resulting loss of accredited capacity and reliability attributes.

From 2014 to 2024, surplus reserve margins in MISO have been exhausted through load growth and unit retirements. Since 2022, MISO has been operating near the level of minimum reserve

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[3] Midcontinent Independent Systems Operator, "MISO's Response to the Reliability Imperative," February, 2024, https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

[4] MISO. "MISO'S Response to the Reliability Imperative Updated February 2024." MISO, February 2024, https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

margin requirements.[5]

According to the Reliability Imperative, MISO uses an annual planning tool called the OMS-MISO Survey to compile information about new resources utilities and states plan to build and older assets they intend to retire. The 2023 survey shows the region's level of "committed" resources declining going forward, with a potential shortfall of 2.1 GW occurring as soon as 2025 and growing larger over time.

MISO lists U.S. Environmental Protection Agency (EPA) regulations that prompt existing coal and gas resources to retire sooner than they otherwise would as a compounding reason for growing challenges to grid reliability. From the report, there is a section titled, "EPA Regulations Could Accelerate Retirements of Dispatchable Resources," which states:

> *"While MISO is fuel- and technology-neutral, MISO does have a responsibility to inform state and federal regulations that could jeopardize electric reliability.* ***In the view of MISO, several other grid operators, and numerous utilities and states, the U.S. Environmental Protection Agency (EPA) has issued a number of regulations that could threaten reliability in the MISO region and beyond.***
>
> *In May 2023, for example, EPA proposed a rule to regulate carbon emissions from all existing coal plants, certain existing gas plants and all new gas plants. As proposed, the rule would require existing coal and gas resources to either retire by certain dates or else retrofit with costly, emerging technologies such as carbon-capture and storage (CCS) or co-firing with low-carbon hydrogen.*
>
> *MISO and many other industry entities believe that while CCS and hydrogen co-firing technologies show promise, they are not yet viable at grid scale — and there are no assurances they will become available on EPA's optimistic timeline.* ***If EPA's proposed rule drives coal and gas resources to retire before enough replacement capacity is built with the critical attributes the system needs, grid reliability will be compromised.*** *The proposed rule may also have a chilling effect on attracting the capital investment needed to build new dispatchable resources*."

Despite these reliability warnings issued by MISO, EPA did not consider the reliability impacts of the proposed MATS rules required emission control upgrades and additions to units. It is likely that many units that would have to incur millions of dollars to retrofit emissions controls to comply with this proposal would not do so.[6]

In light of these shortcomings, the NDTA contracted with Center of the American Experiment to model the impacts of the MATS rules on resource adequacy, reliability, and cost of electricity to consumers. The findings of this analysis are detailed in Section D.

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[5] Midcontinent Independent Systems Operator, "MISO's Response to the Reliability Imperative," February, 2024, https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

[6] Rae E. Cronmiller, "Comments on Proposed National Emission Standards for Hazardous Air Pollution: Coal-and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," The National Rural Electric Cooperative Association, June 23, 2023, Attention Docket ID NO. EPA-HQ-OAR-2018-0794.

Conclusion: The Long Term Reliability of the MISO Grid is Already Precarious

As the state agency responsible for the strategic buildout and framework of electricity distribution, the North Dakota Transmission Authority (NDTA) is deeply concerned about the potential impact of federal rulemakings on the generation fleet in North Dakota and the ability to support future growth initiatives. The current strain on the electric transmission system due to load growth is already posing significant challenges to grid reliability, particularly in areas facing transmission constraints and limited access to dispatchable generation.

The escalating frequency of grid events requiring emergency procedures, such as the 48 Maximum Generation events in MISO since 2016 and the increasing number of alerts issued by SPP, over 194 alerts issued in 2022, underscores the urgency of addressing transmission congestion and bolstering reliable generation capacity. The economic growth and security of North Dakota are directly tied to the timely development of new transmission facilities in tandem with dependable dispatchable electric generation.

The impacts of grid strain extend beyond the energy sector, affecting multiple industries, ratepayers, and overall economic stability. Volatile wholesale prices and transmission congestion undermine business operations and investment confidence, hindering economic growth and prosperity. Moreover, reliable electricity supply is critical for essential services, including Department of Defense facilities, underscoring the broader implications of grid reliability issues.
Achieving a balanced generation portfolio requires careful consideration of reliability and resilience under all weather conditions, especially amidst the electrification of America and the imperative to safeguard public welfare and security.

Additionally, over 50% of the electricity generated in North Dakota is exported to neighboring states, magnifying the ripple effects of any regulations impacting dispatchable electricity generation resources. By responsibly managing the generation portfolio and prioritizing generation adequacy, North Dakota and the nation can seize significant opportunities for economic growth, innovation, and sustainable development.

Section B: The Proposed MATS Rule Will Dramatically Affect North Dakota Lignite Electric Generating Units

The revised MATS Rule includes a proposal to eliminate the "low rank coal" subcategory established for lignite-powered facilities by requiring these facilities to comply with the same mercury emission limitation that currently applies to Electric Generating Units (EGUs) combusting bituminous and subbituminous coals, which is 1.2 pounds per trillion British thermal units of heat input (lb/TBtu). EPA's proposal is a substantial lowering of the current mercury limitation for lignite fired EGUs, which is 4.0 lb/TBtu.[7,8] The proposal also includes a significant reduction in the particulate matter standard applicable to all existing units from 0.03 lb/mmBtu to 0.01 lb/mmBtu. Because North Dakota is somewhat unique to the degree in which its power generation relies upon lignite coal, the compliance costs for this Rule, while likely to substantial for coal plants all around the country, will be most acutely inflicted upon North Dakota's lignite-based power generation facilities.

Numerous comments in the administrative record, including from the regulated facilities in North Dakota and the North Dakota Department of Environmental Quality, provided EPA with notice that the new emission standards are not technologically feasible, will impose crippling compliance costs that may require facility retirement, and will result in a significant portion of the dispatchable power provided by coal-generation facilities being taken off the grid. This report will summarize some of those concerns in the section that follows, however, a full study of the technological feasibility of complying with the new emissions standards is beyond the scope of this report. For purposes of this report, we assume the regulated facilities and state regulator were forthright in their concerns about the feasibility of lignite-based facilities meeting the new standards.

The Proposed MATS Rule Eliminates the Lignite Subcategory for Mercury Emissions

Although the Proposed Rule affects all coal electrical generating utilities (EGUs), reducing the lignite emissions standards to levels of other coal ranks effectively eliminates the lignite sub-category and would have drastic consequences for North Dakota's lignite EGU industry.[9] EPA original decision to regulate separately a subcategory of lignite units was well-supported with documented information and a thorough analysis. In its comments filed in this Docket, on June 22, 2023, the North Dakota Department of Environmental Quality (hereafter DEQ) encouraged EPA to review that prior determination and reaffirm the need for a lignite subcategory and the associated emissions standards.[10]

Specifically, DEQ summarized the original MATS proposal in 2011 and final MATS rule in 2012, in which EPA presented a body of evidence in support of the lignite category. For example, the EPA wrote:

> "For Hg emissions from coal-fired units, we have determined that different emission limits for the two subcategories are warranted. There were no EGUs designed to burn a non-agglomerating virgin coal having a calorific value (moist, mineral matter free

[7] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[8] [8] J. Cichanowicz et al., *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, (June 2, 2023) ("Cichanowicz Report").

[9] EPA characterizes lignite as "low rank virgin coal". 88 Fed. Reg. 24,854, 24,875. For this comment letter, lignite will be used in place of low rank virgin coal.

[10] David Glatt, P.E., "Comments on the Proposed Rulemaking Titled "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review" (Docket ID No. EPA-HQOAR-2018-0794)," On Behalf of the North Dakota Department of Environmental Quality, June 22, 2023.

> basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in an EGU with a height-to-depth ratio of 3.82 or greater among the top performing 12 percent of sources for Hg emissions, indicating a difference in the emissions for this HAP from these types of units.
>
> The boiler of a coal-fired EGU designed to burn coal with that heat value is larger than a boiler designed to burn coals with higher heat values to account for the larger volume of coal that must be combusted to generate the desired level of electricity. Because the emissions of Hg are different between these two subcategories, we are proposing to establish different Hg emission limits for the two coal-fired subcategories."

As explained by DEQ, EPA has not provided any scientific justification to support abandoning the lignite subcategory and requiring those facilities to comply with the emission standards applicable to other coal types. The most EPA identified in support of its proposal was a reference to information nearly 30 years old, which predated EPA's original determination.

The Proposed MATS Rule Will Not Provide Meaningful Human Health or Environmental Benefits

Section 112(f)(2) of the CAA directs EPA to assess the remaining residual public health and environmental risks posed by hazardous air pollutants (HAPs) emitted from the EGU source category.[11] Further regulation under MATS is required only if that residual risk assessment demonstrates that a tightening of the current HAP emission limitations is necessary to protect public health with an ample margin of safety or protect against adverse environmental effects.

When reviewing whether to revise the MATS Rule, EPA determined that further regulation of mercury and other HAPs would be unnecessary to address any remaining residual risk from any affected EGU within the source category. The stringent standards based on state-of-the-art control technologies that are currently imposed on coal-fired EGUs have already achieved significant reductions in HAP emissions. As EPA itself noted, the MATS rule has achieved steep reductions in HAP emission levels since 2010, including a 90 percent reduction in mercury, 96 percent reduction in acid gas HAPs, and an 81 percent reduction in non-mercury metal HAPs.[12]

Data from EPA and the U.N Global Mercury Assessment show mercury emissions from U.S. power plants are now so low they accounted for only 0.12 percent of global mercury emissions in 2022, assuming all other sources remained constant at 2018 levels.[13] These data demonstrate that

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[11] J. Cichanowicz et al., *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, at 29, Figure 6-7 (June 2, 2023) ("Cichanowicz Report").

[12] Fact Sheet, *EPA's Proposal to Strengthen and Update the Mercury and Air Toxics Standards for Power Plants,* *https://www.epa.gov/system/files/documents/2023-04/Fact%20Sheet_MATS%20RTR%20Proposed%20Rule.pdf*

[13] United Nations, "Global Mercury Assessment 2018," UN Environment Programme, August 21, 2019, https://wedocs.unep.org/bitstream/handle/20.500.11822/27579/GMA2018.pdf?sequence=1&isAllowed=y

US mercury emissions from power plants are lower than global cremation emissions, and North Dakota coal facilities emitted 9.25 times less mercury in 2021 than global cremations in 2018.[14]

Mercury Emissions Estimates by Sector 2018 vs U.S. and N.D. Coal Plant Emissions		
Category	US Tons	Percent of Global Emissions
Artisanal and small-scale mining	921.42	37.68
Global stationary combustion of coal	517.45	21.16
Non-ferrous metals production	359.32	14.69
Cement production	256.48	10.49
Waste from products	161.63	6.61
Vinyl chlorine monomer	64.09	2.62
Biomass burning	57.05	2.33
Ferrous metals production	43.89	1.79
Chlor alkali production	16.66	0.68
Waste incineration	16.44	0.67
Oil refining	15.81	0.65
Stationary combustion of oil and gas	7.84	0.32
Cremation	4.1[illegible]	0.17
US stationary combustion of coal	[illegible].90	0.1[illegible]
North Dakota coal combustion	0.46	0.018

As the above chart indicates: the annual mercury emissions from global cremations (where the mercury primarily comes from individuals with dental fillings) exceed the mercury annually emitted by all coal-fired EGUs in the United States combined, and is orders of magnitude more than the mercury emissions from all coal-fired EGUs in North Dakota.[15]

Moreover, the Administrative Record indicates EPA has performed a comprehensive and detailed risk assessment that clearly documents the negligible remaining residual risks posed by the very low amount of HAPs now being emitted by coal-fired EGUs. EPA first performed that risk assessment in 2020, which concluded 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

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[14] ERM Sustainability Initiative, "Benchmarking Air Emissions of the 100 Largest Power Producers in the United States," Interactive Tool, accessed February 29, 2024, https://www.sustainability.com/thinking/benchmarking-air-emissions-100-largest-us-power-producers/

[15] UN Environmental Programme. (2018). Global Mercury Report 2018, Technical Background Report to the Global Mercury Assessment. https://www.unenvironment.org/resources/publication/global-mercury-assessment-technical-background-report

acceptability" for protecting public health with an adequate margin of safety.[16] Similarly, EPA's risk assessment supports the conclusion that residual risks of HAP emissions from the EGU source category are "acceptable" for other potential public health effects, including both chronic and acute non-cancer effects.[17]

These conclusions have been confirmed by the detailed reevaluation of the 2020 risk assessment that the Agency is now completing as part of the current rule-making action. That EPA reevaluation clearly demonstrates that the 2020 risk assessment did not contain any significant methodological or factual errors that could call into question the results and conclusions reached in the 2020 risk assessment. Most notably, EPA used well-accepted approaches and methodologies for performing a residual risk analysis that adhere to the requirements of the statute and are consistent with prior residual risk assessments performed by EPA over the years for other industry sectors.[18]

The results from both residual risk assessments can lead to only one rational conclusion: the current MATS limitations provide an ample margin of safety to protect public health in accordance with CAA section 112.

The DEQ filed comments addressing these points and asking EPA to provide a better health benefit justification than the rationale currently included in the Regulatory Impacts Analysis (RIA).[19] In particular, DEQ noted that EPA cannot rely on non-HAPs' co-benefits to justify the Proposed Rule, and EPA has not identified any HAP-related benefits that would be sufficient to justify the Proposed Rule. The agency also voiced skepticism over what it called EPA' s suspect characterization of the health benefits that it identified, which is quoted below:

> While the screening analysis that EPA completed suggests that exposures associated with mercury emitted from EGUs, including lignite-fired EGUs, are below levels of concern from a public health standpoint, further reductions in these emissions should further decrease fish burden and exposure through fish consumption including exposures to subsistence fishers.[20]

DEQ's well-founded concern is that EPA's admission that current exposure associated with mercury is below levels of concern is directly inconsistent with, not support of, EPA's proposal for a lower standard.

DEQ commented that this theme, unfortunately, is consistent across the entire "Benefits Analysis" section of the RIA, citing another example of this inconsistency, which is quoted below:

> "Regarding the potential benefits of the rule from projected HAP reductions, we note that these are discussed only qualitatively and not quantitatively

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[16] 88 Fed. Reg. at 24,865.
[17] *Id*. at 24,865-66.
[18] 88 Fed. Reg. at 24,865.
[19] 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 (Apr. 2023), Docket ID: EPA-HQ-OAR-2018-0794-5837.
[20] *Id.* At p. 0-8.

> ....Overall, the uncertainty associated with modeling potential of benefits of mercury reduction for fish consumers would be sufficiently large as to compromise the utility of those benefit estimates-though importantly such uncertainty does not decrease our confidence that reductions in emissions should result in reduced exposures of HAP to the general population, including methylmercury exposures to subsistence fishers located near these facilities. Further, estimated risks from exposure to non-mercury metal HAP were not expected to exceed acceptable levels, although we note that these emissions reductions should result in decreased exposure to HAP for individuals living near these facilities."[21]

Comments filed by the Lignite Energy Council (LEC) further emphasize the point. LEC stated that according to the risk review EPA conducted in 2020, which EPA has proposed to reaffirm, the risks from current emissions of hazardous air pollutants (HAP) emitted by coal-fired power plants are several orders of magnitude below what EPA deems sufficient to satisfy the Clean Air Act.[22] LEC points out that EPA has for decades found risks to be acceptable with an ample margin of safety if maximum individual excess cancer risks presented by any single facility is less than "100-in-1 million." In comparison, EPA's analysis of the coal- and oil-fired electric utility source category recognizes the risk it presents is now at one tenth of that acceptable level, with a maximum risk from any individual facility of "9-in-1 million."

However, even that value vastly overstates the risk associated with coal-fired power plants. The "9-in-1 million" risk level identified by EPA is only associated with a single, uncontrolled, residual oil-fired facility located in Puerto Rico.[23] What EPA's discussion of risk fails to recognize, but its analysis clearly shows, is that the highest level of risk presented by any coal-fired power plant is actually "0.3-in-1 million," more than 300 times lower than the threshold EPA deems acceptable.[24]

The level of risk presented by North Dakota lignite-powered plants is lower still. According to EPA's risk review, the maximum risks presented by any North Dakota lignite-fired power plant is "0.08-in-1 million," yet another order of magnitude lower than the highest risk from any coal-fired plant, and more than three orders of magnitude lower than EPA's "acceptable" level of risk with an "ample margin of safety."

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[21] *Id.* at pp. 4-1 - 4-2.

[22] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[23] *Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2020 Risk and Technology Review Final Rule*, Docket ID No. EPA-HQ-OAR-2018-0794-4553, App. 10, Tbls. 1 & 2a (Sept. 2019) ("Risk Assessment") (note that Table 2a is printed upside down in the final September 2019 version of the Residual Risk Assessment posted at www.regulations.gov, which may interfere with search commands; a searchable version of the same table is available in the December 2018 draft version, Docket ID No.). *See also* 84 Fed. Reg. at 2699 ("There are only 4 facilities in the source category with cancer risk at or above 1-in-1 million, and all of them are located in Puerto Rico.").

[24] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

The risks from North Dakota lignite are so low that they are more easily expressed, not in a million, but in a ***billion***—EPA has determined that the excess cancer risks from all North Dakota lignite plants fall between 5- and 80-in-1 billion.[25] Moreover, EPA's analysis indicates that those maximum risks are not associated with mercury.[26]

In fact, EPA's own analysis confirms the risks from North Dakota lignite-powered plants are so low they are little more than a rounding error that does not even qualify as a significant digit. In its analysis of the still low but relatively higher risk from the Puerto Rican oil-fired plants, EPA determined that one of those facilities presented a risk no greater than "1-in-1 million," even though EPA's modeling actually returned a risk level of "1.**09**-in-1 million."6 EPA discarded the extra ".09," apparently finding it too small to matter. However, that extra ".09" risk equates to "90-in-1 billion," and it is therefore higher than the ***entire*** risk identified for any North Dakota lignite plant.

The Administrative Record Indicates the Mercury Standard of 1.2 lb./TBtu is Technically Unachievable for EGUs using North Dakota Lignite Coal

The Administrative Record for the proposed rule suggests EPA made numerous critical mistakes in assuming lignite fired EGUs can achieve a 1.2 Hg/lb limit with 90% Hg removal. As detailed in the Cichanowicz Report, Section 6, EPA assumed the characteristics of lignite and subbituminous coals are similar such that the Hg removal by emission controls capabilities is similar. In this light, EPA did not consider that the high presence of sulfur trioxide ($SO3$) in lignite coal combustion flue gas that significantly limits the Hg emissions reduction potential of emissions controls.[27]

Similarly, as noted by LEC, EPA's proposal references data obtained via an information collection request as indicative of the level of performance achievable at North Dakota lignite facilities, but that data only reflects relatively short-term testing that does not fully capture the significant variability of lignite coals. Also, unlike other types of facilities that may be able to blend coals to achieve greater consistency in the character of their fuel, all North Dakota lignite units are located at mine-mouth facilities without access to other coal types, and therefore depend entirely on the fuel extracted from the neighboring mine. As a result, changes in constituents between seams of lignite coal can result in a high level of variability in the emission rates that result from use of the coal as it is mined over time.[28]

While LEC agreed with EPA that the injection of activated carbon is the most effective means of reducing mercury emissions from lignite-powered units, LEC also criticized EPA for ignoring the well-known diminishing returns of injecting more carbon. With each marginal increase in carbon

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[25] Risk Assessment, Tbl. 2a (indicating cancer risks of 8.07e-08, 3.09e-08, 1.31e-08, 1.21e-08, and 5.12e-09 for Facility NEI IDs 380578086511, 380578086311, 380558011011, 380578086511, 380578086611 (Milton R. Young, Leland Olds, Coal Creek, Antelope Valley, and Coyote).

[26] *Id*., at Tbl. 2a (indicating the target organ of the risk associated with the plants identified in note 5 is "respiratory").

[27] J. Cichanowicz et al., *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, at 29, Figure 6-7 (June 2, 2023) ("Cichanowicz Report").

[28] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

injection, the incremental increase in emission reduction capability falls. Thus, injecting more and more carbon will not necessarily result in greater emission reductions beyond a certain injection level. LEC asked EPA to evaluate the effect of diminishing returns on its conclusion that North Dakota lignite-powered facilities can achieve the standard designed for all other units of 1.2 lb/TBtu.

EPA does not appear to have taken the above concerns into account in claiming lignite- powered facilities can achieve the performance levels achieved at subbituminous plants. As a result, EPA has significantly underestimated the level of control needed to achieve the proposed standard of 1.2 lb/TBtu. Contrary to the analysis EPA relies upon to justify lowering the standard for lignite plants, control efficiencies of greater than 90 percent would be needed for North Dakota lignite-powered facilities.[29] LEC's comments asked EPA to reconsider its proposal in light of these concerns, and in light of EPA's legal obligation to ensure all standards are "achievable," which means they "must be capable of being met under most adverse conditions which can reasonably be expected to recur."[30]

The Administrative Record indicates a key reason why EPA's proposed standards are unachievable is the chemical composition of North Dakota lignite. For example, lignite has different heat and moisture content than subbituminous coals. As a result, a greater volume of fuel and air is needed at lignite plants to produce the same heat input compared to subbituminous plants. Due to higher fuel and air flows, a much greater volume of sorbent is needed to achieve similar emission reductions, and the additional sorbent dramatically increases cost, and therefore reduces the cost-effectiveness, of the controls.[31]

Another distinguishing difference EPA appeared to overlook in its proposal is the higher sulfur concentration in North Dakota lignite relative to subbituminous Powder River Basin coal, which in turn produces a higher level of sulfur trioxide ("SO3"). In the past, EPA has worked with a consultant that recognized this reality as follow:

> With flue gas SO3 concentrations greater than 5-7 ppmv, the sorbent feed rate may be increased significantly to meet a high Hg removal and 90% or greater mercury removal may not be feasible in some cases. Based on commercial testing, capacity of activated carbon can be cut by as much as one half with an SO3 increase from just 5 ppmv to 10 ppmv.[32]

Cichanowicz et al. highlighted this passage from the S&L technology assessment and also noted that the presence of SO3 often affects capture rates in another way—by requiring units with measurable SO3 to be designed with higher gas temperature at the air heater exit to avoid corrosion that would otherwise occur if the SO3 is allowed to cool and condense on equipment

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[29] Cichanowicz Report, at 25, Table 6-1.
[30] *White Stallion Energy Center, LLC v. EPA*, 748 F.3d 1222, 1251 (2014) (citing *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 n. 46 (D.C. Cir.1980)).
[31] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.
[32] Sargent & Lundy, *IPM Model – Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology*, Project 12847-002, at 3 (Mar. 2013).

components. However, that higher exit gas temperature also impacts the effectiveness of sorbent injection systems—special-purpose tests on a fabric filter pilot plant showed an increase in gas temperature from 310ºF to 340ºF lowered sorbent Hg removal from 81% to 68%.[33] The higher levels of SO_3 formed by the higher sulfur content found in lignite fuels will inhibit the ability of injected sorbents to reduce mercury emissions at lignite plants to a far greater extent than at subbituminous plants.

LEC agreed with these concerns in its comments and raised another important consideration — the fact that, unlike subbituminous plants, selective catalytic reduction (SCR) is technically infeasible on North Dakota lignite, due to its chemical composition. Although SCR systems are primarily installed for the control of nitrogen oxides (NO_X), SCR can enhance the oxidation of elemental mercury ("Hg^0") which facilitates removal in downstream control equipment, such as wet flue gas desulfurization (FGD) systems.[34] The higher level of mercury control achievable with an SCR is almost certainly why the one lignite plant (Oak Grove) evaluated by EPA as part of its review of the MATS RTR appears capable of achieving the mercury limit set for other coal ranks—it has an SCR that cannot be installed on North Dakota lignite facilities.[35]

LEC's comments also highlighted the experience of two LEC members that recently evaluated the difference in mercury control achieved by plants using subbituminous coal equipped with an SCR and plants using lignite coal without an SCR. Based on those evaluations, North Dakota lignite-powered facilities were found to have much greater difficulty reducing mercury emissions, despite using more than three times the amount of halogenated activated carbon than the subbituminous plant.

In the past, EPA has questioned whether SCR is technically feasible for North Dakota lignite-powered facilities, and recent research has confirmed that the significant challenges associated with using SCR on North Dakota lignite remain unresolved.[36] Although SCR has been demonstrated on the types of lignite found in other parts of the country, North Dakota lignite differs substantially in chemical makeup because it contains a much higher concentration of alkali metals (*e.g.*, sodium and potassium) that render the catalyst ineffective.[37]

In particular, the relatively high concentration of sodium in North Dakota lignite forms vapor, condenses, and then coats other particles, or it forms its own particles at a size range of 0.02-0.05 µm. As a vapor or as a very small particle, the sodium will pass through any upstream emissions control equipment (*e.g.*, electrostatic precipitators and scrubbers), and thus will reach the SCR regardless of whether the SCR is located before other emission control devices (high-dust configuration) or after those other controls (low-dust or tail-end configurations).[38]

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[33] Sjostrom 2016.

[34] 88 Fed. Reg. at 24875.

[35] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[36] *See* Draft SIP, App. D, at D.2.c-5 (citing Benson, Schulte, Patwardhan, Jones (2021) "The Formation and Fate of Aerosols in Combustion Systems for SCR NO_X Control Strategies" A&WMA's 114th Annual Conference, #983723).

[37] *Id.*

[38] *Id.*

Once the sodium particles reach the SCR, they plug the pores of the catalyst, which are the key feature that allows for improved oxidation of other pollutants. The sodium also poisons the catalyst both inside the pores and on the surface, rendering the active component of the catalyst inactive. Recent efforts to address these concerns through either cleaning or regeneration of the catalyst have not been successful, even at pilot scale. A study recently cited by DEQ in its regional haze plan provides additional details on these efforts and the unsolved technical challenges that remain regarding the impact of alkali metals in North Dakota lignite on the technical feasibility of SCR.[39]

According to LEC, its members report that efforts to identify a willing vendor for an SCR on a North Dakota lignite unit have been unsuccessful—all vendors have declined to offer SCR for use on North Dakota lignite once they have closely reviewed the unique characteristics that make SCR infeasible on that particular fuel.[40]

In short, the Administrative Record and other available evidence indicates that North Dakota lignite-powered facilities will likely not be able to meet the revised emission standards EPA is proposing for the MATS Rule.

