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Regulatory Impact Analysis for Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

United States Environmental Protection Agency

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U.S. Environmental Protection Agency
Office of Water (4303T)
Engineering and Analysis Division
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Abbreviations

AEO	Annual Energy Outlook
ASCC	Alaska Systems Coordinating Council
BA	Bottom ash
BAT	Best available technology economically achievable
BCA	Benefit and Cost Analysis
BEA	U.S. Bureau of Economic Analysis
BLS	U.S. Bureau of Labor Statistics
BMP	Best management practice
BPJ	Best professional judgment
BPT	Best practicable control technology currently available
BSER	Best system of emission reduction
CAA	Clean Air Act
CC	Carbon capture
CCI	Construction cost index
CCR	Coal combustion residuals
CCRMU	CCR management units
CCS	Carbon capture and storage
CEMS	Continuous emission monitoring systems
CES	Clean Energy Standards
CFR	Code of Federal Regulations
CP	Chemical precipitation
CPP	Clean Power Plan
CRL	Combustion residual leachate
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
DOE	Department of Energy
EA	Environmental Assessment
ECI	Employment Cost Index
EGU	Electricity generating units
EIA	Energy Information Administration
EJ	Environmental justice
ELGs	Effluent limitations guidelines and standards
EO	Executive Order
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FOM	Fixed O&M
fPM	Filterable particulate matter
FR	Federal Register
FRCC	Florida Reliability Coordinating Council
GDP	Gross domestic product
GHG	Greenhouse gas

GW	Gigawatt
GWh	Gigawatt-hour
HICC	Hawaii Coordinating Council
HRI	Heat rate improvement
HRR	High recycle rate
HRTR	High Hydraulic Residence Time Reduction
IBR	Inverter-based resources
IPM	Integrated Planning Model
IRA	Inflation Reduction Act of 2022
ISO	Independent system operator
kWh	Kilowatt-hour
LRTR	Low Hydraulic Residence Time Reduction
MATS	Mercury and Air Toxics Standards
Mcf	Million cubic feet
MDS	Mechanical drag system
MRO	Midwest Reliability Organization
MT	Million short tons
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National ambient air quality standards
NAICS	North American Industry Classification System
NERC	North American Electric Reliability Corporation
NOPP	Notice of planned participation
NPCC	Northeast Power Coordinating Council
NPDES	National Pollutant Discharge Elimination System
NPRM	Notice of proposed rulemaking
NSPS	New Source Performance Standards
NTTAA	National Technology Transfer and Advancement Act
O&M	Operation and maintenance
OMB	Office of Management and Budget
POTW	Publicly owned treatment works
PRA	Paperwork Reduction Act
PSES	Pretreatment Standards for Existing Sources
PSNS	Pretreatment Standards for New Sources
QA	Quality assurance
QC	Quality control
Quad	Quadrillion British thermal units
RCRA	Resource Recovery and Conservation Act
RIA	Regulatory Impact Analysis
RFA	Regulatory Flexibility Act
RF	Reliability First Corporation
RGGI	Regional Greenhouse Gas Initiative
RTO	Regional transmission organization
RULOF	Remaining Useful Life and Other Factors

SBA	Small Business Administration
SBREFA	Small Business Regulatory Enforcement Fairness Act
SDE	Spray dry evaporator
SERC	SERC Reliability Corporation
SISNOSE	Significant impact on a substantial number of small entities
SPP	Southwest Power Pool
TDD	Technical Development Document
TRE	Texas Reliability Entity
TWF	Toxic weighting factor
TWh	Terawatt-hour
TWPE	Toxic weighted pound equivalent
UMRA	Unfunded Mandates Reform Act
USC	Ultra-supercritical coal
VIP	Voluntary Incentive Program
VOM	Variable O&M
WECC	Western Electricity Coordinating Council
WMU	Waste management unit

Executive Summary

The U.S. Environmental Protection Agency (EPA) is finalizing revisions to the technology-based effluent limitations guidelines and standards (ELGs) for the steam electric power generating point source category, 40 CFR part 423, which EPA proposed on March 29, 2023 (88 FR 18824). The final rule revises certain best available technology (BAT) effluent limitations and pretreatment standards established in the rules EPA previously promulgated in November 2015 (80 FR 67838) and October 2020 (85 FR 64650) for existing sources for three wastestreams: flue gas desulfurization (FGD) wastewater, bottom ash (BA) transport water, and combustion residual leachate (CRL). The rule also establishes effluent limitations and pretreatment standards for legacy wastewater.

This action is an economically significant regulatory action that was submitted to the Office for Management and Budget (OMB) for interagency review. This Regulatory Impact Analysis (RIA) presents an assessment of the compliance costs and impacts associated with this final rule and presents analyses to meet various statutory and Executive Order requirements. The accompanying *Benefit and Cost Analysis for Supplemental Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (BCA) document presents social costs and benefits of the action, consistent with Executive Orders 12866, 13563 and 14094.

Regulatory Options

For this final rule, EPA evaluated three regulatory options as summarized in Table ES-1. EPA established BAT effluent limitations based on the technologies described in Option B.

Table ES-1: Regulatory Options Analyzed for the Final Rule

Wastestream	Subcategory	Technology Basis for BAT/PSES Regulatory Options[a]			
		2020 Rule (Baseline)	Option A	Option B	Option C
FGD Wastewater	NA (default unless in subcategory)[b]	CP + Bio	ZLD	ZLD	ZLD
	Boilers permanently ceasing the combustion of coal by 2028	SI	SI	SI	SI
	Boilers permanently ceasing the combustion of coal by 2034	NS	CP + Bio	CP + Bio	NS
	High FGD Flow Facilities or Low Utilization Boilers	CP	NS	NS	NS
BA Transport Water	NA (default unless in subcategory)[b]	HRR	ZLD	ZLD	ZLD
	Boilers permanently ceasing the combustion of coal by 2028	SI	SI	SI	SI
	Boilers permanently ceasing the combustion of coal by 2034	NS	HRR	HRR	NS
	Low Utilization Boilers	BMP Plan	NS	NS	NS
CRL	NA (default)[b]	BPJ	CP	ZLD	ZLD
	Discharges of unmanaged CRL	NA	NS	CP	CP
	Boilers permanently ceasing the combustion of coal by 2034	NA	CP	CP	NS
Legacy Wastewater	Operate after 2024	NA	NS	CP	CP

Abbreviations: BMP = Best Management Practice; CP = Chemical Precipitation; HRR = High Recycle Rate Systems; SI = Surface Impoundment; ZLD = Zero Liquid Discharge; NS = Not subcategorized (default technology basis applies); NA = Not applicable

a. See TDD for a description of these technologies (U.S. EPA, 2024e).

b. The table does not present existing subcategories included in the 2015 and 2020 rules as EPA did not reopen the existing subcategorization of oil-fired units or units with a nameplate capacity of 50 MW or less.

Source: U.S. EPA Analysis, 2024

Annualized Compliance Costs

EPA estimates that the regulatory options result in incremental costs to owners and operators of steam electric power plants when compared to the baseline of the 2020 rule (Tables ES-2 and ES-3). On an *after-tax* basis, the final rule (Option B) has estimated incremental annualized compliance costs ranging from $479 million to $956 million.[1]

Table ES-2: Estimated Incremental Annualized After-tax Compliance Costs (Million of 2023$, Discounted to 2024 using 3.76 Percent) - Lower

Regulatory Option	Capital Technology	Other Initial One-Time	Total O&M	Total Costs[a]
Option A	$186	$0.1	$200	$386
Option B	$229	$0.1	$250	$479
Option C	$270	$0.2	$286	$557

a. Costs analyzed over the period 2025-2049.

Source: U.S. EPA Analysis, 2024

Table ES-3: Estimated Incremental Annualized After-tax Compliance Costs (Million of 2023$, Discounted to 2024 using 3.76 Percent) - Upper

Regulatory Option	Capital Technology	Other Initial One-Time	Total O&M	Total Costs[a]
Option A	$372	$0.1	$490	$863
Option B	$415	$0.1	$541	$956
Option C	$456	$0.2	$577	$1,033

a. Costs analyzed over the period 2025-2049.

Source: U.S. EPA Analysis, 2024

This analysis accounts for costs associated with the BA transport water, FGD wastewater, CRL wastestreams (including unmanaged CRL), and legacy wastewater. Costs associated with legacy wastewater limits would be incurred only as plants close and dewater their existing ponds. There is uncertainty on when plants may do so; for the purposes of this analysis, EPA assumed all plants would implement technologies to meet limits for legacy wastewater and incur costs in 2044. EPA believes this could overestimate costs if plants are decommissioned in later years. Similarly, certain plants could incur costs associated with the treatment of unmanaged CRL discharged from landfills, surface impoundments, or other features. These limits would apply only in cases where a permitting authority deems, on a case-by-case basis, that the discharge is functionally equivalent to a direct discharge and requires a permit. Because these discharges are uncertain, EPA assumed that plants incurred costs associated with

1 These costs are the basis for social costs presented in Chapter 11 of the BCA with the main differences being the applied discount rates, the way costs are distributed over the period of analysis, tax considerations, and the annualization period. In the private cost analysis, all costs are annualized over the life of the technology or cost recurrence period (*e.g.*, 1 year, 5 years, 20 years), discounted according to the estimated plant compliance year, and summed over each plant and across plants. After-tax costs are a more meaningful measure of compliance impact on privately owned for-profit plants and incorporate approximate capital depreciation and other relevant tax treatments in the analysis. By contrast, for the social cost analysis, costs are presented on a pre-tax basis and recorded in the year in which they are estimated to be incurred during the analysis period of 2025-2049. The modeled stream of future costs is then discounted back to the estimated rule promulgation year to obtain the total present value, and then annualized over the 25-year analysis period.

unmanaged CRL costs at the same time as they would implement technologies to meet limits for CRL wastestreams. See Section 3.1 for details.

EPA also evaluated whether the New Source Performance Standard (NSPS) requirements of the final rule present a barrier to the entry of new generation. EPA notes that no new coal capacity additions are projected between 2024 and 2050 in AEO2023 (EIA, 2023b) or in the Integrated Planning Model (IPM) detailed in Chapter 5, making the assessment of the relative costs and of any barrier the final ELGs may pose to additional generation hypothetical. Nonetheless, EPA assessed the costs imposed on new plants in relation to the costs for building and operating a new plant and found that the costs for adding treatment technology at a new plant would represent approximately 1 percent of the total annualized costs of building and operating a new plant. Section 3.3 details the analysis.

Impacts on Steam Electric Industry and Electricity Market

EPA assessed the impacts of the regulatory options on the steam electric industry and the electricity market in two ways:

1. A screening-level assessment reflecting historical characteristics of steam electric power plants and with assignment of estimated compliance costs to the plants and their owners. Specifically, EPA calculated cost-to-revenue ratios for individual steam electric power plants and for domestic parent-entities owning these plants to assess the relative impact of compliance outlays. Overall, this screening-level analysis shows that few entities are likely to experience significant changes in compliance costs compared to revenues. See Chapter 4 for details.

2. A broader electricity market-level analysis using the Integrated Planning Model (IPM), which provides a more comprehensive indication of the economic impacts of this final rule, looking specifically at regulatory option B, including an assessment of changes in the operating characteristics of steam electric power plants and other electricity generators resulting from changes in electricity markets under the final rule. See Chapter 5 for details.

Table ES-4 and Table ES-5 summarize IPM results in the baseline (absent Option B) and under Option B (absolute values and changes relative to the baseline). These analyses show that the final rule is estimated to have small impacts on the steam electric power plants, on the entities that own these plants, and on the electricity market as a whole. For example, IPM results for the market show net changes in total generation capacity of 0.4 percent and generation costs of less than 0.2 percent across economic measures for Option B in the model year 2035 after implementation of the revised ELGs (see Table ES-4). The final rule results in a small projected increase in total generation, and a small projected increase in total generation capacity (less than 0.4 percent of the baseline) as the net effect of increases in non-coal generation sources (combination of renewables, natural gas, and energy storage) and decreases in coal-fired generation capacity resulting from early retirements of coal-fired electricity generating units relative to the baseline and already scheduled retirements. The final rule results in a small projected increase in total electricity market costs, the net effect of decreases in fuel costs, variable O&M, and fixed O&M and increases in capital and CCS costs. These projected changes depend on overall changes in capacity, generation mix, and pollutant controls, among other factors (*e.g.*, switch from generating units with higher fixed O&M to units with lower fixed O&M would result in a decrease in total fixed O&M).

Results for steam electric power plants in scope of the final rule (in Table ES-5) also show small impacts, with a net decrease in total capacity under the final rule when compared to the baseline (2.6 percent), and net decreases in total generation by steam electric power plants of 3 percent for the final rule. Projected decreases in fixed O&M and capital costs for steam electric power plants in scope of the final rule reflect projected capacity retirements. The IPM model determines the least cost approach to meeting demand subject to modeled system and operational constraints. Therefore, changes in the national power sector (*e.g.*, generation mix, cost for non-steam electric generation, technology changes, cost for new capacity relative to new coal-steam production costs) affect projected retirements of steam electric capacity.[2] These findings suggest that the final rule will have small economic consequences for the steam electric power generating industry and the electricity market overall.

Looking specifically at plants with estimated incremental compliance costs, the results for the final rule show no change in generation for 1 of the 35 plants with compliance costs, and a slight decrease in generation for another 4 plants. See Chapter 5 for details of these analyses, including results by region and for different model years.

Table ES-4: Modeled Impact of Final Rule on National Electricity Market in the Model Year 2035

Economic Measures[a] (all dollar values in 2023$)	Baseline Value	Option B		
		Value	Difference	% Change
Total Domestic Capacity (GW)	1,712	1,718	6.4	0.4%
Existing			-1.5	-0.1%
New Additions			7.9	0.5%
Early Retirements			1.5	0.1%
Generation (TWh)	5,158	5,160	1.7	0.0%
Costs ($Millions)	$138,325	$138,544	$219	0.2%
Fuel Cost	$39,166	$38,975	-$191	-0.5%
Variable O&M	$5,351	$5,244	-$107	-2.0%
Fixed O&M	$65,915	$65,666	-$249	-0.4%
Capital Cost	$34,149	$34,536	$387	1.1%
CCS Cost[b]	-$6,256	-$5,878	$379	-6.1%
Average Variable Production Cost ($/MWh)	$8.63	$8.57	-$0.06	-0.7%
CO_2 Emissions (Million Metric Tons)	724	713	-11.6	-1.6%
Mercury Emissions (Tons)	2	2	-0.050	-2.0%
NO_X Emissions (Million Tons)	0	0	-0.009	-3.4%
SO_2 Emissions (Million Tons)	0	0	-0.013	-5.3%
HCL Emissions (Million Tons)	0	0	-0.00012	-8.1%

a. See Chapter 5 for a description of the economic measures.

b. "CCS Cost" is the cost of CO_2 transportation and storage and also includes expenses on equipment and pipelines, as well as the total value of 45Q tax credits and enhanced oil recovery (EOR) revenues. In the baseline and under Option B, the total

2 Costs to replace retired capacity are not included in the estimate of compliance costs reported in Table ES-2 and Table ES-3. However, as detailed in Chapter 5, the ELG compliance costs are entered as a fixed cost adder in IPM for units subject to the ELGs and included in the modeled decision of whether to keep generating electricity from that unit or shift to other generators with lower production costs. In cases where the modeled decision is the retirement of a steam electric unit in favor of other generating sources or new capacity, the ELG compliance costs would not be incurred for that unit and the compliance costs reflected in Table ES-2 and Table ES-3 are overestimated. Additionally, the final rule results in projected retirements representing only a fraction of a percent of total capacity, and an even smaller percentage of active capacity.

Table ES-4: Modeled Impact of Final Rule on National Electricity Market in the Model Year 2035				
Economic Measures[a] (all dollar values in 2023$)	Baseline Value	Option B		
		Value	Difference	% Change
private costs are negative because the sum of the tax credits and EOR revenues exceed the equipment and pipeline costs of CO_2 storage. Under Option B, total CCS Costs are less negative, and therefore these costs increase relative to the baseline, as the total amount of the 45Q tax credit received by the sector and/or EOR revenues fall due to lower coal generation.				

Source: U.S. EPA Analysis, 2024

Table ES-5: Impact of Final Rule on Plants in the Steam Electric Power Generating Point Source Category, as a Group, in the Model Year 2035

Economic Measures[a] (all dollar values in 2023$)	Baseline Value	Option B		
		Value	Difference	% Change
Total Domestic Capacity (MW)	220,237	214,455	-5,782	-2.6%
Early Retirements – Number of Plants	78	83	5	6.4%
Full & Partial Retirements – Capacity (MW)	104,544	110,326	5,782	5.5%
Generation (GWh)	789,529	765,950	-23,579	-3.0%
Costs ($Millions)	$28,580	$27,740	-$840	-2.9%
Fuel Cost	$13,957	$13,454	-$503	-3.6%
Variable O&M	$1,976	$1,840	-$136	-6.9%
Fixed O&M	$15,419	$15,041	-$378	-2.5%
Capital Cost	$3,202	$3,000	-$202	-6.3%
CCS Cost[b]	-$5,974	-$5,595	$379	-6.3%
Average Variable Production Cost ($/MWh)	$20.18	$19.97	-$0.21	-1.1%

a. See Chapter 5 for a description of the economic measures.

b. The "CCS Cost" is the cost of CO_2 transportation and storage and also includes expenses on equipment and pipelines, as well as the total value of 45Q tax credits and enhanced oil recovery (EOR) revenues. In the baseline and under Option B, the total private costs are negative because the sum of the tax credits and EOR revenues exceed the equipment and pipeline costs of CO_2 storage. Under Option B, total CCS Costs are less negative, and therefore these costs increase relative to the baseline, as the total amount of the 45Q tax credit received by the sector and/or EOR revenues fall due to lower coal generation.

Source: U.S. EPA Analysis, 2024

Potential Impacts on Employment

In addition to addressing the costs and impacts of the regulatory options, EPA discusses the potential impacts of this rulemaking on employment in Chapter 6. EPA estimates a net increase in employment as a result of the final rule (Option B).

Potential Electricity Price Effects

EPA also assessed the estimated impacts of the regulatory options on electricity prices, assuming a worst-case scenario of full cost pass-through of compliance costs in electricity prices. The Agency conducted this analysis in two parts: (1) an assessment of the estimated annual changes in electricity costs per MWh of total electricity sales; and (2) an assessment of the estimated annual changes in household electricity costs. Chapter 7 details these analyses.

Changes in costs per MWh of total electricity sales are small for all regulatory options; the maximum difference in price effect is a fraction of a cent per kWh. Overall, across the United States, the final rule (Option B) results in an average estimated cost increase of between 0.015¢ and 0.030¢ per kWh.

On the national level, the final rule (Option B) results in estimated average compliance costs per residential household of between $1.61 to $3.14 per year.

Potential Impacts on Small Entities

In accordance with the Regulatory Flexibility Act (RFA) requirements, EPA assessed whether the regulatory options would have "a significant impact on a substantial number of small entities" (SISNOSE). The analysis is detailed in Chapter 8.

Under the final rule (Option B), in the lower bound scenario, EPA estimates that 3 small cooperatives, 4 small nonutilities, and 3 small municipalities owning steam electric power plants would incur costs exceeding one percent of revenue. On a *percentage* basis, small entities represent approximately 5 to 8.5 percent of the total number of small entities owning steam electric power plants (12 to 16 percent of small cooperatives, 3 to 7 percent of small nonutilities, and 10 to 14 percent of small municipalities). In the upper bound scenario, EPA estimates that 4 small cooperatives, 5 small nonutilities, and 3 small municipalities owning steam electric power plants would incur costs exceeding one percent of revenue. On a *percentage* basis, small entities represent approximately 6 to 10 percent of the total number of small entities owning steam electric power plants. (16 to 21 percent of small cooperatives, 4 to 9 percent of small nonutilities, and 10 to 14 percent of small municipalities).

In the lower bound scenario, the analysis shows that 2 small cooperatives, 2 small nonutilities, and 1 small municipality owning steam electric power plants would incur costs greater than three percent of revenue. In the upper bound scenario, the analysis shows that 3 small cooperatives, 2 small nonutilities, and 2 small municipalities owning steam electric power plants would incur costs greater than three percent of revenue. Overall, this screening-level analysis suggests that the analyzed regulatory options are unlikely to have a significant economic impact on a substantial number of small entities.

Unfunded Mandate Reform Act

Under Title II of the Unfunded Mandates Reform Act (UMRA) of 1995 section 202, EPA generally must prepare a written statement, including a cost-benefit analysis, for final and final rules with "Federal mandates" that might result in expenditures by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100 million (adjusted annually for inflation) or more in any one year (*i.e.*, $198 million in 2023 dollars).

EPA estimates that the final rule (Option B) would result in expenditures of at least $198 million for State and local government entities under the upper bound scenario, in the aggregate, in any one year, but not in the lower bound scenario. The Agency does estimate that the private sector would incur expenditures greater than $198 million, in the aggregate, in any one year. For the final rule (Option B), the maximum compliance costs incurred by the private sector in any one year are between $1,380 and $3,156 million in 2028, whereas total annualized compliance costs for plants owned by private sector entities are between $603 and $1,207 million. The implementation period built into the final rule is one way that EPA accounted for the site-specific needs of steam electric power plants.

Other Administrative Requirements

EPA conducted analyses to address other administrative requirements. Key findings, which are discussed further in Chapter 10, include:

- **Executive Order 12866: Regulatory Planning and Review, Executive Order 13563: Improving Regulation and Regulatory Review, and Executive Order 14094 Modernizing Regulatory Review:** Pursuant to the terms of Executive Orders 12866, 13563, and 14094, this action is a "significant regulatory action" because the action is likely to have an annual effect on the economy of $200 million or more. As such, the action is subject to review by the OMB. Any changes made during this period of review will be documented in the docket for this action. EPA prepared an analysis of the estimated benefits and costs associated with this action; this analysis is detailed in Chapter 13 of the BCA (U.S. EPA, 2024a).

- **Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use:** EPA's analyses show that the final rule will not have a significant adverse effect at a national or regional level under Executive Order 13211. Specifically, the Agency's analyses found that the final rule would not reduce electricity production in excess of 1 billion kilowatt hours per year or in excess of 500 megawatts of installed capacity, nor that it would increase U.S. dependence on foreign supply of energy.

- **Executive Orders 12898: Federal Actions to Address Environmental Justice (EJ) in Minority Populations and Low-Income Populations; and Executive Order 14008: Tackling the Climate Crisis at Home and Abroad**: EPA examined whether the benefits from the regulatory options may be differentially distributed among population subgroups in the affected areas. This analysis is detailed in the accompanying *Environmental Justice Analysis for Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EJA) document (U.S. EPA, 2024c). The analysis showed that the human health or environmental risk addressed by this final action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income, or indigenous populations.

- **Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks:** As described in Section 10.3 and detailed in the BCA (U.S. EPA, 2024a), EPA identified several ways in which the final rule could benefit children by reducing health risk from exposure to pollutants present in steam electric power plant discharges, including neurological effects from exposure to lead and mercury.

1 Introduction

1.1 Background

EPA is finalizing a regulation that revises the technology-based effluent limitations guidelines and standards (ELGs) for the steam electric power generating point source category, 40 CFR part 423, which EPA previously proposed on March 29, 2023 (88 FR 18824). The final rule revises certain BAT effluent limitations and pretreatment standards for existing sources previously established in the ELG published in October 2020 (85 FR 64650) for four wastestreams: flue gas desulfurization (FGD) wastewater, bottom ash (BA) transport water, combustion residual leachate (CRL), and legacy wastewater.

This document describes the Agency's analysis of the costs and economic impacts of the regulatory options that were evaluated by EPA. EPA analyzed three regulatory options, including the final rule (Option B). The document also provides information pertinent to meeting several legislative and administrative requirements.

This document complements and builds on information presented separately in other reports, including:

- *Technical Development Document for Supplemental Revisions to the Effluent Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (TDD) (U.S. EPA, 2024e). The TDD provides background on the regulatory options; applicability and summary of the regulatory options; industry description; wastewater characterization and identifying pollutants; and treatment technologies and pollution prevention techniques. It also documents EPA's engineering analyses to support the regulatory options including plant-specific compliance cost estimates, pollutant loadings, and non-water quality environmental impact assessment.

- *Benefit and Cost Analysis for Supplemental Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (BCA) (U.S. EPA, 2024a). The BCA summarizes the societal benefits and costs estimated to result from implementation of the regulatory options.

- *Environmental Assessment for Supplemental Revisions to the Effluent Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EA) (U.S. EPA, 2024b). The EA summarizes the environmental and human health improvements that are estimated to result from implementation of the regulatory options.

- *Environmental Justice Analysis for Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EJA) (U.S. EPA, 2024c). This report presents a profile of the communities and populations potentially impacted by this final rule, analysis of the distribution of impacts in the baseline and finalized changes, and summary of input from potentially impacted communities that EPA met with prior to the final rule.