The Administrative Record Indicates the Lower PM Standard May Also Not Be Technically Feasible

In addition to imposing a more stringent mercury standard on lignite by essentially eliminating the subcategory, EPA's proposal also lowers the standard on fPM for all existing units to the level previously deemed achievable only by new units. However, like its proposed Hg standard for lignite, EPA's proposal to revise the PM standard for all coal types remains unjustified by any demonstration of potential human health or environmental benefits.

The LEC's comments detail particular concerns associated with EPA's failure to provide a reasonable justification for so dramatically reducing the PM limit.[41] As LEC noted, the risks that the MATS Rule is designed to address have already been eliminated, down to several orders of magnitude below the level at which Congress directed EPA to stop regulating. The highest residual risk for the entire source category, which is based on an oil-fired unit, is just one tenth of EPA's acceptable level of risk, and the highest risk from any coal plant is more than an order of magnitude below the risk presented by oil-fired units.

Furthermore, the Administrative Record suggests that EPA's analysis of the achievability of the new 0.01 lb/mmBtu standard is based on an arbitrary data set, and that analysis also suffers from a lack of transparency. Specifically, commenters observed that EPA relies on a Sargent & Lundy memorandum that lacks sufficient detail or supporting documentation to verify the assumptions made, essentially hiding much of the agency's thought process behind the claim that the

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[39] *Id.*

[40] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[41] *Id.*

information on which it is based is not available in public forums.[42] In doing so, EPA seemingly commits what it has previously cited as error in plans developed by states and industry—failing to provide sufficient information to understand the reasoning underlying key conclusions.[43]

Moreover, the Administrative Record indicates the combined effect of both the proposal to require universal use of CEMS and the lower standard of 0.01 lb/mmBtu will present a compounded challenge if finalized as proposed. Commenters indicated that the difficulty in demonstrating achievement of the new standard will be exacerbated by the requirement to use the less accurate CEMS, and the difficulty in using CEMS will be exacerbated by the dramatically lower standard.[44] In particular, serious concerns remain with respect to whether a fPM CEMS can effectively estimate emission rates at such low levels, or whether emissions that low will be too small for a CEMS to differentiate compliance from a false reading.[45] EPA attempts to allay these fears by claiming existing units can simply follow in the footsteps of new units, since new units have been subject to a CEMS requirement with a fPM emission limit of 0.090 lb/megawatt-hour since the inception of MATS.[46] **But that assurance provides no comfort—there are no new units.[47]**

In light of these shortcomings, the NDTA contracted with Center of the American Experiment to model the impacts of the MATS rules on resource adequacy, reliability, and cost of electricity to consumers. The findings of this analysis are detailed in Section D.

Section C: Impact of MATS Regulations- Power Plant Economics and Grid Reliability

Power Plant Economic Impacts

The economic impacts for a lignite power plant from the Mercury and Air Toxics Standards (MATS) finalized rule can be substantial. The updated MATS rule, if implemented by the

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[42] *PM Incremental Improvement Memo*, Doc. ID EPA-HQ-OAR-2018-0794-5836 (March 2023) ("Improvements to existing particulate control devices will be dependent on a range of factors including the design and current operation of the units, which is not documented in public forums. … Unfortunately, the details of how those units' ESP designs, upgrades, and operation are not publicly available …. In order to evaluate the applicability of one or more of these potential improvements, information would need to be known about the existing ESPs and their respective operation which is not documented in public forums.").

[43] *See, e.g., Approval and Promulgation of Implementation Plans; Louisiana; Regional Haze State Implementation Plan*, 82 Fed. Reg. 32,294, 32,298 (July 13, 2017) ("Entergy's DSI and scrubber cost calculations were based on a propriety [sic] database, so we were unable to verify any of the company's costs. … Because of these issues, we developed our own control cost analyses ….").

[44] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[45] *Id.*

[46] 88 Fed. Reg. at 24874. The electrical output-based limit for new EGUs translates to approximately 0.009 lb/mmBtu, which is slightly below EPA's proposed limit of 0.010 lb/mmBtu.

[47] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

Environmental Protection Agency (EPA), aims to reduce mercury and other hazardous air pollutant emissions from coal-fired power plants. Coal-firing power plants, and lignite-firing power plants in particular, may face specific challenges and economic consequences in complying with these regulations, which could result in their forced retirement. Some potential economic impacts include:

1. **Escalating Operational Expenditures:** Under this rule, lignite power plants will face an excessive economic burden from a significant uptick in operational costs due to the integration of pollution control equipment. The installation of advanced technologies like activated carbon injection (ACI) and flue gas desulfurization (FGD) systems necessitates continuous monitoring and maintenance to ensure optimal performance. Design specifications vary from plant to plant which increases the complexities of the operating systems that require regular cleaning, replacement of consumables, and calibration, all of which incur additional expenses. Moreover, the implementation of pollution control, measures may necessitate alterations in combustion processes or the introduction of supplementary fuel, further driving up operational costs. As a result, lignite power plants are burdened with substantial ongoing expenditures, while also lacking a positive cost benefit analysis, which will undermine their economic viability and competitiveness in the energy market**.**

2. **Dilemma of Plant Retrofitting or Retirement:** Lignite power plants are confronted with the challenging prospect of either retrofitting existing facilities or contemplating retirement in response to the stringent requirements of the Mercury and Air Toxics Standards (MATS). Plant retrofitting involves substantial investment in upgrading equipment and implementing advanced pollution control technologies to achieve compliance with regulatory mandates. However, these retrofitting endeavors entail significant additional costs, potentially straining the financial resources of plant owners and operators. Moreover, the uncertainty surrounding the long-term economic viability of retrofitted plants further complicates decision-making processes**.**

3. **Impact on Electricity Prices:** The implementation of pollution control technologies to comply with MATS regulations can impose significant financial burdens on lignite power plants. These costs, encompassing the installation, maintenance, and operation of such technologies, would ultimately be transferred to consumers in the form of higher electricity prices. As power plants seek to recoup the expenses incurred in meeting regulatory requirements, consumers will experience an uptick in their electricity bills. This escalation in electricity prices will have far-reaching implications for households, businesses, and industries reliant on affordable energy. It will affect household budgets, impact the competitiveness of businesses, and influence consumer spending patterns. Additionally, higher electricity prices will introduce challenges for industries sensitive to energy costs, potentially leading to shifts in production, investment, and employment patterns within the broader economy. Therefore, the economic impact of elevated electricity prices resulting

from MATS compliance should be carefully considered within the context of the energy market, taking into account the implications for consumers, businesses, and overall economic growth.

4. **Employment Effects:** The escalation in costs and the possibility of plant retrofitting or retirement can reverberate through the lignite industry and associated sectors, potentially leading to job losses. As lignite power plants grapple with increased operational expenses and the financial strain of compliance with regulatory requirements, they may be compelled to streamline operations or even cease production altogether. Such decisions can have a ripple effect on employment within the community, impacting not only plant workers but also individuals employed in ancillary industries such as mining, transportation, and manufacturing. Job losses in these sectors can contribute to economic challenges, including reduced consumer spending, increased unemployment rates, and a decline in overall economic activity. Furthermore, the social and psychological impacts of job loss on affected individuals and communities cannot be understated, as they may face financial insecurity, stress, and uncertainty about their future prospects. Therefore, the potential job impacts stemming from increased costs and plant adjustments underscore the broader economic implications of regulatory compliance measures in the lignite industry.

5. **Regional Economic Consequences:** Lignite power plants are often linchpins of regional economies, exerting substantial influence on employment, tax revenue, and economic activity. Any shifts in the economic viability of these plants, whether due to increased costs, regulatory compliance burdens, or operational adjustments, will trigger broader consequences for local economies. The potential closure or downsizing of lignite power plants can result in the loss of direct and indirect employment opportunities, affecting not only plant workers but also individuals and businesses reliant on plant-related activities. Moreover, the decline in plant operations will lead to reduced tax revenue for local governments, impacting their ability to fund essential services and infrastructure projects. Additionally, the loss of economic activity associated with lignite power plants will ripple through the supply chain, affecting suppliers, vendors, and service providers in the region. This domino effect will exacerbate economic challenges, including decreased consumer spending, increased business closures, and a general downturn in economic vitality. Therefore, changes in the economic landscape of the lignite industry will have far-reaching consequences for regional economies, underscoring the interconnectedness between energy production, employment, and overall economic well-being at the local level.

6. **Impact on Investment Decisions:** The economic ramifications of the MATS rule can significantly shape investment decisions within the lignite industry. Plant owners and prospective investors must carefully evaluate the long-term economic feasibility and potential returns on investment in light of stringent regulatory compliance mandates. The substantial costs associated with MATS compliance, including technology upgrades and operational adjustments, may deter investment in lignite power plants or prompt

divestment from existing assets. Investors may reassess the risk-return profile of lignite-related ventures, considering factors such as regulatory uncertainty, market volatility, and shifting energy trends. Moreover, the potential for increased operational costs and regulatory burdens may incentivize investment in alternative energy sources or cleaner technologies, which align more closely with evolving environmental and sustainability objectives. Therefore, the economic implications of the MATS rule play a pivotal role in shaping investment decisions within the lignite industry, influencing capital allocation, project planning, and strategic resource allocation strategies.

7. **Legal and Regulatory Costs:** Meeting MATS requirements often entails significant legal and regulatory costs associated with monitoring, reporting, and ensuring continued compliance. Lignite power plants must allocate resources to navigate complex regulatory frameworks, engage legal counsel, and implement robust monitoring and reporting systems to adhere to emissions standards. These additional expenses contribute to the overall economic strain on lignite power plants, exacerbating the financial challenges associated with regulatory compliance. As a result, the burden of legal and regulatory costs further underscores the financial pressures faced by lignite power plant operators, shaping their strategic decision-making and resource allocation efforts.

Grid Reliability Impacts

Compliance with the Mercury and Air Toxics Standards (MATS) rule will likely have grid reliability impacts on regional power grids that rely on lignite- or other coal-firing power plants. The impacts on grid reliability for power grids that rely on lignite- or other coal-firing power plants can include:

1. **Operational Adaptations and Flexibility Constraints**: The implementation of pollution control technologies like activated carbon injection (ACI) and flue gas desulfurization (FGD) systems necessitates operational modifications within lignite power plants. These adjustments may include alterations to combustion processes, fuel handling procedures, and overall plant operations to accommodate the integration of new equipment and systems. However, such operational changes can compromise the inherent flexibility of lignite power plants to respond effectively to fluctuating load conditions and grid demands. The need for continuous operation of pollution control systems, coupled with potential limitations in responsiveness, may impede the plant's ability to ramp up or down quickly in response to changes in electricity demand or supply. Consequently, the reliability of lignite power plants to maintain grid stability and meet grid operator requirements may be compromised, raising concerns about their ability to ensure consistent and secure electricity supply. Thus, while MATS compliance aims to mitigate environmental impacts, the operational adaptations required may introduce challenges to the reliability and flexibility of lignite power plants in supporting a resilient and dynamic energy grid.

2. **Disruptions Due to Equipment Installation**: The installation and retrofitting of pollution control equipment often necessitate temporary shutdowns or reduced operating capacities within lignite power plants. These planned downtime periods are essential for integrating new equipment, conducting modifications, and ensuring compliance with regulatory requirements. However, the interruptions in plant operations during these installation phases will have adverse effects on the overall reliability and availability of the plant. The temporary cessation of power generation activities will disrupt electricity supply, potentially affecting grid stability and reliability. Moreover, extended downtime periods may lead to revenue losses for plant operators and suppliers, as well as inconvenience for consumers and end-users reliant on consistent electricity provision. Therefore, while essential for achieving compliance with MATS regulations, the equipment installation process poses challenges to the reliability and continuity of lignite power plant operations, emphasizing the importance of efficient planning and management to minimize disruptions.

3. **Efficiency Implications**: The introduction of pollution control technologies, especially those targeting mercury emissions reduction, will potentially undermine the overall efficiency of lignite power plants. While these technologies play a crucial role in meeting regulatory standards, they often require additional energy inputs and introduce operational complexities that can compromise plant efficiency. For instance, activated carbon injection (ACI) systems necessitate the injection of powdered carbon into the flue gas stream, which can increase resistance and pressure drops within the system, thus reducing overall efficiency. Similarly, flue gas desulfurization (FGD) systems require energy-intensive processes such as limestone slurry preparation and circulation, further impacting plant efficiency. The reduction in efficiency can translate to decreased electricity output per unit of fuel input, potentially affecting the plant's ability to generate electricity reliably and meet demand fluctuations. Consequently, while pollution control measures are essential for environmental protection, the associated efficiency implications underscore the need for careful optimization and balancing of environmental and operational considerations to ensure reliable power generation from lignite plants.

4. **Elevated Maintenance Demands**: The incorporation of MATS-compliant equipment, including ACI and FGD systems, often translates to heightened maintenance requirements within lignite power plants. The intricate nature of these pollution control technologies necessitates more frequent inspections, cleaning, and servicing to ensure optimal performance and regulatory compliance. However, the increased maintenance needs can result in extended periods of downtime, during which the plant may be unable to generate electricity, impacting its reliability and availability. Moreover, the allocation of resources and manpower to address maintenance tasks diverts attention and resources away from other operational activities, potentially affecting overall plant efficiency and productivity. Therefore, while essential for environmental compliance, the elevated maintenance

demands associated with MATS-compliant equipment pose challenges to the reliability and operational continuity of lignite power plants, highlighting the importance of proactive maintenance planning and execution to minimize disruptions.

5. **Inherent Fuel Supply Hurdles:** Lignite power plants grapple with inherent challenges associated with the utilization of lignite coal, particularly in meeting stringent emission standards. Lignite, characterized by its lower rank and elevated moisture content, poses unique obstacles in combustion processes. The variability in chemical composition across different seams of coal extracted from mines further complicates the task of ensuring consistent and efficient combustion. Each seam presents distinct combustion characteristics, necessitating meticulous adjustments in operational parameters to maintain compliance with emission regulations. Consequently, lignite power plants encounter difficulties in securing a reliable and uniform fuel supply, which undermines their ability to consistently meet emission targets and operational efficiency goals. The intricacies of managing diverse coal qualities exacerbate the complexities of pollution control measures, posing significant operational challenges for lignite power plants.

6. **Integration Challenges**: The introduction of new pollution control technologies into operational lignite power plants may encounter compatibility hurdles. Ensuring seamless integration with existing infrastructure is paramount for preserving reliability. Compatibility issues can emerge from differences in technology specifications, operational parameters, or control systems between the new equipment and the plant's established infrastructure. Unaddressed disparities may lead to operational inefficiencies, malfunctions, or system failures. Thus, meticulous planning and coordination are vital to mitigate compatibility risks and uphold the reliability of lignite power plants. Failure to address these challenges will compromise plant performance, emphasizing the need for thorough assessment and integration procedures when adopting new technologies.

7. **System Coordination and Grid Stability:** Adjustments in operating conditions and responses to fluctuating load demands can disrupt system coordination and compromise grid stability. Lignite power plants must coordinate closely with grid operators to maintain reliable electricity supply while adhering to MATS requirements. Changes in plant operations, such as implementing pollution control technologies or adjusting output levels, can affect the overall balance of supply and demand within the grid. Without effective coordination, these changes may lead to imbalances, voltage fluctuations, or frequency deviations, posing risks to grid stability. Therefore, robust communication and collaboration between lignite power plants and grid operators are essential to ensure seamless integration of plant operations with broader grid dynamics. By coordinating effectively, lignite power plants can contribute to grid stability while meeting regulatory obligations, ensuring the reliable delivery of electricity to consumers.

8. **Continuous Compliance Management**: Adhering to emission limits mandated by MATS necessitates ongoing monitoring and fine-tuning of pollution control equipment. The chemical properties of lignite can vary even within coal seams from the same mine, posing challenges in preparation and adjustment for plant operations. This variability complicates efforts to maintain consistent compliance, requiring dynamic adjustments in day-to-day plant operations. Consequently, ensuring reliable compliance becomes a dynamic process, demanding meticulous attention to detail and proactive management of pollution control systems. Consistent monitoring and adjustment are essential to mitigate emissions effectively while sustaining the operational reliability of lignite power plants amidst the inherent variability of lignite coal properties.

9. **Supply Chain Vulnerabilities:** The consolidation in the power plant equipment sector over the past decade has reduced the number of suppliers available. Relying on specific suppliers for pollution control equipment and technologies introduces supply chain risks. Disruptions in the supply chain, such as shortages, delays, or quality issues, will impede the timely installation and operation of essential equipment, jeopardizing reliability. Lignite power plants must carefully assess and manage these supply chain vulnerabilities to ensure uninterrupted access to critical components and technologies necessary for regulatory compliance and operational integrity. Proactive measures, such as diversifying suppliers or implementing contingency plans, are crucial for mitigating supply chain risks and maintaining the reliability of lignite power plants.

10. **Long-Term Viability and Aging Infrastructure:** Compliance with MATS regulations will raise concerns about the long-term viability of older lignite power plants. Aging infrastructure may struggle to adapt to the requirements of new pollution control technologies, posing challenges that will impact reliability. The integration of these technologies into outdated systems may require extensive retrofitting or upgrades, which can strain resources and prolong downtime. Moreover, the operational lifespan of aging infrastructure may be limited, leading to questions about the economic feasibility of investing in costly compliance measures. Plant owners must carefully assess the cost-benefit ratio of compliance efforts and consider the potential impact on reliability when evaluating the long-term viability of older lignite power plants. Failure to address these challenges will compromise the reliability and competitiveness of these facilities in the evolving energy landscape.

Section D: Modeling Results

Summary

The EPA did not conduct a reliability analysis for its proposed MATS rules or its Post IRA base case, instead it conducted a Resource Adequacy and reserve margin analysis, which EPA has claimed is necessary but not sufficient to grid reliability.[48]

EPA's lack of reliability modeling prompted several entities to voice concerns in the original docket for the Proposed MATS rule would negatively impact grid reliability, including the National Rural Electric Coop Association, the American Coal Council, The Lignite Energy Council, PGen, the American Public Power Association, and the National Mining Association.[49,50,51,52,53,54]

To provide this necessary perspective, Center of the American Experiment modeled the reliability and cost impacts of the proposed Mercury and Air Toxics Standards (MATS) in the subregions consisting of the Midcontinent Independent Systems Operator (MISO) as it relates to the elimination of the subcategory for lignite-fired power plants.[55,]

Our analysis determined that the closure of lignite-fired powered power plants in the MISO footprint would increase the severity of projected future capacity shortfalls, i.e. rolling blackouts, in the MISO system if these resources are replaced with wind, solar, battery storage, and natural gas plants consistent with the EPA's estimates for capacity values for intermittent and thermal resources.

Building these replacement resources would come at a great cost to MISO ratepayers. The existing lignite facilities are largely depreciated assets that generate large quantities of dispatchable, low-cost electricity. Our modeling determined the total cost of replacement generation capacity in the Status Quo, Partial, and Full scenarios will cost $12.93 billion, $14.88 billion, and $16.76 billion, respectively, from 2024 through 2035, resulting in incremental costs of $1.9 billion in the Partial

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[48] Resource Adequacy Analysis Technical Support Document, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal Docket ID No. EPA-HQ-OAR-2023-0072 U.S. Environmental Protection Agency Office of Air and Radiation April 2023.
[49] NRECA Comments, EPA-HQ-OAR-2018-0794-5956, at 5-6.
[50] American Coal Council Comments, EPA-HQ-OAR-2018-0794-6808, at 3.
[51] LEC Comments, EPA-HQ-OAR-2018-0794-5957, at 17.
[52] PGen Comments, EPA-HQ-OAR-2018-0794-5994, at 5.
[53] APPA Comments, EPA-HQ-OAR-2018-0794-5958, at 33.
[54] NMA Comments, EPA-HQ-OAR-2018-0794-5986, at 29.
[55] U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," 88 FR 24854, April 24, 2023, https://www.federalregister.gov/documents/2023/04/24/2023-07383/national-emission-standards-for-hazardous-air-pollutants-coal--and-oil-fired-electric-utility-steam.

scenario and $3.8 billion in the Full scenario through 2035, compared to operating the current lignite facilities under status quo conditions.

MISO residents would also suffer economic damages from the increased severity of rolling blackouts, which can result in food spoilage, property damage, lost labor productivity, and loss of life. American Experiment calculated the economic damages associated with the increase in unserved electricity demand using a metric called the Value of Lost Load (VoLL) criteria, which can be thought of as the Social Cost of Blackouts.

Our analysis found that the MATS rule would cause an additional 73,699 additional megawatt hours (MWh) of unserved load in the in the Full MATS Retirement scenario in 2035 using 2019 hourly electricity demand and wind and solar capacity factors. Using a conservative value for the VoLL of $14,250 per MWh, we conclude the MATS rule would produce economic damages of $1.05 billion under these conditions.

Therefore, the incremental costs stemming from the closure of the 2,264 MW of lignite fired capacity in MISO under the Full scenario exceeds the projected net present value benefits of $3 billion from 2028 through 2037 using a 3 percent discount rate modeled by EPA in its Regulatory Impact Analysis.

Modeling the Reliability and Cost of the MISO Generating Fleet Under Three Scenarios

Our analysis examined the impact of the proposed MATS rules on the reliability of the MISO system through 2035 by comparing two lignite retirement scenarios to a "Status Quo" scenario that represents "business as usual" that assumes no changes to the generating fleet occur due to the MATS rule, or any other of EPA's pending regulations.[56]

Status Quo scenario: Installed generator capacity assumptions for MISO in the Status Quo scenario are based on announced retirements from U.S. Energy Information Administration (EIA) database and utility Integrated Resource Plans (IRPs) through 2035 compiled by Energy Ventures Analysis on behalf America's Power, a trade association whose sole mission is to advocate at the federal and state levels on behalf of the U.S. coal fleet.[57] This database is also used by the NERC LTRA suggesting it is among the most credible databases available for this analysis.[58] It should be noted that this database leaves considerably more coal and natural gas on its system than the MISO grid EPA assumes will be in service in the coming years in its Proposed Rule Supply Resource

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[56] See Appendix 2: Capacity Retirements and Additions in Each Scenario.
[57] America's Power, "Proprietary data base maintained by Energy Ventures Analysis, an energy consultancy with expertise in electric power, natural gas, oil, coal, renewable energy, and environmental policies" Personal Communication, November 3, 2023.
[58] North American Electric Reliability Corporation, "2023 Long-Term Reliability Assessment," December, 2023, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

Utilization file, meaning our reliability assessment will be more conservative than if we used EPA's capacity projections.

Retired thermal resources in the Status Quo scenario are replaced by solar, wind, battery storage, and natural gas in accordance with the current MISO interconnection queue to maintain resource adequacy based on capacity values given to these generators in EPA's Proposed Rule Supply Resource Utilization file.[59] These capacity values are described in greater detail in the section labeled Replacement Capacity Based on EPA Methodology for Resource Adequacy.

Partial MATS Retirement scenario: The Partial MATS retirement scenario assumes 1,150 megawatts (MW) of lignite fired capacity in North Dakota is retired in addition to incorporating all of the announced retirements in the Status Quo. This value was chosen because it represents the retirement of one lignite facility in North Dakota that serves the MISO market. These resources are replaced with wind, solar, battery storage, and natural gas capacity using the methodology described greater detail in the section labeled Replacement Capacity Based on EPA Methodology for Resource Adequacy.[60]

Full MATS scenario: The Full MATS retirement scenario assumes the MATS regulations will cause all 2,264 MW of lignite-fired generators in the MISO system to retire, in addition to incorporating the retirements in the Status Quo scenario will occur.[61] These resources are replaced with wind, solar, battery storage, and natural gas capacity using the methodology described greater detail in the section labeled Replacement Capacity Based on EPA Methodology for Resource Adequacy.[62]

Reliability in each scenario

The EPA did not conduct a reliability analysis for its proposed MATS rules or its Post IRA base case. Instead, it conducted a Resource Adequacy analysis of its proposed rule, compared to the Post IRA base case.

Resource Adequacy and reserve margin analyses can be useful tools for determining resource adequacy and reliability, but the shift away from dispatchable thermal resources (fossil fuel) toward intermittent resources (wind and solar) increases the complexity and uncertainty in these analyses and makes them increasingly dependent on the quality of the assumptions used to construct capacity accreditations.[63]

[59] U.S. Environmental Protect Agency, "Proposed Regulatory Option," Zip File, https://www.epa.gov/system/files/other-files/2023-04/Proposed%20Regulatory%20Option.zip
[60] See Appendix 3: Replacement Capacity Based on EPA Methodology for Resource Adequacy.
[61] These figures represent the rated summer capacity as indicated by the U.S. Energy Information Administration.
[62] See Appendix 3: Replacement Capacity Based on EPA Methodology for Resource Adequacy.
[63] See Appendix 4: Resource Adequacy in Each Scenario.

This is likely a key reason why EPA has distinguished between resource *adequacy* and resource *reliability* in its Resource Adequacy Technical Support Document for its proposed carbon dioxide regulations on new and existing power plants.[64,65] EPA stated:

> "As used here, the term **resource adequacy** is defined as the provision of adequate generating resources to meet projected load and generating reserve requirements in each power region, while **reliability** includes the ability to deliver the resources to the loads, such that the overall power grid remains stable." **[emphasis added].**" EPA goes on to say that "resource adequacy … is necessary (but not sufficient) for grid reliability.[66]

As the grid becomes more reliant upon non-dispatchable generators with lower reliability values, it is crucial to "stress test" the reliability outcomes of systems that use the EPA's capacity value assumptions in their Resource Adequacy analyses by comparing historic hourly electricity demand and wind and solar capacity factors against installed capacity assumptions in the Status Quo, Partial, and Full scenarios.

We conducted such an analysis by comparing EPA's modeled MISO generation portfolio to the historic hourly electricity demand and hourly capacity factors for wind and solar in 2019, 2020, 2021, and 2022. These data were obtained from the U.S. Energy Information Administration (EIA) Hourly Grid Monitor to assess whether the installed resources would be able to serve load for all hours in each Historic Comparison Year (HCY).[67]

For our analysis, hourly demand and wind and solar capacity factors were adjusted upward to meet EPA's peak load, annual generation, and capacity factor assumptions. These assumptions are generous to the EPA because they increase the annual output of wind and solar generators to levels that are not generally observed in MISO.