The revisions to the ELGs for the Steam Electric Power Generating Point Source Category are based on data generated or obtained in accordance with EPA's Quality Policy and Information Quality Guidelines. EPA's quality assurance (QA) and quality control (QC) activities for this rulemaking include the development, approval and implementation of Quality Assurance Project Plans for the use of environmental data generated or collected from all sampling and analyses, existing databases and literature searches, and for the development of any models which used environmental data. Unless otherwise stated within this document, the data used and associated data analyses were evaluated as described in these quality assurance documents to ensure they are of known and documented quality, meet EPA's requirements for objectivity, integrity and utility, and are appropriate for the intended use.

1.2 Overview of the Costs and Economic Impacts Analysis

This section describes the key components of the analysis framework. The Agency's analysis generally follows the methodology EPA previously used to analyze the 2020 rule and 2023 proposal (see RIA; U.S. EPA, 2020, 2023d). Appendix A describes the principal changes to the regulatory options analysis, as compared to analyses of the 2020 rule and 2023 proposal. These changes include:

- Updating the information on the control and treatment technologies and associated costs for BA transport water, FGD wastewater, CRL, and legacy wastewater (see TDD for details; U.S. EPA, 2024e).
- Updating the universe of steam electric power plants and their wastestreams to account for major changes such as additional retirements, fuel conversions, ash handling system conversions, wastewater treatment system updates and updated information on capacity utilization.
- Accounting for announced unit retirements and repowerings[3] in estimating the stream of expenditures under the baseline and each regulatory option during the period of analysis.
- Updating the baseline used in analyses using the Integrated Planning Model (IPM). IPM incorporates the effects of existing regulations and programs or estimated to be in effect by the time the rule resulting from this final rule is implemented. For the final rule, this baseline includes the 2020 rule, as well as expected effects of provisions in the Inflation Reduction Act of 2022. See Section 2.2 for additional discussion of these regulations and Chapter 5, *Assessment of the Impact of the Final Rule on National and Regional Electricity Markets*, for further description of the analysis using IPM, including a description of the analysis baseline.
- Updating electricity generation, sales, and electricity prices based on the most current data from the Energy Information Administration (*e.g.*, 2016-2021 vs. 2013-2018).
- Updating information about the entities that own steam electric generating units, based on EIA data, and recategorizing these entities as small or large using SBA small business size thresholds.

1.2.1 Main Regulatory Options Presented in the Final Rule

For this final rule, EPA evaluated three regulatory options as shown in Table 1-1. EPA finalized BAT effluent limitations based on the technologies described in Option B.

3 Repowering refers to the replacement of coal generation equipment with non-coal generation equipment.

Table 1-1: Regulatory Options Analyzed for the Final Rule

Wastestream	Subcategory	Technology Basis for BAT/PSES Regulatory Options[a]			
		2020 Rule (Baseline)	**Option A**	**Option B**	**Option C**
FGD Wastewater	NA (default unless in subcategory)[b]	CP + Bio	ZLD	ZLD	ZLD
	Boilers permanently ceasing the combustion of coal by 2028	SI	SI	SI	SI
	Boilers permanently ceasing the combustion of coal by 2034	NS	CP + Bio	CP + Bio	NS
	High FGD Flow Facilities or Low Utilization Boilers	CP	NS	NS	NS
Bottom Ash Transport Water	NA (default unless in subcategory)[b]	HRR	ZLD	ZLD	ZLD
	Boilers permanently ceasing the combustion of coal by 2028	SI	SI	SI	SI
	Boilers permanently ceasing the combustion of coal by 2034	NS	HRR	HRR	NS
	Low Utilization Boilers	BMP Plan	NS	NS	NS
CRL	NA (default)[b]	BPJ	CP	ZLD	ZLD
	Discharges of unmanaged CRL	NA	NS	CP	CP
	Boilers permanently ceasing the combustion of coal by 2034	NA	CP	CP	NR
Legacy Wastewater	Operate after 2024	NA	NS	CP	CP

Abbreviations: BMP = Best Management Practice; CP = Chemical Precipitation; HRR = High Recycle Rate Systems; SI = Surface Impoundment; ZLD = Zero Liquid Discharge; NS = Not subcategorized (default technology basis applies); NA = Not applicable

a. See TDD for a description of these technologies (U.S. EPA, 2024e).

b. The table does not present existing subcategories included in the 2015 and 2020 rules as EPA did not reopen the existing subcategorization of oil-fired units or units with a nameplate capacity of 50 MW or less.

Source: U.S. EPA Analysis, 2024

1.2.2 Baseline

The baseline for the analyses supporting this final rule reflects the 2020 rule requirements. The Agency estimated and presents in this report the incremental compliance costs that plants could incur under each of the three regulatory options presented in Table 1-1 relative to this baseline.

EPA updated baseline information to incorporate major changes in the universe and operational characteristics of steam electric power plants such as additional retirements and fuel conversions since the analysis of the 2020 rule detailed in U.S. EPA (2020). EPA also incorporated updated information on the technologies and other controls that plants employ. The current analysis focuses on four wastestreams for which plants are expected to incur costs during the period of analysis: BA transport water, FGD wastewater, CRL (including unmanaged CRL), and legacy wastewater.

1.2.3 Cost and Economic Analysis Requirements under the Clean Water Act

EPA's effluent limitations guidelines and standards for the steam electric industry are promulgated under the authority of the Clean Water Act (CWA) Sections 301, 304, 306, 307, 308, 402, and 501 (33 U.S.C. 1311, 1314, 1316, 1317, 1318, 1342, and 1361). In establishing national effluent guidelines and pretreatment standards for pollutants, EPA considers the availability and economic achievability of control and treatment technologies, as well as specified statutory factors including "costs." 33 U.S.C. 1311(b)(2)(A), 1314(b)(2)(B).

EPA analyzed economic achievability; the cost and economic impact analysis for this rulemaking also focuses on understanding the magnitude and distribution of compliance costs across the industry, and the broader market impacts. This report also documents analyses required under other legislative (*e.g.*, Regulatory Flexibility Act, Unfunded Mandates Reform Act) and administrative requirements (*e.g.*, Executive Order 12866: Regulatory Planning and Review as supplemented by Executive Order 14094: Modernizing Regulatory Review).

1.2.4 Analyses of the Regulatory Options and Report Organization

This document discusses the following analyses EPA performed in support of the regulatory options as compared to the baseline:

- **Overview of the steam electric industry** (Chapter 2), which focuses on changes to the industry since the 2020 rule.

- **Compliance cost assessment** (Chapter 3), which describes the cost components and calculates the industry-wide incremental compliance costs for the regulatory options relative to the baseline.

- **Cost and economic impact screening analyses** (Chapter 4), which evaluates the incremental impacts of compliance on plants and their owning entities on a cost-to-revenue basis.

- **Assessment of impacts in the context of national electricity markets** (Chapter 5), which analyzes the impacts of the final rule (Option B) using IPM and provides insight into the incremental effects of the final rule on the steam electric power generating industry and on national electricity markets, relative to the baseline.

- **Analysis of employment effects** (Chapter 6), which assesses national-level changes in employment in the steam electric industry, relative to the baseline.

- **Assessment of potential electricity price effects** (Chapter 7), which looks at the incremental impacts of compliance in terms of increased electricity prices for households and for other consumers of electricity.

- **Regulatory Flexibility Act (RFA) analysis** (Chapter 8) which assesses the change in impact of the rule on small entities on the basis of a revenue test, *i.e.*, cost-to-revenue comparison.

- **Unfunded Mandates Reform Act (UMRA) analysis** (Chapter 9) which assesses the change in impact on government entities, in terms of (1) compliance costs to government-owned plants and (2) administrative costs to governments implementing the rule. The UMRA analysis also compares the impacts to small governments with those of large governments and small private entities.

- **Analyses to address other administrative requirements** (Chapter 10), such as Executive Order 13211, which requires EPA to determine if this action would have a significant effect on energy supply, distribution, or use.

These analyses generally follow the same methodology used by EPA for the analysis of the 2015 and 2020 rules and 2023 proposal and the discussion follows a presentation very similar to that in the associated RIA documents (U.S. EPA, 2015, 2020, 2023d).

Chapter 11 provides detailed information on sources cited in the text and three appendices provide supporting information:

- *Appendix A: Summary of Changes to Costs and Economic Impact Analysis* lists the principal changes EPA made to its costs and economic impact analysis for the regulatory options, relative to the methodology used to analyze the 2020 rule.

- *Appendix B: Comparison of Incremental Costs and Pollutant Removals* describes EPA's analysis of the cost-effectiveness of the regulatory options.

- *Appendix C: Total Costs Based on 7 Percent Discount Rate* presents compliance cost estimates for the regulatory options based on a 7 percent discount rate.

2 Overview of the Steam Electric Industry

This section provides a general description of the steam electric industry, focusing on changes to the universe of plants and entities that own the plants as compared to the profile used for the 2015 and 2020 rules (U.S. EPA, 2015, 2020). It also discusses the regulations applicable to the universe of plants subject to this final rule.

2.1 Steam Electric Industry

The final rule revises BAT limitations and pretreatment standards for bottom ash transport water, FGD wastewater, CRL, and legacy wastewater for existing sources in the steam electric industry. The Steam Electric Power Generating Point Source Category covers "discharges resulting from the operation of a generating unit by an establishment whose generation of electricity is the predominant source of revenue or principal reason for operation, and whose generation of electricity results primarily from a process utilizing fossil-type fuel (coal, oil, or gas), fuel derived from fossil fuel (*e.g.*, petroleum coke, synthesis gas), or nuclear fuel in conjunction with a thermal cycle employing the steam water system as the thermodynamic medium." (40 CFR 423.10)

EPA had identified 1,080 steam electric power plants – including plants that operate coal, oil, gas, and nuclear generating units – and used this universe in its analysis of the 2015 rule (U.S. EPA, 2015), based on an industry survey the Agency conducted in 2010.[4] Review of more recent data revealed that some of the plants EPA surveyed in 2010 have since retired their coal steam units, converted to different fuels, or made other changes that affect discharge characteristics. The TDD describes the changes in the steam electric industry population since the 2015 and 2020 rule analyses, including retirements, fuel conversions, ash handling conversions, wastewater treatment updates, and updated information on capacity utilization (U.S. EPA, 2024e).

EPA adjusted the 2015 universe to remove coal steam plants that no longer fit the definition of the Steam Electric Power Generating point source category. As a result of these adjustments, EPA estimates that there are 858 plants in the steam electric power generating industry, based on available EIA data. As presented in Table 2-1, the 858 steam electric power plants represent 6.4 percent of the total number of plants in the power generation sector, but represent 54.4 percent of the national total electric nameplate generating capacity with 674,998 MW.[5]

Of the estimated 858 steam electric power plants in the universe, EPA expects only a subset to incur compliance costs under the final rule: those coal fired power plants that discharge BA transport water, FGD wastewater, or CRL. As presented in Table 2-1, EPA estimated between 141 and 170 plants would incur non-zero compliance costs under the final rule (Option B); these plants represent 1 to 1.3 percent of the total plants reported by EIA in 2021 and 15.4 to 17.5 percent of the total generating capacity.

4 See *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey; U.S. Environmental Protection Agency. (2010). *Questionnaire for the Steam Electric Power Generating Effluent Limitations Guidelines*.)

5 The total number of plants and electric generating capacity are for 2021. At the time EPA developed the industry profile, 2021 was the most recent calendar year for which EIA had published detailed annual data.

Table 2-1: Steam Electric Industry Share of Total Electric Power Generation Plants and Capacity in 2021					
		Steam Electric Industry[b]		Plants with Non-Zero Compliance Costs for Final Rule[c]	
	Total[a]	Number	% of Total	Number	% of Total
Plants	13,455	858	6.4%	141 - 170	1.0% - 1.3%
Capacity (MW)	1,241,578	674,998	54.4%	189,572 – 217,184	15.3% - 17.5%

a. Data for total electric power generation industry are from the 2021 EIA-860 database (EIA, 2022c).

b. Steam electric power plant count and capacity were calculated on a sample-weighted basis.

c. See Chapter 3 for details on compliance cost estimates, including number of plants with non-zero compliance costs under the final rule (Option B) and other analyzed regulatory options. Number of affected plants and capacity are presented to reflect the lower and upper bound cost estimates.

Source: U.S. EPA Analysis, 2024; EIA, 2022c.

The following sections present information on ownership, geographic distribution, and operating characteristics of steam electric power plants.

2.1.1 Owner Type and Size

Entities that own electric power plants can be divided into seven major ownership categories: investor-owned utilities, nonutilities[6], federally-owned utilities, State-owned utilities, municipalities, rural electric cooperatives, and other political subdivisions. These categories are important because EPA has to assess the impact of the final rule on State, local, and tribal governments in accordance with UMRA of 1995 (see Chapter 9, *Unfunded Mandates Reform Act (UMRA) Analysis*).

Table 2-2 reports the number of parent entities, plants, and capacity by ownership type for the 858 steam electric power plants (for details on determination of parent entities for steam electric power plants, see Section 4.3). The plurality of steam electric power plants (37 percent of all steam electric power plants) are owned by investor-owned utilities, while nonutilities make up the second largest category (36 percent of all steam electric power plants). In terms of steam electric nameplate capacity, investor-owned utilities account for the largest share (50 percent) of total steam electric nameplate capacity.

Table 2-2: Existing Steam Electric Power Plants, Their Parent Entities, and Nameplate Capacity by Ownership Type, 2021								
	Parent Entities [a,b,c]				Plants [a,b,d]		Capacity (MW) [a,d]	
	Lower Bound		Upper Bound					
Ownership Type	Number	% of Total	Number	% of Total	Number[c]	% of Total	Number[c]	% of Total
Cooperative	22	10.0%	28	7.1%	59	6.9%	39,934	5.9%
Federal	2	0.9%	7	1.7%	23	2.7%	31,154	4.6%
Investor-owned	57	25.9%	88	22.5%	320	37.4%	338,005	50.1%
Municipality	50	22.7%	84	21.5%	111	12.9%	42,882	6.4%
Nonutility	76	34.5%	160	40.9%	308	35.9%	196,559	29.1%
Other political subdivisions	11	5.0%	23	5.8%	33	3.8%	21,474	3.2%
State	2	0.9%	2	0.5%	4	0.5%	4,990	0.7%

6 Nonutilities are entities that own or operate facilities that generate electricity for use by the public but are not public utilities.

Table 2-2: Existing Steam Electric Power Plants, Their Parent Entities, and Nameplate Capacity by Ownership Type, 2021

Ownership Type	Parent Entities [a,b,c]				Plants [a,b,d]		Capacity (MW) [a,d]	
	Lower Bound		Upper Bound					
	Number	% of Total	Number	% of Total	Number[c]	% of Total	Number[c]	% of Total
Total	**220**	**100.0%**	**391**	**100.0%**	**858**	**100.0%**	**674,998**	**100.0%**

a. Numbers may not add up to totals due to independent rounding.

b. Ownership information on steam electric power plants is based on EIA (2022c). Information on parent entities, including type, revenue, and other characteristics, is based on information gathered through Dun and Bradstreet and additional research of publicly available information.

c. Parent entity counts are calculated on a sample-weighted basis and represent the lower and upper bound estimates of the number of entities owning steam electric power plants. For details see Chapter 4.

d. Steam electric power plant count and capacity were calculated on a sample-weighted basis. For details on sample weights, see TDD.

Source: U.S. EPA Analysis, 2024; EIA, 2022c

EPA estimates that between 52 percent and 53 percent of entities owning steam electric power plants are small entities (Table 2-3), according to Small Business Administration (SBA) (SBA, 2023) business size criteria. By definition, states and the federal government are considered large entities.

The size distribution of parent entities owning steam electric power plants varies by ownership type. Under the lower bound estimate, the lowest share of small entities is in the other political subdivision category (18 percent), while small entities make up the largest share of nonutilities and cooperatives (75 percent and 86 percent, respectively). The pattern is similar under the upper bound estimate, but small entities represent 9 percent of other political subdivision entities, 89 percent of cooperatives, and 77 percent of nonutilities.

EPA estimates that, of 858 steam electric power plants, 267 plants (31 percent) are owned by small entities (Table 2-4). Nonutilities represent the majority (50 percent) of plants owned by small entities (134 out of 263 plants), while investor-owned utilities, cooperatives, municipalities, and other political subdivisions[7] make up the remaining 50 percent. For a detailed discussion of the identification and size determination of parent entities of steam electric power plants, see Chapter 4 and Chapter 8.

Table 2-3: Parent Entities of Steam Electric Power Plants by Ownership Type and Size (assuming two different ownership cases)[a,b]

Ownership Type	Lower bound estimate of number of entities owning steam electric power plants				Upper bound estimate of number of entities owning steam electric power plants			
	Small	Large	Total	% Small	Small	Large	Total	% Small
Cooperative	19	3	22	86.4%	25	3	28	89.3%
Federal	0	2	2	0.0%	0	7	7	0.0%
Investor-owned	17	40	57	29.8%	22	66	88	24.6%
Municipality	22	28	50	44.0%	30	54	84	35.6%
Nonutility	57	19	76	75.0%	123	36	160	77.3%
Other political subdivision	2	9	11	18.2%	2	21	23	8.9%
State	0	2	2	0.0%	0	2	2	0.0%

7 Other political subdivisions include public power districts and irrigation projects.

Table 2-3: Parent Entities of Steam Electric Power Plants by Ownership Type and Size (assuming two different ownership cases)[a,b]

Ownership Type	Lower bound estimate of number of entities owning steam electric power plants				Upper bound estimate of number of entities owning steam electric power plants			
	Small	Large	Total	% Small	Small	Large	Total	% Small
Total	**117**	**103**	**220**	**53.2%**	**202**	**189**	**391**	**51.7%**

a. Numbers may not add up to totals due to independent rounding.

b. For details on estimates of the number of majority owners of steam electric power plants see Chapter 4 and Chapter 8.

Source: U.S. EPA Analysis, 2024

Table 2-4: Steam Electric Power Plants by Ownership Type and Size

Ownership Type	Number of Steam Electric Power Plants[a,b,c]			
	Small	Large	Total	% Small
Cooperative	52	7	59	88.1%
Federal	0	23	23	0.0%
Investor-owned	44	276	320	13.9%
Municipality	31	80	111	28.0%
Nonutility	134	174	308	43.6%
Other political subdivisions	6	27	33	18.5%
State	0	4	4	0.0%
Total	**267**	**590**	**858**	**31.2%**

a. Numbers may not sum to totals due to independent rounding.

b. Plant counts are sample-weighted estimates.

c. Plant size was determined based on the size of majority owners. In case of multiple owners with equal ownership shares, a plant was assumed to be small if it is owned by at least one small entity.

Source: U.S. EPA Analysis, 2024

2.1.2 Geographic Distribution of Steam Electric Power Plants

The U.S. bulk power system is composed of three major networks, or power grids, subdivided into several smaller North American Electric Reliability Corporation (NERC) regions:

- The *Eastern Interconnection* covers the largest portion of the United States, from the eastern end of the Rocky Mountains and the northern borders to the Gulf of Mexico states (including parts of northern Texas) on to the Atlantic seaboard.
- The *Western Interconnection* covers nearly all areas west of the Rocky Mountains, including the Southwest.
- The *Texas Interconnected System*, the smallest of the three major networks, covers the majority of Texas.

The Texas system is not connected with the other two systems, while the other two have limited interconnection to each other. The Eastern and Western systems are integrated with, or have links to, the Canadian grid system. The Western and Texas systems have links with Mexico.

These major networks contain extra-high voltage connections that allow for power transmission from one part of the network to another. Wholesale transactions can take place within these networks to reduce power costs, increase supply options, and ensure system reliability.

NERC is responsible for the overall reliability, planning, and coordination of the power grids. An independent, not-for-profit organization, it has regulatory authority for ensuring electric reliability in the United States, under the oversight of the Federal Energy Regulatory Commission (FERC). NERC is organized into six regional entities that cover the 48 contiguous States, and two affiliated councils that cover Hawaii, part of Alaska, and portions of Canada and Mexico.[8] These regional organizations are responsible for the overall coordination of bulk power policies that affect their regions' reliability and quality of service. Interconnection *between* the bulk power networks is limited in comparison to the degree of interconnection *within* the major bulk power systems. Further, the degree of interconnection between NERC regions even within the same bulk power network is also limited. Consequently, each NERC region deals with electricity reliability issues in its own region, based on available capacity and transmission constraints. The regional organizations also facilitate the exchange of information among member utilities in each region and between regions. Service areas of the member utilities determine the boundaries of the NERC regions. Though limited by the larger bulk power grids described above, NERC regions do not necessarily follow any State boundaries. Figure 2-1 provides a map of the NERC regions listed in Table 2-5 that EPA used for the analysis of the regulatory options.[9]

Table 2-5: NERC regions

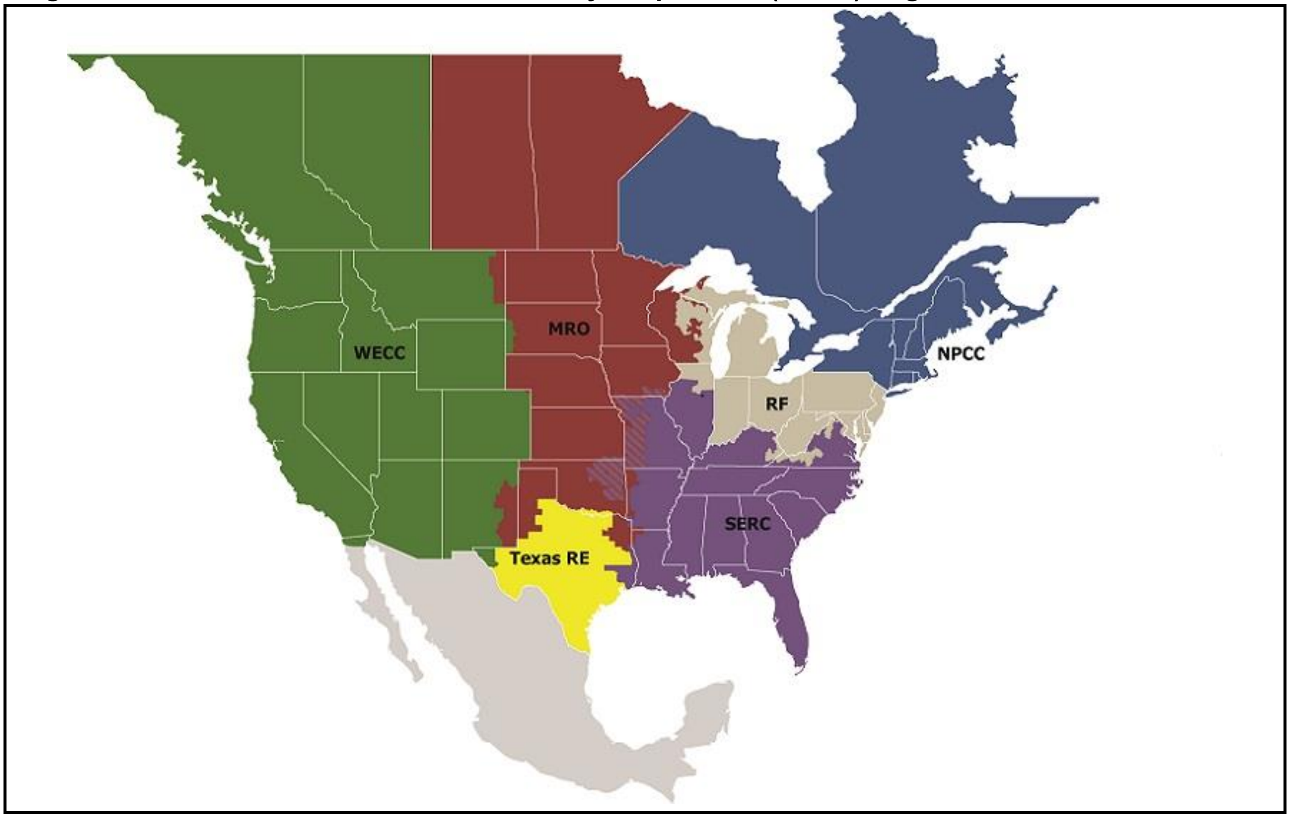
Bulk Power Network	NERC Region	NERC Entity
Eastern Interconnected System	MRO	Midwest Reliability Organization
	NPCC	Northeast Power Coordinating Council (U.S.)
	RF	Reliability First Corporation
	SERC	SERC Reliability Corporation
Western Interconnected System	WECC	Western Electricity Coordinating Council (U.S.)
Texas Interconnected System	TRE	Texas Reliability Entity
	ASCC	Alaska Systems Coordinating Council
	HICC	Hawaii Coordinating Council

Source: NERC, undated

8 Energy concerns in the States of Alaska, Hawaii, the Dominion of Puerto Rico, and the Territories of American Samoa, Guam, and the Virgin Islands are not under reliability oversight by NERC.