Extent of the Capacity Shortfalls

While our modeling determined that the retirement of lignite facilities had a minimal impact on the number of hours of capacity shortfalls observed in the Partial and Full scenarios, retiring the lignite facilities makes the extent of capacity shortfalls worse.

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[64] EPA did not produce a Resource Adequacy Technical Support Document for the MATS rules.
[65] U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," 88 FR 24854, April 24, 2023, https://www.federalregister.gov/documents/2023/04/24/2023-07383/national-emission-standards-for-hazardous-air-pollutants-coal--and-oil-fired-electric-utility-steam.
[66] Resource Adequacy Analysis Technical Support Document, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal Docket ID No. EPA-HQ-OAR-2023-0072 U.S. Environmental Protection Agency Office of Air and Radiation April 2023.
[67] U.S. Energy Information Administration, "Hourly Grid Monitor," https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.

For example, Figure D-1 shows largest capacity shortfalls in the Status Quo scenario, which occur in 2035 using the 2021 Historical Comparison Year for hourly electricity demand and wind and solar capacity factors.

Each resource's hourly performance is charted in the graph below. Thermal units are assumed to be 100 percent available, which is consistent with EPA's capacity accreditation for these resources, and wind and solar are dispatched as available based on 2021 fluctuations in generation. Blue sections reflect the use of "Load Modifying Resources," which are reductions in electricity consumption by participants in the MISO market.

Purple areas show time periods where the batteries are discharged. These batteries are recharged on January 8th and 9th using the available natural gas and oil-fired generators. Red areas represent periods where all of the resources on the grid are unable to serve load due to low wind and solar output and drained battery storage systems. At its peak, the largest capacity shortfall is 15,731 MW.

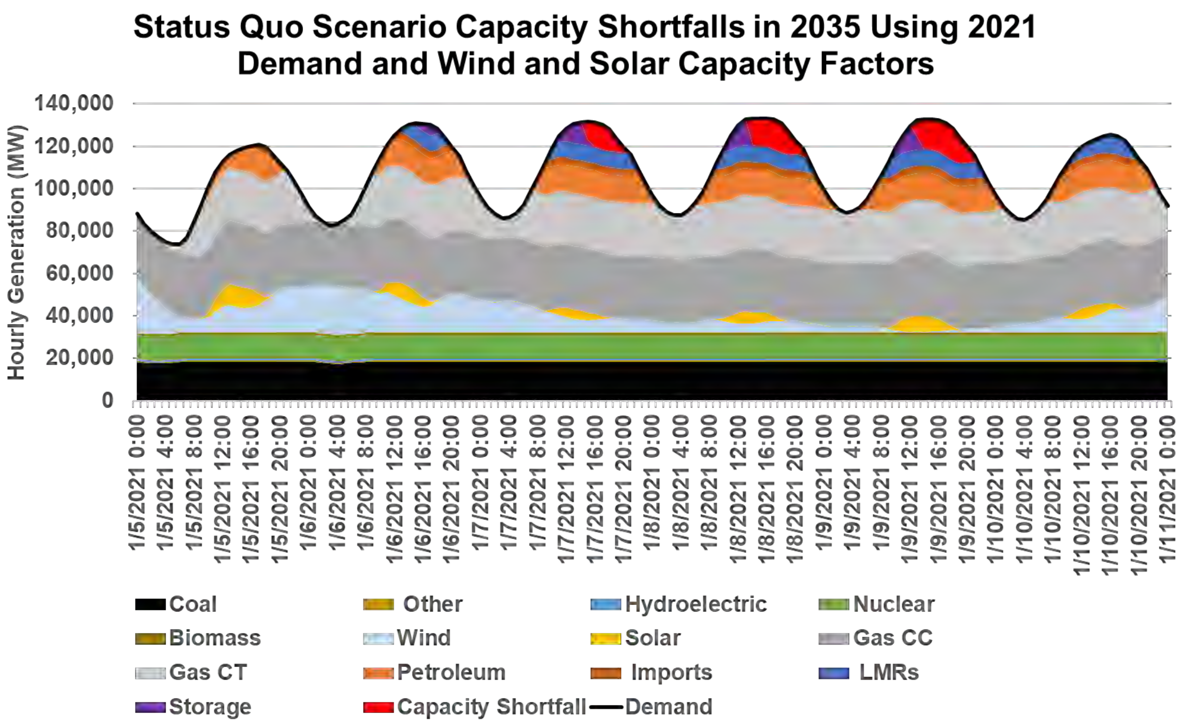

Figure D-1. This figure shows the generation of resources on the MISO grid in the Status Quo during a theoretical week in 2035. The purple portions of the graph show the battery storage discharging to provide electricity during periods of low wind and solar generation. Unfortunately, the battery storage does not last long enough to avoid blackouts during a wind drought.

These capacity shortfalls become more pronounced in the Partial and Full scenarios as less dispatchable capacity exists on the grid to serve load. Figure D-2 shows the three capacity shortfall events in Figure D-1. It depicts the blackouts observed in the Status Quo scenario in green, and the additional MW of unserved load in the Partial and Full scenarios in yellow and red, respectively.

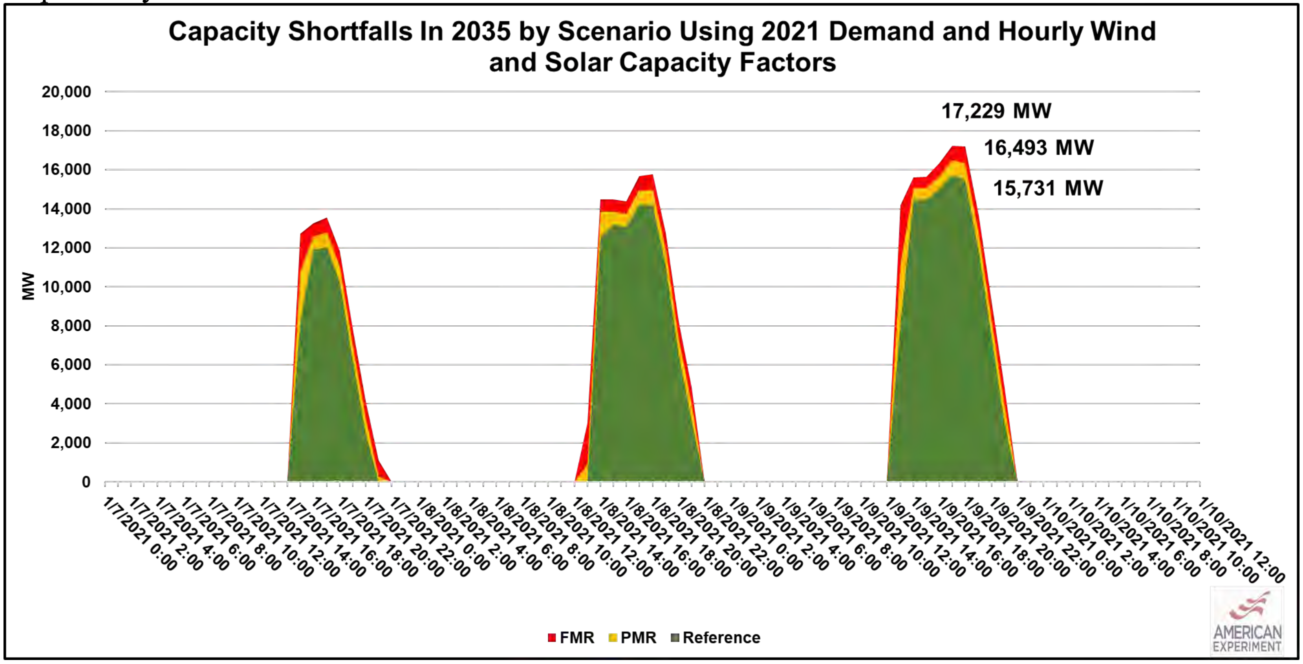

Figure D-2. Capacity shortfalls increase during a hypothetical January 9th, 2035 from 15,731 MW at their peak in the Status Quo to 16,493 MW in the Partial scenario and 17,229 MW in the Full scenario.

Table D-1 shows the largest capacity shortfall, in terms of MW, for each scenario in each of the four Historical Comparison Years studied and the incremental increase in the largest shortfall due to the lignite closures stemming from the MATS rule for the Partial and Full scenarios.

The largest incremental increase in capacity shortfalls would occur in the 2020 HCY in the Full scenario as the blackouts would increase from 552 MW in the Status Quo scenario to 3,295 in the Full scenario, a difference of 2,743 MW.

Maximum MW Shortfalls in 2035 in Each HCY

Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	15,130	15,842	712	16,530	1,400
2020	552	2,587	2,034	3,295	2,743
2021	15,731	16,493	762	17,229	1,498
2022	10,615	11,409	794	12,177	1,562

Table D-1. This table shows the largest capacity shortfall, in terms of MW, for each scenario in each of the four Historical Comparison Years studied and the incremental increase in the largest shortfalls due to the lignite closures stemming from the MATS rule for the Partial and Full scenarios.

It is important to note that this difference is larger than the amount of lignite-fired capacity that is retired in the Full scenario (2,264 MW) because the retirement of these facilities reduces the amount of capacity available to charge battery storage resources.

Unserved MWh in Each Scenario

The amount of unserved load in each scenario can also be measured in megawatt hours (MWh). This metric is a product of the number of hours with insufficient energy resources multiplied by the hourly energy shortfall, measured in MW. This metric may be a more tangible way to understand the impact that the unserved load will have on families, businesses, and the broader economy. Each MWh reflects an increment of time where electric consumers in the MISO grid will not have access to power.

Table D-2 shows the number of MWhs of unserved load in each scenario for the four HCYs studied. In some HCYs, the incremental number of unserved MWhs is fairly small, but in other years they are substantial. In the 2020 HCY, the Partial scenario had 2,042 more MWhs of unserved load than the Status Quo scenario, and the Full scenario had 4,265 MWh of additional unserved load, compared to the Status Quo Scenario.

Total MWh Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	168,723	204,050	35,327	242,393	73,669
2020	582	2,624	2,042	4,847	4,265
2021	244,743	273,927	29,184	304,021	59,278
2022	53,458	62,223	8,765	71,304	17,846

Table D-2. The incremental MWh of unserved load ranges from 2,042 to 35,327 in the Partial scenario, and from 4,265 to 73,669 in the Full scenario.

In the 2019 HCY, the Partial scenario experienced an additional 35,327 MWh of unserved load and the Full scenario experienced 73,669 MWh of unserved load. These additional MWh of unserved load will impose hardships on families, businesses, and the broader economy.

The Social Cost of Blackouts Using the Value of Lost Load (VoLL)

Blackouts are costly. They frequently result in food spoilage, lost economic activity, and they can also be deadly. Regional grid planners attempt to quantify the cost of blackouts with a metric called the Value of Lost Load (VoLL). The VoLL is a monetary indicator *expressing the costs associated with an interruption of electricity supply*, expressed in dollars per megawatt hour (MWh) of unserved electricity.

MISO currently assigns a Value of Lost Load (VOLL) of $3,500 per megawatt hour of unserved load. However, Potomac Economics, the Independent Market Monitor for MISO, recommended a value of $25,000 per MWh for the region.[68] For this study, we used a midpoint value of $14,250 per MWh of unserved load to calculate the social cost of the blackouts under each modeled scenario.

Table D-3 shows the economic damage of blackouts in each scenario in model year 2035 and shows the incremental increase in the VOLL in the Partial and Full scenarios. Incremental VOLL costs are highest using the 2019 HCY where MISO experiences an additional $503.4 million in economic damages due to blackouts in the Partial scenario, and an additional $1.05 billion in the Full scenario.

Value of Lost Load for Capacity Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	$2,404,309,657	$2,907,716,665	$503,407,008	$3,454,098,692	$1,049,789,035
2020	$8,296,505	$37,389,117	$29,092,612	$69,074,216	$60,777,712
2021	$3,487,594,170	$3,903,464,847	$415,870,677	$4,332,301,464	$844,707,294
2022	$761,782,023	$886,680,023	$124,898,001	$1,016,083,680	$254,301,657

Table D-3. MISO would experience millions of dollars in additional economic damage if the lignite fired power plants in its footprint are shut down in response to the MATS regulations.

It is important to note that these VOLL figures are not the total estimated cost impacts of blackouts for the MATS regulations. Rather, they are a snapshot of a range of possible outcomes for the year 2035 based on variations in electricity demand and wind and solar productivity.

The VOLL demonstrates harm of the economy in a multitude of ways. For the industrial/commercial sector, direct costs from losing power (and therefore benefits from avoiding power outages) can be (1) opportunity cost of idle resources, (2) production shortfalls / delays, (3) damage to equipment and capital, and (4) any health or safety impacts to employees. There are also indirect or macroeconomic costs to downstream businesses/consumers who might depend on the products from a company who experiences a power outage.[69]

For the residential sector, the direct costs are different. They can include (1) restrictions on activities (e.g. lost leisure time, lost work time, and associated stress), (2) financial costs through property damage (e.g. damage to real estate via bursting pipes, food spoilage), and (3) health and safety issues (e.g. reliance on breathing machines, air filters).[70]

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[68] David B. Patton, "Summary of the 2022 MISO State of the Market Report," Potomac Economics, July 13, 2023, https://cdn.misoenergy.org/20230713%20MSC%20Item%2006%20IMM%20State%20of%20the%20Market%20Recommendations629500.pdf.

[69] Will Gorman, "The Quest to Quantify the Value of Lost Load: A Critical Review of the Economics of Power Outages," The Electricity Journal Volume 35, Issue 8, October 2022, https://www.sciencedirect.com/science/article/pii/S1040619022001130.

[70] Will Gorman, "The Quest to Quantify the Value of Lost Load: A Critical Review of the Economics of Power Outages," The Electricity Journal Volume 35, Issue 8, October 2022, https://www.sciencedirect.com/science/article/pii/S1040619022001130.

Hours of Capacity Shortfalls

Comparing hourly historic electricity demand and wind and solar output to MISO grid in the Status Quo scenario, our modeling found that MISO would have capacity shortfalls in the 2019, 2021, and 2022 HCYs which can be seen in Table D-4 below.

There would be additional capacity shortfalls in all of the HCYs modeled in the Partial and Full scenarios, where the Partial scenario would experience four additional hours of blackouts in 2019 HCY, one additional hour of blackouts in the 2020 HCY, four additional hours of blackouts in 2021 HCY, and one additional hour of blackouts in the 2022 HCY. In the Full scenario, there would be five additional hours of blackouts in the 2019 HCY, one additional hour of blackouts in the 2020 HCY, eight additional hours in the 2021 HCY, and two additional hours in the 2022 HCY, compared to the Status Quo Scenario.

Hours of Capacity Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	28	32	4	33	5
2020	2	3	1	3	1
2021	24	28	4	32	8
2022	13	14	1	15	2

Table D-4. Capacity shortfalls occur in three of the four HCYs in the Status Quo scenario and all four HCYs for the Partial and Full scenarios.

Cost of replacement generation

Our VOLL analysis demonstrates that the MATS rules will cause significant economic harm in MISO by reducing the amount of dispatchable capacity on the grid due to lignite plant closures stemming from the removal of the lignite subcategory.

However, load serving entities (LSEs) will also begin to incur costs as they build replacement generation to maintain resource adequacy if lignite resources are forced to retire in response to the proposed MATS rules. These costs will be passed on to electricity consumers and must be calculated to produce accurate estimates of the true cost of the MATS regulations.

We modeled the cost of the replacement generation under the Status Quoe, Partial and Full scenarios. The cost of the Partial and Full scenarios, when compared to the Status Quo scenario, is used to determine the additional economic burden that the MATS regulations will impose onto MISO electricity customers.

Our modeling determined the total cost of replacement generation capacity in the Status Quo, Partial, and Full scenarios will cost $12.93 billion, $14.88 billion, and $16.76 billion, respectively, from 2024 through 2035 (see Figure D-3).

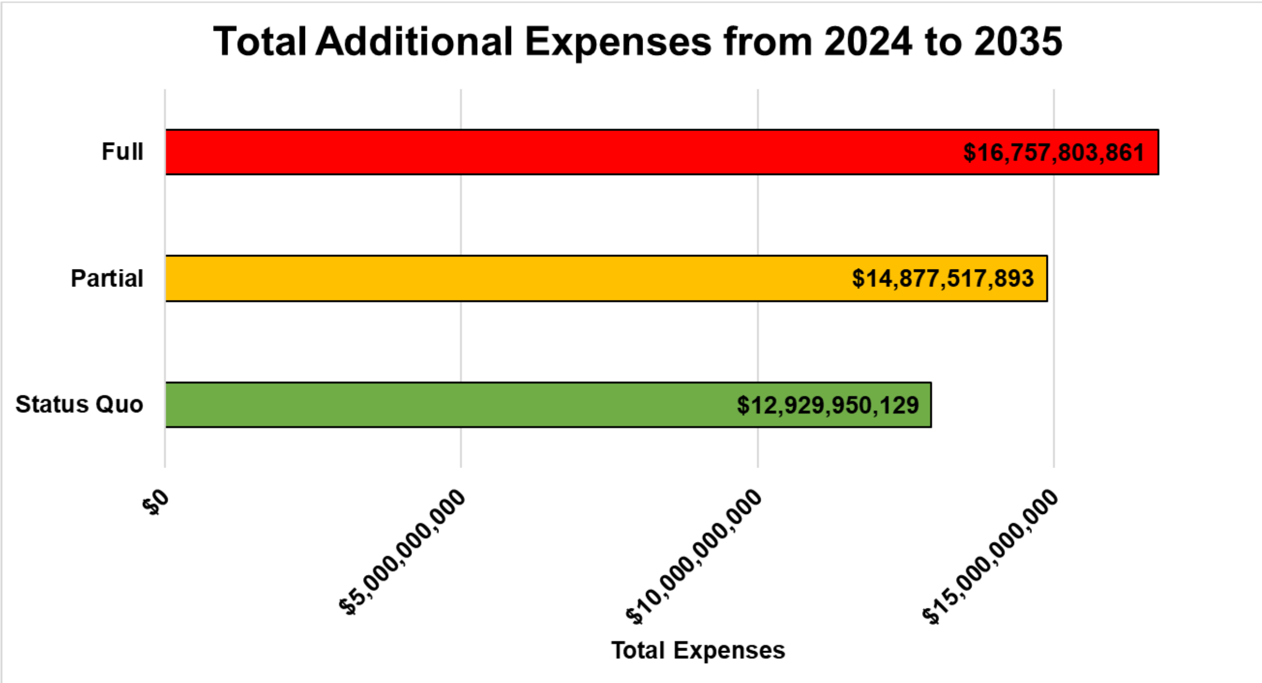

Figure D-3. The Partial scenario will cost $1.95 billion more than the Status Quo scenario from 2024 through 2035 and the Full scenario will cost $3.8 billion more than the Status Quo scenario in this timeframe.

Figure D-4 shows the incremental cost of the Partial and Full scenarios from 2024 through 2030, the period reflecting the up-front costs of complying with the regulations. From 2024 through 2028, LSEs would incur $337 million by building replacement generation in the Partial scenario, compared to the Status Quo scenario, and $654 million in the Full scenario, relative to the Status Quo. It should be noted that these costs are only the cost of building replacement generation and do not factor in the cost of decommissioning or remediating existing power plants or mine sites.

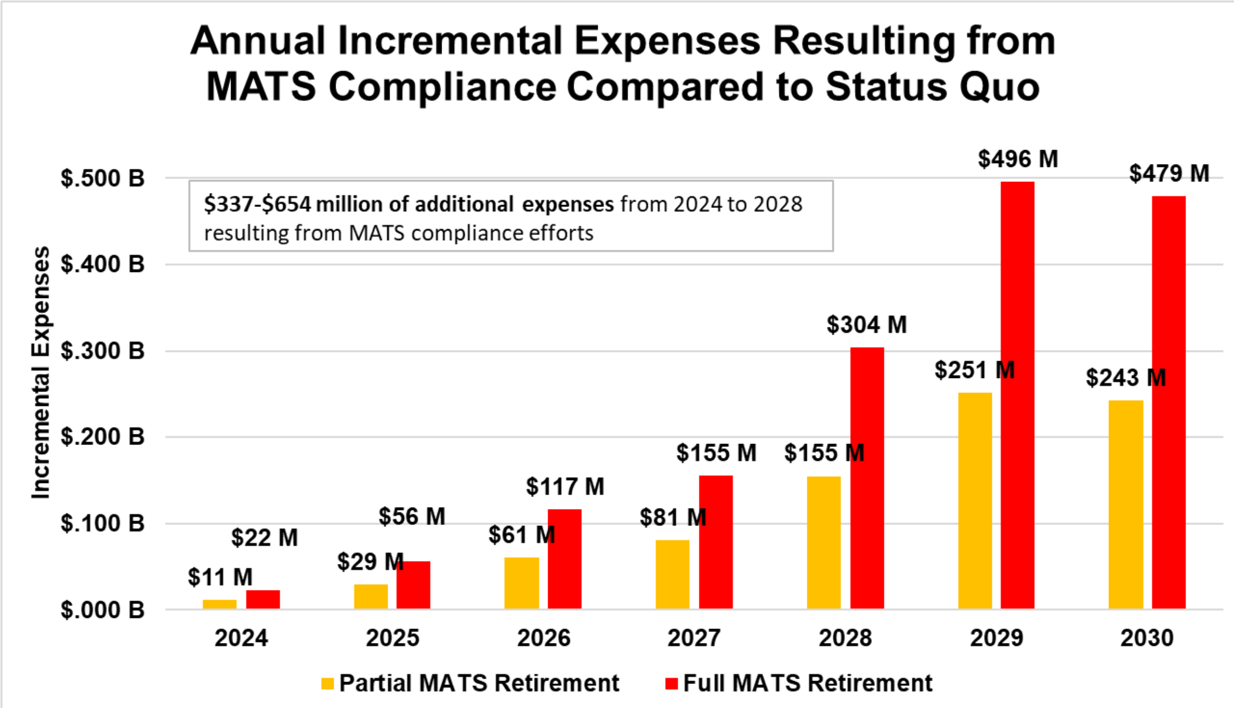

Figure D-4. This figure shows the annual cost of building the replacement capacity needed to maintain resource adequacy after the retirement of the lignite plants based on EPA's capacity accreditation values for wind, solar, storage, and thermal resources.

We describe the total costs of replacement generation capacity for each scenario in greater detail below. The assumptions used to calculate the cost of replacement generation can be found in Appendix 1: Modeling Assumptions.

Status Quo scenario:

The Status Quo scenario results in the retirement of 28,756.8 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. These retirements are already projected to occur without imposition of the new MATS Rule or other federal regulations. This retired capacity is replaced with 4,306 MW of natural gas, 19,436 MW of wind, 29,652 MW of solar, and 3,304 MW of storage.[71]

The total cost of replacement generation for the Status Quo scenario is $12.9 billion. The majority of these expenses consist of additional fixed costs of building new wind, solar, and battery storage facilities, such as fixed operational and maintenance (O&M), capital costs, and utility returns.

Compared to the current grid, the Status Quo scenario saves $32 billion in fuel costs, $11.5 billion in variable operations and maintenance costs, and $5 billion in taxes. However, these savings are

[71] See Appendix 2: Capacity Retirements and Additions in Each Scenario.

far outweighed by $5.1 billion in additional fixed costs, $16 billion in capital costs, $2.1 billion in transmission costs, and $38.2 billion in utility profits (see Figure D-5).

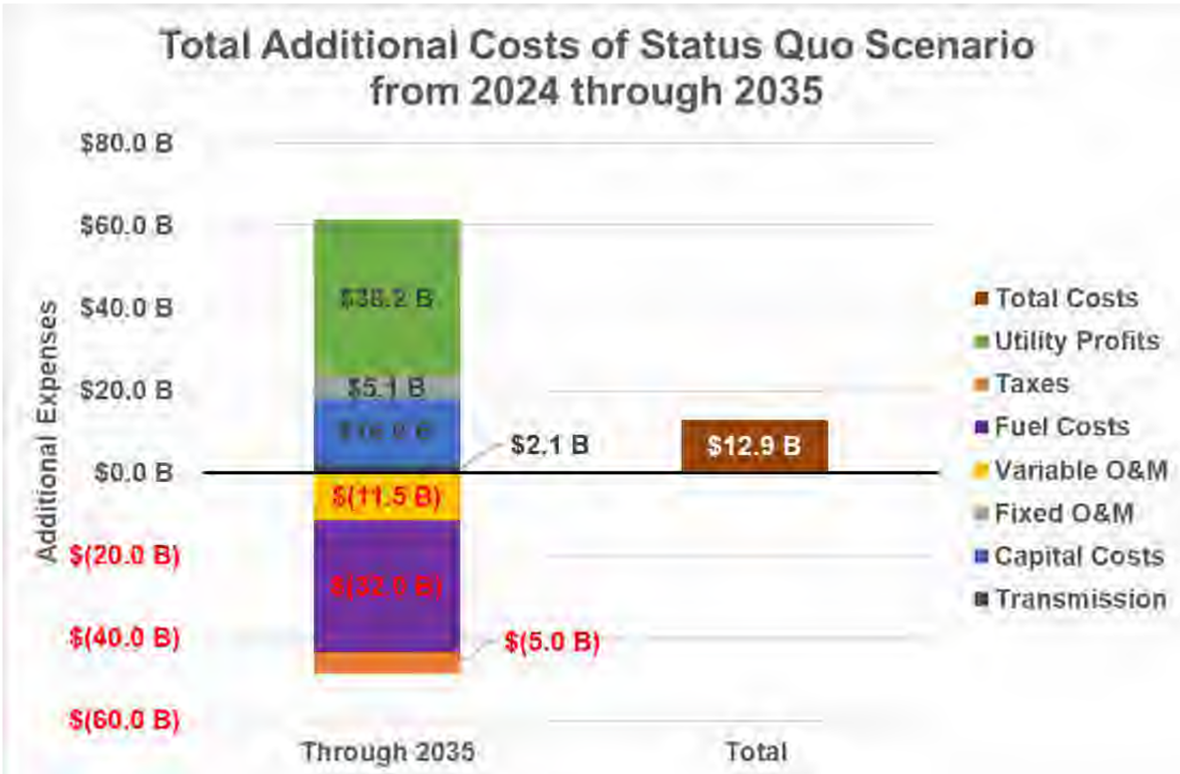

Figure D-5. The Status Quo scenario saves consumers money from lower fuel costs, fewer variable operations and maintenance costs, and lower taxes (due to federal subsidies) but these savings are outweighed by the additional costs. As a result, building the grid in the Status Quo scenario would increase costs by $12.93 billion compared to today's costs.

These additional costs will have an impact on electricity rates. Our cost modeling determined that electricity costs for MISO ratepayers would be 9.89 cents per kWh in the Status Quo scenario, an increase of nearly 3.5 percent relative to current costs of 9.56 cents per kWh.[72]

Partial MATS Retirement scenario:

The Partial scenario results in the closure of 1,151 MW of lignite capacity and necessitates an incremental increase in replacement capacity of 1,015 MW wind, 1,549 MW solar, and 173 MW storage, compared to the Status Quo scenario.[73]

The total cost of replacement generation for the Partial scenario is $14.9 billion, and the total incremental cost is $1.9 billion compared to the Status Quo scenario. The majority of these

[72] Annual Electric Power Industry Report, Form EIA-861 detailed data files, https://www.eia.gov/electricity/data/eia861/.
[73] See Appendix 2: Capacity Retirements and Additions in Each Scenario.

expenses consist of additional fixed costs of building new wind, solar, and battery storage facilities, such as fixed operational and maintenance (O&M), capital costs, and utility returns.

Compared to the current grid, the Partial scenario saves $32.7 billion in fuel costs, $11.6 billion in variable operations and maintenance costs, and $5.1 billion in taxes. However, these savings are far outweighed by $5.3 billion in additional fixed costs, $17.1 billion in capital costs, $2.2 billion in transmission costs, and $39.7 billion in utility profits (see Figure D-6).

Figure D-6. The Partial scenario results in an $14.88 billion in additional costs compared to the current grid due to additional capital costs, fixed operations and maintenance costs, additional transmission costs, and additional utility profits.

Compared to the Status Quo scenario, the incremental savings are $664 million in fuel costs, $119.7 million in variable operations and maintenance costs, and $102.2 million in taxes, which are outweighed by $178.7 million in additional fixed costs, $1.1 billion in capital costs, $116.5 million in transmission costs, and $1.4 billion in utility profits (see Figure D-7).

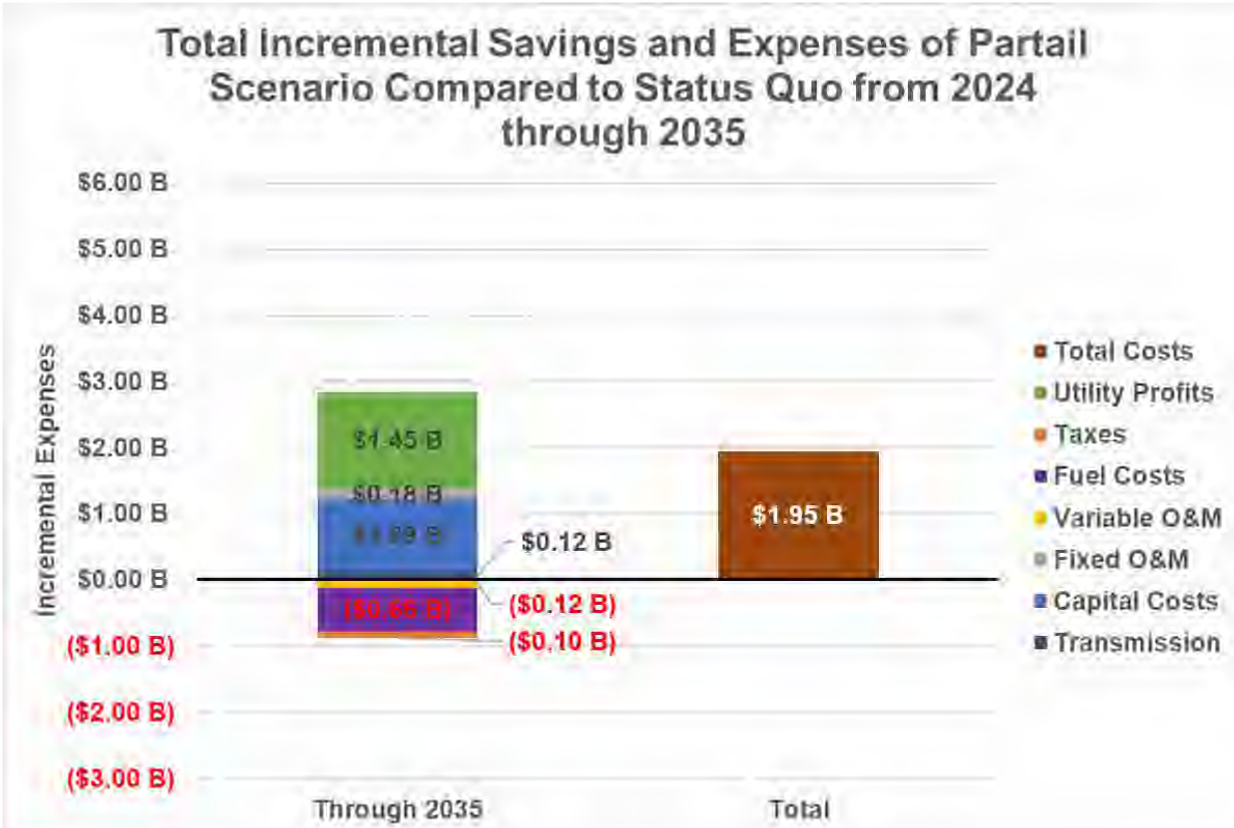

Figure D-7. The Partial scenario will cost MISO ratepayers an additional $1.9 billion from 2024 through 2035.

These incremental costs mean Load Serving Entities will incur an additional $1.9 billion because of these rules. These costs will start incurring before the compliance deadline is finalized in 2028, totaling $337 million of additional expenses compared to the Status Quo scenario (see Figure D-8).

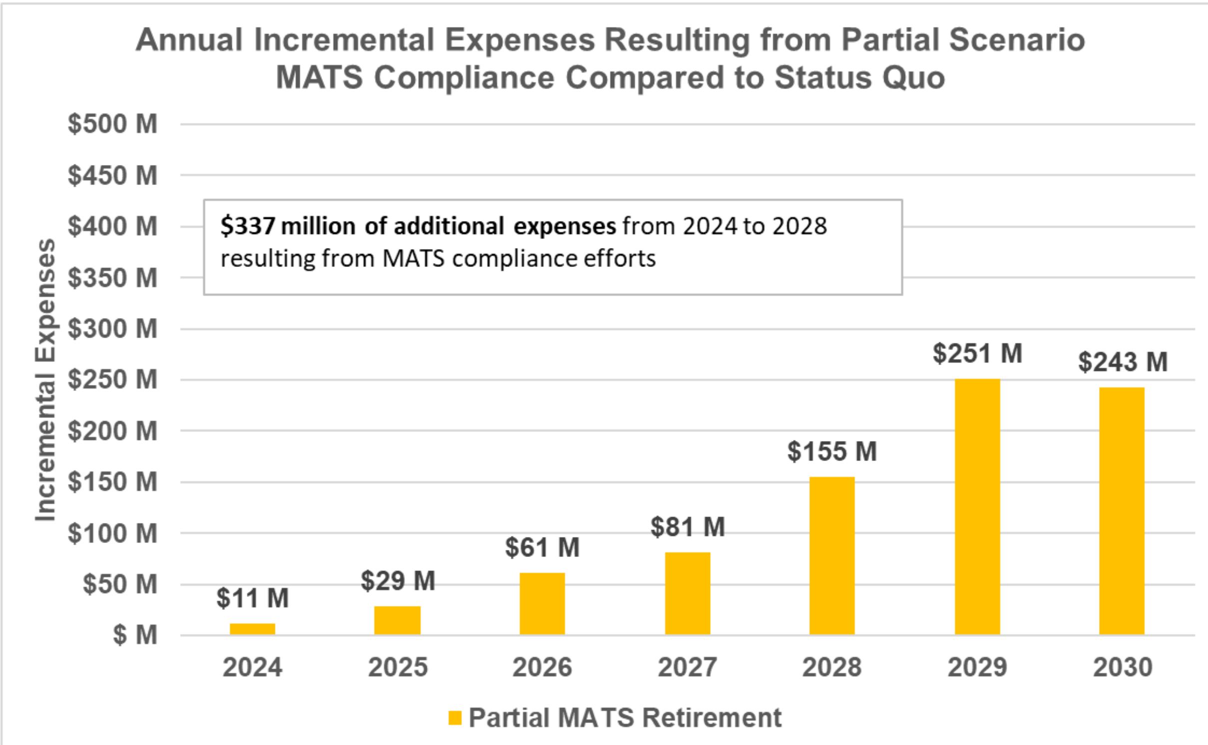

Figure D-8. This figure shows the annual incremental cost incurred by LSEs as a result of the lignite closures in the Partial scenario.

These additional costs will have an impact on electricity rates. Our cost modeling determined that electricity costs for MISO ratepayers would be 9.95 cents per kWh in the Partial scenario, an increase of nearly 3.9 percent relative to current costs of 9.58.

Full MATS scenario:

Under the Full scenario, 2,264 MW of lignite capacity would be forced to retire resulting results in an incremental increase in replacement capacity of 1,997 MW wind, 3,048 MW solar, and 304 MW storage compared to the Status Quo scenario.

The total cost of replacement generation for the Full scenario is $16.8 billion, and the total incremental cost is $3.8 billion compared to Status Quo scenario. The majority of these expenses consist of additional fixed costs of building new wind, solar, and battery storage facilities, such as fixed operational and maintenance (O&M), capital costs, and utility returns.

Compared to the current grid, the Full scenario saves $33.3 billion in fuel costs, $11.7 billion in variable operations and maintenance costs, and $5.2 billion in taxes. However, these savings are far outweighed by $5.4 billion in additional fixed costs, $18.1 billion in capital costs, $2.4 billion in transmission costs, and $41.1 billion in utility profits (see Figure D-9).

Figure D-9. The Full scenario results in an increase of $16.76 billion in costs compared to the current grid.

Compared to the Status Quo scenario, the incremental savings are $1.3 million in fuel costs, $235.1 million in variable operations and maintenance costs, and $202 million in taxes, which are outweighed by $350.8 million in additional fixed costs, $2.1 billion in capital costs, $229.1 million in transmission costs, and $2.8 billion in utility profits (see Figure D-10).

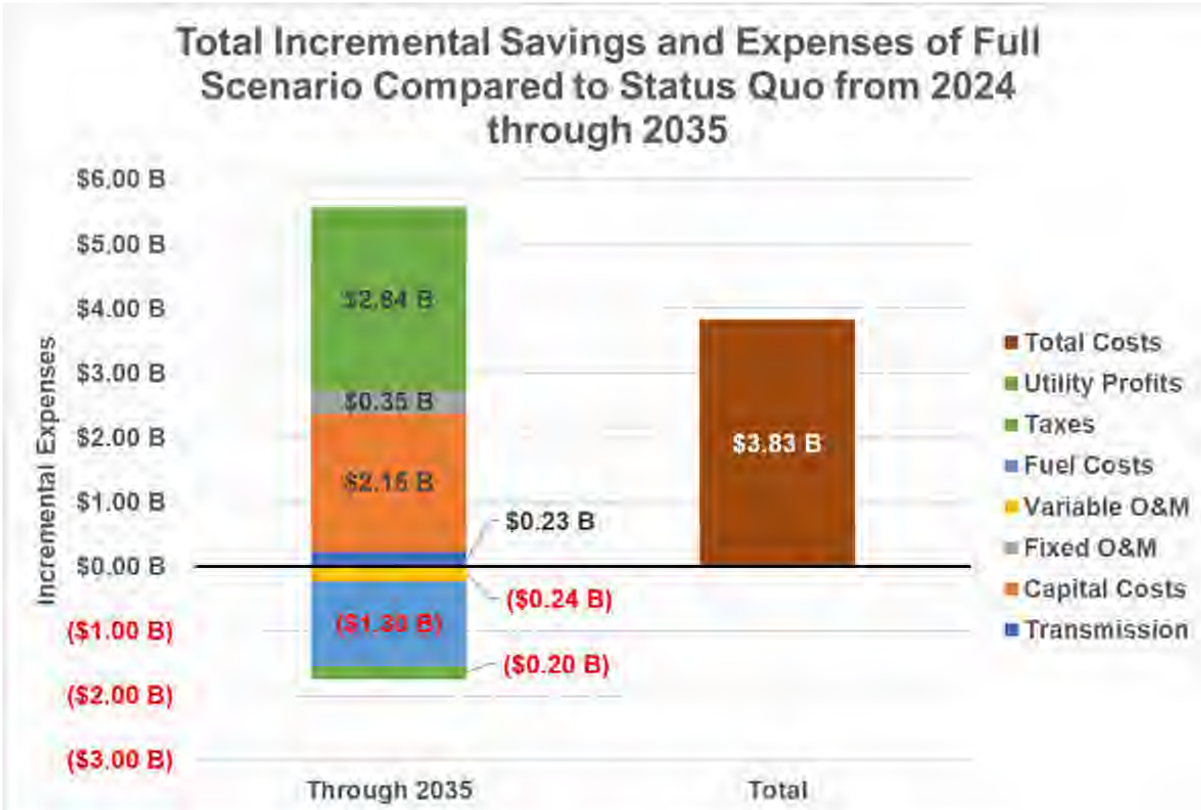

Figure D-10. This figure itemizes the expenses incurred in the Full scenario, which will cost an additional $3.8 billion compared to the Status Quo scenario.

These incremental costs mean Load Serving Entities will incur an additional $3.8 billion in the Full scenario because of these rules. These costs will start incurring before the compliance deadline is finalized in 2028, totaling $654 million of additional expenses compared to the Status Quo scenario (see Figure D-11).

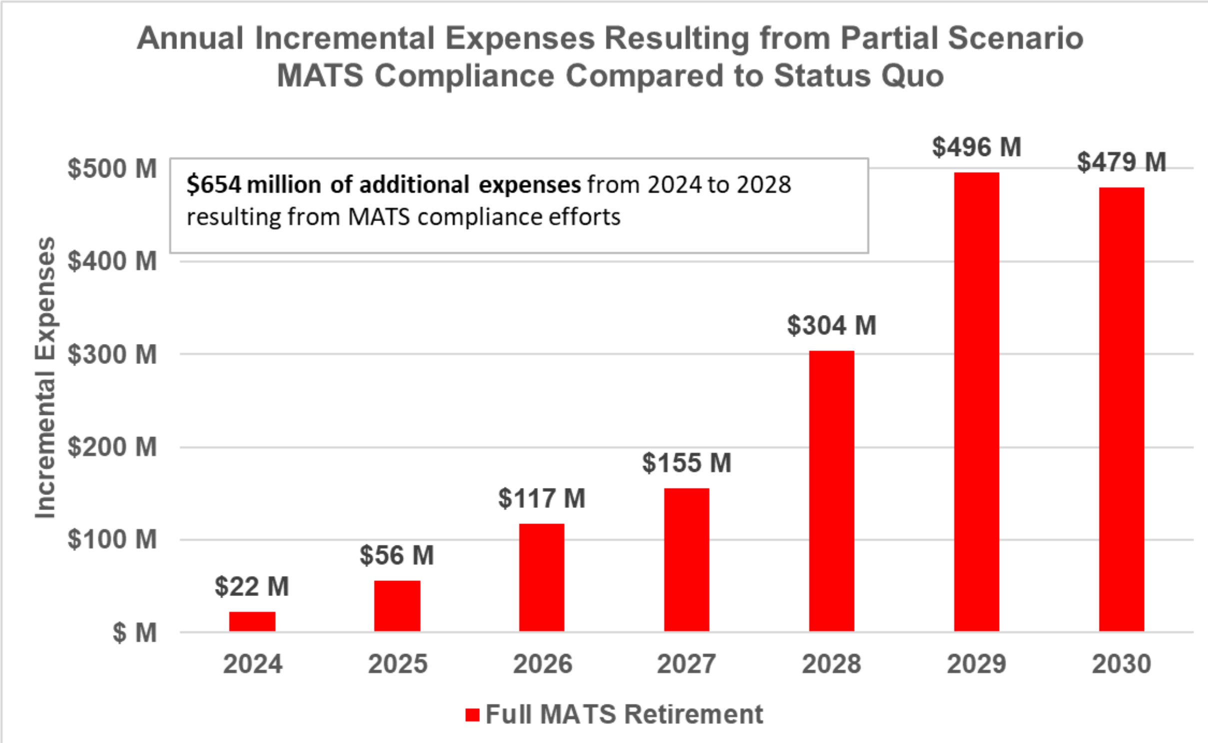

Figure D-11. LSEs would incur an additional $654 million in additional expenses, compared to the Status Quo scenario, as a result of the proposed MATS rules.

These additional costs will have an impact on electricity rates. Our cost modeling determined that electricity costs for MISO ratepayers would be 9.97 cents per kWh in the Full scenario, an increase of nearly 4.1 percent relative to current costs of 9.58.

Conclusion:

By effectively eliminating the subcategory for lignite power plants and ignoring the breadth of evidence demonstrating that these regulations are not reasonably attainable, the MATS rules will increase the severity of capacity shortfalls in the MISO region, resulting in economic damages from the ensuing blackouts ranging from $29 million to $1.05 billion, depending on the HCY used, and imposing $1.9 billion to $3.8 billion in the cost of replacement generation capacity in the Partial and Full scenarios, respectively.

Therefore, the costs stemming from the closure of the 2,264 MW of lignite fired capacity in MISO exceeds the projected net present value benefits of $3 billion from 2028 through 2037 using a 3 percent discount rate modeled by EPA in its Regulatory Impact Analysis.[74]

[74] 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 (Apr. 2023), Docket ID: EPA-HQ-OAR-2018-0794-5837.

Appendix 1: Modeling Assumptions

Electricity Consumption Assumptions

Annual electricity consumption in each model year is increased in accordance with EPA's assumptions in the IPM in each of the MISO subregions.

Peak Demand and Reserve Margin Assumptions

The modeled peak demand and reserve margin in each of the model years are increased in accordance with the IPM in each of the MISO subregions.

Time Horizon Studied

This analysis studies the impact of the proposed MATS rules from 2024 through 2035 to accurately account for the costs LSEs would incur by building replacement generation in response to the potential shutdown of lignite capacity.

This timeline downwardly biases the cost of compliance with the regulations because power plants are long term investments, often paid off over a 30-year time period. This means the changes to the resource portfolio in MISO resulting from these rules will affect electricity rates for decades beyond 2035.

Hourly Load, Capacity Factors, and Peak Demand Assumptions

Hourly load shapes and wind and solar generation were determined using data for the entire MISO region obtained from EIA's Hourly Grid Monitor. Load shapes were obtained for 2019, 2020, 2021, and 2022. [75] These inputs were entered into the model to assess hourly load shapes and assess possible capacity shortfalls in 2035 using each of the historical years.

Capacity factors used for wind and solar facilities were adjusted upward to match EPA assumptions that new wind and solar facilities will have capacity factors as high as 42.2 percent and 24.7 percent, respectively. These are generous assumptions because the current MISO-wide capacity factor of existing wind turbines is only 36 percent, and solar is 20 percent.

Our analysis upwardly adjusted observed capacity factors to EPA's estimates despite the fact that EPA's assumptions for onshore wind are significantly higher than observed capacity factors reported from Lawrence Berkeley National Labs, which demonstrates that new wind turbines entering operation since 2015 have never achieved annual capacity factors of 42.2 percent (See Figure D-12).[76]

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[75] Energy Information Administration, "Hourly Electric Grid Monitor," Accessed August 12, 2022, https://www.eia.gov/ electricity/gridmonitor/dashboard/electric_overview/balancing_authority/MISO
[76] Lawrence Berkely National Labs, "Wind Power Performance," Land Based Wind Report, Accessed July 27, 2023, https://emp.lbl.gov/wind-power-performance.

Figure D-12. This *figure shows capacity factors for U.S. onshore wind turbines by the year they entered service. In no year do these turbines reach EPA's assumed 42.2 percent capacity factor on an annual basis.*

Another generous assumption is that we did not hold natural gas plants accountable to other EPA rules, such as the Carbon Rule, that may be in effect in addition to the MATS rule and would cap natural gas generators at 49 percent capacity factors to avoid using carbon capture and sequestration or co-firing with hydrogen. Doing so would have resulted in even more capacity shortfalls.

Line Losses

Line losses are assumed to be 5 percent of the electricity transmitted and distributed in the United States based on U.S. on EIA data from 2017 through 2021.[77]

Value of Lost Load

The value of lost load (VoLL) is a monetary indicator *expressing the costs associated with an interruption of electricity supply*, expressed in dollars per megawatt hour (MWh) of unserved electricity.

[77] Energy Information Administration, "How Much Electricity is Lost in Electricity Transmission and Distribution in the United States," Frequently Asked Questions, https://www.eia.gov/tools/faqs/faq.php?id=105&t=3

Our analysis uses a conservative midpoint estimate of $14,250 per MWh for VoLL. This value is higher than MISO's previous VoLL estimate of $3,500 per MWh, but significantly lower than the Independent Market Monitor's suggested estimate of $25,000 per MWh.[78]

Plant Retirement Schedules

Our modeling utilizes announced coal and natural gas retirement dates from U.S. EIA databases and announced closures in utility IRPs using a dataset collected by NERA economic consulting.

Plant Construction by Type

The resource adequacy and reliability portions of this analysis use MISO Interconnection Queue data to project into the future. EPA capacity values are applied to each newly constructed resource until the MISO system hits its target reserve margin based on EPA's peak demand forecast in its IPM.

Load Modifying Resources, Demand Response, and Imports

Our model allows for the use of 7,875 MW of Load Modifying Resources (LMRs) and 3,638 MW external resources (imports) in determining how much reliable capacity will be needed within MISO to meet peak electricity demand under the new MATS rules.

Utility Returns

Most of the load serving entities in MISO are vertically integrated utilities operating under the Cost-of-Service model. The amount of profit a utility makes on capital assets is called the Rate of Return (RoR) on the Rate Base. For the purposes of our study, the assumed rate of return is 9.9 percent with debt/equity split of 48.92/51.08 based on the rate of return and debt/equity split of the ten-largest investor-owned utilities in MISO.

Transmission

This analysis assumes the building of transmission estimated at $10.3 billion, which is consistent with MISO tranche 1 for the Status Quo Scenario. For the Full and Partial scenarios, transmission costs are estimated to be $223,913 per MW of new installed capacity to account for the increased wind, solar, storage, and natural gas capacity additions.

Taxes and Subsidies

Additional tax payments for utilities were calculated to be of 1.3 percent of the rate base. The state income tax rate of 7.3 percent was estimated by averaging the states within the MISO region. The

[78] Potomac Economics, "2022 State of the Market Report for the MISO Electricity Markets," Independent Market Monitor for the Midcontinent ISO, June 15, 2023, https://www.potomaceconomics.com/wp-content/uploads/2023/06/2022-MISO-SOM_Report_Body-Final.pdf.

Federal income tax rate is 21 percent. The value of the Production Tax Credit (PTC) is $27.50. The Investment Tax Credit (ITC) 30 percent through 2032, 26 percent in 2033, and 22 percent in 2034.

Battery Storage

Battery storage assumes a 5 percent efficiency loss on both ends (charging and discharging).

Maximum discharge rates for the MISO system model runs were held at the max capacity of the storage fleet, less efficiency losses. Battery storage is assumed to be 4-hour storage, while pumped storage is assumed to be 8-hour storage.

Wind and Solar Degradation

According to the Lawrence Berkeley National Laboratory, output from a typical U.S. wind farm shrinks by about 13 percent over 17 years, with most of this decline taking place after the project turns ten years old. According to the National Renewable Energy Laboratory, solar panels lose one percent of their generation capacity each year and last roughly 25 years, which causes the cost per megawatt hour (MWh) of electricity to increase each year.[79] However, our study does not take wind or solar degradation into account.

Capital Costs, and Fixed and Variable Operation and Maintenance Costs

Capital costs for all new generating units are sourced from the EIA 2023 Assumptions to the Annual Energy Outlook (AOE) Electricity Market Module (EMM). These costs are held constant throughout the model run. Expenses for fixed and variable O&M for new resources were also obtained from the EMM. MISO region capital costs were used, and national fixed and variable O&M costs were obtained from Table 3 in the EMM report.[80]

Discount Rate

A discount rate of 3.76 percent is used in accordance with EPA's assumptions in the IPM.

Unit Lifespans

Different power plant types have different useful lifespans. Our analysis takes these lifespans into account. Wind turbines are assumed to last for 20 years, solar panels are assumed to last 25 years, battery storage for 15 years. Natural gas plants are assumed to last for 30 years.

Repowering

Our model assumes wind turbines, solar panels, and battery storage facilities are repowered after they reach the end of their useful lives. Our model also excludes economic repowering, a growing

[79] Liam Stoker, "Built Solar Assets Are 'Chronically Underperforming,' and Modules Degrading Faster than Expected, Research Finds," PV Tech, June 8, 2021, https://www.pv-tech.org/built-solar-assets-are-chronically-underperforming-andmodules-degrading-faster-than-expected-research-finds/.
[80] U.S. Energy Information Administration, "Electricity Market Module," Assumptions to the Annual Energy Outlook 2022, March 2022, https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

trend whereby wind turbines are repowered after just 10 to 12 years to recapture the wind Production Tax Credit (PTC). This trend will almost certainly grow in response to IRA subsidies.

EPA does not appear to take repowering into consideration because the amount of existing wind on its systems never changes. If our understanding of EPA's methodology is accurate, this a large oversight that must be corrected.

Fuel Cost Assumptions

Fuel costs for existing power facilities were estimated using FERC Form 1 filings and adjusted for current fuel prices.[81,82] Fuel prices for new natural gas power plants were estimated by averaging annual fuel costs within the MISO region according to EPA.[83] Existing coal fuel cost assumptions of $17.82 per MWh were based on 2020 FERC Form 1 filings.