9 Some 2023 Annual Energy Outlook (AEO) data were based on an older version of NERC regions which contained regions that are not used in this analysis. EPA used best professional judgement (BPJ) to allocate 2023 AEO data for these regions into the appropriate NERC regions used in this analysis.

Figure 2-1: North American Electric Reliability Corporation (NERC) Regions



Note: The AK and HICC regions are not shown.
Source: NERC, undated.

The evaluated options are estimated to have a different effect on profitability, electricity prices, and other impact measures across NERC regions. This is because of variations in the economic and operational characteristics of steam electric and other power plants across NERC regions, including the share of the region's electricity demand met by steam electric power plants subject to the final rule under the different options. Other factors include the baseline economic characteristics of the NERC regions, together with market segmentation due to limited interconnectedness among NERC regions. To assess the potential reliability impact of the regulatory options, EPA assessed the distribution of steam electric power plants and their capacity across NERC regions.

As reported in Table 2-6, NERC regions differ in terms of both the number of steam electric power plants and their capacity. Steam electric power plants are primarily located in the RF, SERC, and WECC regions (20 percent, 28 percent, and 18 percent of plants, respectively); these three regions also account for a majority of the steam electric nameplate capacity in the United States (23 percent, 38 percent, and 15 percent, respectively).

Table 2-6: Steam Electric Power Plants and Nameplate Capacity by NERC Region, 2021

NERC Region	Plants[a,b]		Capacity (MW)[a,b]	
	Number	% of Total	MW	% of Total
AK	2	0.2%	120	0.0%
HICC	10	1.2%	1,155	0.2%
MRO	136	15.9%	82,012	12.1%
NPCC	80	9.3%	28,669	4.2%
RF	170	19.8%	151,710	22.5%
SERC	238	27.8%	255,610	37.9%
TRE	66	7.7%	54,407	8.1%
WECC	155	18.1%	101,315	15.0%
TOTAL	**858**	**100.0%**	**674,998**	**100.0%**

a. Numbers may not add up to totals due to independent rounding.

b. The numbers of plants and capacity are calculated on a sample-weighted basis.

Source: U.S. EPA Analysis, 2024; EIA, 2022c

2.1.3 Electricity Generation

Total net electricity generation in the United States for 2021 was 4,110 TWh.[10] The 2021 EIA data was the most recent year of finalized EIA data that was available at the time of analysis. Coal generation accounted for 22 percent of total electricity generation, behind natural gas (38 percent), but ahead of nuclear (19 percent) and renewables (14 percent). Other energy sources accounted for comparatively smaller shares of total generation, with hydropower representing 6 percent and petroleum less than one percent.

As presented in Table 2-7, the 7-year period of 2015 through 2021 saw total net generation increase by approximately 0.8 percent with the 269 TWh increase (89 percent) in generation from renewables and 246 TWh (18 percent) increase in generation from natural gas more than offset the 454 TWh (34 percent) drop in generation from coal-fueled generators.[11]

Between 2015 and 2021, the amount of electricity generated by utilities declined by 4.5 percent while that generated by nonutilities rose by 8 percent. Comparing 2015 and 2021 values, across all fuel-source categories, utilities generated a larger share of their electricity using natural gas (a 26 percent increase) and renewables (a 137 percent increase) even as their overall generation declined. For nonutilities, the largest percent increase in electricity generation (82 percent) occurred for renewables, whereas generation from natural gas increased 12 percent.

10 One terawatt-hour is 10^{12} watt-hours.

11 The decline in 2021 is likely partially driven by the economic effects of the COVID-19 pandemic and relatively warmer winter weather (U.S. Energy Information Administration. (2021d). U.S. energy consumption fell by a record 7% in 2020. *Today in Energy*. https://www.eia.gov/todayinenergy/detail.php?id=47397).

Table 2-7: Net Generation by Energy Source and Ownership Type, 2015-2021 (TWh)									
	Utilities			Nonutilities			Total		
Energy Source	2015	2021	% Change	2015	2021	% Change	2015	2021	% Change
Coal	996	672	-32.5%	354	223	-37.0%	1,350	896	-33.6%
Hydropower	226	225	-0.3%	18	22	17.4%	244	246	1.0%
Nuclear	417	431	3.4%	380	349	-8.3%	797	780	-2.2%
Petroleum	18	15	-17.5%	10	5	-51.4%	27	19	-29.5%
Natural Gas	618	777	25.8%	716	802	12.1%	1,333	1,579	18.4%
Other Gases	4	2	-39.6%	13	11	-11.9%	17	14	-18.3%
Renewables[a]	38	89	137.3%	264	482	82.2%	302	571	89.1%
Other[b]	0	0	1.4%	7	4	-36.0%	7	5	-34.0%
Total	**2,315**	**2,212**	**-4.5%**	**1,762**	**1,898**	**8%**	**4,078**	**4,110**	**0.8%**

a. Renewables include wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

b. Other includes batteries, hydrogen, purchased steam, sulfur, tire-derived fuels and other miscellaneous energy sources.

Source: EIA, 2022d; 2016

2.2 Other Environmental Regulations and Policies

The 2015, 2020 and 2023 RIAs described factors, such as deregulation and environmental regulations and programs, that have affected the steam electric power generating industry, and electrical power generation more generally, over the last decades. See Chapter 2 in U.S. EPA (2015, 2020, 2023d).2015, 2020, 2023d). The sections below provide updated discussions on changes to key environmental regulations since 2020 as well as greenhouse gas (GHG) reduction targets and energy provisions of the Inflation Reduction Act (IRA) of 2022 that may affect the power generating industry.

2.2.1 Coal Combustion Residuals Rule

On April 17, 2015, the Agency promulgated the Disposal of Coal Combustion Residuals from Electric Utilities final rule (2015 CCR rule). This rule finalized national regulations to provide a comprehensive set of requirements for the safe disposal of coal combustion residuals (CCR), commonly referred to as coal ash, from steam electric power plants. The final 2015 CCR rule was the culmination of extensive study on the effects of coal ash on the environment and public health. The rule established technical requirements for CCR landfills and surface impoundments under subtitle D of the Resource Conservation and Recovery Act (RCRA), the nation’s primary law for regulating solid waste.

These regulations established requirements for the management of coal ash (including its disposal), including requirements designed to prevent leaking of contaminants into groundwater, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments. Additionally, the 2015 CCR rule set recordkeeping and reporting requirements as well as requirements for each plant to establish and post specific information to a publicly accessible website. The rule also established requirements to distinguish between the beneficial use of CCR from disposal.

As a result of the D.C. Circuit Court decisions in Utility Solid Waste Activities Group v. EPA, 901 F.3d 414 (D.C. Cir. 2018), and Waterkeeper Alliance Inc. et al. v. EPA, No. 18-1289 (D.C. Cir. filed March 13, 2019), the EPA Administrator signed two rules: A Holistic Approach to Closure Part A: Deadline to Initiate Closure and Enhancing Public Access to Information (CCR Part A rule) on July 29, 2020, and A Holistic Approach to Closure Part B: Alternate Liner Demonstration (CCR Part B rule) on October 15, 2020. EPA finalized five amendments to the 2015 CCR rule which are relevant to the management of the wastewaters covered by this ELG because these wastewaters have historically been co-managed with CCR in the same surface impoundments. First, the CCR Part A rule established a new deadline of April 11, 2021, for all unlined surface impoundments in which CCR are managed ("CCR surface impoundments"), as well as CCR surface impoundments that failed the location restriction for placement above the uppermost aquifer, to stop receiving waste and begin closure or retrofit. EPA established this date after evaluating the steps that owners and operators need to take for CCR surface impoundments to stop receiving waste and begin closure, and the timeframes needed for implementation. (This would not affect the ability of plants to install new, composite-lined CCR surface impoundments.) Second, the Part A rule established procedures for plants to obtain approval from EPA for additional time to develop alternative disposal capacity to manage their wastestreams (both CCR and non-CCR) before they must stop receiving waste and begin closing their CCR surface impoundments. Third, the Part A rule changed the classification of compacted-soil-lined and clay-lined surface impoundments from lined to unlined. Fourth, the Part B rule finalized procedures potentially allowing a limited number of facilities to demonstrate to EPA that, based on groundwater data and the design of a particular surface impoundment, the unit ensures there is no reasonable probability of adverse effects to human health and the environment. Should EPA approve such a submission, these CCR surface impoundments would be allowed to continue to operate.

As explained in the 2015 and 2020 ELG rules, the ELGs and CCR rule may affect the same electric generating unit (EGU) or activity at a plant. Therefore, when EPA finalized the ELG and CCR rules in 2015, and as well revisions to both rules in 2020, the Agency coordinated the ELG and CCR rules to minimize the complexity of implementing engineering, financial, and permitting activities. Likewise, EPA considered the interaction of these two rules during the development of this final rule. EPA's analytic baseline includes the final requirements of these rules using the most recent data provided under the CCR rule reporting and recordkeeping requirements. This is further described in the TDD (see Section 3, U.S. EPA, 2024e).[12]

Concurrently with the final ELG, in a separate rulemaking, EPA is also finalizing regulatory requirements for inactive CCR surface impoundments at inactive utilities ("legacy CCR surface impoundment" or "legacy impoundment"). This action is being taken in response to the August 21, 2018, opinion by the U.S. Court of Appeals for the District of Columbia Circuit in the *USWAG* decision that vacated and remanded the provision exempting legacy impoundments from the CCR regulations. This action includes adding a definition for legacy CCR surface impoundments and other terms relevant to this rulemaking. It also requires that legacy CCR surface impoundments comply with certain existing CCR regulations with tailored compliance deadlines.

EPA is also establishing requirements to address the risks from currently exempt solid waste management that involves the direct placement of CCR on the land. EPA is extending a subset of the existing requirements in 40 CFR part 257, subpart D to CCR surface impoundments and landfills that closed prior to the effective date of the 2015 CCR rule, inactive CCR landfills, and other areas where CCR is managed directly on the land. In this action, EPA refers to these as CCR management units, or CCRMU. This rule

12 For more information on the CCR Part A and Part B rules, including information about ongoing implementation of these rules, visit https://www.epa.gov/coalash/coal-ash-rule.

will apply to all existing CCR facilities and all inactive facilities with legacy CCR surface impoundments subject to this final rule.

Finally, EPA is making a number of technical corrections to the existing regulations, such as correcting certain citations and harmonizing definitions.[13]

2.2.2 Air Pollution Rules and Implementation

EPA is taking several actions to regulate a variety of conventional, hazardous, and greenhouse gas (GHG) air pollutants, including actions to regulate the same steam electric plants subject to part 423. In light of these ongoing actions, EPA has worked to consider appropriate flexibilities in this proposed ELG rule to provide certainty to the regulated community while ensuring the statutory objectives of each program are achieved. Furthermore, to the extent that these actions are finalized and already impacting steam electric power plant operations, EPA has accounted for these changed operations in its Integrated Planning Model (IPM) modeling discussed in Chapter 5 of this document**.**

2.2.2.1 The Revised Cross State Air Pollution Rule Update and the Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards

On June 5, 2023, EPA promulgated its final Good Neighbor Plan, which secures significant reductions in ozone-forming emissions of nitrogen oxides (NO_X) from power plants and industrial facilities. 88 FR 36654. The Good Neighbor Plan ensures that 23 states meet the Clean Air Act's (CAA's) "Good Neighbor" requirements by reducing pollution that significantly contributes to problems attaining and maintaining EPA's health-based air quality standard for ground-level ozone (or "smog"), known as the 2015 Ozone National Ambient Air Quality Standards (NAAQS), in downwind states. Further information on this action is available on EPA's website.[14]

As of September 21, 2023, the Good Neighbor Plan's "Group 3" ozone-season NO_X control program for power plants is being implemented in: Illinois, Indiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and Wisconsin. Pursuant to court orders staying the Agency's State Implementation Plan disapproval action in the following states, EPA is not currently implementing the Good Neighbor Plan "Group 3" ozone-season NO_X control program for power plants in: Alabama, Arkansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nevada, Oklahoma, Texas, Utah, and West Virginia.[15]

On January 16, 2024, EPA signed a proposal to partially approve and partially disapprove State Implementation Plan submittals addressing interstate transport for the 2015 ozone NAAQS from Arizona, Iowa, Kansas, New Mexico, and Tennessee and proposed to include these states in the Good Neighbor Plan beginning in 2025.

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13 For further information on the CCR regulations, including information about the CCR Part A and Part B rules' ongoing implementation, visit *www.epa.gov/coalash/coal-ash-rule*

14 *See https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs*.

15 Further information on EPA's response to the stay orders can be found online at: *https://www.epa.gov/Cross-State-Air-Pollution/epa-response-judicial-stay-orders.*

On April 30, 2021, EPA published the final Revised Cross-State Air Pollution Rule (CSAPR) Update, 86 FR 23054, which resolved 21 states' good neighbor obligations for the 2008 ozone NAAQS, following the remand of the 2016 CSAPR Update (81 FR 74504) in *Wisconsin v. EPA*, 938 F.3d 308 (D.C. Cir. 2019). Together, these two rules establish the Group 2 and Group 3 market-based emissions trading programs for 22 states in the eastern United States for emissions of NO_X from fossil fuel-fired EGUs during the summer ozone season.[16]

2.2.2.2 Clean Air Act Section 111 Proposed Rule

Concurrently with the final ELG, EPA is finalizing the repeal of the Affordable Clean Energy Rule, establishing Best System of Emissions Reduction (BSER) determinations and emission guidelines for existing fossil fuel-fired EGUs, and establishing BSER determinations and accompanying standards of performance for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbines and modified fossil fuel-fired EGUs. Specifically, for coal-fired EGUs, EPA is establishing final standards based on carbon capture and storage/sequestration with 90 percent capture with a compliance date of January 1, 2032. For coal-fired EGUs retiring by January 1, 2039, EPA is establishing final standards based on 40 percent natural gas co-firing with a compliance date of January 1, 2030.

While four subcategories for coal-fired EGUs were proposed, EPA is finalizing just the two subcategories for coal-fired EGUs as described in the preceding paragraph. Consistent with 40 CFR 60.24a(e) and the Agency's explanation in the proposal, states have the ability to consider, *inter alia*, a particular source's remaining useful life when applying a standard of performance to that source.[17]

In addition, EPA is creating an option for states to provide for a compliance date extension for existing sources of up to one year under certain circumstances for sources that are installing control technologies to comply with their standards of performance. States may also provide, by inclusion in their state plans, a reliability assurance mechanism of up to one year that under limited circumstances would allow existing EGUs that had planned to cease operating by a certain date to temporarily remain available to support reliability. Any extensions exceeding 1-year must be addressed through a state plan revision.[18]

2.2.2.3 Mercury and Air Toxics Standards Final Rule

On March 6, 2023, EPA published a final rule which reaffirmed that it remains appropriate and necessary to regulate hazardous air pollutants (HAP), including mercury, from power plants after considering cost. This action revoked a 2020 finding that it was not appropriate and necessary to regulate coal- and oil-fired power plants under CAA section 112, which covers toxic air pollutants. EPA reviewed the 2020 finding and considered updated information on both the public health burden associated with HAP emissions from coal- and oil-fired power plants, as well as the costs associated with reducing those emissions under the Mercury and Air Toxics Standards (MATS). After weighing the public risks these emissions pose to

16 *See www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs*.

17 See 88 FR 33383 (invoking Remaining Useful Life and Other Factors (RULOF) based on a particular coal-fired EGU's remaining useful life "is not prohibited under these emission guidelines").

18 Further information about the CAA section 111 rule is available online at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power*. https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.

all Americans (and particularly exposed and sensitive populations) against the costs of reducing this harmful pollution, EPA concluded that it remains appropriate and necessary to regulate these emissions. This action ensures that coal- and oil-fired power plants continue to control emissions of hazardous air pollution and that the Agency properly interprets the CAA to protect the public from hazardous air emissions.

Concurrently with the final ELG, EPA is finalizing an update to the National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired EGUs, commonly known as the Mercury and Air Toxics Standards (MATS) for power plants, to reflect recent developments in control technologies and the performance of these plants. This final rule includes an important set of improvements and updates to MATS and also fulfills EPA's responsibility under the Clean Air Act to periodically re-evaluate its standards in light of advancements in pollution control technologies to determine whether revisions are necessary. The improvements consist of:

- Further limiting the emission of non-mercury HAP metals from existing coal-fired power plants by significantly reducing the emission standard for filterable particulate matter (fPM), which is designed to control non-mercury HAP metals. EPA is finalizing a two-thirds reduction in the fPM standard;[19]
- Tightening the emission limit for mercury for existing lignite-fired power plants by 70 percent;[20]
- Strengthening emissions monitoring and compliance by requiring coal-and oil-fired EGUs to comply with the fPM standard using PM continuous emission monitoring systems (CEMS);[21]
- Revising the startup requirements in MATS to assure better emissions performance during startup.

Additional information on the final MATS is available on EPA's website.[22]

2.2.2.4 National Ambient Air Quality Standards Rules for Particulate Matter Final Rule

On February 7, 2024, the EPA Administrator signed a final rule strengthening the National Ambient Air Quality Standards for Particulate Matter (PM NAAQS) to protect millions of Americans from harmful and costly health impacts, such as heart attacks and premature death. Particle or soot pollution is one of the most dangerous forms of air pollution, and an extensive body of science links it to a range of serious and in some cases deadly illnesses. EPA set the level of the primary (health-based) annual particulate matter ($PM_{2.5}$) standard at 9.0 micrograms per cubic meter to provide increased public health protection, consistent with the available health science. EPA did not change the current primary and secondary (welfare-based) 24-hour $PM_{2.5}$ standards, the secondary annual $PM_{2.5}$ standard, and the primary and

19 Also, EPA is finalizing the removal of the low-emitting EGU provisions for fPM and non-mercury HAP metals.

20 This level aligns with the mercury standard that other coal-fired power plants have been achieving under the current MATS.

21 PM CEMS provide regulators, the public, and facility owners or operators with cost-effective, accurate, and continuous emission measurements. This real-time, quality-assured feedback can lead to improved control device and power plant operation, which will reduce air pollutant emissions and exposure for local communities.

22 *See https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards.*

secondary PM10 standards. EPA also revised the Air Quality Index to improve public communications about the risks from $PM_{2.5}$ exposures and made changes to the monitoring network to enhance protection of air quality in communities overburdened by air pollution. More information about this action is available on EPA's website.[23]

2.2.3 Greenhouse Gas Reduction Targets

On April 22, 2021, President Biden announced 2030 GHG reduction targets for the United States.[24] As part of reaching net zero emissions by 2050, the nationally determined contribution submitted to the United Nations Framework Convention on Climate Change includes a 50 percent to 52 percent reduction from 2005 levels by 2030. These reduction targets were developed through the National Climate Task Force and support the commitments of the United States under the Paris Agreement. These policies are anticipated to result in significantly reduced reliance on coal-fired generation.

The steam electric sector is one of the largest contributors of U.S. GHG emissions. EPA estimates that 25 percent of 2021 GHG emissions in the U.S. came from electricity generation (largely comprised of emissions from steam electric power plants).[25] Although this fraction continues to decline, several models looking at plausible pathways to meet the announced 2030 goal have determined that as much as 90 to 100 percent of coal combustion may have to be reduced (Bistline et al., 2022).

2.2.4 Inflation Reduction Act of 2022

On August 16, 2022, President Biden signed into law the Inflation Reduction Act (IRA). The IRA marks the most significant action Congress has taken on clean energy and climate change in the nation's history. The IRA provides tax credits, financing programs, and other incentives, some of which are administered by EPA, that will accelerate the transition to forms of energy that produce little or no greenhouse gas emissions and other water and air pollutants. As such, it includes many provisions that will affect the steam electric power generating industry, causing both direct effects through changes in the production of electricity and indirect effects on electricity demand and changes to fuel markets.

In September 2023 EPA published a report on the effect of the IRA on the electricity sector and on the economy in general (U.S. EPA, 2023c).The report found that the IRA would lead to emission reductions from the electric power sector of 49 to 83 percent below 2005 levels in 2030. The associated shifts from fossil fuel generation would also lead to reductions in water and air pollution from the sector. The study also found that the IRA would lower economy-wide CO_2 emissions, including emissions from electricity generation and use, by 35 percent to 43 percent below 2005 levels in 2030. Across the end-use sectors, the study found that buildings exhibit the greatest reductions from 2005 levels of direct plus indirect CO_2 emissions from electricity, followed by industry and transportation. Though it focuses on changes in climate-forcing emissions (in part attributable to the models it uses), the study also implies important changes in the emissions of other pollutants throughout the economy. EPA used IPM to evaluate the impacts of the final ELG relative to a baseline that reflects impacts from other relevant policies and

23 *See https://www.epa.gov/pm-pollution/national-ambient-air-quality-standards-naaqs-pm*.

24 See https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/.

25 See https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions.

environmental regulations that affect the power sector, including the IRA and other on-the-books federal and state rules (see Chapter 5 for additional information).

2.2.5 Recent Developments in Assuring Electric Reliability and Resource Adequacy

The nature and components of the bulk power sector have been evolving away from older and less efficient legacy fossil generation (mostly coal power plants) towards more decentralized, renewable assets and flexible gas-fired generation. Stakeholders have raised concerns that centralized dispatchable power plants are coming offline faster than new generation can replace the reliability attributes associated with them. However, a combination of technology innovation, revised market signals from the Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), and reforms recently completed and underway by Federal Energy Regulatory Commission (FERC) are collectively poised to address current reliability challenges associated with the transition along with expected higher load growth and the increasing frequency of extreme weather events.

EPA has continued to learn and engage on reliability issues, particularly as part of the Agency's implementation of the *Joint Memorandum on Interagency Communication and Consultation on Electric Reliability*.[26] As part of this process, EPA has engaged in regular meetings with Department of Energy (DOE), North American Electric Reliability Corporation (NERC), FERC, and the various ISOs/RTOs.

FERC, NERC, RTOs, and ISOs are already taking steps to ensure reliability during this period of asset evolution. Among FERC's actions to help address reliability is Order 2023, or "Improvements to Generator Interconnection Procedures," which will help expedite interconnections for new assets waiting to connect to the grid. This is a very important development to ensure future resource adequacy because interconnection wait times for new energy assets entering energy markets have increased, which is stifling the ability of replacement generation to connect to the grid. FERC's final action on extreme cold weather preparedness will support the new peak demand hours, which have migrated to winter months. New reliability standards issued for inverter-based resources "will help ensure reliability of the grid by accommodating the rapid integration of new power generation technologies, known as inverter-based resources (IBRs), that include solar photovoltaic, wind, fuel cell and battery storage resources…."[27] FERC has also undertaken various transmission-related efforts, from inter-regional transmission capacity efforts to reconductoring and dynamic line rating, that would help bolster reliability by increasing the transmission capacity of existing lines and creating incentives for new, inter-regional transmission. Increasing transmission capacity can enhance reliability by increasing the amount of generation that can access the grid to help meet demand.

Furthermore, there are new technologies coming online that can also help provide reliability attributes. The deployment of many of these technologies has been accelerating due to the incentives in the IRA. The rapid increase in energy storage deployment across the nation is an important part of future grid reliability, particularly as the duration of storage assets expands. Examples of existing and emerging storage resources include various types of fuel cells, batteries, pumped hydro-electric reservoirs, and underground hydrogen caverns. Energy storage can help buttress reliability by storing renewable energy

26 Available online at: https://www.epa.gov/power-sector/electric-reliability-mou.

27 For further information about FERC actions to address IBRs, see *https://www.ferc.gov/news-events/news/ferc-moves-protect-grid-transition-clean-energy-resources.*

for dispatch when demand is high. Improved management of demand response assets, better designed electricity tariff structures, aggregation of distributed resources like roof-top solar panels, and integration of behind-the-meter battery storage can further support balancing peak demand on power grids. For example, programs to manage demand, which have shown value well before the recent energy transition, incentivize customers to shift their demand during periods when there is ample supply, which can help reduce instances when supply is tight.

Despite these concerns, there are also existing procedures in place to ensure electricity system reliability and resource adequacy over both the short and long-term. For example, regional planning organizations typically have incentive or planning procedures to ensure that there is sufficient capacity to meet future demand such as day-ahead reserve and capacity markets and seasonal reserve margins. Furthermore, EPA understands that before a unit implements a retirement decision, the unit's owner will follow the processes put in place by the relevant 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.