Inflation Reduction Act (IRA) Subsidies

Our analysis assumes all wind projects will qualify for IRA subsidies and elect the Production Tax Credit, valued at $27.50 per MWh throughout the model run. Solar facilities are assumed to select the Investment Tax Credit in an amount of 30 percent of the capital cost of the project.

Appendix 2: Capacity Retirements and Additions in Each Scenario

This section details the capacity additions and retirements in the MISO region under each scenario.

Status Quo scenario: The Status Quo scenario results in the retirement of 28,756.8 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. Additions in the Status Quo scenario consist of 4,306 MW of natural gas, 19,436 MW of wind, 29,652 MW of solar, and 3,304 MW of storage.

Annual retirement and additions can be seen in Figure D-13 below.

[81] Trading Economics, "Natural Gas," https://tradingeconomics.com/commodity/natural-gas.
[82] https://data.nasdaq.com/data/EIA/COAL-us-coal-prices-by-region
[83] U.S. Energy Information Administration, "Open Data," https://www.eia.gov/opendata/v1/qb.php?category=40694&sdid=SEDS.NUEGD.WI.A

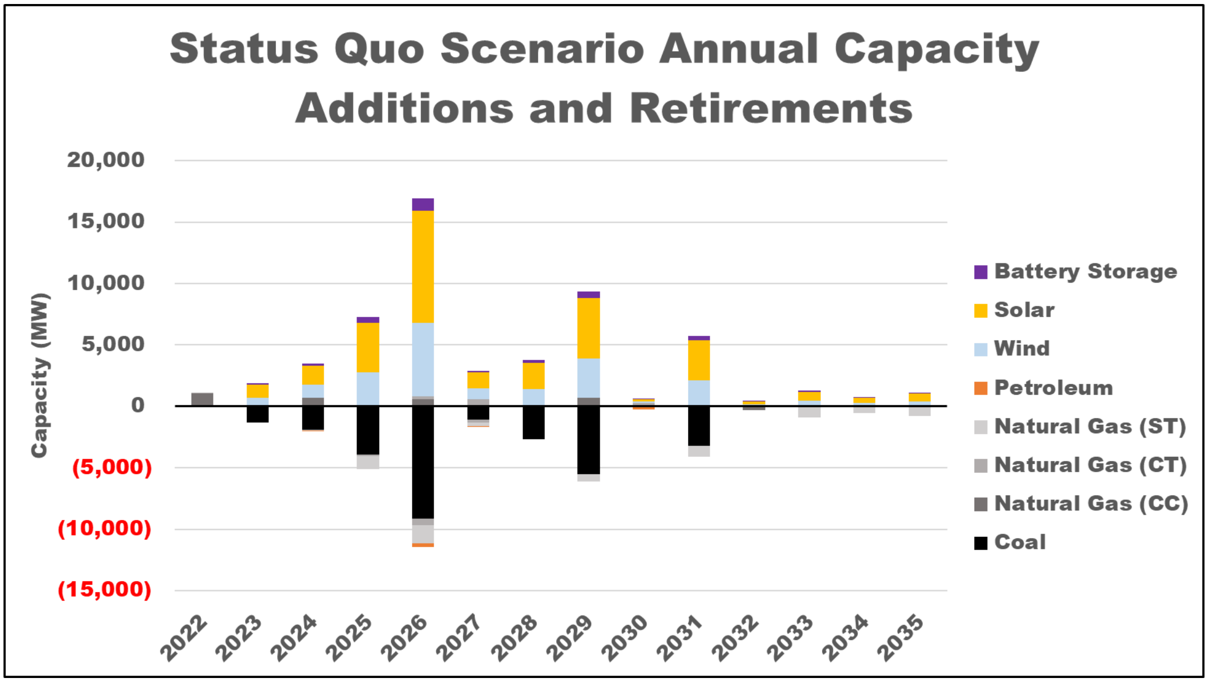


Figure D-13. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

Partial scenario: The Partial scenario results in the retirement of 29,908 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. To replace this retired capacity, additions in the Partial scenario consist of 4,306 MW of natural gas, 20,451 MW of wind, 31,201 MW of solar, and 3,477 MW of storage (see Figure D-14). The incremental closure of 1,151 MW of lignite capacity results in an incremental increase in a replacement capacity of 1,015 MW wind, 1,549 MW solar, and 173 MW storage (see Figure D-15).[84]

[84] Replacement capacity is more than the retiring 1,151 MW of coal capacity because intermittent resources like wind and solar have lower capacity values than coal capacity.

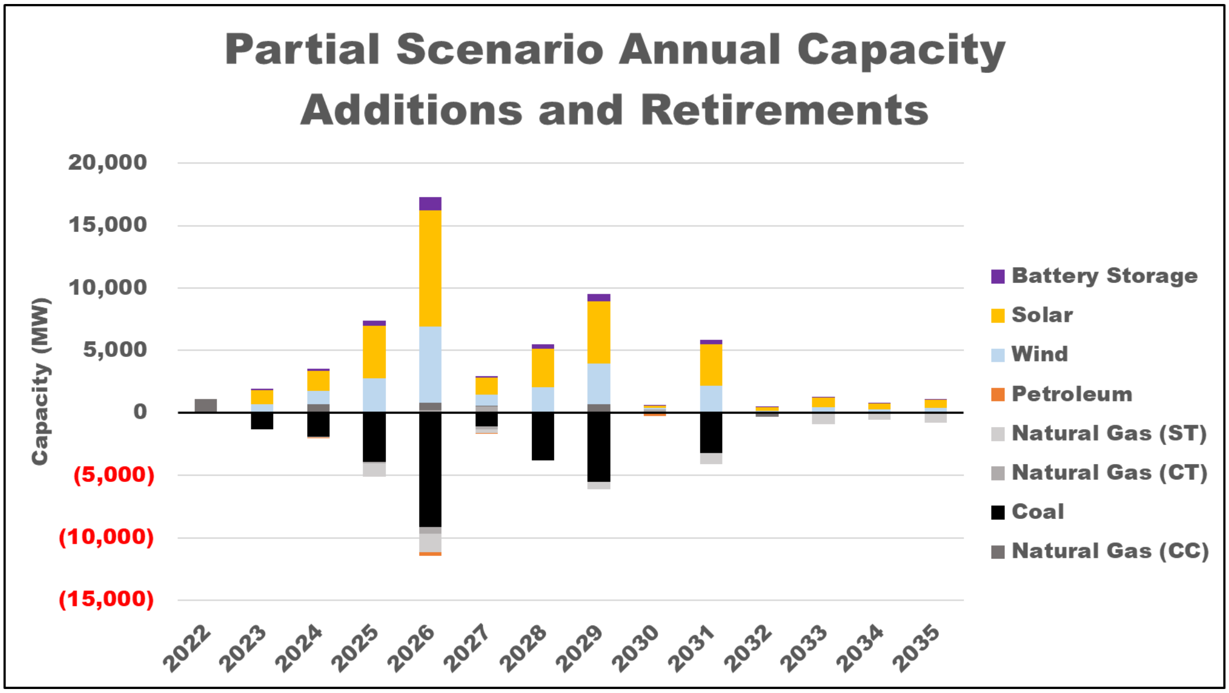


Figure D-14. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

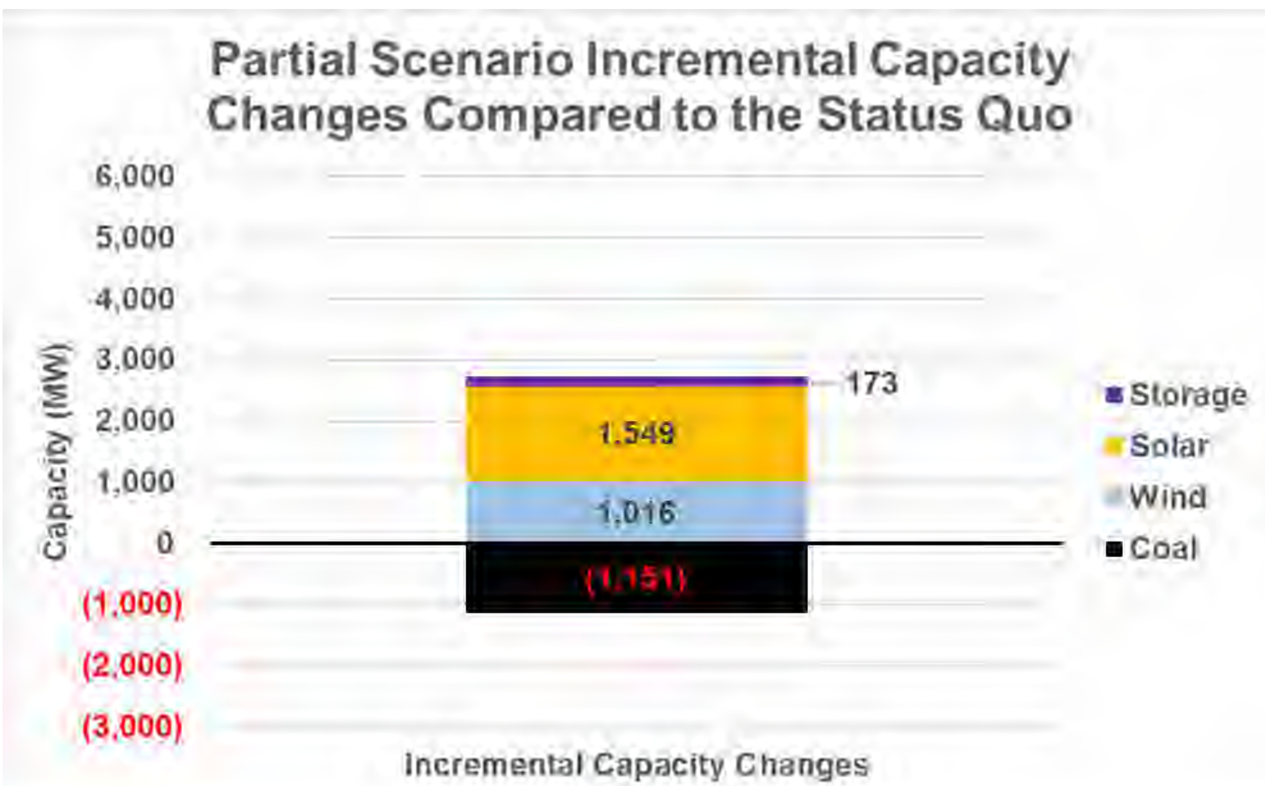


Figure D-15. This figure shows the incremental capacity retirements and additions in the MISO region under the Partial scenario.

Full Scenario: The Full scenario results in the retirement of 31,021 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. To replace this retired capacity, additions in the Full scenario consist of 4,306 MW of natural gas, 21,433 MW of wind, 32,700 MW of solar, and 3,644 MW of storage (see Figure D-16). The incremental closure of 2,264 MW of lignite capacity results in an incremental increase in a replacement capacity of 1,997 MW wind, 3,048 MW solar, and 304 MW storage, compared to the Status Quo scenario (see Figure D-17).

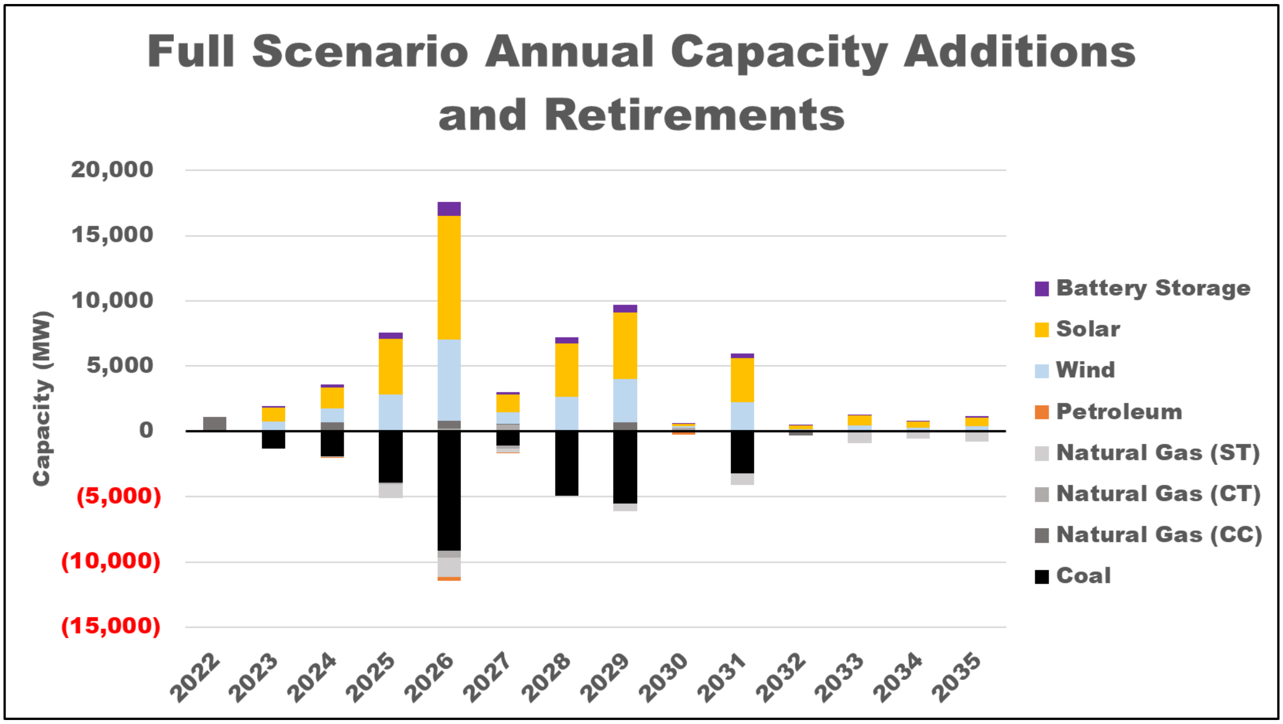


Figure D-16. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

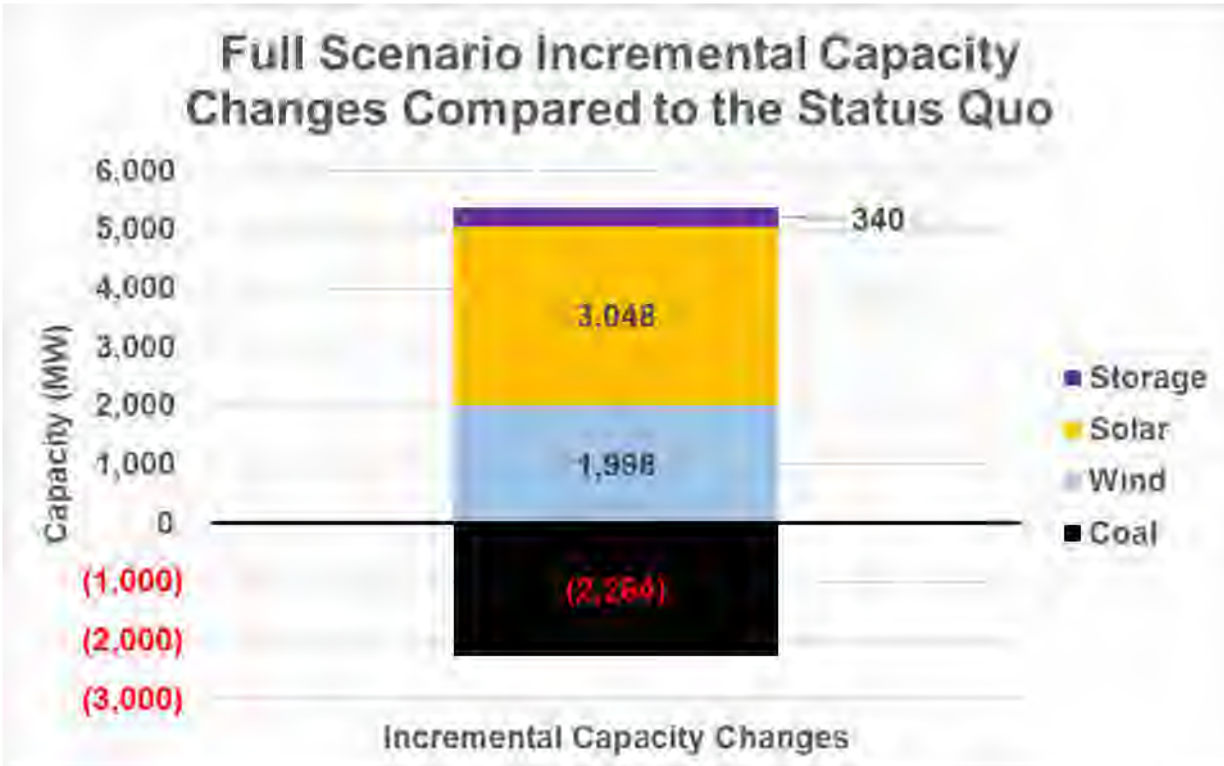


Figure D-17. This figure shows the incremental capacity closures and additions in the Full scenario.

Figure D-18 shows the capacity retirements and additions in the Partial and Full scenarios.

Comparison:

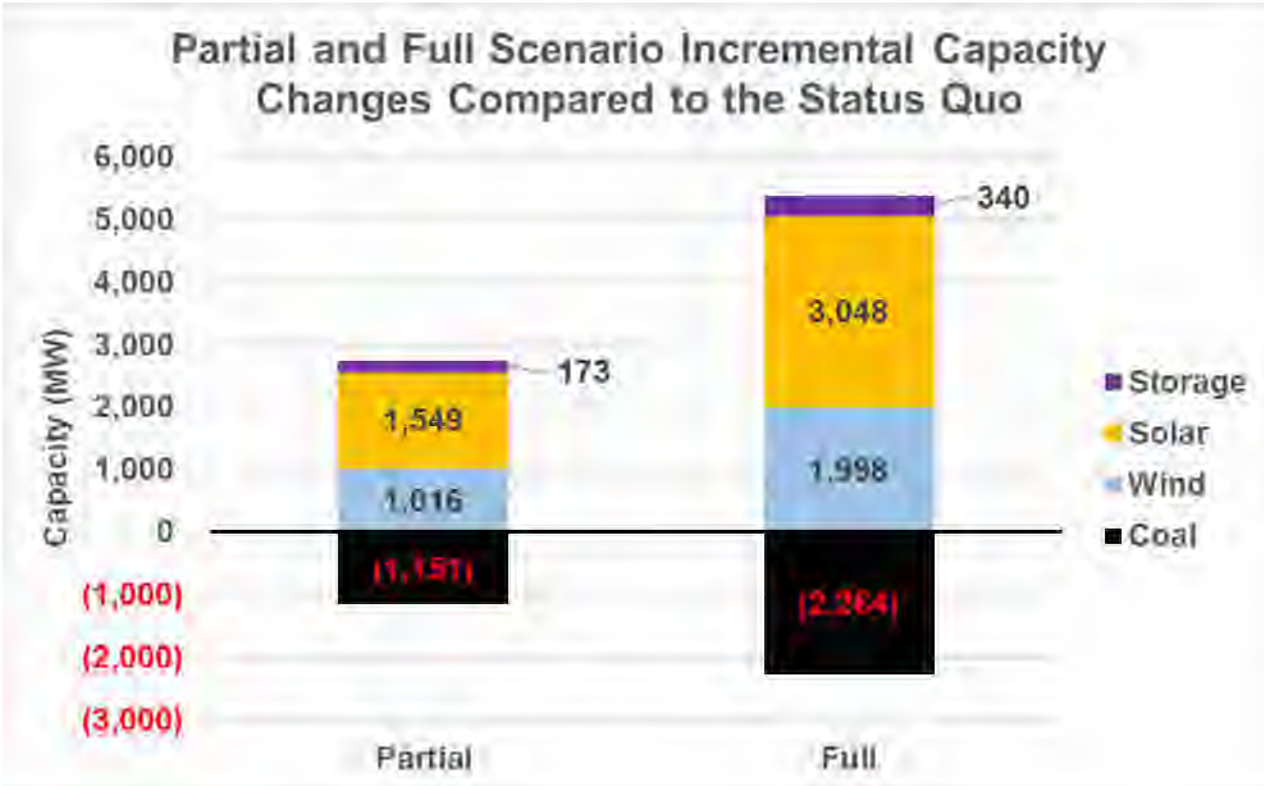


Figure D-18 comparison. This figure demonstrates the incremental retirements and additions in each scenario.

Appendix 3: Replacement Capacity Based on EPA Methodology for Resource Adequacy

The capacity selected in our model to replace the retiring resources is based on two main factors. The first factor is the MISO interconnection queue, which is predominantly filled with solar and wind projects and a relatively small amount of natural gas. The second factor is the EPA's resource adequacy (RA) accreditation values in the Integrating Planning Model's (IPM) Proposed Rule Supply Resource Utilization file and Post-IRA Base Case found in the Regulatory Impact Analysis.

The IMP assumes a capacity accreditation of 100 percent for thermal resources, and variable intermittent technologies (primarily wind and solar) receive region-specific capacity credits to help meet target reserve margin constraints. Due to their variability, resources such as wind and solar received a lower capacity accreditation when solving for resource adequacy (see Table D-4).

EPA Integrated Planning Model

Capacity Accreditation in MISO

Resource	Capacity Value
Existing Wind	19%
Existing Solar	55%
New Onshore Wind 2035	17%
New Solar 2035	52%
Thermal	100%
Battery Storage	100%

Table D-4. This figure shows the capacity values for each resource based on EPA's estimates in its IPM.

In order to determine whether the available blend of power generation sources will be able to meet projected demand, each available generation source is multiplied against its capacity value, and the available resources are then "stacked" to determine if there is enough accredited power generation capacity to meet projected demand and maintain resource adequacy.

It should be noted that EPA's accreditation values from the IPM are generous compared to the accreditation values given by RTOs. For example, in the MISO region, grid planners assume that dispatchable thermal resources like coal, natural gas, and nuclear power plants will be able to produce electricity 90 percent of the time when the power is needed most, resulting in a UCAP rating of 90 percent. In contrast, MISO believes wind resources will only provide about 18.1 percent of their potential output during summer peak times, and solar facilities will produce 50 percent of their potential output. This report uses the generous capacity values provided by EPA; however, if the capacity values used by the RTOs were to be utilized, the projected energy shortfalls and blackouts would be even worse.

Appendix 4: Resource Adequacy in Each Scenario

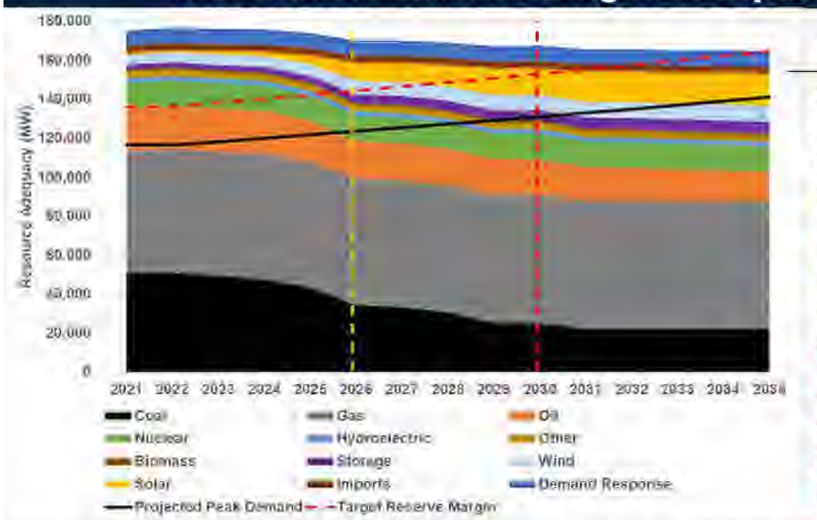
We performed a Resource Adequacy analysis on each of the three scenarios modeled to determine the potential impact to grid reliability in MISO region if implementation of the MATS Rule results in the forced retirement of lignite power plants.

Status Quo scenario

Under the Status Quo scenario, there is enough dispatchable capacity in MISO to meet the projected peak demand and target reserve margin established by EPA in the RIA documents

Proposed Rule Supply Resource Utilization file until the end of 2025, shown in the black font in the table in Figure D-19.[85]

Status Quo Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But...



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	14%	4%	106%
2029	17%	4%	100%
2030	16%	4%	98%
2031	18%	4%	94%
2032	18%	4%	92%
2033	18%	4%	90%
2034	18%	4%	89%
2035	18%	4%	87%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage, and thermal resources (100%). EPA assumes a 16.8 percent reserve margin. Different than MISO cleared UCAP (unforced [accredited] capacity). Red indicates intermittent generation is necessary to meet Target Reserve Margins. The rest of the reserve margin not covered in the table consists of load modifying resources.

- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2029: Reserve margin depends on W/S/B*
- *2030 – 2035: Peak Demand depends on W/S/B*

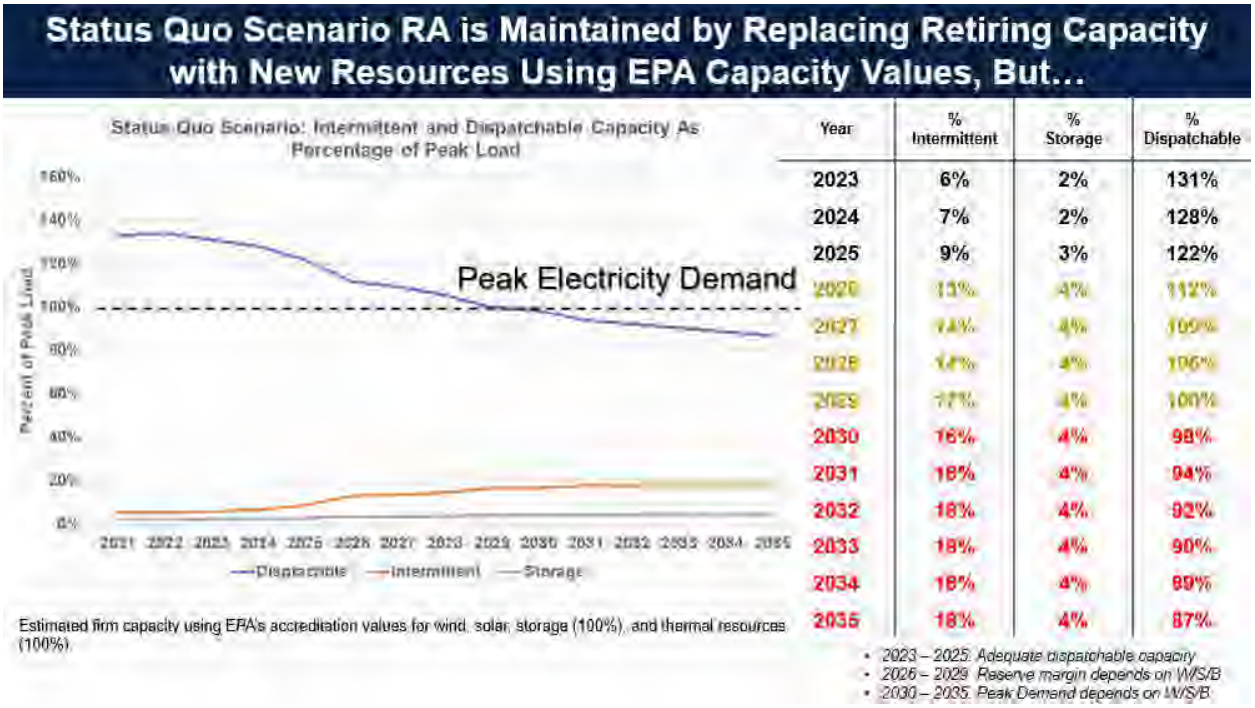
Figure D-19. By 2030, MISO will rely on wind, solar, and battery storage to meet its projected peak demand and target reserve margin.