2.3 Market Conditions and Trends in the Electric Power Industry

The 34 percent decline in coal-fueled electricity generation summarized in Table 2-7 for the period of 2015 through 2021 exemplifies an ongoing trend over the last decade: the progressive reduction in coal-fired generation capacity as coal units and plants retire. In 2023, EIA reported that retirements of coal generation capacity in the US in 2022 were 11.5 GW, slightly higher than the average of 11 GW per year between 2015 to 2020. Moreover, EIA predicted that coal-fired and natural gas utility-scale power plant retirements in 2023 would account for 58 and 40 percent of total electric generating capacity retirements for that year, corresponding to 8.9 and 6.2 GW respectively (EIA, 2022b; EIA, 2023c). Capacity additions in the same year are predicted to consist primarily of solar (54 percent), natural gas (14 percent), and wind (11 percent).

One factor in the decline in the coal-fueled power generation is the aging fleet of coal-fired power plants. The life expectancy of coal plants is approximately 40 to 50 years, and with the majority of plants being built in the 1970s and 1980s, almost all plants that retired in 2015 were more than 40 years old (Kolstad, 2017; EIA, 2023c). Mills, Wiser and Seel (2017) also found that coal plants that retired between 2010 and 2016 had an average age of 52 years, and plants with stated plans to retire were not younger on average. Coal plant retirements due to aging are likely to continue in the coming years, as the average age of coal plants in operation in the United States as of 2021 is 45 years (EIA, 2021b)

The lower costs of natural gas, as well as technological advances in solar and wind power have also been important market factors. Fell and Kaffine (2018) found negative impacts on coal-fired generation from both lower natural gas prices and increased wind generation, with declining natural gas prices having a stronger effect. In 2019, coal-fired generation dropped to its lowest level since 1976, primarily driven by increased availability of highly efficient, low-cost natural gas generation, which has reduced coal plant utilization and resulted in the retirement of some coal plants (EIA, 2020).

In 2021, EIA reported that coal generation increased for the first time since 2014. However, this was a temporary divergence from a longer-term trend as additional retirements of coal-fired plants and lower natural gas prices caused coal-fired electricity generation to fall once again in 2022 (EIA, 2023d). This 2022 decline was exacerbated by a coal supply shortage, precipitated by diminished electricity demand due to pandemic-related economic impacts, as well as a 9 percent reduction in coal production resulting from declining global coal demand and heightened competition from natural gas (EIA, 2023d).

Russia's 2022 invasion of Ukraine and the subsequent agreement between the United States and European Commission to supply additional liquefied natural gas (LNG) to the European market resulted in increased energy prices. With Russia being a huge supplier of the world's oil and natural gas, cutbacks in supply and geopolitical uncertainty caused higher prices and volatility across global energy markets. While coal was temporarily cost-competitive with natural gas, leading to the observed increases in coal-fired generation, this short-term impact has ceased with natural gas prices falling to their pre-invasion prices, at the start of 2023. (Federal Reserve Bank of St. Louis, 2023; The White House, 2022; Wilson, 2022).

Knittel, Metaxoglou and Trindade (2015) found that utilities invested more in natural gas capacity when the prices dropped as a result of the boom in shale gas production, although the magnitude of their investments differed depending on the structure of the electricity market in which they operated. Additionally, in 2020, renewable electricity generation surpassed coal-fired electricity generation as much of the US's coal-fired generation capacity has been replaced or converted to natural gas-fired generation since 2007 (EIA, 2021c). Furthermore, in 2022, generation from renewable sources – wind, solar, hydro, biomass, and geothermal – surpassed coal-fired generation in the electric power sector for the first time. In the preceding year, 2021, renewables had already outpaced nuclear generation for the first time, and this trend persisted, with renewable sources consistently providing more electricity than nuclear generation throughout the subsequent year (EIA, 2023g).

Changes in electricity generation have had impacts in fuel markets. Coal consumption in the electric power industry declined by about 40 percent between 2005 and 2017, whereas natural gas consumption increased by about 24 percent in the same time period, resulting in natural gas consumption doubling coal consumption in 2017 (EIA, 2018). In 2021, EIA reported that the number of producing coal mines in the United States was 548, representing a 62 percent drop since the most recent peak in 2008 of 1,435 producing mines (EIA, 2019, 2023a). EIA reported that this reduction in producing coal mines reflects reductions in investments in the coal industry and declining international and domestic decline for coal (EIA, 2021a). In 2022, EIA reported that natural gas consumption totaled 33.4 quadrillion British thermal units (quads) and that coal consumption totaled 9.85 quads (EIA, 2023j). Market conditions have also negatively affected nuclear-powered generation, though this final rule has no effect on the nuclear-powered sector, except as it affects relative prices through its impacts on coal-fired generation (EIA, 2022e).

The decline in coal is not independent of environmental regulations affecting coal-fired electricity generation, as power companies have cited regulations promulgated, particularly in the last decade, as reasons for their decision when announcing unit or plant closures, fuel switching, or other operational changes. However, fuel prices and trends toward alternative fuels also appear to be drivers of the shift away from coal for electricity generation. Coglianese, Gerarden and Stock (2020) found that the decrease in natural gas prices accounted for 92 percent of the decline in coal production while environmental regulations accounted for 6 percent. Linn and McCormack (2019) found that while air emissions regulations were responsible for most reductions in nitrogen oxides from the electricity sector, they had only a small effect on profitability and retirement at coal plants.

As the electric power infrastructure adjusts to market trends by moving toward optimal infrastructure and operations to deliver the country's electricity, EPA recognizes that the changes can have negative effects for some communities and positive effects for others.

3 Compliance Costs

In developing the final rule, EPA assessed the costs and economic impacts for three regulatory options summarized in Table 1-1. The options are labeled Option A through Option C in order of the stringency of the effluent limits, relative to the baseline. Key inputs for these analyses include the estimated costs to steam electric power plants (and their business, government, or non-profit owners) for implementing control technologies upon which the final BAT limitations and pretreatment standards are based,[28] and to the state and federal government for administering this rule. This chapter summarizes EPA estimates of the incremental compliance costs attributable to the regulatory options. EPA determined that state and federal governments would not incur significant incremental administrative costs.[29]

EPA applied the same methodology used to analyze the 2015 and 2020 rules, as well as the 2023 proposed rule, to calculate industry-level annualized compliance costs. See Chapter 3 of the respective RIA documents for details (U.S. EPA, 2015, 2020, 2023d). Additionally, EPA estimated that some plants incurred compliance costs for CRL treatment after the expected retirement year.

Costs associated with legacy wastewater limits under Options B and C would be incurred only as plants close and dewater their existing ponds. There is uncertainty on when plants may do so. For the purpose of this analysis, EPA anticipates that pond closures will occur on 2044 for all plants and that plants will incur initial one-time costs (*e.g.*, capital costs) in this year followed by O&M costs in the following years of the analysis (there are no incremental legacy wastewater costs under Option A).[30] Similarly, certain plants could incur costs associated with the treatment of unmanaged CRL discharged from landfills, surface impoundments, or other features in cases where a permitting authority deems, on a case-by-case basis, the discharge to be the functional equivalent of a direct discharge and requiring a permit. The costs associated with treatment of unmanaged CRL are uncertain. As a result, the Agency estimated lower- and upper-bound cost estimates for treating unmanaged CRL. These unmanaged CRL costs are added to the costs associated with CRL treatment incurred by plants. As a result, the total costs for all regulatory options as well as their estimated impacts on plants and entities are estimated using a lower and upper bound of costs.

The TDD describes the control technologies and their respective wastewater treatment performance in greater detail (U.S. EPA, 2024e). The TDD also describes how EPA estimated plant-specific capital and operation and maintenance (O&M) costs for each treatment technology, as well as for BMP plans. The cost analysis uses the 2020 rule as the baseline and incorporates technologies that plants have implemented, or would implement, to meet the 2020 ELGs, in absence of the changes in this final rule.

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28 Dischargers are not required to use the technologies specified as the basis for the rule. They are free to identify other perhaps less expensive technologies as long as they meet the BAT limitations and pretreatment standards in the rule.

29 EPA estimates that the final rule will not impose significant additional administrative cost to the State and federal governments. See Section 10.7, *Paperwork Reduction Act of 1995*, for additional discussion.

30 Assuming the same 40-year surface impoundment operating life used in the 2015 CCR rule record and acknowledging that these impoundments could be anywhere in that 40-year lifespan, EPA used the midpoint of 20-years as a reasonable approximation for purposes of ensuring that these costs are included in the main cost analyses of the final rule. To the extent that costs could be incurred before this date at some plants and after this date at other plants, these nationwide costs may either over- or underestimate the site-specific costs at any particular plant.

3.1 Analysis Approach and Inputs

EPA updated estimated costs to plants for meeting the limitations of the regulatory options. There are four principal steps to compliance cost development, the last two of which are the focus of the discussion below:

1. Determining the set of plants potentially implementing compliance technologies for each regulatory option. See TDD for details (U.S. EPA, 2024e).
2. Developing plant-level costs for each wastestream and technology option. See TDD for details.
3. Estimating the year when each steam electric power plant would be required to meet new BAT effluent limits and pretreatment standards. This schedule supports analysis of the timing of compliance costs and benefits for analyses discussed in this document and in the BCA. EPA accounted for any planned unit retirements or units ceasing the combustion of coal but did estimate that some units will incur compliance costs associated with CRL treatment after retirement or ceasing the combustion of coal (see the TDD for details regarding how EPA estimated leachate flow rates for these plants).
4. Estimating *total* industry costs for all plants in the steam electric universe for each of the regulatory options.

EPA reports costs in 2023 dollars and discounts the costs to 2024.

3.1.1 Plant-Specific Costs Approach

As detailed in the TDD (U.S. EPA, 2024e), EPA developed costs for steam electric power plants to implement treatment technologies or process changes to control the wastestreams addressed by the regulatory options.

EPA assessed the operations and treatment system components currently in place at a given unit (or required to be in place to comply with other existing environmental regulations), identified equipment and process changes that plants would likely make to meet each of the regulatory options presented in Table 1-1. EPA developed costs to meet each regulatory option based on current plant equipment, processes, and treatment technologies, accounting for compliance with the 2020 rule in the baseline. Thus, the estimated costs of the regulatory options are additive to the costs of treatment technologies that plants have implemented or would implement to meet the 2020 rule. Plants that do not generate a wastestream or that employ technologies which would already meet the given limitations or standards do not incur incremental costs under the regulatory options.

In cases where several different technology options were available to meet the regulatory option limits, EPA estimated the costs of each possible option and selected the least-cost technology for each plant. For example, as detailed in the TDD, for zero-discharge systems used to meet FGD and CRL limits under

Option B and Option C, EPA generally selected the least cost option between systems using membrane filtration or spray dry evaporators (SDEs).[31]

As noted above, there is uncertainty on which plants may incur costs to meet effluent limits for unmanaged CRL as it will depend on case-by-case findings by future permitting authorities. To account for this uncertainty, EPA developed lower and upper bound scenarios that provide a range of probabilistic cost estimates based on different sets of assumptions regarding which plants may incur costs and the compliance approach. The upper bound scenario is based on probabilistically combining three sets of plant-level cost estimates using equal weights: cost estimates based on (1) each plant’s closest waste management unit (WMU; either an impoundment or a landfill), (2) cases of corrective action at the WMU level, and (3) cases of corrective action where surface impoundment flows are combined at the plant level. The lower bound scenario is based on probabilistically combining plant-level costs estimates based on corrective action remedies at the WMU level or at the plant level combined with the share of remedies expected to use pumping and treating of groundwater (either alone or in combination with other remedies with groundwater collection or extraction), which make unmanaged CRL most likely to be subject to the limitations in the final rule and therefore to incur costs. Like for the upper bound scenario, EPA assumed that cost estimates were equally probable in calculating a probabilistic average plant-level cost. U.S. EPA (2024d) provides additional details on the approach used to estimate costs for unmanaged CRL treatment.

3.1.2 Plant-Level Costs

Following the approach used for the analysis of the 2015 and 2020 rules and 2023 proposal (U.S. EPA, 2015, 2020, 2023d), EPA estimated compliance costs for all existing steam electric power plants, estimated to be a total 858 plants for the point source category overall. EPA assessed that only a fraction of the universe of steam electric power plants — 232 plants — generate the wastestreams covered by the regulatory options. Furthermore, out of these plants, only a subset would incur non-zero costs under any of the scenarios analyzed for the regulatory options, based on existing control technologies. This subset of plants that incur non-zero costs varies depending on the regulatory option and cost scenario (Between 139 and 170 plants incur non-zero costs across the three regulatory options and two cost scenarios). The TDD provides additional details on this analysis.

The major components of technology costs are:

- *Capital costs* include the cost of compliance technology equipment, installation, site preparation, construction, and other upfront, non-annually recurring outlays associated with compliance with the regulatory options. EPA generally assumes that plants incur all capital costs in the year when their permit is renewed to incorporate the new limitations or standards (see *Technology Implementation Years* below). As explained in the TDD, all compliance technologies are assumed to have a useful life of 20 years.

31 One exception to this approach is CRL where EPA selected membrane filtration as the basis of the estimated compliance costs for five plants that are projected to cease operation after the period of analysis even though SDEs costs would have been lower. This resulted in the estimated total compliance costs for Option B and Option C presented in Section 3.2 being overstated by approximately $6 million (1.5 percent) on an after-tax basis.

- *Initial one-time costs* (apart from capital costs above), if applicable, include a one-time monitoring and recordkeeping cost in the first year if operation for plants operating membrane filtration system to treat FGD wastewater or CRL wastewater (see TDD for more information).

- *Annual fixed O&M costs*, if applicable, include regular *annual* monitoring. Plants incur these costs each year.

- *Annual variable O&M costs*, if applicable, include annual operating labor, maintenance labor and materials, electricity required to operate wastewater treatment systems, chemicals, combustion residual waste transport and disposal operation and maintenance, and savings from not operating and maintaining ash/FGD pond systems. Plants incur these costs each year.

In addition to these initial one-time and annual outlays, certain other costs are estimated to be incurred on a non-annual, periodic basis:

- *5-Yr fixed O&M costs*, if applicable, include remote MDS chain replacement costs that plants are estimated to incur every five years, beginning five years after the technology implementation year.

- *6-Yr fixed O&M costs*, if applicable, include mercury analyzer operations and maintenance costs that plants are estimated to incur every six years, beginning in the technology implementation year.

- *10-Yr fixed O&M costs*, if applicable, include savings from not needing to periodically maintain ash/FGD pond systems. Plants are estimated to incur savings every 10 years from not needing to purchase earthmoving equipment for the pond systems, beginning 5 years after the technology implementation year.

Based on information in the record concerning the normal downtime of electricity generating units, EPA estimated that plants would be able to coordinate the implementation of wastewater treatment systems during already scheduled downtime.

3.1.3 Technology Implementation Years

The years in which individual steam electric power plants are estimated to implement control technologies are an important input to the time profile of costs that plants would incur due to the regulatory options. This profile is used to estimate the annualized costs to the steam electric industry and society associated with the regulatory options.

EPA envisions that each plant to which the regulatory options would apply would study available technologies and operational measures, and subsequently install, incorporate, and optimize the technology most appropriate for each site. As part of its consideration of the technological availability and economic achievability of the BAT limitations and pretreatment standards in the rule and following the approach the Agency used for the 2015 and 2020 rules as well as the 2023 proposal, EPA considered the magnitude and complexity of process changes and new equipment installations that would be required at plants to meet the requirements of the regulatory options in determining the time plant owners may need to comply with any revised limitations or pretreatment standards. See discussion in the TDD (U.S. EPA, 2024e).

As described in greater detail in the NPRM, EPA is establishing availability timing for BAT limitations that is "as soon as possible" after the effective date of any final rule but "no later than" five years from the effective date (*i.e.*, a 2029 deadline).[32]

The timing decision represents when the technologies are available, accounting for the need to provide sufficient time for plant owners to raise capital, plan and design systems, procure equipment, and construct and then test systems. EPA also considered the time frames needed for appropriate consideration of any plant changes being made in response to other agency rules affecting the steam electric power generating industry. Specifying compliance deadlines in the future enables plants to take advantage of planned shutdown or maintenance periods to install new pollution control technologies. This allows for the coordination of generating unit outages in order to maintain grid reliability and prevent any potential impacts on electricity availability caused by forced outages. It is not possible to predict, for each plant, exactly the date the final rule will be incorporated into permits, for purposes of determining exactly when plants will incur costs to meet the new requirements. Similar to the approach used in analyzing the 2015, 2020, and proposed 2023 rules, EPA generally expects plants to meet the new BAT limitations and pretreatment standards in a somewhat staggered fashion, given that (1) the permitting authority determines the date after considering certain specified factors, and (2) all permits are not re-issued at the same time due to their 5-year permit term. Thus, for the cost and economic impact analyses, EPA assumed implementation over a 5-year period preceding the established "no later than" date.[33, 34]

Costs associated with legacy wastewater limits under Options B and C would be incurred only as plants close and dewater their existing ponds. Given the uncertainty on when plants may do so, for the purpose of this analysis EPA assumed that any pond closures would occur after 2044 and further assumed that costs to comply with the limits would be incurred starting in that year.

Similarly, certain plants could incur costs associated with the treatment of unmanaged CRL discharged from landfills, surface impoundments, or other features in cases where a permitting authority deems, on a case-by-case basis, the discharge to be the functional equivalent of a direct discharge and requiring a permit. Because these discharges are uncertain, EPA assumed plants would incur costs associated with treating unmanaged CRL at the same time as other wastewater treatment technologies.

For the purpose of this analysis, EPA accounted for the timing of announced unit retirements or repowerings in determining the compliance year for the plant. Specifically, in cases where the announced retirement occurs after the default compliance year based on the permit renewal cycle but before the rule compliance deadline, EPA assumed that permit authorities would set the "no later than" compliance date

32 EPA did not estimate costs over different timeframes for indirect dischargers. The CWA mandates that such dischargers meet applicable standards three years from promulgation of final PSES. This timing is consistent with the modeling approach during Period 1 as described in the BCA.

33 For the purpose of the analysis, EPA assigned an estimated compliance year to each of the 232 steam electric power plants analyzed for the final rule based on each plant's estimated NPDES permit renewal year and, similar to the approach used for the 2015 and 2020 rules and 2023 proposal, the assumption that all permits will be renewed promptly (no administrative continuances). EPA projected future NPDES permit years by assuming permits are renewed every 5 years, *i.e.*, a permit expiring in 2023 would be renewed in 2028 and 2033.

34 EPA initially estimated a compliance year for each plant based on a compliance deadline of 2030. During the analyses, EPA subsequently revised the deadline to 2029 and revised plant-specific compliance years by subtracting one year for each plant rather than re-estimating compliance years only for those plants whose compliance year did not meet the deadline.

to correspond to the retirement date. In these cases, the plant would incur no incremental costs to comply with the final rule.

EPA also accounted for announced unit retirements or repowerings in the social cost analysis, which is discussed and detailed in Chapter 12 of the BCA. Specifically, EPA assumed zero O&M costs for BA transport water and FGD wastewater treatment in all years following a unit's retirement or repowering, but continued O&M costs for CRL since treatment of the CRL wastewater is expected to continue even after a unit ceases to generate electricity.

3.1.4 Total Compliance Costs

EPA used the following methodology and assumptions to aggregate compliance cost components, described in the preceding sections, and develop total plant compliance costs for regulatory options A through C:

- EPA estimated compliance costs (including zero costs) for each of the 232 steam electric power plants with the relevant wastestreams, *i.e.*, coal-fired power plants (see TDD for details). All other plants covered by the steam electric power point source category do not generate wastestreams covered by the regulatory options and therefore incur zero costs.

- EPA restated compliance costs estimated in the preceding step, accounting for the specific years in which each plant is assumed to undertake compliance-related activities and in 2023 dollars, using the Construction Cost Index (CCI) from McGraw Hill Construction (2023), the Employment Cost Index (ECI) published by the Bureau of Labor Statistics (BLS) (2023), and the Gross Domestic Product (GDP) deflator index published by the U.S. Bureau of Economic Analysis (BEA) (2023).[35]

- EPA discounted all cost values to 2024, using a rate of 3.76 percent.[36]

35 Specifically, EPA brought all compliance costs to an estimated technology implementation year using the CCI from McGraw Hill Construction (McGraw Hill Construction Engineering News-Record. (2023). *Construction Cost Index (CCI)*) or the ECI from the Bureau of Labor Statistics (U.S. Department of Labor. Bureau of Labor Statistics. (2023). *Total compensation for All Civilian workers in All industries and occupations, Index*), depending on the cost component. The Agency used the average of the year-to-year changes in the CCI (or ECI) over the most recent ten-year reporting period to bring these values to an estimated compliance year. Because the CCI (or ECI) is a nominal cost adjustment index, the resulting technology cost values are as of the compliance year and in the dollars of the technology implementation year. To restate compliance cost values in 2023 dollars, the Agency deflated the nominal dollar values to 2023 using the average of the year-to-year changes in the GDP deflator index published by the BEA over the most recent ten-year reporting period. As a result, all dollar values reported in this analysis are in constant dollars of the year 2023.

36 Compliance costs are discounted and annualized using a rate of 3.76 percent, which is the estimated weighted average cost of capital for the power sector (see U.S. Environmental Protection Agency. (2023a). *Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model Post-IRA 2022 Reference Case*. Retrieved from **https://www.epa.gov/system/files/documents/2023-03/EPA%20Platform%20v6%20Post-IRA%202022%20Reference%20Case.pdf** for details). This rate differs from the social discount rate of 2 percent used when presenting the social costs and benefits in the BCA, following OMB guidance in Circular A-4 (U.S. Office of Management and Budget. (2023). *Circular A-4: Regulatory Analysis*. Retrieved from https://www.whitehouse.gov/wp-content/uploads/2023/11/CircularA-4.pdf).

- EPA annualized one-time costs and costs recurring on other than an annual basis over a specific useful life, implementation, and/or event recurrence period, using a rate of 3.76 percent: [37]
  - Capital costs of each compliance technology: 20 years
  - Initial one-time costs: 20 years[38]
  - 5-Yr O&M: 5 years
  - 6-Yr O&M: 6 years
  - 10-Yr O&M: 10 years

- EPA added annualized capital, initial one-time costs, and annualized O&M costs recurring on other than an annual basis to the annual O&M costs to derive total annualized compliance costs.

EPA accounted for the timing of announced plant retirements in determining the useful life over which to annualize recurring costs. In cases where a plant's announced retirement year occurs after the first instance of a recurring O&M cost for BA transport water and FGD wastewater treatment but before the second instance, EPA adjusted the useful life of that cost category to be the number of years that the plant is expected to operate after the first instance.

EPA did not adjust the annualization of capital costs to reflect plant-specific considerations. EPA annualized capital costs over 20 years but recognizes that some plants may retire units sooner than the 20-year life of the equipment. EPA determined the 20-year annualization period to be reasonable for this analysis because some regulators may allow utilities to recover the value of undepreciated assets in their rate base on a case-by-case basis.[39]

For the assessment of compliance costs to steam electric power plants, EPA considered costs on both a pre-tax and after-tax basis. Pre-tax costs provide insight on the total expenditures as initially incurred by the plants. After-tax costs are a more meaningful measure of compliance impact on privately owned for-profit plants, and incorporate approximate capital depreciation and other relevant tax treatments in the analysis. EPA calculated the after-tax value of compliance costs by applying combined federal and State tax rates to the pre-tax cost values for privately owned for-profit plants.[40] For this adjustment, EPA used State corporate rates from the Federation of Tax Administrators (2023) combined with a 21 percent federal corporate tax rate. As discussed in the relevant sections of this document, EPA uses either pre- or after-tax compliance costs in different analyses, depending on the concept appropriate to each analysis

37 U.S. Environmental Protection Agency. (2023d). *Regulatory Impact Analysis for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*. (EPA-821-R-23-002).

38 EPA annualized these non-equipment outlays over 20 years to match the estimated performance life of compliance technology components.

39 EPA received public comments on the 2023 proposed rule confirming that a typical depreciation and amortization period is 20+ years. One commenter stated that "typical amortization periods for investments" on the scale of the 2020 Final Rule are 20 years (EPA-HQ-OW-2009-0819-10079). Another commenter described the rate recovery request of a utility to comply with the 2020 Final Rule with a proposed 20-year depreciation and amortization period, though noted that depreciation periods for equipment could be as long as 50 or 60 years (EPA-HQ-OW-2009-0819-10161).

40 Government-owned entities and cooperatives are not subject to income taxes. To distinguish among the government-owned, privately owned, and cooperative ownership categories, EPA relied on the Steam Electric Survey and additional research on parent entities using publicly available information. See *Chapter 4: Cost and Economic Impact Screening Analyses* for further discussion of these determinations.

(*e.g.*, cost-to-revenue screening-level analyses are conducted using after-tax compliance costs). Note that for social costs, which are discussed and detailed in Chapter 12 of the BCA, EPA uses pre-tax costs.[41]

3.1.5 Voluntary Incentive Program

As described in the 2020 rule and 2023 proposed rule, under the voluntary incentive program (VIP), plants that discharge directly to waters can voluntarily commit to meeting more stringent FGD limitations based on a membrane filtration treatment technology instead of limits based on CP+LRTR technology. VIP participants had more time – until 2028 – to meet the lower limits based on membrane filtration, as compared to having to meet the limits based on CP+LRTR by 2025. Plants identified as participating in the VIP program in the baseline (*i.e.*, to comply with the 2020 rule) incur zero FGD wastewater treatment costs in this final rule.

3.2 Key Findings for Regulatory Options

3.2.1 Estimated Industry-level Total Compliance Costs

Table 3-1 and Table 3-2 present lower and upper bound compliance cost estimates for the regulatory options.[42]

Table 3-1: Estimated Total Annualized Compliance Costs (in millions, 2023$, at 2024) – Lower Bound

Regulatory Option	Pre-Tax Compliance Costs				After-Tax Compliance Costs			
	Capital Technology	Other Initial One-Time	Total O&M	Total	Capital Technology	Other Initial One-Time	Total O&M	Total
Option A	$232	$0.1	$247	$479	$186	$0.1	$200	$386
Option B	$284	$0.2	$312	$596	$229	$0.1	$250	$479
Option C	$336	$0.2	$359	$695	$270	$0.2	$286	$557

Source: U.S. EPA Analysis, 2024.

41 As described in Chapter 12 of the BCA, EPA used costs incurred by steam electric power plants for the labor, equipment, material, and other economic resources needed to comply with the regulatory options as a proxy for social costs. The social cost analysis considers costs on an as-incurred, year-by-year basis. In the social cost analysis, EPA assumed that the market prices for labor, equipment, material, and other compliance resources represent the opportunity costs to society for use of those resources in regulatory compliance. EPA further assumed that the regulatory options do not affect the aggregate quantity of electricity that would be sold to consumers and, thus, that the rule's social cost would include no changes in consumer and producer surplus *from changes in electricity sales* by the electricity industry in aggregate. Given the small impact of the regulatory options on electricity production cost for the total industry (see *Chapter 5*), this is a reasonable assumption.

42 As discussed in Section 3.1.1 (see footnote 31), EPA did not select the lowest-cost technology for five plants to meet zero-discharge limits for CRL. This resulted in the estimated total compliance costs for Option B and Option C presented in this section being overstated by approximately $6 million (1.5 percent of total costs) on an after-tax basis.

Table 3-2: Estimated Total Annualized Compliance Costs (in millions, 2023$, at 2024) – Upper Bound								
Regulatory Option	Pre-Tax Compliance Costs				After-Tax Compliance Costs			
	Capital Technology	Other Initial One-Time	Total O&M	Total	Capital Technology	Other Initial One-Time	Total O&M	Total
Option A	$453	$0.1	$595	$1,048	$372	$0.1	$490	$863
Option B	$505	$0.2	$659	$1,164	$415	$0.1	$541	$956
Option C	$557	$0.2	$706	$1,263	$456	$0.2	$577	$1,033

Source: U.S. EPA Analysis, 2024.

Table 3-3 and Table 3-4 show the breakout of total upper and lower bound compliance costs for each option by wastestream.[43]

Table 3-3: Estimated Total Annualized Compliance Costs, by Wastestream (in millions, 2023$, at 2024) – Lower Bound										
Regulatory Option	Pre-Tax Compliance Costs					After-Tax Compliance Costs				
	BA Transport Water	FGD Wastewater	CRL	Legacy	Net Total Costs	BA Transport Water	FGD Wastewater	CRL	Legacy	Net Total Costs
Option A	$19	$179	$281	$0	$479	$15	$139	$232	$0	$386
Option B	$19	$179	$370	$28	$596	$15	$139	$302	$23	$479
Option C	$30	$205	$433	$28	$695	$23	$160	$350	$23	$557

Source: U.S. EPA Analysis, 2024.

Table 3-4: Estimated Total Annualized Compliance Costs, by Wastestream (in millions, 2023$, at 2024) – Upper Bound										
Regulatory Option	Pre-Tax Compliance Costs					After-Tax Compliance Costs				
	BA Transport Water	FGD Wastewater	CRL	Legacy	Net Total Costs	BA Transport Water	FGD Wastewater	CRL	Legacy	Net Total Costs
Option A	$19	$179	$849	$0	$1,048	$15	$139	$709	$0	$863
Option B	$19	$179	$939	$28	$1,164	$15	$139	$778	$23	$956
Option C	$30	$205	$1,001	$28	$1,263	$23	$160	$826	$23	$1,033

Source: U.S. EPA Analysis, 2024.

3.2.2 *Estimated Regional Distribution of Incremental Compliance Costs*

Table 3-5 and Table 3-6 report the estimated lower and upper bound annualized total costs for each regulatory option at the level of a North American Electric Reliability Corporation (NERC) region.[44] As

43 One retired plant incurs legacy costs in the analysis. These costs are reflected in the total cost values in tables in Section 3.2. The costs for this plant are not incorporated in the rest of the RIA analyses because the plant does not have generation revenue or ratepayers.

44 No steam electric power plant is estimated to incur compliance costs in the ASCC and HICC NERC regions and these two regions are therefore omitted from the presentation of results.

explained in Chapter 2 (Overview of the Steam Electric Industry), because of differences in operating characteristics of steam electric power plants across NERC regions, as well as differences in the economic and electric power system regulatory circumstances of the NERC regions themselves, the regulatory options may affect costs, profitability, electricity prices, and other impact measures differently across NERC regions.

Table 3-5: Estimated Annualized Total Compliance Costs by NERC Region (in millions, 2023$, at 2024) – Lower Bound

NERC Region[a]	Pre-Tax Incremental Compliance Costs				After-Tax Incremental Compliance Costs			
	Capital Technology	Other Initial One-Time	Total O&M	Total	Capital Technology	Other Initial One-Time	Total O&M	Total
Option A								
MRO	$29.1	$0.0	$24.9	$54.0	$23.6	$0.0	$20.1	$43.7
NPCC	$3.0	$0.0	$3.0	$6.0	$2.2	$0.0	$2.2	$4.4
RF	$70.3	$0.0	$76.0	$146.3	$54.3	$0.0	$58.7	$113.0
SERC	$111.4	$0.0	$116.7	$228.2	$91.6	$0.0	$97.4	$189.0
TRE	$4.1	$0.0	$3.8	$7.9	$3.6	$0.0	$3.2	$6.8
WECC	$13.5	$0.0	$22.7	$36.2	$10.6	$0.0	$17.9	$28.5
Total	**$231.7**	**$0.1**	**$247.5**	**$479.2**	**$186.1**	**$0.1**	**$199.8**	**$386.0**
Option B								
MRO	$39.5	$0.0	$30.3	$69.8	$32.4	$0.0	$24.3	$56.7
NPCC	$3.3	$0.0	$2.9	$6.1	$2.4	$0.0	$2.1	$4.5
RF	$89.6	$0.1	$118.4	$208.0	$69.0	$0.1	$90.3	$159.3
SERC	$129.3	$0.1	$128.3	$257.7	$106.7	$0.0	$106.9	$213.6
TRE	$5.1	$0.0	$4.1	$9.2	$4.3	$0.0	$3.5	$7.8
WECC	$17.1	$0.0	$27.4	$44.5	$14.0	$0.0	$22.4	$36.5
Total	**$284.1**	**$0.2**	**$311.7**	**$596.0**	**$229.0**	**$0.1**	**$249.8**	**$479.0**
Option C								
MRO	$44.2	$0.0	$32.8	$77.0	$35.8	$0.0	$26.1	$61.9
NPCC	$3.3	$0.0	$2.9	$6.1	$2.4	$0.0	$2.1	$4.5
RF	$103.2	$0.1	$132.0	$235.3	$79.0	$0.1	$100.3	$179.3
SERC	$156.2	$0.1	$150.1	$306.4	$129.1	$0.1	$124.5	$253.6
TRE	$7.7	$0.0	$6.4	$14.1	$6.5	$0.0	$5.4	$11.9
WECC	$21.2	$0.0	$34.4	$55.6	$17.1	$0.0	$27.7	$44.8
Total	**$335.9**	**$0.2**	**$358.9**	**$695.0**	**$270.1**	**$0.2**	**$286.4**	**$556.6**

a. EPA estimated zero ELG compliance costs in the ASCC and HICC regions. These two regions are omitted from the table presentation. This omission does not affect totals.

Source: U.S. EPA Analysis, 2024.

Table 3-6: Estimated Annualized Total Compliance Costs by NERC Region (in millions, 2023$, at 2024) – Upper Bound

NERC Region[a]	Pre-Tax Incremental Compliance Costs				After-Tax Incremental Compliance Costs			
	Capital Technology	Other Initial One-Time	Total O&M	Total	Capital Technology	Other Initial One-Time	Total O&M	Total
Option A								
MRO	$54.8	$0.0	$63.3	$118.2	$43.2	$0.0	$48.6	$91.9
NPCC	$3.2	$0.0	$3.2	$6.4	$2.3	$0.0	$2.3	$4.7
RF	$109.9	$0.0	$135.2	$245.2	$86.4	$0.0	$106.9	$193.3
SERC	$225.3	$0.0	$292.7	$518.1	$192.1	$0.0	$252.3	$444.4
TRE	$8.4	$0.0	$8.3	$16.8	$7.3	$0.0	$7.2	$14.6
WECC	$49.8	$0.0	$90.9	$140.7	$39.4	$0.0	$71.8	$111.3
Total	**$452.6**	**$0.1**	**$595.0**	**$1,047.7**	**$372.0**	**$0.1**	**$490.5**	**$862.6**
Option B								
MRO	$65.3	$0.0	$68.7	$134.0	$52.0	$0.0	$52.8	$104.9
NPCC	$3.5	$0.0	$3.0	$6.5	$2.6	$0.0	$2.2	$4.8
RF	$129.2	$0.1	$177.6	$306.9	$101.1	$0.1	$138.5	$239.6
SERC	$243.2	$0.1	$304.3	$547.6	$207.2	$0.0	$261.9	$469.1
TRE	$9.4	$0.0	$8.7	$18.0	$8.1	$0.0	$7.5	$15.6
WECC	$53.4	$0.0	$95.6	$149.0	$42.9	$0.0	$76.4	$119.2
Total	**$505.1**	**$0.2**	**$659.2**	**$1,164.4**	**$414.9**	**$0.1**	**$540.5**	**$955.6**
Option C								
MRO	$69.9	$0.0	$71.2	$141.1	$55.4	$0.0	$54.6	$110.1
NPCC	$3.5	$0.0	$3.0	$6.5	$2.6	$0.0	$2.2	$4.8
RF	$142.8	$0.1	$191.3	$334.2	$111.0	$0.1	$148.5	$259.6
SERC	$270.0	$0.1	$326.1	$596.2	$229.6	$0.1	$279.5	$509.1
TRE	$12.0	$0.0	$11.0	$23.0	$10.3	$0.0	$9.4	$19.7
WECC	$57.5	$0.0	$102.5	$160.0	$46.0	$0.0	$81.6	$127.5
Total	**$556.9**	**$0.2**	**$706.4**	**$1,263.5**	**$456.0**	**$0.2**	**$577.1**	**$1,033.3**

a. EPA estimated zero ELG compliance costs in the ASCC and HICC regions. These two regions are omitted from the table presentation. This omission does not affect totals.

Source: U.S. EPA Analysis, 2024.

3.2.3 Key Uncertainties and Limitations

Economic analyses are not perfect predictions and thus, like all such analyses, this analysis has some uncertainties and limitations.

- The compliance costs used in this analysis for the regulatory options reflect unit retirements, conversions, and repowerings that have occurred or have been announced and are scheduled to occur by the end of 2029. For details, see TDD (U.S. EPA, 2024e). To the extent that actual unit retirements, conversions, and repowerings at steam electric power plants differ from announced changes, estimated annualized compliance costs of the regulatory options may differ from actual costs.

- EPA assumed that the equipment installed to meet any new limitations could reasonably be estimated to operate for 20 years or more, based on a review of reported performance characteristics of the equipment components. EPA also determined the 20-year annualization period to be reasonable for this analysis because some regulators may allow utilities to recover the value of undepreciated assets in their rate base on a case-by-case basis. EPA thus used 20 years as the basis for the cost and economic impact analyses that account for the estimated operating life of compliance technology. To the extent that the actual service life is longer or shorter than 20 years, costs presented on annual equivalent basis would be over- or under-stated. This includes cases where a plant upgrades treatment technologies to comply with the ELGs but ceases operating before the 20-year life of the equipment.

- Annualized compliance costs depend on the assumed technology implementation year. For the purpose of the cost and economic impact analyses, EPA determined years in which technology implementation would reasonably be estimated to occur across the universe of steam electric power plants, based on plant-specific information about existing NPDES permits and extrapolating future permit issuance dates assuming permits are renewed every five years. To the extent that compliance costs are incurred in an earlier or later year, the annualized values presented in this section may under or overstate the annualized total costs of the regulatory options.

- Plants may incur compliance costs associated with meeting legacy wastewater limits when they close and dewater their existing ponds. As there are no requirements for the ponds to be closed, there is uncertainty on whether and when operators may incur such costs. EPA assumed that pond closures will occur in 2044 at which time plants would incur initial one-time costs associated with treatment of legacy wastewater. As a result, this analysis may under or overstate compliance costs in cases where plants choose to close their ponds before or after 2044.

- Plants may incur compliance costs to comply with unmanaged CRL discharged from landfills, surface impoundments, or other features in cases where a permitting authority deems, on a case-by-case basis, the discharge to be the functional equivalent of a direct discharge and requiring a permit. Because these discharges are uncertain, EPA developed lower and upper bound analyses scenarios that rely on probabilistic estimates of plants that may be subject to the limits, compliance approach, and associated costs. See Section 3.1.1 for a description of these scenarios. Additionally, EPA assumed plants would incur these costs at the same time as they would incur costs associated with other treatment technologies. This may under or overstate the costs of unmanaged CRL treatment if plants incur these costs before or after the assumed compliance year in the analysis.

3.3 Costs to New Sources

Electric power generating plants that meet the definition of a “new source” will be required to achieve the final NSPS, in the case of direct dischargers, or Pretreatment Standards for New Sources (PSNS), in the case of indirect dischargers. This section summarizes the data and methodology used to estimate compliance costs for new steam electric power plants (for a more detailed description of the methodology, see TDD, U.S. EPA, 2024e). The section also assesses the relative magnitude of the compliance costs by comparing them to the costs of new coal steam generation. EPA’s final rule is based on the suite of technologies identified for Option B. EPA’s approach to assess costs to new sources and the potential barrier to entry for new plants is based on the same methodology used for the 2015 rule (U.S. EPA, 2015).

3.3.1 Analysis Approach and Inputs

EPA developed compliance costs for new plants using a methodology similar to the one used to develop compliance costs for existing plants (see TDD for details). EPA did not have information about which entities will construct new plants, the exact characteristics of such plants, or the timing of new plant construction. As a result, EPA calculated and analyzed compliance costs for a hypothetical plant. The Agency treated the incurrence of costs in this analysis as though new plants would be constructed, and additional wastewater treatment costs incurred, as of the rule promulgation, (*i.e.*, 2024). This is a conservative assumption since new sources would not incur costs until there is an NPDES permit applying the NSPS to them.

Compliance costs for new plants under the final NSPS (Option B) include capital costs, initial one-time costs, and annual O&M costs. EPA made the same adjustments to the plant-specific costs for new plants described in the TDD, as those made to develop total compliance costs for existing plants:

- First, EPA brought all compliance costs to 2024 using CCI (or ECI) and restated in 2023 dollars using GDP Deflator.
- EPA then annualized each non-annual cost component over the expected useful life of the technology/processes it represents (capital cost and initial one-time costs over 20 years) using 3.76 percent as the assumed cost of capital.
- Finally, EPA added these annualized capital, initial one-time, and O&M costs.

Table 3-7 presents estimated new plant compliance costs under the final rule (Option B) for new sources. The Agency estimated costs for a new 650 MW coal-fired steam electric power plant. Per MW, EPA estimated that a new plant will cost $4,916 per MW. For more details on the methodology used to estimate compliance costs for new plants, see the TDD (U.S. EPA, 2024e).

Table 3-7: Annualized Pre-tax Compliance Costs for a Hypothetical New 650 MW Plant Under Final Rule (2023$, at 2024)

Total Costs				Costs per MW[a]			
Capital Costs	Non-Fuel O&M Costs	One-Time Costs	Total Annualized Costs	Capital Costs	Non-Fuel O&M Costs	One-Time Costs	Total Annualized Costs
$1,482,503	$1,701,998	$11,088	$3,195,589	$2,281	$2,618	$17	$4,916

a. Unit costs are based on capacity of 650 MW.

Source: U.S. EPA analysis, 2024.

3.3.2 Key Findings for Regulatory Options

EPA assessed the effects of the final NSPS requirements under the final rule for new plants by comparing the compliance costs for new plants to the overall cost of *building and operating* new plants, on a per

MW basis. This analysis assesses the requirements and costs imposed on new plants in relation to the costs that would be incurred for building and operating new plant *without the new plant requirements*.[45]

To assess the relative magnitude of compliance costs for new plants, EPA compared the pre-tax costs presented in Section 3.2.1, to the total cost of building and operating a new plant, also on a pre-tax and per MW basis. EPA obtained the overnight capital[46] and O&M costs of building and operating a new plant from EIA (2024). These costs are based on a new ultra-supercritical coal (USC) plant with no carbon capture (CC) technology with a total generation capacity of 650 MW (EIA, 2024). EPA compared the ELG cost estimates for the 650 MW plant presented in Table 3-7 to the costs of a new USC plant without CC.

EPA also estimated annual fuel O&M costs for operating the plant based on an assumed capacity factor of 90 percent, annual heat rate of a new USC without CC from EIA (2024), and weighted average cost of coal delivered to the power sector from EIA (2023h). EPA annualized new USC without CC plant building and operating costs over 40 years using a discount rate of 3.76 percent.[47] EPA then compared the estimated compliance costs for new plants to the costs of constructing and operating new coal steam capacity. Table 3-8 presents the results of this comparison. The Agency estimated that compliance costs for adding treatment technology at a new plant would represent 1.1 percent of the total annualized costs of building and operating a new plant.

Table 3-8: One-Time & O&M costs for a Hypothetical New 650 MW Plant Under Final Rule

Cost Component	Annualized Costs of New Coal-fired Generation (2023$/MW)	Compliance Costs (2023$/MW)	% of New Generation Cost
Capital	$199,936	$2,281	1.1%
Non-Fuel Annual O&M[a]	$112,095	$2,618	1.0%
Fuel Annual O&M	$153,535		
Total Annualized Costs[b]	$465,566	$4,916	1.1%

a. Fuel costs were estimated assuming heat rate of 8,638 Btu/kWh (EIA, 2024) and the cost of coal delivered to the power sector of 2.25 2023$/MMbtu (EIA (2023h) weighted average cost for all coal ranks in 2022 dollars, converted to 2023 dollars using GDP deflator).

b. Includes annualized initial one-time costs.

Source: EIA, 2024; U.S. EPA analysis, 2024.

45 Note that the market analyses described in Chapter 5 also incorporate costs to new sources as part of inputs to the Integrated Planning Model (IPM). This analysis tests the impact of the new plant requirements in electricity markets accounting for the expected number and timing of new plant installations, and provides additional insight on whether the costs of meeting the standards specified by the final NSPS and PSNS would affect future capacity additions. Since IPM projects no new coal-fired generating plant in the Base Case, however, the market analysis does not offer additional insight on the impacts of the NSPS compliance costs on new generating capacity.

46 Overnight capital costs includes labor and material costs due to installation, mechanical equipment and labor, electrical instrumentation, and indirect management costs according to U.S. Energy Information Administration. (2024). *Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies.* Retrieved from https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

47 The Agency annualized capital costs for a new USC coal unit without CC based on the predicted performance life reported in ibid..

3.3.3 Key Uncertainties and Limitations

Despite EPA's use of the best available information and data available, including information provided to EPA in the industry survey, this analysis has uncertainties and limitations.

- EPA notes that no new coal capacity additions are projected between 2024 and 2050 in AEO2023 (EIA, 2023b), making the assessment of the relative costs and of any barrier the final ELGs may pose to additional generation hypothetical. Similarly, results of the electricity market model using IPM (Chapter 5) shows no additional coal steam capacity being built through 2050 in the Base Case (in the absence of the ELGs) or in the policy case (with the ELGs), and do not offer a basis for determining, using IPM, whether the ELGs present a cost barrier to new coal generation. However, as discussed in Chapter 5, the IPM results demonstrate that the ELGs do not pose a barrier to new electricity generation overall; the model shows increases new capacity projected in IPM under the final rule option.

- Second, EPA made assumptions about plant characteristics in the absence of the final rule. These assumptions affect the types of wastestreams that a plant would generate and changes needed to meet the final limitations and standards. To the extent that the characteristics of new plants differ from EPA's assumed characteristics, the costs may be under or overstated.

- Finally, the costs of implementing and operating compliance technology vary based on the size of the generating plant and plant configuration. To the extent that the size and configuration of a potential new coal plant is different from assumptions that underlay new capacity costs, the relative magnitude of the compliance costs for new steam electric capacity may be under- or over-estimated. For instance, EPA used data from EIA on the cost of additional capacity based on a new 650 MW USC without CC plant (EIA, 2024). The cost of building new capacity for a smaller or larger plant may be smaller or larger on a per MW basis than those of a 650 MW plant.

4 Cost and Economic Impact Screening Analyses

4.1 Analysis Overview

Following the same methodology used for the 2015, 2020 and proposed 2023 rule analyses (U.S. EPA, 2015, 2020, 2023d), EPA assessed the costs and economic impacts of the regulatory options in two ways:

1. A screening-level assessment reflecting current operating characteristics of steam electric power plants and with assignment of estimated compliance costs to those plants. This analysis assumes no changes in operating characteristics — *e.g.*, quantity of generated electricity and revenue — as a result of the regulatory options. This screening-level assessment, which is documented in this chapter, includes two specific analyses:
   - A cost-to-revenue screening analysis to assess the impact of compliance outlays on individual steam electric power plants (Section 4.2)
   - A cost-to-revenue screening analysis to assess the impact of compliance outlays on domestic parent-entities owning steam electric power plants (Section 4.3)
2. A broader electricity market-level analysis based on IPM (the Market Model Analysis). This analysis, which provides a more comprehensive indication of the economic achievability of the final rule, including an assessment of incremental plant closures (or avoided closures), is discussed in Chapter 5. Unlike the preceding analysis discussed in this chapter, the Market Model Analysis accounts for estimated changes in the operating characteristics of plants from both estimated changes in electricity markets and operating characteristics of plants independent of, and as a result of, the regulatory options.

4.2 Cost-to-Revenue Analysis: Plant-Level Screening Analysis

The cost-to-revenue measure compares the cost of implementing and operating compliance technologies with the plant's operating revenue and provides a screening-level assessment of the impact that might be estimated of the regulatory options. As discussed in U.S. EPA (2015; see Chapter 2), the majority of steam electric power plants operate in states with regulated electricity markets. EPA estimates that plants located in these states may be able to recover compliance cost-based increases in their production costs through increased electricity prices, depending on the business operation model of the plant owner(s), the ownership and operating structure of the plant itself, and the role of market mechanisms used to sell electricity. In contrast, in states in which electric power generation has been deregulated, cost recovery is not guaranteed. While plants operating within deregulated electricity markets *may be* able to recover some of their additional production costs through increased revenue, it is not possible to determine the extent of cost recovery ability for each plant.[48]

In assessing the cost impact of the regulatory options on steam electric power plants in this screening-level analysis, the Agency assumed that the plants would not be able to pass any of the change in their

48 While the regulatory status in a given state affects the ability of electric power plants and their parent entities to recover electricity generation costs, it is not the only factor and should not be used solely as the basis for cost-pass-through determination.

production costs to consumers (zero cost pass-through). This assumption is used for analytic convenience and provides a *worst-case* scenario of regulatory impacts to steam electric power plants.[49]

4.2.1 Analysis Approach and Data Inputs

As described in Chapter 1, EPA estimates all steam electric power plants to meet any new requirements for bottom ash transport water, FGD wastewater, and CRL between 2026 and 2030. The Agency used the same approach from the 2015 rule, 2020 rule, and 2023 proposed rule to conduct the analysis of the final rule's regulatory options A through C.