Beginning in 2026, MISO becomes reliant upon wind, solar, imports, or demand response (DR) to meet its target reserve margin, but the RTO still has enough dispatchable capacity to meet its projected peak demand. By 2030, the MISO region will rely on thermal resources and 4-hour battery storage to meet its peak demand, and by 2031 the region will no longer have enough dispatchable capacity or storage to meet its projected peak demand, and it will rely exclusively on non-dispatchable resources and imports to meet its target reserve margin.[86]

The trend of falling dispatchable capacity relative to projected peak demand can be seen more clearly in Figure D-20 below. By 2035, dispatchable capacity consisting of thermal generation and battery storage will only be able to provide 91 percent of the projected peak demand, necessitating the use of wind and solar to maintain resource adequacy.

[85] Analysis of the Proposed MATS Risk and Technology Review (RTR) | US EPA, https://www.epa.gov/power-sector-modeling/analysis-proposed-mats-risk-and-technology-review-rtr

[86] While battery storage is considered dispatchable in this analysis for the sake of simplicity, battery resources are not a substitute for generation because as grids become more reliant upon wind and solar, battery resources may not be sufficiently charged to provide the needed dispatchable power.



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	14%	4%	106%
2029	17%	4%	100%
2030	16%	4%	98%
2031	18%	4%	94%
2032	18%	4%	92%
2033	18%	4%	90%
2034	18%	4%	89%
2035	18%	4%	87%

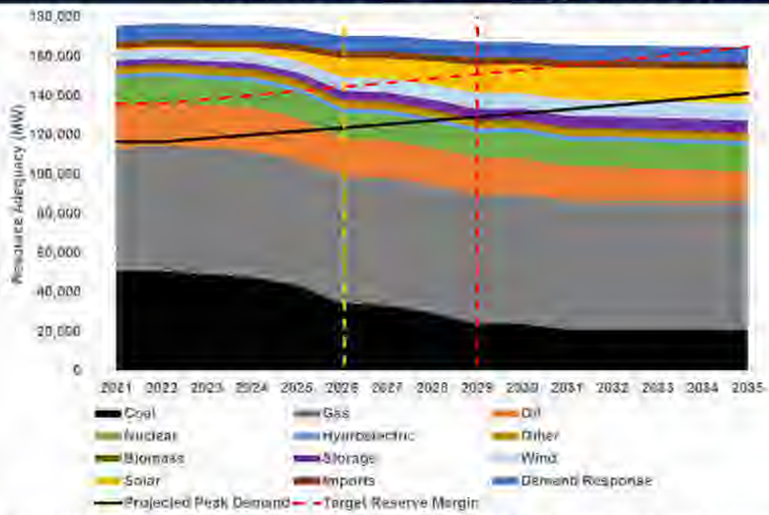
- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2029: Reserve margin depends on W/S/B*
- *2030 – 2035: Peak Demand depends on W/S/B*

D-20. By 2035, dispatchable generators will only constitute 87 percent of projected peak demand, with storage accounting for four percent of peak demand capacity.

Partial scenario

Like the Status Quo Scenario, there is enough dispatchable capacity in MISO under the Partial scenario to meet the projected peak demand and target reserve margin established by EPA in the RIA documents Proposed Rule Supply Resource Utilization file until the end of 2025, shown in the black font in the table in Figure D-21.

Partial Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	108%
2028	15%	4%	105%
2029	17%	4%	99%
2030	17%	4%	96%
2031	18%	4%	93%
2032	18%	4%	92%
2033	18%	4%	90%
2034	18%	4%	88%
2035	18%	4%	86%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%). EPA assumes a 16.8 percent reserve margin. Different than MISO cleared UCAP (unforced [accredited] capacity). Red indicates intermittent generation is necessary to meet Target Reserve Margins. The rest of the reserve margin not covered in the table consists of load modifying resources.

- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2028: Reserve margin depends on W/S/B*
- *2029 – 2035: Peak Demand depends on W/S/B*

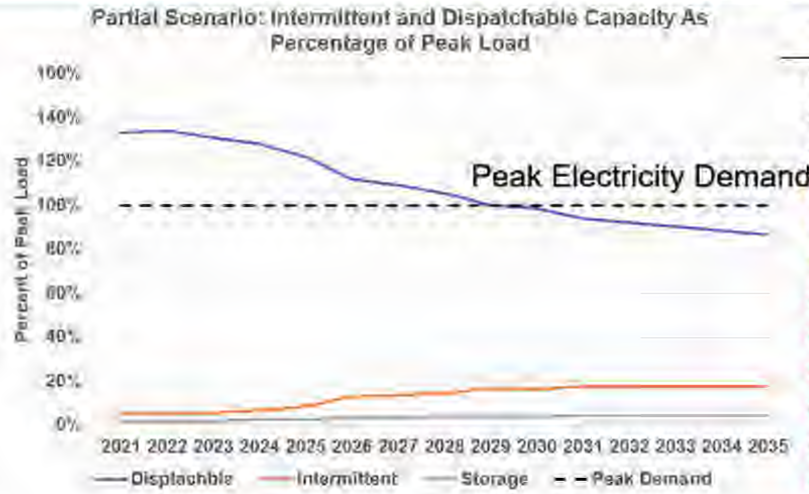
Figure D-21. By 2029, MISO will rely on wind, solar, and battery storage to meet its projected peak demand and target reserve margin.

MISO becomes reliant upon wind, solar, imports, or demand response (DR) to meet its target reserve margin in 2025, but the RTO still has enough dispatchable capacity to meet its projected peak demand. The percentage of MISO's projected peak demand that will be met by dispatchable resources in 2028 declines from 106 percent in the Status Quo scenario to 105 percent in the Partial scenario, reflecting the loss of 1,151 MW of lignite power plants in North Dakota.

In this scenario, the MISO region will no longer have enough dispatchable capacity to meet its projected peak demand in 2029, a year earlier than the Status Quo scenario, and it will rely on non-dispatchable resources, imports, or storage to meet its target reserve margin.

The trend of falling dispatchable capacity relative to projected peak demand can be seen more clearly in Figure D-22 below. By 2035, dispatchable capacity will only be able to provide 86 percent of the projected peak demand.

Partial Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	108%
2028	15%	4%	105%
2029	17%	4%	99%
2030	17%	4%	98%
2031	18%	4%	93%
2032	18%	4%	92%
2033	18%	4%	90%
2034	18%	4%	88%
2035	18%	4%	86%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%).

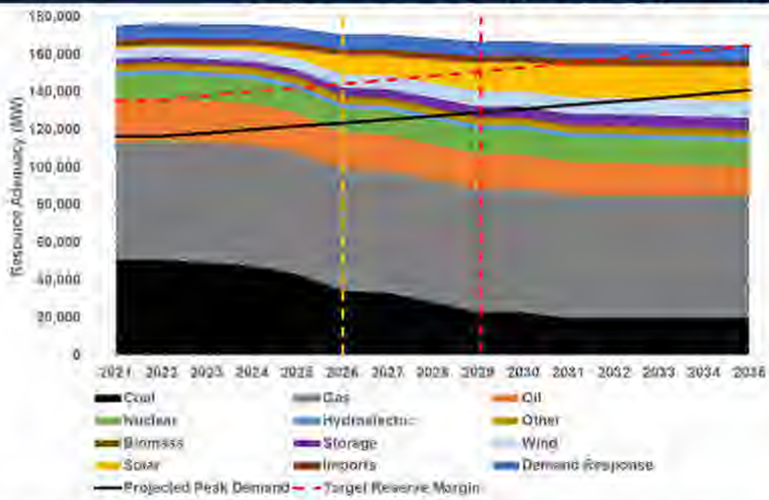
- 2023 – 2025: Adequate dispatchable capacity
- 2026 – 2028: Reserve margin depends on W/S/B
- 2029 – 2035: Peak Demand depends on W/S/B

Figure D-22. The percentage of peak electricity demand being served by dispatchable resources drops by one percent in 2028, relative to the Status Quo scenario, due to the closure of lignite capacity in MISO due to the MATS rule.

Full scenario

Like the Status Quo scenario and Partial scenario, there is enough dispatchable capacity in MISO under the Full scenario to meet the projected peak demand and target reserve margin established by EPA in the RIA documents Proposed Rule Supply Resource Utilization file until the end of 2025, shown in the black font in the table in Figure D-23.

Full Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	16%	4%	104%
2029	18%	4%	98%
2030	18%	4%	97%
2031	19%	5%	92%
2032	19%	4%	91%
2033	19%	4%	89%
2034	19%	4%	87%
2035	19%	4%	85%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%). EPA assumes a 16.8 percent reserve margin. Different than MISO cleared UCAP (unforced [accredited] capacity). Red indicates intermittent generation is necessary to meet Target Reserve Margins. The rest of the reserve margin not covered in the table consists of load modifying resources.

- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2028: Reserve margin depends on W/S/B*
- *2029 – 2035: Peak Demand depends on W/S/B*

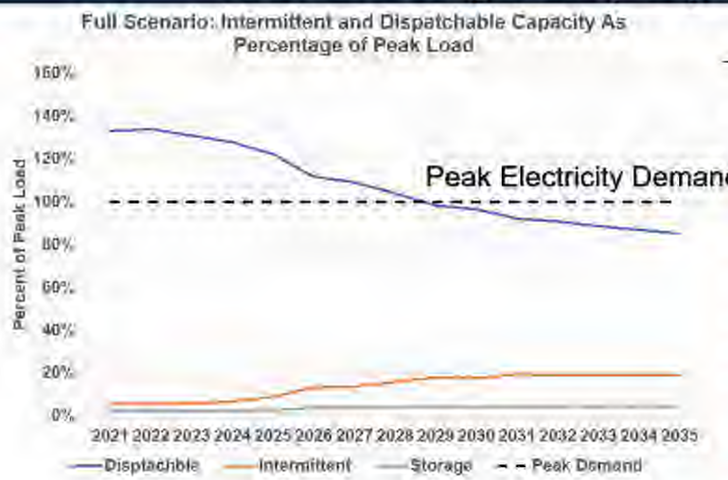
Figure D-23. The amount of dispatchable capacity available to meet projected peak demand in 2028 falls from 106 percent in the Status Quo scenario to 104 percent in the Full scenario, reflecting the closure of all the lignite capacity in MISO that year.

MISO becomes reliant upon wind, solar, imports, or demand response (DR) to meet its target reserve margin in 2025, but the RTO still has enough dispatchable capacity to meet its projected peak demand. The percentage of MISO's projected peak demand that will be met by dispatchable resources in 2028 declines from 106 percent in the Status Quo scenario to 104 percent in the Full scenario, reflecting the loss of 2,264 MW of lignite power plants in North Dakota.

In this scenario, the MISO region will no longer have enough dispatchable capacity to meet its projected peak demand in 2029, a year earlier than the Status Quo scenario, and it will rely on non-dispatchable resources, imports or storage to meet its target reserve margin.

The trend of falling dispatchable capacity relative to projected peak demand can be seen more clearly in Figure D-24 below. By 2035, dispatchable capacity will only be able to provide 85 percent of the projected peak demand, a two percent decline relative to the Status Quo scenario, necessitating the use of wind and solar to maintain resource adequacy.

Full Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
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2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	6%	109%
2028	16%	8%	104%
2029	18%	4%	98%
2030	18%	4%	97%
2031	19%	5%	92%
2032	19%	4%	91%
2033	19%	4%	89%
2034	19%	4%	87%
2035	19%	4%	85%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%).

- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2028: Reserve margin depends on W/S/B*
- *2029 – 2035: Peak Demand depends on W/S/B*

Figure D-24. The amount of peak demand that can be met with dispatchable resources in 2028 falls from 106 in the Status Quo scenario to 104 in the Full scenario.

No. ________

In the Supreme Court of the United States

STATE OF NORTH DAKOTA, STATE OF WEST VIRGINIA, et al.,

Applicants,

v.

ENVIRONMENTAL PROTECTION AGENCY,

Respondent.

TO THE HONORABLE JOHN G. ROBERTS, JR.,
CHIEF JUSTICE OF THE UNITED STATES
AND CIRCUIT JUSTICE FOR THE D.C. CIRCUIT

STATES' EMERGENCY APPLICATION FOR AN IMMEDIATE STAY OF ADMINISTRATIVE ACTION PENDING REVIEW IN THE D.C. CIRCUIT

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PARTIES TO THIS PROCEEDING

Applicants in this Court and Petitioners in the D.C. Circuit Court of Appeals are the State of North Dakota, State of West Virginia, State of Alaska, State of Arkansas, State of Georgia, State of Idaho, State of Indiana, State of Iowa, State of Kansas, Commonwealth of Kentucky, State of Louisiana, State of Mississippi, State of Missouri, State of Montana, State of Nebraska, State of Oklahoma, State of South Carolina, State of South Dakota, State of Tennessee, State of Texas, State of Utah, Commonwealth of Virginia, and State of Wyoming.

Respondent in this Court and Respondent in the D.C. Circuit Court of Appeals is the United States Environmental Protection Agency.

Intervenor for Petitioner in the D.C. Circuit Court of Appeals is San Miguel Electric Cooperative, Inc.

Intervenors for Respondent in the D.C. Circuit Court of Appeals are (1) Air Alliance Houston, Alliance of Nurses for Healthy Environments, American Academy of Pediatrics, American Lung Association, American Public Health Association, Chesapeake Climate Action Network, Citizens for Pennsylvania's Future, Clean Air Council, Clean Wisconsin, Downwinders at Risk, Environmental Defense Fund, Environmental Integrity Project, Montana Environmental Information Center, Natural Resources Council of Maine, Natural Resources Defense Council, the Ohio Environmental Council, Physicians for Social Responsibility, and Sierra Club; (2) the State of Massachusetts, State of Minnesota, State of Connecticut, State of Illinois, State of Maine, State of Maryland, State of Michigan, State of New Jersey, State of New York, State of Oregon, State of Pennsylvania, State of Rhode Island, State of

Vermont, State of Wisconsin, District of Columbia, City of Baltimore, City of Chicago, City of New York.

RELATED PROCEEDINGS

This application arises from an August 8 Order from the D.C. Circuit Court of Appeals denying six motions to stay filed in eight consolidated cases:

- No. 24-1119: *State of North Dakota, et al v. EPA* (lead case)
- No. 24-1154: *NACCO Natural Resources Corporation v. EPA, et al*
- No. 24-1179: *National Rural Electric Cooperative Association, Lignite Energy Council, National Mining Association, Minnkota Power Cooperative, Inc., East Kentucky Power Cooperative, Inc., Associated Electric Cooperative, Inc., Basin Electric Power Cooperative, Rainbow Energy Center, LLC v. EPA, et al*
- No. 24-1184: *Oak Grove Management Company, LLC, et al v. EPA, et al*
- No. 24-1190: *Talen Montana, LLC v. EPA, et al*
- No. 24-1194: *Westmoreland Mining Holdings LLC, Westmoreland Mining, and Westmoreland Rosebud Mining LLC v. EPA, et al*
- No. 24-1201: *America's Power, and Electric Generators MATS Coalition v. EPA*
- No. 24-1217: *NorthWestern Corporation, d/b/a NorthWestern Energy v. EPA*
- No. 24-1223: *Midwest Ozone Group v. EPA, et al*

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TO THE HONORABLE JOHN G. ROBERTS, CHIEF JUSTICE OF THE UNITED STATES AND CIRCUIT JUSTICE FOR THE DISTRICT OF COLUMBIA CIRCUIT:

INTRODUCTION

Applicants, including nearly half the States in the country, seek to stay an EPA Rule which reduces the Mercury and Air Toxics Standards ("MATS") for coal-fired power plants by 66-70%. With one sentence, and without any indication of why it determined a stay was unwarranted, the D.C. Circuit denied six motions and disregarded thousands of pages of briefing and declarations attesting that the Rule will impose tremendous costs and risk destabilizing the nation's power grids without creating *any* relevant or quantifiable benefit to public health.

Under Section 112 of the Clean Air Act, EPA has rulemaking authority to set emission levels for specifically listed hazardous air pollutants ("HAPs"). That authority is for protecting public health and the environment from those listed HAP emissions. Section 112 does not bestow EPA with a general rulemaking authority for combating climate change or achieving other environmental policy goals.

The Rule at issue here loses sight of that purpose. EPA cannot quantify any relevant or meaningful public health or environmental benefit from the mandated reduction in HAP emissions. None. EPA acknowledges that the standards already in place have achieved HAP emission levels that are **well below** any threshold that would impact public health. Indeed, health risks from HAP emissions for the worst performing coal-fired plant in the country are already orders of magnitude below the Clean Air Act's aspirational standard, where, by statute, EPA could discontinue regulating the emission source entirely.

Conversely, implementation costs for the Rule will be substantial, there is a significant likelihood power plants will be forced to retire, and, at minimum, prices for electricity will increase. Without a stay, the Rule will require investment and shutdown decisions to be made immediately, and those decisions will not be reversible if Applicants later prevail on the merits. Not coincidentally, grid regulators around the country are warning that the long-term reliability of our nation's already-precarious power grids will be threatened.

"When States … seek to stay the enforcement of a federal regulation … often the 'harms and equities [will be] very weighty on both sides.'" *Ohio v. EPA*, 144 S. Ct. 2040, 2052 (citation omitted). But that's not the case here. The disparity between injuries likely to result from not granting a stay and the lack of injuries from granting a stay could not be more stark. *Cf. Philip Morris USA Inc. v. Scott*, 561 U.S. 1301, 1305 (2010) (Scalia, J.) (granting stay where "[r]efusing a stay may visit an irreversible harm … but granting it will apparently do no permanent injury").

EPA knows that to impose this Rule on the nation it doesn't need to prevail on the merits, all it needs to do is prevent a stay of the Rule during the pendency of the challenge—the multi-year timelines for powerplant investment decisions and time needed to get a Clean Air Act merits decisions will do the rest. EPA knows this because they've already ran that play before, using the MATS Rule.

The last time the MATS Rule was litigated, this Court eventually held that EPA acted "unreasonably when it deemed cost irrelevant to the decision to regulate power plants." *Michigan v. EPA*, 576 U.S. 743, 760 (2015). But that victory proved hollow, because without a stay during the years it took for a merits decision, power plants were forced to make and implement compliance and retirement decisions, resulting in billions expended and a multitude of plant closures in response to an unlawful regulation. Rather than showing contrition for upending an entire industry with an unlawful regulation, EPA celebrated how many power plants had been forced into compliance by the time the rule was declared unlawful. Joe Rago, *A Supreme Carbon Rebuke*, Wall St. J. (Feb. 10, 2016), https://tinyurl.com/zwstzuw3. The last time the MATS Rule was litigated became a textbook example for when agency rules should be stayed. *E.g.,* Ronald Cass, *Staying Agency Rules: Constitutional Structure and Rule of Law in the Administrative State*, 69 Admin. L. Rev. 225, 254-57 (2017).

And beyond the sharp imbalance of imminent and irreparable harms, Applicants also have a high likelihood of prevailing on the merits.

Under Section 112(d)(6) of the Clean Air Act, EPA may only revise HAP emission standards "as necessary (taking into account developments in practices, processes, and control technologies)." 42 U.S.C. § 7412(d)(6). The operative statutory phrase is "revise as necessary," yet EPA never determined that this Rule was "necessary." Nor could it. A Section 112 rule that imposes tremendous costs without achieving *any* relevant health benefit could hardly be "necessary." EPA's failure to establish that the Rule is "necessary" renders it unlawful out of the gate.

Rather than trying to establish any necessity, EPA claims that power plants have been able to comply with the current standard at lower cost than anticipated, and interprets that to be a "development" under Section 112(d)(6). But even setting aside EPA's failure to address Section 112(d)(6)'s use of the term "necessary," EPA's interpretation of the term "development" does not hold water. The primary emission control technologies have not changed in the last decade. And the alleged cost efficiencies EPA points to for using long-existent control technologies cannot justify the Rule's dramatic ratcheting down of the standards.

The Rule is also arbitrary and capricious multiple times over. For one, the Rule's cost-benefit analysis is indefensible. Even taking EPA's calculations at face value, the estimated cost per ton of HAP removed exponentially exceeds cost-benefit ratios that EPA itself has rejected as unreasonable for other Section 112 rulemakings. Yet in exchange for those astronomical costs, EPA cannot point to any relevant, quantifiable public health benefit to be gained. EPA has never before used its Section 112(d)(6) rulemaking authority to impose costs of such a magnitude without any corresponding, quantifiable benefit to public health to show for it.

For another, EPA failed to adequately consider the Rule's significant and foreseeable impacts on our nation's already-strained power grids. EPA promulgated this Rule as one part of a "suite" of rules targeting coal-fired power plants with retirement-inducing costs. EPA's perfunctory conclusion that the tremendous costs of this Rule (and related rules) will have no effect on the power sector does not reflect reasoned analysis entitled to any degree of deference. EPA is not an expert on the power grid, and, despite the Rule's foreseeable impact on the power grid, EPA did not seek input from the Federal Energy Regulatory Commission (FERC), the North

American Electric Reliability Corporation (NERC), or any other similar entity that could have apprised it of *this* Rule's likely impact on long term grid reliability.

And finally, there is considerable evidence that EPA's stated reason for engaging in this rulemaking is pretextual. *Cf. Dep't of Commerce v. New York*, 588 U.S. 752, 784-85 (2019) ("[T]he evidence tells a story that does not match the explanation the Secretary gave for his decision. … Accepting contrived reasons would defeat the purpose of the enterprise."). Contrary to EPA's stated purpose of protecting public health from HAP emissions (which the Rule doesn't do), there is evidence that EPA is using its rulemaking authority under Section 112(d)(6) as part of an effort to force a nationwide transition away from coal for putative climate change reasons—pursuing a national policy choice this Court has expressly held the agency lacks authority to make. *Contra West Virginia v. EPA*, 597 U.S. 697, 735 (2022) (holding it "not plausible" that the Clean Air Act empowers EPA to "force a nationwide transition away from the use of coal to generate electricity").

"Stay applications are nothing new. They seek a form of interim relief perhaps 'as old as the judicial system of the nation.'" *Ohio*, 144 S. Ct. at 2052 (citation omitted). The D.C. Circuit's one-sentence denial of the stay motions filed below demonstrates a failure to learn from the *Michigan v. EPA* saga, and it did not identify (for the parties, or for this Court) which prong of the stay analysis its decision rested upon. To avoid imminent and irreparable harms from a rule likely to be set aside, this Court should stay the Rule's implementation pending resolution of the merits.

DECISION BELOW

The D.C. Circuit's order denying the motions for a stay pending review of the Rule is unpublished. It is reproduced at App. 1a-2a. The relevant Rule, *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, is published at 89 Fed. Reg. 38508 (May 7, 2024) and reproduced at App. 59a-144a.

JURISDICTION

This Court has jurisdiction over this Application under 28 U.S.C. §§ 1254(1) and 2101(f). It has the authority to grant Applicants' requested relief under both the Administrative Procedure Act, 5 U.S.C. § 705, and the All Writs Act, 28 U.S.C. § 1651.

BACKGROUND

Section 112 of the Clean Air Act (codified at 42 U.S.C. § 7412) provides EPA with statutory authority to set emission levels for protecting public health and the environment from certain HAPs specifically enumerated in Section 112(b)(1). 42 U.S.C. § 7412(b)(1); *see also Sierra Club v. EPA*, 895 F.3d 1, 7 (D.C. Cir. 2018) ("There are 189 hazardous air pollutants subject to regulation"). Carbon dioxide and other greenhouse gases are not HAPs subject to EPA's Section 112 authority, and combating climate change is not the purpose of Section 112.

When setting emission levels for the HAPs regulated under Section 112, the statute first requires EPA to set standards based on what is achievable with current technology. *See* 42 U.S.C. § 7412(d)(1), (3). Then, the Clean Air Act requires EPA to periodically evaluate whether to revise them. For public health, the Clean Air Act requires that eight years after setting a standard, EPA must evaluate if any "residual risks" remain to public health from those HAP emissions (the "Residual Risk Review"). 42 U.S.C. § 7412(f). And for technological advances, the Clean Air Act requires that every eight years after setting a standard, EPA must review and revise "as necessary," by "taking into account developments in the practices, processes and control technologies" (the "Technology Review"). 42 U.S.C. § 7412(d)(6).

EPA has promulgated over 100 HAP standards for a wide variety of emission sources under Section 112. *See* 40 C.F.R. 63 Subparts F through HHHHHHH. The Final Rule challenged here pertains to certain HAP emissions from coal- and oil-fired power plants (referred to as electric utility steam generating units or "EGUs").