EPA updated the approach used for the 2015 and 2020 rules and 2023 proposal to incorporate more recent data. For the current analysis, EPA used 2024 as the basis for comparing after-tax compliance costs (see Chapter 3) to revenue at the plant level.[50] For this comparison, EPA developed plant-level revenue values for all steam electric power plants using data from the Department of Energy's Energy Information Administration (EIA) on electricity generation by prime mover, and utility/operator-level electricity prices and disposition. Specifically, EPA multiplied the 6-year average of electricity generation values over the period 2016 to 2021 from the EIA-923 database by 6-year average electricity prices over the period 2016 to 2021 from the EIA-861 database (EIA, 2022a, 2022d).[51, 52] EPA estimated compliance costs in 2023 dollars. To provide cost and revenue comparisons on a consistent analysis-year (2024) and dollar-year (2023) basis, EPA adjusted the EIA electricity price data, which are reported in nominal dollars of each year.

Cost-to-revenue ratios are used to describe impacts to entities because they provide screening-level indicators of potential economic impacts. Just as for the plants owned by small entities under guidance in U.S. EPA (2006), and the approach EPA has used previously in previous regulatory analyses (U.S. EPA, 2015, 2020, 2023d), EPA assesses plants incurring costs below one percent of revenue as unlikely to face material economic impacts, plants with costs of at least one percent but less than three percent of revenue

49 Even though the majority of steam electric power plants may be able to pass increases in production costs to consumers through increased electricity prices, it is difficult to determine exactly which plants would be able to do so. Consequently, EPA concluded that assuming zero cost pass-through is appropriate as a screening-level, upper bound estimate of the potential impact of compliance expenditures on steam electric power plants and their parent entities. The analysis, while helpful to understand potential cost impact, does not generally indicate whether profitability is jeopardized, cash flow is affected, or risk of financial distress is increased.

50 For private, tax-paying entities, *after-tax costs* are a more relevant measure of potential private cost burden than *pre-tax costs*. For non-tax-paying entities (*e.g.*, State government and municipality owners of steam electric power plants), the estimated costs used in this calculation include no adjustment for taxes.

51 In using the year-by-year revenue values to develop an average over the data years, EPA set aside from the average calculation any generation values that are anomalously low. Such low generating output likely results from temporary disruption in operation, such as a generating unit being out of service for maintenance.

52 EPA's first step in calculating plant revenue was to restate electricity prices in 2023 dollars using the Gross Domestic Product (GDP) deflator index published by the U.S. Bureau of Economic Analysis (BEA) (U.S. Bureau of Economic Analysis. (2023). *Table 1.1.9 Implicit Price Deflators for Gross Domestic Product (GDP Deflator)*. Retrieved from https://apps.bea.gov/iTable/?reqid=19&step=3&isuri=1&1921=survey&1903=11). These individual yearly values were then averaged and brought forward to 2024 using electricity price projections from the Annual Energy Outlook publication for 2023 (AEO2023) (U.S. Energy Information Administration. (2023b). *Annual Energy Outlook 2023*. Retrieved from https://www.eia.gov/outlooks/aeo/). AEO2023 contains projections and analysis of U.S. energy supply, demand, and prices through 2050. AEO2023 electricity price projections are in constant dollars; therefore, these adjustments yield 2024 revenue values in dollars of the year 2023 (converted from 2022 dollars to 2023 dollars).

as having a higher chance of facing material economic impacts, and plants incurring costs of at least three percent of revenue as having a still higher probability of material economic impacts.

4.2.2 Key Findings for Regulatory Options

Table 4-1 and Table 4-2 present the lower and upper bound cost-to-revenue analysis results for each of the regulatory options. Under all regulatory options analyzed, most plants would not experience compliance costs exceeding one or three percent of revenue.

Table 4-1: Plant-Level Cost-to-Revenue Analysis Results by Owner Type and Regulatory Option – Lower Bound

Owner Type	Total Number of Plants[a]	Number of Plants with a Ratio of			
		0%[a,b]	≠0 and <1%	≥1 and 3%	≥3%
Option A					
Cooperative	59	44	10	3	2
Federal	23	17	4	2	0
Investor-owned	320	238	63	14	5
Municipality	111	100	4	2	5
Nonutility	308	289	15	1	3
Political Subdivision	33	29	3	0	1
State	4	2	2	0	0
Total	**858**	**719**	**101**	**22**	**16**
Option B					
Cooperative	59	44	8	5	2
Federal	23	17	4	2	0
Investor-owned	320	237	59	17	7
Municipality	111	100	2	4	5
Nonutility	308	288	14	3	3
Political Subdivision	33	29	3	0	1
State	4	2	1	1	0
Total	**858**	**717**	**91**	**32**	**18**
Option C					
Cooperative	59	44	8	5	2
Federal	23	17	4	2	0
Investor-owned	320	237	53	23	7
Municipality	111	100	2	4	5
Nonutility	308	288	14	3	3
Political Subdivision	33	29	3	0	1
State	4	2	1	0	1
Total	**858**	**717**	**85**	**37**	**19**

a. Plant counts are weighted estimates.

b. These plants already meet discharge requirements for the wastestreams controlled by a given regulatory option and therefore are not estimated to incur compliance costs.

Source: U.S. EPA Analysis, 2024.

Table 4-2: Plant-Level Cost-to-Revenue Analysis Results by Owner Type and Regulatory Option – Upper Bound

Owner Type	Total Number of Plants[a]	Number of Plants with a Ratio of			
		0%[a,b]	≠0 and <1%	≥1 and 3%	≥3%
Option A					
Cooperative	59	41	9	4	5
Federal	23	14	6	2	1
Investor-owned	320	224	64	19	13
Municipality	111	97	5	3	6
Nonutility	308	284	17	4	3
Political Subdivision	33	27	5	0	1
State	4	2	1	1	0
Total	**858**	**688**	**107**	**33**	**29**
Option B					
Cooperative	59	41	7	6	5
Federal	23	14	5	3	1
Investor-owned	320	223	62	20	15
Municipality	111	97	3	5	6
Nonutility	308	284	15	6	3
Political Subdivision	33	27	5	0	1
State	4	2	1	1	0
Total	**858**	**687**	**98**	**41**	**31**
Option C					
Cooperative	59	41	7	6	5
Federal	23	14	5	2	2
Investor-owned	320	223	57	25	15
Municipality	111	97	3	5	6
Nonutility	308	284	13	8	3
Political Subdivision	33	27	5	0	1
State	4	2	1	0	1
Total	**858**	**687**	**91**	**46**	**33**

a. Plant counts are weighted estimates.

b. These plants already meet discharge requirements for the wastestreams controlled by a given regulatory option and therefore are not estimated to incur compliance costs.

Source: U.S. EPA Analysis, 2024.

4.2.3 Uncertainties and Limitations

Despite EPA's use of the best available information and data, this analysis of plant-level impacts has uncertainties and limitations, including:

- The impact of the regulatory options may be over- or under-estimated as a result of differences between actual 2024 plant revenue and those estimated using EIA databases for 2015 through 2021.
- As noted above, the zero cost pass-through assumption represents a worst-case scenario from the perspective of the plant owner. To the extent that companies are able to pass some compliance costs on to consumers through higher electricity prices, this analysis overstates the potential impact of the regulatory options on steam electric power plants.

- EPA assumes that owners of plants that retire or repower during the period of analysis, but after installing equipment to comply with the final rule, will continue to amortize capital expenses over the 20-year life of the technology. To the extent that plant owners use an accelerated amortization schedule, this analysis may understate the potential impact of the baseline and regulatory options on steam electric power plants.

4.3 Cost-to-Revenue Screening Analysis: Parent Entity-Level Analysis

Following the methodology EPA used for the analysis of the 2015 and 2020 rules and 2023 proposal analyses (U.S. EPA, 2015, 2020, 2023d), EPA also assessed the economic impact of the regulatory options at the parent entity level. The cost-to-revenue screening analysis at the entity level adds particular insight on the impact of compliance requirements on those entities that own multiple plants.

EPA conducted this screening analysis at the *highest* level of *domestic* ownership, referred to as the "domestic parent entity." For this analysis, the Agency considered only entities with the largest share of ownership (*e.g.*, majority owner) in at least one surveyed steam electric power plant.[53,54] The entity-level analysis maintains the worst-case analytical assumption of no pass-through of compliance costs to electricity consumers used for the plant-level cost-to-revenue analysis in Section 4.2.

4.3.1 Analysis Approach and Data Inputs

Following the approach used in the 2015, 2020, and proposed 2023 rule analyses (U.S. EPA, 2015, 2020, 2023d), to assess the entity-level economic/financial impact of compliance requirements, EPA summed plant-level annualized after-tax compliance costs calculated in Section 3.2 to the level of the steam electric power plant owning entity and compared these costs to parent entity revenue.

Similar to the plant-level analysis, EPA used cost-to-revenue ratios of one and three percent as markers of potential impact for this analysis. Also similar to the assumptions made for the plant-level analysis, for this entity-level analysis the Agency assumed that entities incurring costs below one percent of revenue are unlikely to face significant economic impacts, while entities with costs of at least one percent but less than three percent of revenue have a higher chance of facing significant economic impacts, and entities incurring costs of at least three percent of revenue have a still higher probability of significant economic impacts.

Following the approach used in the 2015, 2020, and 2023 rule analyses (U.S. EPA, 2015, 2020, 2023d; see Section 4.3), EPA analyzed two cases that provide approximate upper and lower bound estimates on: (1) the number of entities incurring compliance costs and (2) the costs incurred by any entity owning one or more steam electric power plant.

This entity-level cost-to-revenue analysis involved the following steps: (1) Determining the parent entity; (2) Determining the parent entity revenue; and (3) Estimating compliance costs at the level of the parent

53 Throughout these analyses, EPA refers to the owner with the largest ownership share as the "majority owner" even when the ownership share is less than 51 percent.

54 When two entities have equal ownership shares in a plant (*e.g.*, 50 percent each), EPA analyzed both entities and allocated plant-level compliance costs to each entity.

entity. The sections below highlight updates to incorporate more recent data than were used for the 2015, 2020, and proposed 2023 rules.

Determining the Parent Entity

EPA used information from the 2021 EIA-860 database which provides owners and the share of ownership in electric generating units (EIA, 2022c) to determine ownership of each coal-fired steam electric power plant and surveyed non-coal steam electric power plants (see U.S. EPA, 2015 for discussion of how non-coal steam electric power plants are incorporated in the analysis). EPA supplemented this information with data from corporate/financial websites and from the Steam Electric Survey to identify the highest-level domestic parent entity for each plant.

Determining Parent Entity Revenue

For each parent entity identified in the preceding step, EPA determined revenue values based on information from corporate or financial websites, if those values were available. EPA tried to obtain revenue for years 2020 and 2021 and used the average of reported values. If revenue values were not reported on corporate/financial websites, the Agency used 2019-2021 average revenue values from the EIA-861 database (EIA, 2022a). Additionally, EPA used entity-level revenue values from Dun and Bradstreet (Dun & Bradstreet, 2021) or Experian (Experian, 2023) if those values were available.

EPA updated entity revenue values to 2023 dollars using the GDP Deflator. For this analysis, the Agency assumed that these average historical revenue values are representative of revenues as of 2024. Although the entity-level revenue values might reasonably be estimated to change by 2024 (*i.e.*, have increased or decreased relative to average historical revenue), EPA was less confident in the reliability of projecting revenue values *at the entity level* than in that of projecting plant-level revenue values to reflect changes in generation. For the entity-level analysis, therefore, EPA did not project or further adjust revenue values developed using the sources and methodology described above but used these values *as is*. In effect, plants and their parent entities are assumed to be the same ‘business entities’ in terms of constant dollar revenue in 2024 as they were in the year for which revenue were reported.

Estimating Compliance Costs at the Level of the Parent Entity

Following the approach used in the analysis of the 2015 rule, to account for the parent entities of all 858 steam electric power plants, EPA analyzed two approximate bounding cases that provide a range of estimates for the number of entities incurring compliance costs and the costs incurred by any entity owning a steam electric power plant: (1) A lower bound estimate that assumes that the surveyed owners represent all owners, which effectively assumes that any non-surveyed plants are owned by the same surveyed entities and maximizes the number of plants owned by any given entity; and (2) An upper bound estimate that assumes that the non-surveyed owners are different from those surveyed but have similar characteristics, which results in a greater number of owners but minimizes the number of plants owned by each. See Chapter 4 in U.S. EPA (2015) for details.

4.3.2 Key Findings for Regulatory Options

Table 4-3 presents the results from the entity-level impact analysis under the lower bound (Case 1) and upper bound (Case 2) estimates of the number of entities incurring costs for each regulatory option under the lower bound cost scenario. Table 4-4 presents the results for the upper bound cost scenario. The tables show the number of entities that incur costs in four ranges: no cost, and non-zero costs less than one percent of an entity's revenue, at least one percent but less than three percent of revenue, and at least three percent of revenue.

Overall, this screening-level analysis shows that few entities are likely to experience significant changes in cost-to-revenue ratios under any of the regulatory options compared to the baseline.

Table 4-3: Entity-Level Cost-to-Revenue Analysis Results – Lower Bound

Entity Type	Case 1: Lower bound estimate of change in number of firms owning plants that face requirements under the regulatory analysis						Case 2: Upper bound estimate of change in number of firms owning plants that face requirements under the regulatory analysis					
	Total Number of Entities	Number of Entities with a Ratio of					Total Number of Entities	Number of Entities with a Ratio of				
		0%[a]	≠0 and <1%	≥1 and 3%	≥3%	Unknown		0%[a]	≠0 and <1%	≥1 and 3%	≥3%	Unknown
Option A												
Cooperative	22	10	10	0	2	0	28	13	13	0	2	0
Federal	2	1	1	0	0	0	7	3	4	0	0	0
Investor-owned	57	27	29	1	0	0	88	20	67	1	0	0
Municipality	50	39	6	4	1	0	84	71	8	4	1	0
Nonutility	76	65	9	0	2	0	160	139	19	0	2	0
Other[b]	11	9	2	0	0	0	23	20	3	0	0	0
State	2	1	1	0	0	0	2	1	1	0	0	0
Total	**220**	**152**	**58**	**5**	**5**	**0**	**391**	**266**	**115**	**5**	**5**	**0**
Option B												
Cooperative	22	10	9	1	2	0	28	13	12	1	2	0
Federal	2	1	1	0	0	0	7	3	4	0	0	0
Investor-owned	57	27	29	1	0	0	88	20	67	1	0	0
Municipality	50	39	6	3	2	0	84	71	8	3	2	0
Nonutility	76	65	7	2	2	0	160	139	17	2	2	0
Other[b]	11	9	2	0	0	0	23	20	3	0	0	0
State	2	1	1	0	0	0	2	1	1	0	0	0
Total	**220**	**152**	**55**	**7**	**6**	**0**	**391**	**266**	**112**	**7**	**6**	**0**
Option C												
Cooperative	22	10	9	1	2	0	28	13	12	1	2	0
Federal	2	1	1	0	0	0	7	3	4	0	0	0
Investor-owned	57	27	29	1	0	0	88	20	67	1	0	0
Municipality	50	39	6	3	2	0	84	71	8	3	2	0
Nonutility	76	65	7	2	2	0	160	139	17	2	2	0
Other[b]	11	9	2	0	0	0	23	20	3	0	0	0
State	2	1	0	1	0	0	2	1	0	1	0	0
Total	**220**	**152**	**54**	**8**	**6**	**0**	**391**	**266**	**111**	**8**	**6**	**0**

a. These entities own only plants that already meet discharge requirements for the wastestreams addressed by a given regulatory option and are therefore not estimated to incur any compliance technology costs.

b. Other political subdivision.

Source: U.S. EPA Analysis, 2024.

Table 4-4: Entity-Level Cost-to-Revenue Analysis Results – Upper Bound

Entity Type	Case 1: Lower bound estimate of change in number of firms owning plants that face requirements under the regulatory analysis						Case 2: Upper bound estimate of change in number of firms owning plants that face requirements under the regulatory analysis					
	Total Number of Entities	Number of Entities with a Ratio of					Total Number of Entities	Number of Entities with a Ratio of				
		0%[a]	≠0 and <1%	≥1 and 3%	≥3%	Unknown		0%[a]	≠0 and <1%	≥1 and 3%	≥3%	Unknown
Option A												
Cooperative	22	7	12	0	3	0	28	9	16	0	3	0
Federal	2	1	1	0	0	0	7	2	5	0	0	0
Investor-owned	57	24	31	2	0	0	88	11	75	2	0	0
Municipality	50	37	8	1	4	0	84	69	10	1	4	0
Nonutility	76	63	10	1	2	0	160	137	20	1	2	0
Other[b]	11	6	5	0	0	0	23	14	9	0	0	0
State	2	1	1	0	0	0	2	1	1	0	0	0
Total	**220**	**139**	**68**	**4**	**9**	**0**	**391**	**242**	**136**	**4**	**9**	**0**
Option B												
Cooperative	22	7	11	1	3	0	28	9	15	1	3	0
Federal	2	1	1	0	0	0	7	2	5	0	0	0
Investor-owned	57	24	31	2	0	0	88	11	75	2	0	0
Municipality	50	37	8	1	4	0	84	69	10	1	4	0
Nonutility	76	63	8	3	2	0	160	137	18	3	2	0
Other[b]	11	6	5	0	0	0	23	14	9	0	0	0
State	2	1	0	1	0	0	2	1	0	1	0	0
Total	**220**	**139**	**64**	**8**	**9**	**0**	**391**	**242**	**132**	**8**	**9**	**0**
Option C												
Cooperative	22	7	11	1	3	0	28	9	15	1	3	0
Federal	2	1	1	0	0	0	7	2	5	0	0	0
Investor-owned	57	24	31	2	0	0	88	11	75	2	0	0
Municipality	50	37	8	1	4	0	84	69	10	1	4	0
Nonutility	76	63	8	3	2	0	160	137	18	3	2	0
Other[b]	11	6	5	0	0	0	23	14	9	0	0	0
State	2	1	0	1	0	0	2	1	0	1	0	0
Total	**220**	**139**	**64**	**8**	**9**	**0**	**391**	**242**	**132**	**8**	**9**	**0**

a. These entities own only plants that already meet discharge requirements for the wastestreams addressed by a given regulatory option and are therefore not estimated to incur any compliance technology costs.

b. Other political subdivision.

Source: U.S. EPA Analysis, 2024.

4.3.3 Uncertainties and Limitations

Despite EPA's use of the best available information and data, this analysis of entity-level impacts has uncertainties and limitations, including:

- The entity-level revenue values obtained from the corporate and financial websites or EIA databases are for 2019 through 2021. To the extent that actual 2024 entity revenue values are different, on a constant dollar basis, from those estimated using historical data, the cost-to-revenue measure for parent entities of steam electric power plants may be over- or under-estimated.

- The assessment of entity-level impacts relies on approximate upper and lower bound estimates of the number of parent entities and the numbers of steam electric power plants that these entities own. EPA expects that the range of results from these analyses provides appropriate insight into the overall extent of entity-level effects.

- As is the case with the plant-level analysis discussed in Section 4.2, the zero cost pass-through assumption represents a worst-case scenario from the perspective of the plant owner. To the extent that companies are able to pass some compliance costs on to consumers through higher electricity prices, this analysis may overstate the potential impact of the baseline and regulatory options on steam electric power plants. Also, as is the case with the plant-level analysis discussed in Section 4.2, the assumption that owners of plants that retire or repower during the period of analysis, but after installing equipment to comply with the final rule, will continue to amortize capital expenses over the 20-year life of the technology, may understate the potential impact of the baseline and regulatory options on steam electric power plants.

5 Assessment of the Impact of the Final Rule on National and Regional Electricity Markets

Following the approach used to analyze the impacts of the 2015 and 2020 rules and other various regulatory actions affecting the electric power sector over the last decade, EPA used the Integrated Planning Model (IPM®), a comprehensive electricity market optimization model that can evaluate such impacts within the context of regional and national electricity markets. To assess market-level effects of the final rule, EPA used the latest version of this analytic system: Integrated Planning Model Version 6 (IPM v6) Post-IRA 2022 Reference Case (U.S. EPA, 2023a).[55] EPA ran IPM for Option B, excluding costs associated with legacy wastewater limits or the treatment of unmanaged CRL, to evaluate the impacts of the final rule.

This market model analysis is a more comprehensive analysis compared to the screening-level analyses discussed in Chapter 4; it is meant to inform EPA's assessment of whether the proposed rule would result in any capacity retirements (full or partial plant closures)[56] and to provide insight on impacts on the overall electricity market, including to assess whether the proposed rule may significantly affect the energy supply, distribution or use under Executive Order 13211 (see Section 10.6).

In contrast to the screening-level analyses, which are static analyses and do not account for interdependence of electric generating units in supplying power to the electric transmission grid, IPM accounts for potential changes in the generation profile of steam electric and other units and consequent changes in market-level generation costs, as the electric power market responds to changes in generation costs for steam electric units due to the regulatory options. IPM is also dynamic in that it is capable of using forecasts of future conditions to make decisions for the present. Additionally, in contrast to the screening-level analyses in which EPA assumed no pass through of compliance costs, IPM depicts production activity in wholesale electricity markets where some recovery of compliance costs through increased electricity prices is possible but not guaranteed. Finally, IPM incorporates electricity demand growth assumptions from the Department of Energy's *Annual Energy Outlook 2023* (U.S. EIA, 2023b), whereas the screening-level analyses discussed in other chapters of this report assume that plants would generate approximately the same quantity of electricity in 2024 as they did on average during 2015-2020.

Changes in electricity production costs and potential associated changes in electricity output at steam electric power plants can have a range of broader market impacts that extend beyond the effect on steam electric power plants. In addition, the impact of compliance requirements on steam electric power plants may be seen differently when the analysis considers the impact on those plants in the context of the broader electricity market instead of looking at the impact on a standalone, single-plant basis. Therefore, use of a comprehensive, market model analysis system that accounts for interdependence of electric generating units is important in assessing regulatory impacts on the electric power industry as a whole.

55 For more information on IPM, see https://www.epa.gov/airmarkets/clean-air-markets-power-sector-modeling.

56 For the 2015 rule analysis, EPA used IPM to inform assessment of the economic achievability of the ELG options under CWA Sections 301(b)(2)(A) and 304(b)(2) (see U.S. Environmental Protection Agency. (2015). *Regulatory Impact Analysis for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*. (EPA-821-R-15-004).).

EPA's use of IPM v6 for this analysis is consistent with the intended use of the model to evaluate the effects of changes in electricity production costs, on electricity generation costs, subject to specified demand and emissions constraints. As discussed in greater detail in U.S. EPA (2023a), IPM generates least-cost resource dispatch decisions based on user-specified constraints such as environmental, demand, and other operational constraints. The model can be used to analyze a wide range of electric power market scenarios. Applications of IPM have included capacity planning, environmental policy analysis and compliance planning, wholesale price forecasting, and asset valuation.

IPM uses a long-term dynamic linear programming framework that simulates the dispatch of generating capacity to achieve a demand-supply equilibrium on a seasonal basis and by region. The model computes optimal capacity that combines short-term dispatch decisions with long-term investment decisions. Specifically, IPM seeks the optimal solution to an "objective function," which is the summation of all the costs incurred by the electric power sector, *i.e.*, capital costs, fixed and variable O&M costs, and fuel costs, on a net present value basis over the entire evaluated time horizon. The objective function is minimized subject to a series of supply and demand constraints. Supply-side constraints include capacity constraints, availability of generation resources, plant minimum operating constraints, transmission constraints, fuel supply constraints, and environmental constraints. Demand-side constraints include reserve margin constraints and minimum system-wide load requirements. The assumptions for total electricity demand and demand growth over IPM's period of analysis (see Section 5.1.1) are obtained from the Department of Energy's *Annual Energy Outlook 2023* (EIA, 2023b). IPM runs under the assumption that electricity demand must be met and maintains a consistent expectation of future load. This analysis does not consider the relationship of the price of power on the quantity of electricity demanded (U.S. EPA, 2023a).

The final difference between EPA's electricity market optimization model analysis and the analysis in Chapter 4 is the inclusion of estimated market-level impacts of environmental rules in the analysis baseline. The screening-level analysis estimates the impacts resulting from compliance with the final rule only, relative to a baseline that includes compliance with the 2020 ELG. Though the screening-level analysis and EPA's assumptions regarding baseline operating practices and plant and firm revenue implicitly account for existing environmental rules (*e.g.*, to the extent that these rules affect the status or characteristics of generating units), it does not explicitly estimate the effects of these rules across the entire electricity market over the period of analysis. The IPM analysis, on the other hand, dynamically estimates changes in capacity and generation over the IPM analysis period that account for retrofits and retirements as a result of a broader set of environmental rules. Notably, for the analysis for the final rule, EPA started from an electricity market "reference case" (Summer 2022) that includes the Inflation Reduction Act provisions directed towards electricity generators,[57] the Good Neighbor Plan which addresses transport under the National Ambient Air Quality Standards (NAAQS) for ozone, as well as the requirements of the 2020 ELG, Cross-State Air Pollution Rule (CSAPR and CSAPR Update), Mercury

57 As detailed in U.S. Environmental Protection Agency. (2023a). *Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model Post-IRA 2022 Reference Case*. Retrieved from **https://www.epa.gov/system/files/documents/2023-03/EPA%20Platform%20v6%20Post-IRA%202022%20Reference%20Case.pdf**, the IRA includes tax credit provisions that affect power sector operations. IPM accounts for the Clean Electricity Investment and Production Tax Credits (provisions 48E and 45Y of the IRA), the credit for Carbon Capture and Sequestration (provision 45Q), the impacts from the Zero-Emission Nuclear Power Production Credit (provision 45U), the Credit for the Production of Clean Hydrogen (provision 45V), and the Advanced Manufacturing Production Tax Credit (45X).

and Air Toxics Standards (MATS), CWA section 316(b) rule, and the final 2015 CCR rule and CCR Part A rule, among others (U.S. EPA, 2023a). The reference case also includes the effects of the Regional Greenhouse Gas Initiative (RGGI), California's Global Warming Solutions Act, Renewable Portfolio Standards state-level policies, including recent Clean Energy Standards (CES) in Illinois, Oregon, Delaware, North Carolina, and Massachusetts (U.S. EPA, 2023a).

In analyzing the effect of Option B using IPM v6, EPA specified incremental capital costs[58] and fixed and variable O&M costs that are estimated to be incurred by steam electric power plants and generating units to comply with the final rule requirements for BA transport water, FGD wastewater, and CRL (in the IPM documentation, these costs are referred to as "cost adders".[59] Compliance costs were developed using the same approach described in Chapter 3, based on the technology options and compliance deadlines for this final rule (see Table 1-1 and Section 3.1.3 for the technology basis and compliance deadlines, respectively). As described in Section 3.1.3 for the screening analysis, the IPM analysis assumes an implementation year based on the compliance deadline and each plant's expected permit renewal year. EPA ran IPM to simulate the dispatch of electricity generating units that would meet demand at the lowest costs subject to the same constraints as those present in the analysis baseline. Within this optimization framework, IPM provides generating units the option to retrofit or retire a portion or all of the unit's capacity, depending on the specified unit operating costs, which include ELG compliance costs.

The rest of this chapter is organized as follows:

- Section 5.1 summarizes the key inputs to IPM and the key outputs reviewed as indicators of the effect of the final rule.
- Section 5.2 provides the findings from the market model analysis.
- Section 5.3 discusses the effects of the final rule on new coal capacity.
- Section 5.4 identifies key uncertainties and limitations in the market model analysis.

5.1 Model Analysis Inputs and Outputs

To assess the impact of the final rule, EPA compared the policy run (Option B) to an IPM v6 Baseline projection of electricity markets and plant operations that includes the modeled effects of the 2020 rule, among existing environmental regulations.

5.1.1 Analysis Years

As described in U.S. EPA (2023a), IPM v6 models the electric power market over the 34-year period from 2028 to 2059, breaking this period into the seven representative run years shown in Table 5-1. As discussed in Chapter 1, steam electric power plants are estimated to implement control technologies to meet the regulatory option requirements starting in 2025 and no later than December 2029. This

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58 Capital costs are represented as the net present value of levelized stream of annual capital outlays and were specified in terms of the expected useful life of the capital outlay (20 years) using IPM's real discount rate for all expenditures (3.76 percent; see Chapter 10 in the IPM documentation [ibid.] for more information on IPM's financial discount rate).

59 The costs modeled in IPM do not include compliance costs associated with legacy wastewater or CRL discharged via groundwater.

technology implementation window primarily falls within the time period captured by the 2028 run year. The 2050 run year captures the last year in the analysis period (2049).

Table 5-1: IPM Run Years

Run Year	Years Represented
2028	2028
2030	2029-2031
2035	2032-2037
2040	2038-2042
2045	2043-2047
2050	2048-2052
2055	2053-2059

Source: U.S. EPA, 2023a

To assess the effect of the final rule on electricity markets during the period *after* technology implementation by *all* steam electric power plants – the *steady state* post-compliance period – EPA analyzed detailed results reported for the IPM 2035 run year. The Agency also analyzed results summarized at the level of the overall electricity market for the other run years. As discussed in Chapter 3, under the final rule specifications considered for this analysis, this *steady state* period is estimated to begin in the first year following the technology implementation window, *i.e.*, 2030, and continue into the future. Because the model run year 2035 captures decisions made through the end of 2031, by which time all plants will have achieved the revised limitations and standards, EPA determined that 2035 is an appropriate run year to capture steady-state regulatory effects. Effects that may occur during the post-compliance "steady state" include potential *permanent* changes in generating capacity from changes in early retirement (closure) of generating units,[60] *long-term* changes in electricity production costs due to changes in operating expenses, *permanent* changes in electric generating capability and production efficiency at steam electric power plants, and, as described above, changes in dispatches of other generating units resulting from the changes in electric generating capacity.

5.1.2 Key Inputs to IPM V6 for the Market Model Analysis of the Final Rule

5.1.2.1 Existing Plants

The inputs for the electricity market analyses include compliance costs and the technology implementation year. IPM models the entire electric power generating industry using a total of 20,239 generating units at 8,980 plants. EPA estimated that 105 steam electric power plants may incur non-zero compliance costs under Option B, based on the costing methodologies described in the TDD (U.S. EPA, 2024e) and timing of any announced retirements and repowerings relative to compliance deadlines.

EPA input the final rule capital and O&M costs (including costs incurred on a non-annual, periodic basis such as every 5 years or every 10 years) into IPM as capital and fixed O&M (FOM) cost adders that

60 Early retirement of generating units reflects reductions in generating capacity relative to the baseline and relative to any scheduled retirements.

represent an incremental annual charge for operating the relevant EGUs.[61] The capital costs were annualized using IPM's conventional framework for recognizing costs incurred over time, assuming a capital recovery period of 15 years.[62] Annualized capital cost and FOM cost adders are represented in IPM as incremental costs specific to individual model plants and begin in the same technology implementation years discussed in Chapter 3.

5.1.2.2 New Capacity

EPA did not specify ELG compliance costs for new coal capacity. IPM projections include new generating capacity as needed to meet demand. As described below, IPM projects no new coal capacity under the baseline or under Option B.

5.1.3 Key Outputs of the Market Model Analysis Used in Assessing the Effects of the Final Rule

IPM generates a series of outputs at different levels of aggregation (model plant, region, and nation). For this analysis, EPA used a subset of the available IPM output for each model run (baseline and Option B), focusing on metrics that quantify projected changes in capacity (including early retirements[63] and new capacity), generation, production costs, electricity prices, and emissions. See U.S. EPA (2023a) for descriptions of the IPM variables.

EPA compared national-level outputs for IPM run years (2028, 2030, 2035, 2040, 2045, and 2050). EPA then looked at changes in more detailed regional and plant-level outputs for the 2035 run year. Comparison of these outputs for the baseline and Option B provides insight into the incremental effect of the final rule on steam electric power plants and the broader electric power markets.[64]

5.2 Findings from the Market Model Analysis

The impacts of the final rule are assessed as the difference between key economic and operational impact metrics that compare the results for Option B to the baseline. This section presents two sets of analysis:

61 There were no variable O&M (VOM) cost adders for the final rule.

62 IPM seeks to minimize the total, discounted net present value, of the costs of meeting demand, accounting for power operation constraints, and environmental regulations over the entire planning horizon. These costs include the cost of any new plant, pollution control construction, fixed and variable operating and maintenance costs, and fuel costs. As described in the IPM documentation, "*Capital costs in IPM's objective function are represented as the net present value of levelized stream of annual capital outlays, not as a one-time total investment cost. The payment period used in calculating the levelized annual outlays never extends beyond the model's planning horizon: it is either the book life of the investment or the years remaining in the planning horizon, whichever is shorter. This approach avoids presenting artificially lower capital costs for investment decisions taken closer to the model's time horizon boundary simply because some of that cost would typically be serviced in years beyond the model's view. This treatment of capital costs ensures both realism and consistency in accounting for the full cost of each of the investment options in the model.*" (U.S. Environmental Protection Agency. (2023a). *Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model Post-IRA 2022 Reference Case*. Retrieved from **https://www.epa.gov/system/files/documents/2023-03/EPA%20Platform%20v6%20Post-IRA%202022%20Reference%20Case.pdf**, page 2-7).

63 Early retirement refers to the retirement of an EGU before its planned or previously announced retirement year.

64 IPM output also includes total fuel usage, which is not part of the analysis discussed in this Chapter.

- *Analysis of national-level impacts*: EPA compared baseline and Option B IPM results reported for a series of run years to provide insight on the direction and magnitude of market-level changes attributable to the final rule over time.
- *Analysis of long-term regulatory impacts*: As discussed earlier, to assess the long-term impact of the final rule, EPA compared baseline and Option B IPM results reported for 2035. These results provide insight on the effect of the final rule both for the entire electricity market and for steam electric power plants specifically.

5.2.1 National-level Analysis Results for Model Years 2028-2050

Table 5-2 shows baseline values of total system costs, wholesale electricity price, total existing capacity, new capacity, plant retirements, and generation mix at the national-level based on IPM results for the baseline (*i.e.*, without the final rule). The baseline projections show a decline in total coal generation capacity during the period (from 105.8 GW in 2028 to 28.4 GW in 2050; 73 percent reduction) and nuclear generation capacity (from 93.6 GW in 2028 to 45.4 GW in 2050; 51 percent reduction), and increases in generation capacity from renewables and natural gas. These projections are consistent with the market trends discussed in Section 2.3. Table 5-3 provides incremental changes in these measures for Option B relative to the baseline (negative values represent decreases relative to the baseline). Note that while the table includes projections for the 2050 run year, the represented period (2048-2052) includes years 2050-2052 outside of the analysis period EPA used in its analysis of the social costs and benefits, which covers 2025 through 2049.

Table 5-2: Baseline Projections, 2028-2050

Economic Measures	Baseline					
	2028	2030	2035	2040	2045	2050
Total Costs						
Total Costs (million 2023$)	$128,379	$134,505	$138,325	$142,675	$154,477	$164,934
Prices						
National Wholesale Electricity Price (mills/kWh)	34.50	39.71	32.77	31.52	26.46	34.16
Total Capacity (Cumulative GW)						
Renewables[a]	496.5	543.8	805.8	1,055.3	1,344.2	1,368.9
Coal	105.8	85.0	51.6	42.4	29.6	28.4
Nuclear	93.6	90.9	83.7	79.1	64.8	45.4
Natural Gas	471.0	478.6	476.0	516.1	565.6	673.5
Oil/Gas Steam	62.6	64.3	55.3	54.2	53.9	52.3
Other[c]	53.2	65.1	120.1	146.0	182.9	184.0
Grand Total	**1,282.7**	**1,327.7**	**1,592.4**	**1,893.0**	**2,241.2**	**2,352.5**
New Capacity (Cumulative GW)[b]						
Renewables[a]	78.9	126.2	388.4	637.9	926.8	951.5
Coal	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	33.8	41.8	41.7	82.6	148.9	268.8
Other[c]	16.6	28.6	83.5	109.4	146.4	147.4
Grand Total	**129.3**	**196.6**	**513.6**	**830.0**	**1,222.1**	**1367.7**
Retirements (Cumulative GW)						
Combined Cycle	0.8	0.8	2.1	2.7	8.7	16.2
Coal	37.8	56.7	83.7	93.0	105.7	106.9

Table 5-2: Baseline Projections, 2028-2050						
Economic Measures	Baseline					
	2028	2030	2035	2040	2045	2050
Combustion Turbine	0.5	0.9	2.2	2.4	13.2	17.6
Nuclear	0.0	2.7	9.9	14.5	28.7	48.2
Oil/Gas	12.4	12.4	22.7	23.7	24.0	25.6
Other[c]	3.0	3.0	3.1	3.2	3.2	3.2
Grand Total	**54.4**	**76.5**	**123.7**	**139.4**	**183.4**	**217.7**
Generation Mix (thousand GWh)[d]						
Renewables[a]	1,433.5	1,626.9	2,548.3	3,432.4	4,375.7	4,438.4
Coal	472.4	409.6	235.7	136.8	48.5	99.6
Nuclear	751.1	729.1	667.0	614.4	470.8	351.7
Natural Gas	1,652.0	1,670.3	1,344.4	936.5	616.8	870.7
Oil/Gas Steam	25.5	24.5	7.7	4.9	4.5	4.5
Other[c]	83.4	99.4	178.4	223.1	309.0	315.1
Grand Total	**4,418.0**	**4,559.9**	**4,981.4**	**5,348.1**	**5,825.3**	**6,079.9**

a. Renewables include hydropower and non-hydropower renewables.

b. Reported values for new generation capacity include new modeled capacity and new hardwired capacity.

c. Values for energy storage are reported in the "Other" category.

d. Electricity generation reported in this table does not include generation from distributed solar photovoltaic and differs from generation reported later in Table 5-4, which does include this source.

Source: U.S. EPA Analysis, 2024.

Table 5-3: Incremental National Impact of Final Option B Relative to Baseline, 2028-2050						
Economic Measures	Option B Changes Relative to Baseline					
	2028	2030	2035	2040	2045	2050
Total Costs						
Total Costs (million 2023$)	$31	$670	$219	$355	-$16	$47
Prices						
National Wholesale Electricity Price (mills/kWh)	0.08	0.53	0.05	0.00	-0.02	-0.02
Total Capacity (Cumulative GW)						
Renewables[a]	1.8	2.1	2.2	1.1	-0.3	-0.3
Coal	-4.8	-5.6	-5.6	-1.1	-0.1	-0.1
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	3.6	3.9	4.2	1.1	0.2	0.3
Oil/Gas Steam	-0.2	-0.2	-0.1	-0.1	-0.1	-0.1
Other[c]	0.1	0.1	1.4	0.2	0.0	0.0
Grand Total	**0.5**	**0.3**	**2.1**	**1.1**	**-0.4**	**-0.2**
New Capacity (Cumulative GW)[b]						
Renewables[a]	1.8	2.1	2.2	1.1	-0.3	-0.3
Coal	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	3.5	3.9	4.2	1.1	0.2	0.3
Other[c]	0.1	0.1	1.4	0.2	0.0	0.0
Grand Total	**5.4**	**6.0**	**7.9**	**2.3**	**-0.1**	**0.0**
Retirements (GW)						
Combined Cycle	0.0	0.0	0.0	0.0	0.0	0.0

Table 5-3: Incremental National Impact of Final Option B Relative to Baseline, 2028-2050

Economic Measures	Option B Changes Relative to Baseline					
	2028	2030	2035	2040	2045	2050
Coal	4.8	5.6	6.0	1.5	0.5	0.5
Combustion Turbine	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0
Oil/Gas	0.2	0.2	0.1	0.1	0.1	0.1
Other[c]	0.0	0.0	0.0	0.0	0.0	0.0
Grand Total	**4.9**	**5.7**	**6.1**	**1.6**	**0.6**	**0.6**
Generation Mix (thousand GWh)						
Renewables[a]	5.8	5.6	6.6	3.6	-0.3	-0.1
Coal	-18.1	-10.6	-21.2	-6.7	-1.1	-0.7
Nuclear	0.0	0.0	0.0	0.4	0.3	0.0
Natural Gas	12.6	6.3	14.9	2.4	1.2	1.0
Oil/Gas Steam	-1.0	-1.7	-0.6	0.0	-0.1	-0.1
Other[c]	0.2	0.2	2.1	0.0	0.0	-0.3
Grand Total	**-0.5**	**-0.3**	**1.7**	**-0.3**	**0.1**	**0.0**

a. Renewables include hydropower and non-hydropower renewables.

b. Reported values for new generation capacity includes new modeled capacity and new hardwired capacity.

c. Values for energy storage are reported in the "Other" category.

Source: U.S. EPA Analysis, 2024.

5.2.1.1 Findings for the Final Rule

Under Option B, total costs to electric power plants are projected to be greater than the baseline from 2028 to 2040. The increases in costs are greatest in the early years of the modeling period (*e.g.*, by $670 million in 2030), which is consistent with the timing of steam electric ELG implementation. IPM projects small increases in wholesale electricity prices in 2028 through 2040 with an increase of 0.53 mills per kWh in 2030 relative to a baseline price of $40 mills/kWh. IPM projects no change or small decreases in wholesale electricity prices in 2040 to 2050 with decreased of 0.02 mills per kWh in 2045 and 2050 relative to the baseline prices of 26 and 34 mills/kWh, respectively.

Looking at results for total capacity by energy source, coal capacity is estimated to decrease for all years from 2028 to 2050, adding to the already significant reductions projected in the baseline. Meanwhile, smaller decreases in capacity from oil/gas steam (0.1 to 0.2 GW), and greater increases in natural gas capacity (0.2 to 4.2 GW) are estimated to occur from 2028 to 2050. Capacity from renewables is estimated to increase during 2028 to 2040 but decrease during 2045 to 2050.

Additional coal retirements are estimated for all years, ranging between 0.5 to 6.0 GW of the 37.8 to 106.9 GW estimated to retire in the baseline. This accounts for most of the incremental retirements in the electric market as a whole (for Option B relative to the baseline), which range between 0.6 to 6.1 GW. Additional oil/gas steam retirements are also estimated for all years, ranging between 0.1 to 0.2 GW above retirements estimated in the baseline.

Lastly, examining results for generation by energy source, generation from coal is estimated to decrease for all years from 2028 to 2050 by 0.7 to 18.1 thousand GWh, with the largest declines occurring in the first few years. These changes are offset in part by an increase in natural gas generation (1.0 to

14.9 thousand GWh increase), nuclear generation (up to 0.4 thousand GWh increase), and generation by renewables, which increases between 2028 and 2040 by 3.6 to 6.6 thousand GWh.

5.2.2 Detailed Analysis Results for Model Year 2035

In the following results which reflect conditions for model year 2035 (2032 through 2037), all plants are estimated to meet the revised BAT limits and pretreatment standards associated with the final rule (Option B). For this more detailed analysis, following the approach used for the 2015, 2020, and proposed 2023 rules (U.S. EPA, 2015, 2020, 2023d), EPA used parsed IPM outputs and considered impact metrics of interest at three levels of aggregation:

- Impact on national and regional electricity markets (Section 5.2.2.1),
- Impact on steam electric power plants as a group (Section 5.2.2.2), and
- Impact on individual steam electric power plants (Section 5.2.2.3).

5.2.2.1 Impact on National and Regional Electricity Markets

The market-level analysis assesses national and regional changes as a result of the regulatory requirements. EPA analyzed six measures:

- *Changes in available capacity*: This measure analyzes changes in the nameplate capacity available to generate electricity. A long-term reduction in available capacity may result from partial or full closures of steam electric power plants. Conversely, increased capacity may result from *avoided* partial or full closure of the plants or the addition of new capacity. Only capacity that is projected to remain operational in the baseline case but is closed in the policy case is considered a closure attributable to the final rule. The model may project partial (*i.e.*, unit) or full plant early retirements (closures) for the final rule. It may also project partial or full avoided closures in which a unit or plant that is estimated to close in the baseline is estimated to continue operation in the policy case. Avoided closures may occur, in particular, when the regulation results in lower costs for a given plant.

- *Changes in the wholesale price of electricity*: This measure represents the change in the annual average energy price (the marginal cost of meeting demand in each time segment, averaged annually) plus any capacity prices associated with maintaining a reserve margin. In the long term, electricity prices may change as a result of changes in generation costs at steam electric power plants or due to generating unit and/or plant closures.

- *Changes in generation*: This measure considers the amount of electricity generated. At a regional level, long-term changes in generation may result from plant closures or a change in the amount of electricity traded between regions. The quantity of electricity demanded does not change between the baseline and the final rule because meeting demand is an exogenous constraint imposed by the model. However, the quantity of electricity demanded for electricity does vary across the modeling horizon according to the model's underlying electricity demand growth assumptions.

- *Changes in costs*: This measure considers changes in the overall cost of generating electricity, including fuel costs, variable and fixed O&M costs, capital costs, and carbon capture and storage (CCS) costs. These costs are not limited to steam electric generating units or to compliance costs of the final rule, but more broadly reflect changes in the cost of generating electricity across all units. Fuel costs and variable O&M costs are production costs that vary with the level of generation. Fuel costs generally account for the single largest share of production costs. Fixed O&M costs and capital costs do not vary with generation. They are fixed in the short-term and therefore do not affect the dispatch decision of a unit (given sufficient demand, a unit will dispatch as long as the price of electricity is at least equal to its per MWh production costs). However, in the long-run, these costs need to be recovered for a unit to remain economically viable.

- *Changes in average variable production costs per MWh*: This measure considers the change in average variable production cost per MWh. Variable production costs are a subset of the costs in the bullet above and include fuel costs and other variable O&M costs but exclude fixed O&M costs and capital costs. Production cost per MWh is a primary determinant of how often a generating unit is dispatched. This measure presents similar information to total fuel and variable O&M costs, but normalized for changes in generation between the baseline and policy case.

- *Changes in CO_2, NOx, SO_2, Hg, and HCL emissions*: This measure considers the change in emissions resulting from electricity generation, for example due to changes in the fuel mix. Compliance with the final rule is estimated to increase generation costs when compared to the baseline and make electricity generated by some steam electric units more expensive compared to that generated at other steam electric or non-steam electric units. These changes may in turn result in changes in air pollutant emissions, depending on the emissions profile of dispatched units. Projected changes in air emissions are used as inputs for the analysis of air-related benefits of the final rule (see Chapter 8 in the BCA (U.S. EPA, 2024a)).

Table 5-4 summarizes IPM results for the final rule at the level of the national market and also for regional electricity markets defined on the basis of NERC regions. All of the impact metrics described above are reported at both the national and NERC level except electricity prices, which are calculated in IPM only at the regional level (*i.e.*, not aggregated to national level). Differences in the relative magnitude of impacts across the NERC regions largely reflect regional differences in the number of plants incurring costs and the magnitude of these costs for the final rule as compared to the baseline and the generation mix.