In 2012, EPA issued the original MATS rule for mercury and other specified HAPs from coal- and oil-fired EGUs. *See* 77 Fed. Reg. 9304 (Feb. 16, 2012). The original MATS rule identified different emission standards for mercury from power plants that use lignite coal compared to other types of coal. That distinction was based on science: lignite is more variable (in terms of heat, moisture, and mercury content) than other types of coal, and available technologies cannot consistently achieve the same control levels. *See* 77 Fed. Reg. at 9393. For all other covered HAPs (i.e., the non-mercury metal HAPs), the original MATS Rule allowed for measuring filterable particulate matter (fPM) as a surrogate for total non-mercury metal HAPs.

Several parties challenged the original MATS Rule, arguing that EPA failed to consider the substantial costs the Rule would impose on the already heavily regulated power sector. *See Michigan*, 576 U.S. at 747-50. This Court agreed and found the original MATS Rule unlawful because EPA unreasonably "deemed cost irrelevant to the decision to regulate power plants." *Id.* at 760. But without a stay while the merits were litigated, EGUs were forced by the original MATS Rule to incur compliance costs or make retirement decisions in the interim, resulting in billions expended and many plant closures in response to an unlawful regulation.

This "results first, legality second" approach was intentional. Then-EPA Administrator Gina McCarthy proclaimed this Court's ruling on the lawfulness of the MATS Rule did not matter, because given the time it took to litigate, "[m]ost of [the EGUs] are already in compliance, [and] investments have been made." Timothy Cama & Lydia Wheeler, *Supreme Court Overturns Landmark EPA Air Pollution Rule,* The Hill (June 29, 2015), https://tinyurl.com/yw5b3z8u. And on remand to the D.C. Circuit, EPA argued (and that court accepted) that costs had by then become a moot point because they'd already been imposed. App. 792a-93a (EPA Resp. to Petitioners' Motions To Govern Future Proceedings, *White Stallion Energy Ctr., LLC. v. EPA*, No. 12-1100, Entry 1579186 at 14-15 (D.C. Cir. Oct. 21, 2015)); *see also* App. 794a-95a (D.C. Cir. Order, *White Stallion Energy Ctr., LLC. v. EPA*, No. 12-1100, Entry 1588459 at 1-2 (D.C. Cir. Dec. 15, 2015)). So ultimately, EPA unlawfully failed to consider the rule's costs, yet succeeded in having those costs imposed anyway.

In 2020, EPA conducted the 8-year Residual Risk and Technology Reviews. In its Residual Risk Review, EPA "determined that the current [standard] provides an ample margin of safety to protect public health and prevent an adverse environmental effect." 85 Fed. Reg. 31286, 31314 (May 22, 2020). And in the Technology Review, EPA determined there were no developments in emission control technologies, practices, or processes that warranted revising the rule. 85 Fed. Reg. at 31298 ("there are no developments in HAP emissions controls to achieve further cost-effective reductions beyond the current standards"). Accordingly, EPA concluded it was not "necessary" to revise the original MATS rule. 85 Fed. Reg. at 31314.

But six months later there was a change in presidential Administration, and the current Administration issued Executive Order 13990, entitled "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis." 86 Fed. Reg. 7037 (Jan. 25, 2021). Without identifying any legal or factual basis to do so, the Executive Order directed EPA to consider "suspending, revising, or rescinding" the 2020 Residual Risk and Technology Reviews for the MATS Rule—a rule that has nothing to do with greenhouse gases or climate change.

Following Executive Order 13990, EPA reconsidered its 2020 Residual Risk and Technology Reviews for the MATS Rule. For public health, EPA reached the exact same conclusion—that the original rule provided an ample margin of safety to protect public health. 88 Fed. Reg. 24854, 24895 (Apr. 24, 2023). As EPA noted, its 2020 residual 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 … [and] the results of the 2020 residual risk assessment … indicated low residual risk from the coal- and oil-fired EGU source category." 88 Fed. Reg. at 24866.

EPA's longstanding practice is that an ample margin of safety is a maximum excess cancer risk to the most exposed individual of less than 100-in-a-million. *See*

Nat. Res. Def. Council v. EPA, 529 F.3d 1077, 1082 (D.C. Cir. 2008). And under the Clean Air Act, EPA has discretion to delete a source category from regulation entirely if its HAP emissions do not "cause a lifetime risk of cancer greater than one in one million to the individual in the population who is most exposed." 42 U.S.C. § 7412(c)(9)(B)(i); *see also Nat. Res. Def. Council*, 529 F.3d at 1082 (one-in-one million standard is the Clean Air Act's "aspirational goal"). Here, under the standards already in place, the lifetime cancer risk of the person most exposed to coal-fired HAP emissions in the country is 0.344-in-a-million—significantly lower than the one-in-a-million threshold where EPA can stop regulating a source category entirely. App. 642a (NACCO Cmt. at 15, EPA-HQ-OAR-2018-0794-6000) (citing App. 650a-661a (Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2020 Risk and Technology Review Final Rule, EPA-HQ-OAR-2018-0794-4553, App. 10, Tbls. 1 & 2a. (Sept. 2019)).

That should have been the end of it. In other Section 112(d)(6) rulemakings, EPA itself has taken the position that if its standards already "provide an ample margin of safety to protect public health and prevent adverse environmental effects, one can reasonably question whether further reviews of technological capability are 'necessary.'" 69 Fed. Reg. 48338, 48351 (Aug. 9, 2004); *see also* 71 Fed. Reg. 76603, 76608 (Dec. 21, 2006). But in this rulemaking, where the risk from coal-fired units is less than the negligible level of one-in-one-million, EPA did not even ask the question. Instead, EPA reversed course, deciding to see if it could interpret "development" in a way that would allow it to lower HAP emission standards for coal-fired EGUs in the absence of any significant new practices, processes, or control technologies, and without quantifiable public health benefit from that reduction in HAP emissions. And lo and behold, EPA claimed to find "developments" that would justify dramatically revising the MATS rule in two ways: (1) reducing the surrogate fPM emission standard for all coal-fired EGUs by 66%; and (2) reducing the mercury emission standard for lignite coal-fired EGUs by 70%.

For the surrogate fPM standard, EPA's Technology re-Review again found "no new practices, processes, or control technologies" for the relevant HAP emissions. 88 Fed. Reg. at 24868. The primary control technologies used in 2012 are the same as today. *See* App. 662a (2023 Tech Review at 1). Nonetheless, EPA justified ratcheting down the standards under Section 112(d)(6) on the grounds that existing control technologies "are more widely used, more effective, and cheaper." 88 Fed. Reg. at 24866-72. EPA further concluded that "…most EGUs were reporting fPM emission rates well below the 0.030 lb/MMBtu standard. The fleet was achieving these performance levels at lower costs than estimated" during promulgation of the original MATS rule. 89 Fed. Reg. at 38530.

EPA's "development," in other words, was that EGUs were meeting the standard at lesser costs than estimated in 2012. EPA also determined there were marginal improvements in fPM control technology since the original MATS rule, stating that "industry has learned and adopted 'best practices' associated with monitoring ESP operation," and more "durable" materials for fabric filters have been developed since the original MATS rule. 89 Fed. Reg. at 38530.

And for the mercury emission standard, EPA revised the standard for lignite-firing EGUs because of alleged cost efficiencies for activated carbon injection control technology—the same technology that was in place at the time of the original MATS Rule. 88 Fed. Reg. at 24880. Then, with almost no record support, and in the face of numerous comments to the contrary, EPA determined those alleged cost efficiencies make lignite-firing EGUs capable of meeting the same control standard as other types of coal, dropping the emission standard by 70%. 89 Fed. Reg. at 38586.

EPA also prepared an analysis of the potential costs and benefits of the Rule in its Regulatory Impact Analysis ("RIA"). App. 685a, 718a-19a (RIA 3-1, 4-1–4-2). Able to point to no quantifiable public health benefit from the Rule's reduction in HAP emissions, EPA attempted to justify the Rule by claiming climate change benefits. 89 Fed. Reg. at 38561-62 (quantifying alleged particulate matter, ozone, and "climate" benefits); *see also* App. 723a-24a (RIA 4-16–4-17) (assessing climate impacts in its benefits analysis). EPA also claimed vague and unquantifiable benefits from mercury-reduction for subsistence fish consumers but recognized that these postulated benefits are so small they cannot be reliability extrapolated or quantified. App. 722a (RIA 4-5).

In exchange for zero quantifiable benefits from the mandated reduction in HAP emissions, the Rule imposes tremendous costs. For surrogate fPM emissions, the cost-effectiveness is $10.5 million per ton of HAP removed. 89 Fed. Reg. at 38532-33. Commenters noted this cost is much higher than the cost-benefit ratios EPA itself has explicitly *rejected* in other Section Rule 112 rulemakings for being excessive. And

EPA admits as much. 89 Fed. Reg. at 38523 ("EPA acknowledges that the cost-effectiveness values for these standards are higher than cost-effectiveness values that the EPA concluded were not cost-effective … for some prior rules.").

Commenters also stressed that the Rule's substantial compliance costs will result in serious economic harm and threaten power grid reliability. Yet EPA failed to address power outages or grid reliability in its RIA, matter-of-factly stating that the Rule will have no significant impact on the power grid or energy prices. *See* App. 685a-717a (RIA Section 3); 89 Fed. Reg. at 38555-56. And while EPA claims it consulted with the Department of Energy, the agency points only to a generic Memorandum of Understanding with DOE regarding interagency cooperation. Nothing in the record indicates EPA consulted with DOE (or any other grid operator or reliability expert) on *this specific rule*. *See* App. 676a-677a (Response to Comments at 156-57) ("This process is not linked to any one regulatory effort or final action.").

Moreover, EPA is promulgating this Rule against the backdrop of its failure to accurately estimate the impact the last MATS Rule would have on power plant operations. The last time the MATS Rule was litigated, EPA claimed it would only cause about 5,000 MW of generation to go offline. 77 Fed. Reg. at 9407 ("…expected retirements of coal-fueled units as a result of this final rule (4.7 GW) are fewer than was estimated at proposal and much fewer than some have predicted"). EPA was wrong. It ended up being closer to 60,000 MW.[1] Our power grids do not have the

[1] *See, e.g.,* U.S. Energy Info. Admin., *Planned coal-fired power plant retirements continue to increase* (Mar. 20, 2014), bit.ly/4dbYwfM (between 2012 and 2020, "about 60 gigawatts of coal-fired capacity is projected to retire … assum[ing] implementation of the MATS standards"); Pratson et. al., *Fuel Prices,*

same buffer of dispatchable generation that they did a decade ago. App. 595a (Vigesaa Decl. ¶11-12); App. 282a (Lane Decl. ¶¶12-13); App. 272a-273a (Huston Decl. ¶¶8-14).

Applicant States, along with many other petitioners, moved the D.C. Circuit to stay implementation of the MATS Rule pending litigation and provided an array of declarations describing the imminent harms threatened by the Rule's compliance deadlines. During the D.C. Circuit stay briefing, this Court issued its decisions in *Loper Bright* and *Ohio v. EPA*. *Loper Bright Enter. v. Raimondo*, 144 S. Ct. 2244 (2024); *Ohio v. EPA*, 144 S. Ct. 2040 (2024). The D.C. Circuit denied the stay motions on August 6, 2024, stating only that "Petitioners have not satisfied the stringent requirements for a stay pending court review." App. 1a. Applicants now move this Court for a stay of the Rule pending resolution of the merits.

REASONS TO GRANT THE APPLICATION

This Court should stay the Rule until the merits of the challenges to it are resolved because the States will suffer irreparable harm absent a stay, a stay will not injure other parties or the public interest, and the States will likely succeed on the merits. *Winter v. Nat. Res. Def. Council, Inc.,* 555 U.S. 7, 20 (2008).

Of course, this application is not the only Clean Air Act-related emergency stay this Court has seen recently. States' Emergency Application for an Immediate Stay,

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Emission Standards, and Generation Costs for Coal v Natural Gas Power Plants, Am. Chem. Soc'y, Env'l Sci. & Tech., 4929 (Mar. 2013), bit.ly/3w7yLN2 (most coal-fired EGU retirements in the wake of the original MATS Rule were due to "stronger regulations," not unrelated market forces); *see also* App. 620a (Nat'l Min. Ass'n Cmt. at 2 & n.4, EPA-HQ-OAR-2009-0234-20531) (for the nearly 60 gigawatts of coal-fired EGU retirements announced between 2012 and 2016, "virtually all" the stated closures were "either fully or partially attributable to MATS and other EPA regulations").

West Virginia v. EPA, No. 24A95 (docketed July 26, 2024), https://www.supremecourt.gov/search.aspx?filename=/docket/docketfiles/html/public/24a95.html. But these stay applications are the result of EPA's decision to bundle and simultaneously promulgate a "suite" of rules targeting coal-fired power plants with retirement-inducing costs. S*ee* EPA, *Biden-Harris Administration Finalizes Suite of Standards to Reduce Pollution from Fossil Fuel-Fired Power Plants* (Apr. 25, 2024), https://tinyurl.com/y5u92sx3. Serial agency actions that ignore congressional direction in order to destroy an entire industry require serial remedies.

I. THE STATES WILL SUFFER IRREPARABLE HARM WITHOUT A STAY

Absent a stay, Applicant States will suffer imminent and irreparable injury from the Rule. Applicant States, grid operators, and regulated EGUs provided an array of declarations establishing that the Rule will seriously undermine the long term reliability of our nation's power grids. Though retirements necessitated by the Final Rule may not happen for several years, irreversible decisions to put power plants on retirement tracks will need to be made now. But even short of potential power grid failures, the Rule will cause imminent and significant cost increases for ratepayers and consumers of electricity, including Applicant States themselves as major consumers of electricity.

A. The Rule Jeopardizes the Stability of the Nation's Power Grids.

Power grid instability and failures are frequently paid for in human lives. *E.g.,* App. 680a-82a (FERC-NERC-Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States at 8-10 (Nov. 16,

2021) (over 200 fatalities during weather event "with most of the deaths connected to the power outages")). Consequently, threats to power grid reliability constitute irreparable harm. *E.g., Texas v. EPA*, 829 F.3d 405 (5th Cir. 2016) ("the threat of grid instability and potential brownouts alone constitute irreparable injury."). And here, State and grid regulators have attested to the Rule's significant, foreseeable, and negative impacts on grid reliability. *See, e.g.*, App. 595a-600a (Vigesaa Decl. ¶¶11-26; App. 162a-168a (Fedorchak Decl. ¶¶7-24); App. 285a-293a (Lane Decl. ¶¶18-34); App. 550a-551a (Rickerson Decl. ¶¶13-15); App. 518a-525a (Nowakowski Decl. ¶¶7-12); App. 603a-604a (Webb Decl. ¶¶6-10); App. 273a (Huston Decl. ¶12).

According to a study commissioned by the North Dakota Transmission Authority, if the Rule causes any of North Dakota's lignite-fired EGUs to retire—which it appears designed to do—it will risk causing the entire MISO grid (which covers all or part of 15 states and parts of Canada) to experience black-outs resulting in economic damages ranging from $29 million to over $1 billion. App. 598a-600a (Vigesaa Decl. ¶¶22-25). Other declarants have attested to the devastating effects of grid failure, including documented health impacts and morbidity. App. 341a-342a (McLennan Decl. ¶67); App 541a-542a (Purvis Decl. ¶31) ("Other concrete damages would occur such as business shutdowns, food spoilage, property damage, and lost labor productivity").

Notwithstanding EPA's nothing-to-see-here attitude, there is substantial evidence in the record indicating that coal-fired power plant shutdowns are not only possible but likely due to the Rule, and that those retirements will cause significant threats to the long term reliability of the power grid. *E.g.,* App. 609a-610a (Bohrer Decl. ¶¶21-24); App. 329a-332a, 343a-344a (McLennan Decl. ¶¶34-39, 70) ("Recent test data suggest that Minnkota will not be able to meet the New Mercury Limitation even at the higher PAC injection rates that EPA assumed to be sufficient to meet the New Mercury Limitation."); App. 558a-559a (Tschider Decl. ¶¶21-23); App. 306a-308a (McCollam Decl. ¶¶34-43); App. 537a-539a (Purvis Decl. ¶¶24-25) (upgrades to comply "will certainly fail, despite best engineering and maintenance practices, due to the lack of any margin to meet the aggressively low new fPM limitation").

EPA has never grappled with this information, preferring to stick its head in the sand and rely on its unrealistic and counterfactual model which predicts that absolutely zero EGU retirements or shutdowns will occur as a result of the Rule. 89 Fed. Reg. at 38526. Though in a telling section, EPA dismisses widespread concerns about the Rule's foreseeable impact on power grid reliability by assuming that State or regional regulators will be able to use emergency powers to prop up the power grid if the Rule makes EGUs no longer commercially viable. 89 Fed. Reg. at 38526.

Moreover, this Rule is not the first time EPA has significantly underestimated the impact that its regulations will have on the power grid. As noted *supra*, the last time the MATS Rule was litigated EPA claimed that the Rule would only cause about 5,000 MW to go offline. But that ended up being wrong by over a factor of ten. Our power grids do not have the same buffer of dispatchable power that they had ten or even five years ago, and an error of the same magnitude as EPA's last profound error will risk catastrophic impacts to our nation's power grids. App. 595a (Vigesaa Decl. ¶11-12); App. 282a (Lane Decl. ¶¶12-13); App. 272a-273a (Huston Decl. ¶¶8-14).

"EPA has no expertise on grid reliability." *Texas*, 829 F.3d at 432. Nor did EPA seek input from FERC or NERC before promulgating the Rule, entities entrusted with maintaining the reliability of our nation's power grids and which could have apprised it of the Rule's likely impact on grid reliability. EPA's lack of expertise, its pattern of grossly underestimating its Rules' impacts on power plant operations, and the seriousness of the attendant consequences weigh strongly in favor of a stay.

B. The Rule Will Impose Irreparable Economic Injury

In addition to the Rule's threats to grid reliability, Applicant States will suffer irreparable economic harm as a result of the Rule. EPA recognizes that compliance with the Rule will impose nearly a billion dollars in costs (presuming plants are able to comply at all). 89 Fed. Reg. at 38513, 38561. And as noted *supra*, complying with the Rule's three-to-four-year implementation period requires EGUs to make compliance and retirement decisions *now*. App. 609a-611a (Bohrer Decl. ¶¶24-28); App. 338a (McLennan Decl. ¶58); App. 560a-561a (Tschider Decl. ¶¶25-30); App. 306a-309a (McCollam Decl. ¶¶34-43); App. 179a (Friez Decl. ¶¶16-17); App. 533a-535a (Purvis Decl. ¶¶15-19).

Without a stay, EGUs must immediately begin incurring costs. As of yet, it has not actually been established that EGUs will be able to consistently meet the Rule's new emission standards, and testing is needed to determine a pathway to compliance, if compliance is even possible. *E.g.,* App. 334a (McLennan Decl. ¶45) ("Minnkota must immediately begin mercury testing"); App. 555a (Tschider Decl.

¶11) ("must begin implementing the required controls and monitoring system immediately"). And beyond initial testing, supply constraints and the realities of power plant modification mean that meeting the Rule's three or four year deadlines require work to begin imminently. App. 609a-611a (Bohrer Decl. ¶¶24-28); App. 338a (McLennan Decl. ¶58); App. 560a-561a (Tschider Decl. ¶¶25-30); App. 306a-309a (McCollam Decl. ¶¶34-43); App. 179a (Friez Decl. ¶¶16-17); App. 533a-535a (Purvis Decl. ¶¶15-19).

And even if EGUs are able to find a way to consistently comply with the Rule, and even if they can meet the Rule's deadlines for doing so, implementing the Rule will inevitably result in increased electricity prices for ratepayers, including Applicant States themselves as consumers of electricity. *E.g.*, App. 168a-170a (Fedorchak Decl. ¶¶25-33) (compliance costs for just *one* lignite-fired plant in North Dakota will cause *at least* a 0.5 percent rate increase); *see also* App. 287a-288a (Lane Decl. ¶23); App. 274a (Huston Decl. ¶¶16-17); App. 608a-609a (Bohrer Decl. ¶¶18-21); App. 333a-334a (McLennan Decl. ¶43); App. 561a (Tschider Decl. ¶29); App. 306a-307a (McCollam Decl. ¶¶33-35); App. 531a-532a (Purvis Decl. ¶11); App. 274a (Huston Decl. ¶17) (explaining how costs of installations are passed on to consumers). Indeed, EPA doesn't dispute that complying with the Rule will necessarily impose costs resulting "in the form of higher electricity bills." App. 782a (EPA Br. 44).

Applicant States (and their ratepaying citizens) will not be able to recover these costs even if they prevail on the merits, making those injuries irreparable. *E.g., Thunder Basin Coal Co. v. Reich*, 510 U.S. 200, 220-21 (1994) (Scalia, J., concurring in part and in the judgment) ("complying with a regulation later held invalid almost *always* produces the irreparable harm of nonrecoverable compliance costs").

II. THE BALANCE OF HARMS AND THE PUBLIC INTEREST FAVOR A STAY

The balance of harms and public interest weigh strongly in favor of a stay because, as discussed *supra*, EPA cannot point to any relevant, quantifiable harm to the public in staying the Rule. EPA acknowledges that the status quo, without the new Rule, already protects public health with an "ample margin of safety." 89 Fed. Reg. at 38508. Indeed, the current standard already far exceeds the Clean Air Act's aspirational standard for protecting public health, where, by statute, EPA could discontinue regulating the EGUs entirely. Conversely, the economic injuries and threats to power grid stability in the absence of a stay are real and imminent.

The public interest also strongly favors preserving the status quo when the public's access to affordable electricity is threatened. *Texas*, 829 F.3d at 435 (granting stay of EPA action that threatened to impose retirement-inducing costs on coal-fired plants because the "public interest in ready access to affordable electricity" outweighed "inconsequential" emissions reductions that implementation would have achieved during the pendency of the litigation); *see also, e.g., West Virginia v. EPA*, 90 F.4th 323, 332 (4th Cir. 2024) ("the public [] has an interest in the efficient production of electricity and other industrial activity in the State, even as such production is balanced with environmental needs"); *Sierra Club v. Ga. Power Co.*, 180 F.3d 1309, 1311 (11th Cir. 1999) (denying preliminary injunction where it threatened to reduce power generation, as "[a] steady supply of electricity … especially … [for]

the elderly, hospitals and day care centers, is critical"); *Tri-State Generation & Transmission Ass'n v. Shoshone River Power, Inc.*, 805 F.2d 351, 357 (10th Cir. 1986) (public interest in residents not "los[ing] their source of electric power").

In short, even EPA acknowledges that current levels of HAP emissions from the worst performing coal-fired EGUs in the country already provide more than an ample margin of safety. There is no relevant, quantifiable public health benefit that will be gained by denying a stay, whereas the risks of not imposing a stay are tremendous. The balance of equities and public interest tilt sharply in favor of a stay.

III. APPLICANTS WILL LIKELY PREVAIL ON THE MERITS

In promulgating the challenged Rule, EPA disregarded the statutory text constraining its ability to exercise Section 112(d)(6) rulemaking authority only when doing so is "necessary." A revision can hardly be "necessary," when there is no relevant health benefit from it (as EPA itself has recognized in the past). And EPA's capacious interpretation of Section 112(d)(6)'s use of the term "development" to mean meeting the standard at lower costs is not a rational, let alone the "best" reading of the statute, and not entitled to any deference. *Loper Bright*, 144 S. Ct. at 2273.

Moreover, EPA's cost-benefit analysis of the Rule is indefensible, and the agency largely ignored evidence about one of the most critical aspects of the problem—the impact the Rule would have on grid reliability. All of which leads to the inexorable conclusion that the Rule's claimed public health benefits are merely pretext for EPA's true purpose in promulgating the Rule: regulating criteria pollutants related to climate change. *Contra West Virginia*, 597 U.S. at 735.

A. EPA Has Exceeded the Authority Delegated by Congress

Section 112(d)(6) of the Clean Air Act directs EPA to "review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards promulgated under this section no less often than every 8 years." 42 U.S.C. § 7412(d)(6). The "operative" phrase is "revise as necessary," and "EPA must consider practical and technological advances" when determining whether revision is "necessary." *La. Envtl. Action Network v. EPA,* 955 F.3d 1088, 1097-98 (D.C. Cir. 2020). Here, EPA has not even attempted to satisfy the statutory requirement that the Rule be "necessary," and its legal theory about what constitutes a "development" is unmoored from the statute.

1. Revising the MATS Standard Is Not "Necessary"

As a matter of common understanding and parlance, "necessary" means "needed for some purpose or reason; essential." Black's Law Dictionary, *Necessary* (11th ed. 2019); *see also, e.g.,* Merriam Webster's Collegiate Dictionary, *Necessary* (10th ed. 1994) ("absolutely needed"). Use of the term "necessary" is context-dependent, and requires answering the question necessary *for what*? *Armour & Co. v. Wantock*, 323 U.S. 126, 129-30 (1944) ("the word 'necessary,' [] has always been recognized as a word to be harmonized with its context"). And in the context of Clean Air Act Section 112, the "for what" can only be protecting public health and the environment from adverse effects of the regulated HAPs. *See, e.g.*, 42 U.S.C. §§ 7412(b)(3)(B), (C) (substances shall be included or deleted from regulation under Section 112 based on "adverse effects to human health or adverse environmental effects"). And that is doubly true for power plants, where Congress required EPA to "perform a study of the hazards to public health" before it undertook any regulation of power plants under Section 112. 42 U.S.C. § 7412(n)(1)(A).

Here, the Rule's revisions to the MATS standard can hardly be deemed "necessary" when EPA is unable to point to *any* meaningful public health benefit to be gained from the Rule. Indeed, in other Section 112(d)(6) rulemakings, EPA itself has acknowledged that when its HAP emission standards already "provide an ample margin of safety to protect public health and prevent adverse environmental effects, one can reasonably question whether further reviews of technological capability are 'necessary.'" 69 Fed. Reg. at 48351; *see also* 71 Fed. Reg. 34422, 34437 (Jun. 14, 2006) (where an existing HAP emission standard "obtains protection of public health with an ample margin of safety and prevents adverse environmental effects, it is unlikely that it would be 'necessary' to revise the standard further, regardless of possible developments in control options").

EPA makes no attempt to quantify any public health or environmental benefits from the Rule's mandated reduction in HAP emissions. 89 Fed. Reg. at 38518-19; 38562. Instead, the only alleged "benefits" EPA purports to quantify in the Rule are reducing criteria pollutants and greenhouse gas emissions. *See* 89 Fed. Reg. at 38561 (pointing to alleged particulate matter, ozone, and "climate" benefits). But these alleged ancillary benefits cannot be used to justify EPA's exercise of rulemaking authority under Section 112(d)(6). As Chief Justice Roberts recognized the last time the MATS Rule was litigated, it is improper for EPA to use its Section 112 authority to "get at the criteria pollutants that you otherwise would have to go through a much more difficult process to regulate. In other words, you can't regulate the criteria pollutants through the HAP program ...." App. 798a-99a (Transcript of Oral Argument at 59:19–60:5, *Michigan v. EPA*, Nos. 14-46, 14-47, 14-49 (Mar. 25, 2015)); *cf., e.g., Wyoming v. Dep't of Interior*, 493 F. Supp. 3d 1046, 1079 (D. Wyo. 2020) (agency "cannot rationally claim the Rule's objective is waste prevention while justifying its considerable costs almost entirely on climate change benefits").

Rather than trying to meet Section 112(d)(6)'s necessary requirement by establishing any relevant, quantifiable benefit to the Rule, EPA claims Section 112(d)(6) gives it the power to ratchet down HAP emission standards simply on the basis that "less is better." App. 739a (EPA Br. 1) (arguing its Section 112(d)(6) authorities are guided by a "[l]ess is better" standard). But this "less is better" assertion has no basis in the text of Section 112(d)(6) and ignores the statutory language constraining EPA's ability to make Section 112(d)(6) revisions only when doing so is "necessary." Congress could have said that EPA should revise these standards whenever "possible." But it didn't.

In short, the Rule is not "necessary" under the language of Section 112(d)(6) and any common sense meaning of that term, and EPA's failure to make any necessity determination before promulgating the Rule contravenes the statutory text.

2. There Has Not Been a "Development" to Justify Revising the MATS Rule

Rather than establishing that the Rule's revisions are "necessary" because the reduction in HAP emissions provides any relevant public health benefit, EPA grounds the Rule solely on the contention that there have been "developments" that enable dramatically ratcheting down the standards. 89 Fed. Reg. at 38518. But even setting aside its failure to grapple with the term "necessary," EPA's capacious interpretation of the term "development" is also wrong.

As used in the context of Section 112(d)(6), "development" must mean some new, significant change that is correlated to revision of the emission standard. *E.g.*, Am. Heritage Dictionary (5th ed. 2011), *Development* ("A significant event, occurrence, or change"). Congress cannot have intended to empower EPA to revise the Section 112(d)(6) standards every time there is some alleged cost savings or some minor change or modification equivalent to a cell phone software patch.

EPA itself has previously recognized that a determination there are no substantially new practices, processes or control technologies means there are no "developments" that would allow revising an emission standard under Section 112(d)(6). *See* App. 646a-647a (2018 Tech Review Memo at 9-10); *see also* 76 Fed. Reg 81328, 81341 (Dec. 27, 2011) (defining "developments" for purposes of Section 112(d)(6) as: "(1) Any add-on control technology or other equipment that was not identified and considered during development of the [prior standard]; (2) Any improvements in add-on control technology or other equipment (that were identified and considered during development of the [prior standard]) that could result in significant additional emissions reductions; (3) Any work practice or operational procedure that was not identified or considered during development of the [prior standard]; and (4) 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 [prior standard]"). None of these criteria are met here.

Nonetheless, to advance a policy goal of forcing coal-fired EGUs out of the market by setting dramatically reduced emission standards, EPA now interpreted the term "development" in Section 112(d)(6) to include the fact that EGUs have been able to comply with the existing standards at less costs than previously predicted. EPA purports to have found that many coal-fired plants have been able to comply with the surrogate fPM emission standards with more cost efficiency than EPA assumed when it promulgated the original MATS Rule. For surrogate fPM emissions, EPA claims as a "development" its alleged finding "that a majority of sources were not only reporting fPM emissions significantly below the current emission limit, but also that the fleet achieved lower fPM rates at lower costs than the EPA estimated when it promulgated the 2012 MATS Final Rule." 89 Fed. Reg. at 38521. Similarly, for mercury emissions from lignite-fired EGUs, EPA claims that alleged cost efficiencies for controlling mercury emissions from lignite-fired EGUs mean that those EGUs can be held to the same mercury emission standard as other coal-fired EGUs, and it "expect[s] that the units could meet the final, more stringent, emission standard of 1.2 lb/TBtu by utilizing brominated activated carbon at the injection rates suggested in the beyond-the-floor memorandum from the 2012 MATS Final Rule." 89 Fed. Reg. at 38547.

But those alleged cost efficiencies are not "developments" under Section 112(d)(6). The "core requirement" for tightening HAP emission standards under

Section 112(d)(6) is for EPA to identify new *technological* developments. *Natural Res. Def. Council v. EPA*, 529 F.3d at 1080, 1084 (summarizing Section 112(d)(6) as commanding "the Administrator to 'review, and revise as necessary' the *technology-based* standards in light of *technological developments*") (emphasis added). And that interpretation makes sense; Congress intended Section 112(d)(6) to serve as a periodic review of whether there were substantial changes in control technologies that would allow EPA to revise previously issued standards. There must be a substantial change in control technology or processes that is directly correlated to the mandated reduction in emission levels.

EPA now claims that a Section 112(d)(6) "development" can mean any "incremental changes," to include alleged cost efficiencies. App. 749a (EPA Br. 11). But the flaws in EPA's legal theory are obvious. All regulated sources must comply with a HAP emission standard once it is issued, or they must stop emitting. And for emission sources with variable fuel supplies (like coal-fired EGUs), they must do so at a level that ensures continuous compliance. If meeting an emission standard with alleged cost efficiency qualified as a "development," then the simple fact that a facility was complying with the relevant HAP emissions standard would allow EPA to continually tighten that standard in perpetuity until regulated sources can no longer meet the standards and are forced to shut down. This ever-tightening squeeze cannot be what Congress intended. *See, e.g.*, *Griffin v. Oceanic Contractors, Inc.*, 458 U.S. 564, 575, (1982) (interpretation of a statute that would produce absurd results is to be avoided if alternative interpretations, consistent with legislative purpose, are available). Even EPA has previously recognized that Section 112(d)(6) puts meaningful constraints on its ability to continuously ratchet down HAP emission standards. *See* 70 Fed. Reg. 19992, 20008 (Apr. 15, 2005) ("We reiterate that there is no indication that Congress intended for section 112(d)(6) to inexorably force existing source standards progressively lower and lower in each successive review cycle …").

EPA has relied upon the D.C. Circuit's decision in *Nat'l Ass'n for Surface Finishing v. EPA* to justify its capacious interpretation of the term "development." *See* App. 751a (EPA Br. 13 (citing 795 F.3d 1 (D.C. Cir. 2015)). But for a variety of reasons, EPA's invocation of that decision is not persuasive.

For one, in *Surface Finishing*, the D.C. Circuit specifically noted that the petitioner trade association *did not challenge* EPA's broad legal interpretation of the word "developments" under Section 112(d)(6). 795 F.3d at 8. Consequently, the Court did not address, let alone rule upon, the validity of EPA's capacious interpretation of the term. *Cf. Webster v. Fall*, 266 U.S. 507, 511 (1925) ("Questions which merely lurk in the record, neither brought to the attention of the court nor ruled upon, are not to be considered as having been so decided as to constitute precedents."). Here, Applicants *do affirmatively* challenge EPA's interpretation.

Second, the *Surface Finishing* court specifically relied upon "the familiar deferential standard announced in *Chevron*." 795 F.3d at 7. *Chevron* is of course no longer good law, and courts must now "exercise their independent judgment in deciding whether an agency has acted within its statutory authority, as the APA requires." *Loper Bright*, 144 S. Ct at 2273. The D.C. Circuit's one-sentence denial of

Petitioners' motions to stay gives no indication that the court gave proper, or any, consideration to these critical issues and changes in law.

And third, in *Surface Finishing* EPA identified several technologies—emissions elimination devices, HEPA filters, enclosing tank hoods and fume suppressants—in support of its determination that there had been "developments" that warranted a reduction there. 795 F.3d at 11. Here, by contrast, EPA has not identified any such new technologies. Electrostatic precipitators and fabric filters were available for surrogate fPM control under the original MATS rule in 2012, and EPA itself determined those are the same technologies used today. *See* 88 Fed. Reg. at 24865. Similarly, activated carbon injection was available for control of mercury emissions under the original MATS rule in 2012, and that is the same technology used to control mercury emissions today. *See* 89 Fed. Reg. at 38517.

Finally, the marginal purported "developments" (other than alleged cost efficiencies) that EPA identified in the Final Rule cannot save it. For surrogate fPM emissions, EPA claims that increased durability in filter-bag material for baghouse controls is a development that warrants a ratcheting down of the fPM standard. 89 Fed. Reg. at 38530. But improvements in filter durability cannot be a "development" under the Clean Air Act, because in setting the HAP emission standard EPA already presumed that no malfunctions will occur. *See* 77 Fed. Reg. 9304, 9393 (Feb. 16, 2012). In other words, the MATS standard already assumes that the filter-bags will *never* break, so any alleged improvement in their durability is not a "development" that would justify further tightening the standard. Similarly, for mercury emissions, activated carbon injection has been used since 2011, when EPA first proposed the original MATS standard, and the Final Rule's emphasis on the effectiveness of brominated powdered activated carbon is misplaced—as this product was both available and in use when EPA set the mercury standard in the original MATS rule. 89 Fed. Reg. at 38547; 76 Fed. Reg. 24976, 25014 (May 3, 2011). It cannot be a "development" justifying revising the standard.

* * * *

In summary, EPA can only revise HAP emission standards under Section 112(d)(6) when doing so is "necessary." EPA failed to make any determination that the challenged Rule's revision to the MATS standard were "necessary," and revisions without any corresponding benefit to either the public health or the environment from the mandated reduction in HAP emission can scarcely be described as "necessary." But even if a "development" in control technologies could be used to justify a Section 112(d)(6) revision without any corresponding benefit to public health or the environment, there has been no such development that would support the Rule's dramatic revisions to the standard here, and EPA's capacious interpretation of the term is not entitled to any degree of deference.

B. The Final Rule is Arbitrary and Capricious

An agency's rulemaking is arbitrary and capricious "if the agency has relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem…or is so implausible that it could not be ascribed to a difference in view of the product of agency expertise." *Motor Vehicle Mfrs. Ass'n v.*

State Farm, 463 U.S. 29, 43 (1983). This Rule is arbitrary and capricious for many reasons, each of which warrants vacating it.

1. EPA's Cost-Benefit Analysis is Indefensible

This Rule makes clear that EPA has not learned the lessons this Court set forth in *Michigan v. EPA* regarding the agency's previous attempt to regulate HAP emissions for the coal and oil-fired EGU source category.

In *Michigan*, this Court made clear that Clean Air Act Section 112(n)(1)(A)'s use of the term "appropriate and necessary" "plainly subsumes consideration of cost." 576 U.S. at 753, 756. And EPA acknowledges that consideration of costs is similarly relevant for Section 112(d)(6) rulemakings. *See* App. 754a (EPA Br. 16 ("EPA considers 'costs, technical feasibility, and other factors when evaluating whether it is necessary to revise existing emission standards under [Section 7412](d)(6)) (quoting 89 Fed. Reg. at 38531); *see also Ass'n of Battery Recyclers v. EPA*, 716 F.3d 667, 673-74 (D.C. Cir. 2013) (rejecting argument that cost is irrelevant to emission standard revisions under Section 112(d)(6)).

EPA's cost-benefit analysis for this Rule, to the extent it can be called a cost-benefit analysis at all, provides no basis to justify the Rule. EPA anticipates that that the Rule will impose compliance costs of at least $860 million. 89 Fed. Reg. at 38512. Those costs of nearly a billion are weighed against zero quantifiable public health benefits from the mandated reduction in HAP emissions. In order to claim some "benefits" of the Rule, EPA pivots to pointing to alleged benefits that are unrelated to HAP emissions. 89 Fed. Reg. at 38512 (claiming $300 million in health benefits from reductions of non-HAP pollutants and $130 million in other "climate benefits"). As noted *supra*, alleged benefits unrelated to the Rule's mandated reduction in HAP emissions cannot drive Section 112 rulemaking. And yet, even with these impermissibly considered ancillary benefits, EPA acknowledges that the Rule *still* has a "negative net monetized benefit"—meaning the costs of the Rule still outweigh the benefits by at least $440 million. *Id*. at 38511.

Moreover, under EPA's own calculations, the estimated cost-per-ton of HAP removed exponentially exceeds cost-benefit ratios that EPA has *rejected* for other Section 112 rulemakings. For surrogate fPM emissions, by EPA's own math, the cost effectiveness is $10.5 million per ton of HAP removed. 89 Fed. Reg at 38532-33. That is orders of magnitude higher than dollars per ton costs that EPA has explicitly rejected as being excessive. *See* 89 Fed. Reg. at 38522-23; 80 Fed. Reg. 75178, 75201 (Dec. 1, 2015) ($23,000 per ton of surrogate fPM emissions deemed excessive); 85 Fed. Reg. 42074, 42090 (Jul. 13, 2020) ($14,000 per ton volatile HAP emissions deemed excessive); 78 Fed. Reg. 10006, 10020-21 (Feb. 12, 2013) ($268,000 per ton of surrogate fPM emissions deemed excessive); 88 Fed. Reg. 11556, 11565 (Feb. 23, 2023) ($4.7M per ton of lead emissions deemed excessive). These costs will likely force power plant retirements and threaten grid reliability, *see supra*, but, even if they didn't, they will increase the price of electricity for consumers.

Having found that the costs of the Rule outweigh its benefits by at least $440 million (even when counting alleged ancillary benefits), 89 Fed. Reg. at 38512, EPA decided to ignore that analysis and rely instead on "alternative metrics." 89 Fed. Reg. at 38532. EPA claims that the benefits of the Rule's mandated reduction in HAP emissions escape quantification. *See* 89 Fed. Reg. at 38559. That claim is in stark contrast to the original MATS rule, wherein EPA was able to quantify the alleged benefits of reducing the very same HAP emissions. *See* 77 Fed. Reg. at 9425 (concluding the 2012 MATS rule's reduction of 20 tons of mercury emissions would provide $4-$6 million in benefits). And regardless, EPA's attempt to avoid accountability for this Rule's indefensible cost-benefit analysis by pointing to unquantifiable (and unchallengeable) benefits is contrary to the reasoned decisionmaking demanded from the agency by this Court in *Michigan*. *Accord, e.g., GPA Midstream Ass'n v. DOT*, 67 F.4th 1188, 1200 (D.C. Cir. 2023) ("Without quantified benefits to compare against costs, it is not apparent just how the agency went about weighing the benefits against the costs.").

Moreover, *every* single past instance of rulemaking cited by EPA to justify abandoning any attempt to quantify the relevant benefits of this Rule either found the cost effectiveness to be within the range of acceptable values before considering other cost metrics, or declined to enact the rule due to facility-specific determinations of "poor cost effectiveness" even after considering other cost metrics. *See* 89 Fed. Reg. at 38532 n. 52 (citing 87 Fed. Reg. 27002, 27008 (May 6, 2022); 87 Fed. Reg. 1616, 1635 (proposed Jan. 11, 2022); 80 Fed. Reg. 50386, 50398 (Aug. 19, 2015); 80 Fed. Reg. 37366, 37381 (Jun. 30, 2015); 80 Fed. Reg. 14248, 14254 (Mar. 18, 2015); 77 Fed. Reg. 58220, 58226 (Sep. 19, 2012); 77 Fed. Reg. 49490, 49523 (Aug. 16, 2012)).

EPA's inability (or refusal) to quantify *any* HAP-related benefits of the Rule speaks volumes about the Rule's necessity and the adequacy of existing regulations.

And given that it is arbitrary and capricious for EPA to impose significant economic costs "for a few dollars" of benefit," *Michigan,* 576 U.S. at 752, so too where EPA imposes substantial costs with "no meaningful benefit." *Mexican Gulf Fishing Co. v. U.S. Dep't of Commerce,* 60 F.4th 956, 966 (5th Cir. 2023).

2. EPA Failed to Adequately Consider Power Grid Impacts

In *Ohio v. EPA*, this Court recently issued a stay after the D.C. Circuit refused to, admonishing the agency must materially address comments relevant to its rulemaking. Here again, the D.C. Circuit denied a stay where EPA has done the same thing, this time regarding the Rule's foreseeable impact on our power grids.

Numerous commentators for this Rule put EPA on notice that our nation's power grids are already extremely strained, and that the Rule will likely force at least some coal-fired plants to retire. *See, e.g.,* App. 636a (Rainbow Energy Center Cmt. at 4, EPA-HQ-OAR-2018-0794-5990); *see also* App. 614a (MISO Cmt. on Docket ID Nos. EPA-HQ-OLEM-2021-0283, EPA-HQ-OLEM-2021-0282, EPA-HQ-OLEM-2021-0280, at 3); App. 617a-618a (Minnkota Power Coop. Inc. Cmt. at 2-3, EPA-HQ-OAR-2018-0794-5978); App.639a (Power Generators Air Coalition Cmt. at 12, EPA-HQ-OAR-2018-0794-5994); App. 625a-626a (NRECA Cmt. at 5-6, EPA-HQ-OAR-2018-0794-5956); App. 628a-633a (Cichanowicz Technical Cmt. at 39-44). Yet EPA failed to meaningfully address grid reliability in its Regulatory Impact Analysis, *see* App. 685a-717a (RIA Section 3), and EPA has never meaningfully considered the voluminous information it received describing the Rule's serious risks to the power grid.

EPA's perfunctory conclusion that the significant costs the Rule imposes on coal-fired EGUs will have no effect on the power sector, 89 Fed. Reg. at 38555-56, does not reflect reasoned analysis entitled to any degree of deference. "EPA has no expertise on grid reliability," *Texas*, 829 F.3d at 432, and comment after comment put EPA on notice that the Rule will foreseeably have significant impacts on power grid reliability. Nonetheless, the Final Rule does not reflect any attempt by EPA to seek input from FERC, NERC, or any similar entity that could have apprised it of the Rule's likely impact on grid reliability. *Cf. Del. Dep't of Nat. Res. & Envtl. Control v. EPA*, 785 F.3d 1, 18 (D.C. Cir. 2015) (encouraging EPA to solicit input from FERC on remand, as "[t]here is no indication that either FERC, the federal entity responsible for the reliability of the electric grid, 16 U.S.C. § 824o (b)(1), or NERC, FERC's designated electric reliability organization … was involved in this rulemaking or submitted their views to EPA.").

While EPA claimed in its briefing below that it "consult[ed] 'other federal agencies, reliability experts, and grid operators'" on the Rule, App. 772a (EPA Br. 34), that assertion appears to be a red herring. In support of that claim, EPA cited only on its own response to comments, where it describes a generic Memorandum of Understanding with the Department of Energy for interagency cooperation on certain aspects of grid reliability. App. 772a (EPA Br. 34). EPA does not indicate it consulted with DOE (or any other grid operator or reliability expert) on *this specific rule.* App. 676a-677a (Response to Comments at 156-57) ("This process is not linked to any one regulatory effort or final action.").

In its briefing below, EPA also pointed to its "state-of-the art" model, which assumes the Rule will cause *zero* plant retirements, to defend its conclusion that the Rule will have no impact on power grid reliability. App. 772a (EPA Br. 34). But EPA made no effort to ensure its model reflected the many comments it received warning that its baseline assumption of zero coal-fired power plants being forced to retire was likely incorrect, resulting in the agency reaching a conclusion that entirely ignores away a significant aspect of the problem. *Cf. Small Ref. Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 535 (D.C. Cir. 1983) ("agency must explain the assumptions and methodology used in preparing [a] model and, if the methodology is challenged, must provide a complete analytic defense") (internal quotations omitted). EPA's failure to adequately consider one of the Rule's most important impacts was arbitrary and capricious. *State Farm*, 463 U.S. at 43.

Moreover, as noted *supra*, EPA has a history of dramatically underestimating the impact of its MATS rules on power plant operations. The last time EPA promulgated a MATS Rule it assured the country it would only cause about 5,000 MW to go offline, and it ended up being wrong by over a factor of ten. The dramatic difference represents a profound failure on EPA's part to analyze the rule's impacts on power generation and provides "proof that the harm has occurred in the past and is likely to occur again." *Wis. Gas Co. v. FERC,* 758 F.2d 669, 674 (D.C. Cir. 1985). Consequently, EPA's perfunctory conclusion that this Rule (dropping emission standards by 66-70%) will not cause a single retirement, App. 700a (RIA at 3-16), should be viewed with extreme skepticism given the number of comments and declarations attesting EPA has gotten it profoundly wrong again.

Lastly, EPA's analysis of the Rule's power grid impacts is also arbitrary and capricious because it fails to "acknowledge and account for" the impacts of "contemporaneous and closely related rule[s]." *Portland Cement Ass'n v. EPA,* 665 F.3d 177, 187 (D.C. Cir. 2011). EPA expressly issued this Rule as part of a "suite" of rules targeting coal-fired power plants. *See* EPA, *Biden-Harris Administration Finalizes Suite of Standards to Reduce Pollution from Fossil Fuel-Fired Power Plants* (Apr. 25, 2024), https://tinyurl.com/y5u92sx3. EPA's failure to meaningfully assess how the confluence of these (and many other) rules targeting coal-fired power plants will affect the power grid further cements its arbitrary and capriciousness.

3. EPA's Basis for Promulgating the Rule is Pretextual

As an independent problem, EPA's stated justifications for the Rule appear to be pretextual. *Dep't of Com.*, 588 U.S. at 785. When an agency promulgates a rule, it must truthfully "disclose the basis of its action," and courts must set aside the rule if "the evidence tells a story that does not match the explanation." *Id.* at 780, 784. Accepting "contrived reasons" would vitiate the reasoned-explanation requirement and convert judicial review into an "empty ritual." *Id.* at 784-85. There is considerable evidence that is the case here. And in such cases, courts must evaluate "pretext" in light of "all evidence in the record before the court." *Id.* at 782.

Despite claiming it engaged in this rulemaking to protect the public from HAP emissions, 89 Fed. Reg. at 38509-10, available evidence indicates that EPA is using its Section 112(d)(6) authority as part of an effort to force a nationwide transition away from coal for putative climate change reasons. *Contra West Virginia*, 597 U.S. at 735 (2022) (declaring it "not plausible" the CAA empowers EPA to "force a nationwide transition away from the use of coal to generate electricity").

The current EPA Administrator has made no secret that the agency would respond to this Court's curtailment of its authority to implement climate change-related rules by issuing a "suite" of rules designed to close fossil fuel-fired power plants using a variety of regulatory authorities unrelated to climate change.

As just one example, Administrator Regan said his agency would "couple" climate regulations with "health-based" regulations to regulate greenhouse gases and get around the *West Virginia v. EPA* decision.

> **PBS**: How much of a setback is [the *West Virginia v. EPA* decision] to your efforts to regulate greenhouse gases?
>
> **Regan**: …We still will be able to regulate climate pollution. And we're going to use all of the tools in our toolbox. …
>
> **PBS**: Well, can you give us a couple of examples of the kind of tools that you believe you still can use to regulate this industry?
>
> **Regan**: …We also have a suite of regulations that are facing the power sector. And so, *as we couple the regulation of climate pollution with the regulation of health-based pollution*, we are providing the power sector with a very clear picture of what regulations they're facing so that they can make the right investment decisions.

PBS, *EPA Administrator Michael Regan discusses Supreme Court ruling on climate change*, YouTube (June 30, 2022) (emphasis added), https://www.youtube.com/watch?v=Ic_1UxwsXj8 (accessed May 7, 2024); *see also, e.g.*, White House, *Press Gaggle by Principal Deputy Press Secretary Karine Jean-Pierre & Env't Prot. Agency Adm'r Michael Regan* (Feb. 17, 2022) (stating if the Supreme Court limits EPA's ability to regulate greenhouse gas emissions, EPA will respond with "bread-and-butter regulations," such as "regulating mercury"), https://tinyurl.com/bddpr22j; Chemnick et al., *What the EPA's New Plans for Regulating Power Plans Mean for Carbon*, Sci. Am. (Mar. 11, 2022) (noting that when asked about the impending *West Virginia* decision, Administrator Regan said he "[doesn't] believe [EPA] ha[s] to overly rely on any one regulation" and suggested EPA could still achieve its climate goals by using authorities for protecting the public from mercury and air toxins).

Such public comments match internal documents that have been produced through FOIA indicating that EPA and the White House Climate Office contrived revising the MATS Rule as a means of reducing power plant emissions for climate change reasons. For example, in February 2021, EPA prepared a presentation for the White House *Climate Advisor*. *See* Power Sector Strategy: Climate, Public Health, Environmental Justice, Briefing for Gina McCarthy and Ali Zaidi (Feb. 4, 2021). App. 145a (Chang Decl. ¶¶3-5). While heavily redacted, the document evidences EPA's intent to use its regulatory authority under various programs, including the MATS Rule, for reducing power plant emissions to implement the Administration's climate agenda. App. 146a (Chang Decl. ¶¶6-7).

EPA's public statements and internal documents show that the "sole stated reason" for the Rule—*i.e.*, protecting the public from exposure to the regulated HAPs—was likely "contrived." *Dep't of Com.*, 588 U.S. at 784. This is not a case where the Court must risk substantial intrusion on Administrator Regan to inquire about his "mental processes," *Citizens to Preserve Overton Park, Inc. v. Volpe*, 401

U.S. 402, 420 (1971), as his public statements already lay bare his motivations. And the fact that EPA can identify no quantifiable public health benefits from the Rule's mandated reduction in HAP emissions, and instead claims millions of dollars in "climate" benefits, resolves any doubt as to EPA's true intent.

The purpose for EPA's "suite" of rules targeting coal-fired plants is recognized around the world, *e.g.,* Milman, *New US climate rules for pollution cuts 'probably terminal' for coal-fired plants*, Guardian (May 2, 2024), https://tinyurl.com/ykmb9xvn, and courts are "not required to exhibit a naiveté from which ordinary citizens are free." *Dep't of Com.*, 588 U.S. at 785 (citation omitted).

CONCLUSION

For the reasons set forth above, the Court should stay the Rule pending resolution of the merits, including through resolution of any petitions for certiorari.

Respectfully submitted.

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