Table 5-4: Impact of Final Rule on National and Regional Markets in the Year 2035

Economic Measures (all dollar values in 2023$)	Baseline Value	Option B		
		Value	Difference	% Change
National Totals				
Total Domestic Capacity (GW)	1,712	1,718	6.4	0.4%
Existing			-1.5	-0.1%
New Additions			7.9	0.5%
Early Retirements			1.5	0.1%
Wholesale Price ($/MWh)	$32.77	$32.82	$0.05	0.1%
Generation (TWh)	5,158	5,160	1.7	0.0%

Table 5-4: Impact of Final Rule on National and Regional Markets in the Year 2035

Economic Measures (all dollar values in 2023$)	Baseline Value	Option B Value	Option B Difference	Option B % Change
Costs ($Millions)	$138,325	$138,544	$219	0.2%
Fuel Cost	$39,166	$38,975	-$191	-0.5%
Variable O&M	$5,351	$5,244	-$107	-2.0%
Fixed O&M	$65,915	$65,666	-$249	-0.4%
Capital Cost	$34,149	$34,536	$387	1.1%
CCS Cost[b]	-$6,256	-$5,878	$379	-6.1%
Average Variable Production Cost ($/MWh)	$8.63	$8.57	-$0.06	-0.7%
CO_2 Emissions (Million Metric Tons)	724	713	-11.6	-1.6%
Mercury Emissions (Tons)	2	2	-0.050	-2.0%
NO_X Emissions (Million Tons)	0	0	-0.009	-3.4%
SO_2 Emissions (Million Tons)	0	0	-0.013	-5.3%
HCL Emissions (Million Tons)	0	0	-0.00012	-8.1%
Midwest Reliability Organization (MRO)				
Total Domestic Capacity (GW)	224	228	3.9	1.8%
Existing			2.4	1.1%
New Additions			1.5	0.7%
Early Retirements			-2.4	-1.1%
Wholesale Price ($/MWh)	$25.88	$25.83	-$0.05	-0.2%
Generation (TWh)	641	642	1	0.2%
Costs ($Millions)	$11,368	$11,469	$101	0.9%
Fuel Cost	$1,627	$1,578	-$49	-3.0%
Variable O&M	$292	$286	-$6	-1.9%
Fixed O&M	$7,076	$7,137	$61	0.9%
Capital Cost	$3,835	$3,929	$94	2.5%
CCS Cost[b]	-$1,462	-$1,461	$0	0.0%
Average Variable Production Cost ($/MWh)	$2.99	$2.90	-$0.09	-3.0%
CO_2 Emissions (Million Metric Tons)	53	52	-1.526	-2.9%
Mercury Emissions (Tons)	1	1	-0.002	-0.4%
NO_X Emissions (Million Tons)	0	0	-0.001	-2.3%
SO_2 Emissions (Million Tons)	0	0	-0.0004	-0.7%
HCL Emissions (Million Tons)	0	0	-0.000005	-1.4%
Northeast Power Coordinating Council (NPCC)				
Total Domestic Capacity (GW)	128	129	0.9	0.7%
Existing			1.0	0.8%
New Additions			0.0	0.0%
Early Retirements			-1.0	-0.8%
Wholesale Price ($/MWh)	$32.99	$32.91	-$0.086	-0.3%
Generation (TWh)	346	346	0	0.0%
Costs ($Millions)	$11,078	$11,073	-$6	-0.1%
Fuel Cost	$1,682	$1,678	-$4	-0.3%
Variable O&M	$283	$283	$0	-0.1%
Fixed O&M	$5,068	$5,071	$3	0.1%
Capital Cost	$4,044	$4,041	-$3	-0.1%
CCS Cost[b]	$0	$0	$0	NA
Average Variable Production Cost ($/MWh)	$5.68	$5.67	-$0.01	-0.2%
CO_2 Emissions (Million Metric Tons)	33	33	-0.108	-0.3%
Mercury Emissions (Tons)	0	0	0.000	0.0%

Table 5-4: Impact of Final Rule on National and Regional Markets in the Year 2035				
Economic Measures (all dollar values in 2023$)	Baseline Value	Option B		
		Value	Difference	% Change
NO_X Emissions (Million Tons)	0	0	-0.0001	-0.3%
SO_2 Emissions (Million Tons)	0	0	0.000	0.0%
HCL Emissions (Million Tons)	0	0	0.000	0.0%
Reliability First Corporation (RF)				
Total Domestic Capacity (GW)	306	306	0.1	0.0%
Existing			-3.6	-1.2%
New Additions			3.7	1.2%
Early Retirements			3.6	1.2%
Wholesale Price ($/MWh)	$31.99	$32.09	$0.10	0.3%
Generation (TWh)	1,039	1,039	0	0.0%
Costs ($Millions)	$30,899	$30,865	-$34	-0.1%
Fuel Cost	$9,702	$9,647	-$55	-0.6%
Variable O&M	$1,389	$1,318	-$71	-5.1%
Fixed O&M	$14,505	$14,294	-$211	-1.5%
Capital Cost	$6,402	$6,707	$305	4.8%
CCS Cost[b]	-$1,099	-$1,101	-$2	0.2%
Average Variable Production Cost ($/MWh)	$10.67	$10.56	-$0.12	-1.1%
CO_2 Emissions (Million Metric Tons)	192	183	-9.031	-4.7%
Mercury Emissions (Tons)	0	0	-0.027	-8.0%
NO_X Emissions (Million Tons)	0	0	-0.005	-8.5%
SO_2 Emissions (Million Tons)	0	0	-0.008	-13.3%
HCL Emissions (Million Tons)	0	0	-0.00007	-17.5%
Southeast Electric Reliability Council (SERC)				
Total Domestic Capacity (GW)	448	449	1.0	0.2%
Existing			-1.6	-0.3%
New Additions			2.5	0.6%
Early Retirements			1.6	0.3%
Wholesale Price ($/MWh)	$33.14	$33.25	$0.11	0.3%
Generation (TWh)	1,534	1,535	1	0.0%
Costs ($Millions)	$46,339	$46,488	$149	0.3%
Fuel Cost	$17,681	$17,604	-$77	-0.4%
Variable O&M	$2,045	$2,016	-$29	-1.4%
Fixed O&M	$20,546	$20,441	-$105	-0.5%
Capital Cost	$8,656	$8,638	-$17	-0.2%
CCS Cost[b]	-$2,589	-$2,212	$377	-14.6%
Average Variable Production Cost ($/MWh)	$12.86	$12.78	-$0.07	-0.6%
CO_2 Emissions (Million Metric Tons)	267	266	-0.6565	-0.2%
Mercury Emissions (Tons)	0	0	-0.0202	-4.8%
NO_X Emissions (Million Tons)	0	0	-0.0029	-3.3%
SO_2 Emissions (Million Tons)	0	0	-0.0037	-4.7%
HCL Emissions (Million Tons)	0	0	-0.00005	-13.1%
Texas Reliability Entity (TRE)				
Total Domestic Capacity (GW)	201	201	0.04	0.0%
Existing			0.02	0.0%
New Additions			0.03	0.0%
Early Retirements			-0.02	0.0%
Wholesale Price ($/MWh)	$28.02	$28.03	$0.0124	0.0%

Table 5-4: Impact of Final Rule on National and Regional Markets in the Year 2035				
Economic Measures (all dollar values in 2023$)	**Baseline Value**	**Option B**		
		Value	**Difference**	**% Change**
Generation (TWh)	507	507	0.09	0.0%
Costs ($Millions)	$11,258	$11,260	$2	0.0%
Fuel Cost	$1,518	$1,517	-$1	-0.1%
Variable O&M	$194	$193	$0	-0.2%
Fixed O&M	$7,180	$7,181	$1	0.0%
Capital Cost	$2,903	$2,902	-$1	-0.1%
CCS Cost[b]	-$537	-$534	$3	-0.6%
Average Variable Production Cost ($/MWh)	$3.38	$3.37	$0.00	-0.1%
CO_2 Emissions (Million Metric Tons)	37	37	-0.0271	-0.1%
Mercury Emissions (Tons)	0	0	-0.0001	-0.1%
NO_X Emissions (Million Tons)	0.01143	0.01143	0.000007	0.1%
SO_2 Emissions (Million Tons)	0.00861	0.00856	-0.0001	-0.6%
HCL Emissions (Million Tons)	0.00010	0.00010	-0.0000002	-0.2%
Western Electricity Coordinating Council (WECC)				
Total Domestic Capacity (GW)	406	406	0.4	0.1%
Existing			0.3	0.1%
New Additions			0.2	0.0%
Early Retirements			-0.3	-0.1%
Wholesale Price ($/MWh)	$39.03	$39.04	$0.014	0.0%
Generation (TWh)	1,091	1,092	0	0.0%
Costs ($Millions)	$27,383	$27,389	$6	0.0%
Fuel Cost	$6,956	$6,951	-$5	-0.1%
Variable O&M	$1,148	$1,147	-$1	-0.1%
Fixed O&M	$11,539	$11,542	$2	0.0%
Capital Cost	$8,309	$8,319	$10	0.1%
CCS Cost[b]	-$570	-$570	$0	0.0%
Average Variable Production Cost ($/MWh)	$7.43	$7.42	-$0.01	-0.1%
CO_2 Emissions (Million Metric Tons)	142	142	-0.2301	-0.2%
Mercury Emissions (Tons)	1	1	0.0000	0.0%
NO_X Emissions (Million Tons)	0	0	-0.00003	-0.1%
SO_2 Emissions (Million Tons)	0	0	-0.0002	-0.6%
HCL Emissions (Million Tons)	0	0	0.0000	0.0%

a. Numbers may not add up due to rounding.

b. The ”CCS Cost” is the cost of CO2 transportation and storage and also includes expenses on equipment and pipelines, as well as the total value of 45Q tax credits and enhanced oil recovery (EOR) revenues. In the baseline and under Option B, the total private costs are negative because the sum of the tax credits and EOR revenues exceed the equipment and pipeline costs of CO2 storage. Under Option B, total CCS Costs are less negative, and therefore these costs increase relative to the baseline, as the total amount of the 45Q tax credit received by the sector and/or EOR revenues fall due to lower coal generation.

Source: U.S. EPA Analysis, 2024.

5.2.2.1.1 Findings for Regulatory Option B

As reported in Table 5-4, the Market Model Analysis indicates that the final rule can be expected to have small effects on the electricity market, relative to the baseline, on both a national and regional sub-market basis, in the year 2035.

At the national level, total annual costs increase by an estimated $219 million (approximately 0.2 percent) relative to the baseline. Total annual costs vary by region and are estimated to increase in the MRO, SERC, and WECC regions and decrease in the NPCC, RF, and TRE. Total costs in the SERC region change by the largest amount with an increase of $149 million (0.5 percent), followed by the MRO region with an increase of $101 million (0.8 percent); changes in estimated total annual costs in the other regions range between $6 million (WECC) and -$34 million (RF). Overall, at the national level, the net change in total capacity, including decreases in existing capacity (which includes early retirements) and reductions in new plants/units, is an increase of approximately 6.4 GW in capacity, which is 0.4 percent of total market capacity. Overall, the final rule is estimated to have a minimal effect on capacity availability and supply reliability across the regions and at the national level. The net capacity increase is a result of an increases in capacity in the SERC region of 1 GW and the MRO region of 3.9 GW (0.2 and 1.8 percent of total market capacity in those regions, respectively) due to greater increases of new capacity additions and existing capacity that more than offset decreases from early retirements. Overall impacts on wholesale electricity prices are similarly minimal. Wholesale electricity prices are estimated to increase in the RF, SERC, TRE, and WECC regions with decreases in the MRO and NPCC regions. Price changes in individual regions range from $0.09 per MWh (0.3 percent) in NPCC to $0.10 per MWh 0.3 percent) in RF. Finally, at the national level, total costs are estimated to increase by $0.05 (approximately 0.1 percent).

At the national level in the year 2035, there are decreases in emissions among all air pollutants modeled. NO_x emissions decrease by 3.4 percent; SO_2 emissions decrease by 5.3 percent; CO_2 emissions decrease by 1.6 percent, mercury emissions decrease by 2 percent; and HCL emissions decrease by 8.1 percent. The impact on emissions varies across regions and by pollutant. Emissions increase in some and decrease in other NERC regions, but the general trend is a decrease in air emissions at the U.S. and regional levels.[65] Furthermore, emission increases modeled in some regions are transient; for example, IPM state-level outputs shows emissions for some pollutants in Texas (part of the TRE NERC region) increasing in some years and decreasing in other years.

5.2.2.2 Impact on Steam Electric Power Plants as a Group

For the analysis of impact on steam electric power plants as a group, EPA used the same IPM v6 results for 2035 used above to analyze the impact on national and regional electricity markets; however, this analysis considers the effect of the final rule on the subset of plants to which the ELGs apply, *i.e.*, steam electric power plants. The purpose of the previously described electricity market-level analysis is to assess the impact of the final rule on the entire electric power sector, *i.e.*, including generators such as combustion turbines, wind or solar to which the ELGs do not apply. By contrast, the purpose of this analysis is to assess the impact of the final rule specifically on steam electric power plants. The analysis results for the group of steam electric power plants overall show a slightly greater impact on a percentage basis than that observed over *all* generating units in the IPM universe (*i.e.*, market-level analysis discussed in the preceding section [*Impact on National and Regional Electricity Markets*]); this is because, at the market level, impacts on steam electric units are offset by changes in capacity and energy production in the non-steam electric units.

65 The changes in emissions only accounts for changes in the profile of electricity generation, and do not include emissions associated with transportation or auxiliary power, which EPA analyzed separately (see TDD for details).

The metrics of interest are largely the same as those presented above in assessing the effect of the final rule on the aggregate of the 688 steam electric power plants explicitly represented in IPM (as opposed to additional steam electric power plants that were not surveyed by EPA in the Steam Electric Survey [see U.S. EPA, 2015]).[66] In addition, a few measures differ: (1) new market-wide capacity additions and prices are not relevant at the level of steam electric power plants, (2) changes in emissions at only the 688 steam electric power plants provide incomplete insight for the overall estimated effect of the rule on emissions and are therefore not presented, and (3) the number of steam electric power plants with projected closure (or avoided closure) is presented.

The following four measures are reported in the analysis of steam electric power plants as a group. In all instances, the measures are tabulated for 688 steam electric power plants explicitly included in EPA's Steam Electric Survey and analyzed in the Market Model Analysis (note that steam electric power plants not included in the tabulation incur no compliance costs for the options EPA analyzed in IPM or are retired and not represented in IPM):

- *Changes in available capacity*: These changes are defined in the same way as in the preceding section (Impact on National and Regional Electricity Markets), with the exception of the units used (MW).
- *Changes in generation*: Long-term changes in generation may result from either changes in available capacity (see discussion above) or in the dispatch of a plant due to changes in production cost resulting from compliance response.
- *Changes in costs*: These changes are defined in the same way as in the preceding section (Impact on National and Regional Electricity Markets).
- *Changes in variable production costs per MWh*: These changes are defined in the same way as in the preceding section (Impact on National and Regional Electricity Markets).

Table 5-5 reports results of the Market Impact Analysis for steam electric power plants, as a group.

The impacts of the final rule on steam electric power plants differ from the total market impacts as these plants become less competitive compared to plants that see no production cost increases under the final rule. As a result, capacity and generation impacts are greater for this set of plants than for the entire electricity market, relative to the baseline, but absolute differences are still small. As described above for the market-level analysis, those impacts vary across the NERC regions.

66 There are 688 steam electric power plants that were surveyed by EPA in the Steam Electric Survey and are represented in IPM. EPA estimates that there are 858 plants in the total steam electric power generating industry, calculated on a sample-weighted basis. For details on sample weights, see TDD.

Table 5-5: Impact of the Final Rule on In-Scope Plants, as a Group, in the Year 2035[a]

Economic Measures (all dollar values in 2023$)	Baseline Value	Option B		
		Value	Difference	% Change
National Totals				
Total Domestic Capacity (MW)	220,237	214,455	-5,782	-2.6%
Early Retirements – Number of Plants	78	83	5	6.4%
Full & Partial Retirements – Capacity (MW)	104,544	110,326	5,782	5.5%
Generation (GWh)	789,529	765,950	-23,579	-3.0%
Costs ($Millions)	$28,580	$27,740	-$840	-2.9%
Fuel Cost	$13,957	$13,454	-$503	-3.6%
Variable O&M	$1,976	$1,840	-$136	-6.9%
Fixed O&M	$15,419	$15,041	-$378	-2.5%
Capital Cost	$3,202	$3,000	-$202	-6.3%
CCS Cost[b]	-$5,974	-$5,595	$379	-6.3%
Average Variable Production Cost ($/MWh)	$20.18	$19.97	-$0.21	-1.1%
Midwest Reliability Organization (MRO)				
Total Domestic Capacity (MW)	27,018	27,018	0	0.0%
Early Retirements – Number of Plants	25	26	1	4.0%
Full & Partial Retirements – Capacity (MW)	21,954	21,954	0	0.0%
Generation (GWh)	69,410	68,117	-1,293	-1.9%
Costs ($Millions)	$2,400	$2,399	-$1	0.0%
Fuel Cost	$1,156	$1,129	-$27	-2.3%
Variable O&M	$192	$189	-$3	-1.7%
Fixed O&M	$1,671	$1,704	$33	2.0%
Capital Cost	$842	$837	-$4	-0.5%
CCS Cost[b]	-$1,462	-$1,461	$0	0.0%
Average Variable Production Cost ($/MWh)	$19.43	$19.36	-$0.07	-0.4%
Northeast Power Coordinating Council (NPCC)				
Total Domestic Capacity (MW)	7,626	7,626	0	0.0%
Early Retirements – Number of Plants	2	2	0	0.0%
Full & Partial Retirements – Capacity (MW)	2,709	2,709	0	0.0%
Generation (GWh)	18,184	18,131	-53	-0.3%
Costs ($Millions)	$857	$856	-$1	-0.1%
Fuel Cost	$242	$241	-$1	-0.4%
Variable O&M	$24	$24	$0	-0.5%
Fixed O&M	$591	$591	$0	0.0%
Capital Cost	$0	$0	$0	NA
CCS Cost[b]	$0	$0	$0	NA
Average Variable Production Cost ($/MWh)	$14.64	$14.62	-$0.02	-0.1%
ReliabilityFirst Corporation (RF)				
Total Domestic Capacity (MW)	48,588	44,410	-4,178	-8.6%
Early Retirements – Number of Plants	14	17	3	21.4%
Full & Partial Retirements – Capacity (MW)	24,251	28,429	4,178	17.2%
Generation (GWh)	143,716	130,430	-13,286	-9.2%
Costs ($Millions)	$5,996	$5,387	-$610	-10.2%
Fuel Cost	$2,289	$2,043	-$246	-10.8%
Variable O&M	$490	$400	-$90	-18.3%

Table 5-5: Impact of the Final Rule on In-Scope Plants, as a Group, in the Year 2035[a]

Economic Measures (all dollar values in 2023$)	Baseline Value	Option B		
		Value	Difference	% Change
Fixed O&M	$3,737	$3,467	-$271	-7.2%
Capital Cost	$578	$578	-$1	-0.1%
CCS Cost[b]	-$1,099	-$1,101	-$2	0.2%
Average Variable Production Cost ($/MWh)	$19.34	$18.73	-$0.61	-3.1%
Southeast Electric Reliability Council (SERC)				
Total Domestic Capacity (MW)	93,041	91,447	-1,594	-1.7%
Early Retirements – Number of Plants	21	22	1	4.8%
Full & Partial Retirements – Capacity (MW)	38,147	39,741	1,594	4.2%
Generation (GWh)	407,266	398,315	-8,950	-2.2%
Costs ($Millions)	$13,938	$13,706	-$232	-1.7%
Fuel Cost	$7,976	$7,746	-$231	-2.9%
Variable O&M	$939	$896	-$43	-4.6%
Fixed O&M	$6,257	$6,118	-$139	-2.2%
Capital Cost	$1,354	$1,158	-$196	-14.4%
CCS Cost[b]	-$2,589	-$2,212	$377	-14.6%
Average Variable Production Cost ($/MWh)	$21.89	$21.70	-$0.20	-0.9%
Texas Reliability Entity (TRE)				
Total Domestic Capacity (MW)	13,834	13,849	15	0.1%
Early Retirements – Number of Plants	5	5	0	0.0%
Full & Partial Retirements – Capacity (MW)	8,887	8,872	-15	-0.2%
Generation (GWh)	37,973	37,944	-29	-0.1%
Costs ($Millions)	$1,419	$1,420	$1	0.1%
Fuel Cost	$535	$534	-$1	-0.2%
Variable O&M	$70	$70	$0	-0.4%
Fixed O&M	$1,067	$1,068	$1	0.1%
Capital Cost	$282	$281	-$1	-0.4%
CCS Cost[b]	-$537	-$534	$3	-0.6%
Average Variable Production Cost ($/MWh)	$15.95	$15.92	-$0.02	-0.1%
Western Electricity Coordinating Council (WECC)				
Total Domestic Capacity (MW)	30,131	30,105	-26	-0.1%
Early Retirements – Number of Plants	11	11	0	0.0%
Full & Partial Retirements – Capacity (MW)	8,596	8,622	26	0.3%
Generation (GWh)	112,981	113,014	32	0.0%
Costs ($Millions)	$3,971	$3,972	$1	0.0%
Fuel Cost	$1,758	$1,761	$3	0.2%
Variable O&M	$260	$261	$0	0.1%
Fixed O&M	$2,095	$2,093	-$2	-0.1%
Capital Cost	$146	$146	$0	0.0%
CCS Cost[b]	-$288	-$288	$0	0.0%
Average Variable Production Cost ($/MWh)	$17.86	$17.89	$0.03	0.1%

a. Numbers may not add up due to rounding.

b. The "CCS Cost" is the cost of CO_2 transportation and storage and also includes expenses on equipment and pipelines, as well as the total value of 45Q tax credits and enhanced oil recovery (EOR) revenues. In the baseline and under Option B, the total private costs are negative because the sum of the tax credits and EOR revenues exceed the equipment and pipeline costs

Table 5-5: Impact of the Final Rule on In-Scope Plants, as a Group, in the Year 2035[a]				
Economic Measures (all dollar values in 2023$)	Baseline Value	Option B		
		Value	Difference	% Change
of CO2 storage. Under Option B, total CCS Costs are less negative, and therefore these costs increase relative to the baseline, as the total amount of the 45Q tax credit received by the sector and/or EOR revenues fall due to lower coal generation.				

Source: U.S. EPA Analysis, 2024.

5.2.2.2.1 Findings for the Final Rule (Regulatory Option B) in the 2035 Model Year

Under the final rule, the steam electric capacity is estimated to decrease approximately 2.6 percent.

For the group of steam electric power plants, total capacity decreases by 5,782 MW or approximately 2.6 percent of the 220,237 MW in baseline capacity. This decrease is largely attributable to net decreases in total capacity of 4,178 MW (8.6 percent) and 1,594 MW (1.7 percent) in the RF and SERC regions, respectively. One plant in SERC, one plant in MRO, and three plants in RF are projected to close under the final rule.

The change in total generation is an indicator of how steam electric power plants fare, relative to the rest of the electricity market. While at the market level there is essentially no projected change in total electricity generation,[67] for steam electric power plants, total generation is estimated to decrease by 23,579 GWh (3 percent). RF is projected to experience the largest decrease in generation from steam electric power plants, 13,286 GWh (9.2 percent), with SERC estimated to experience the second largest decrease in generation from steam electric power plants at 8,950 GWh (2.2 percent). Generation from steam electric power plants is estimated to change in the remaining regions by less than <0.1 to -1.9 percent.

The results for the group of steam electric power plants show a net decrease in total costs of $840 million (2.9 percent). Total costs vary be region with the largest decrease in costs coming from the RF region ($610 million; 10.2 percent) followed by the SERC region ($232; 1.7 percent) and the largest increase[68] in costs coming from the WECC and TRE regions ($1 million; <0.1 percent and $1 million; 0.1 percent, respectively). At the national level, variable production costs for steam electric power plants decrease by $0.21 per MWh (1.1 percent). Effects vary by region, with changes ranging from $0.03 per MWh in WECC and TRE to -$0.61 per MWh in RF.

5.2.2.3 Impact on Individual Steam Electric Power Plants

Results *for the group* of steam electric power plants as a whole may mask shifts in economic performance among *individual* steam electric power plants. To assess potential plant-level effects, EPA analyzed the

67 At the national level, the demand for electricity does not change between the baseline and the analyzed regulatory options (generation within the regions is allowed to vary) because meeting demand is an exogenous constraint imposed by the model.

68 While costs decrease under Option B, this does not mean that plant owners would be undertaking changes on their own in the absence of the rule in order to save costs. The values reported in this table are for in-scope plants only. The negative changes follow from the decline in capacity and generation. Individual plants would not necessarily face lower costs than the rest of the market in the absence of the final rule.

distribution of plant-specific changes between the baseline and the final rule for three metrics: capacity utilization,[69] electricity generation, and variable production costs per MWh.[70]

Table 5-6 presents the estimated number of steam electric power plants with specific degrees of change in operations and financial performance as a result of the final rule. In addition to the category of all plants, the table also reports these metrics for plants that incur costs under Option B and plants that incur no costs under Option B separately. Metrics of greatest interest for assessing the adverse impacts of the final rule on steam electric power plants include the number of plants with reductions in capacity utilization or generation (on the left side of the table), and the number of plants with increases in variable production costs (on the right side of the table).

This table excludes steam electric power plants with modeled significant status changes in 2035 that render these metrics of change not meaningful – *i.e.*, a plant is assessed as either a full, partial, or avoided closure in the IPM results for either the baseline or the regulatory option. The measures presented in Table 5-5, such as *change in electricity generation*, are not meaningful for these plants. For example, for a plant that is projected to close in the baseline but avoids closure under the final rule, the percent change in electricity generation relative to baseline cannot be calculated. On this basis, 382 plants are excluded from assessment of effects on individual steam electric power plants under the final rule. In addition, the change in variable production cost per MWh of generation could not be developed for 58 plants with zero generation in either the baseline or under the final rule (because the divisor, MWh, is zero).[71] For *change in variable production cost per MWh*, these plants are recorded in the "N/A" column.

69 Capacity utilization is defined as generation divided by capacity times 8,760 hours.

70 Variable production costs per MWh is defined as variable O&M cost plus fuel cost divided by net generation projected in IPM.

71 In some cases, non-retired plants will be modeled to have zero generation in 2035. These plants may generate electricity in later years.

Table 5-6: Impact of Final Rule on Individual In-Scope Plants in the Year 2035

Economic Measures	Reduction			No Change	Increase			N/A[b,c]	Total
	> 3%	≥1% and <3%	<1%		<1%	≥1% and <3%	≥3%		
Steam Electric Power Plants that Incur Costs under Option B									
Change in Capacity Utilization[a]	1	0	1	1	2	0	3	27	35
Change in Generation	3	1	0	1	1	0	2	27	35
Change in Variable Production Costs/MWh	0	0	4	0	4	0	0	27	35
Steam Electric Power Plants that Incur No Costs under Option B									
Change in Capacity Utilization[a]	10	6	45	196	34	3	4	355	653
Change in Generation	16	16	29	196	22	7	12	355	653
Change in Variable Production Costs/MWh	1	11	25	35	164	4	0	413	653
All Steam Electric Power Plants									
Change in Capacity Utilization[a]	11	6	46	197	36	3	7	382	688
Change in Generation	19	17	29	197	23	7	14	382	688
Change in Variable Production Costs/MWh	1	11	29	35	168	4	0	440	688

a. The change in capacity utilization is the difference between the capacity utilization percentages in the baseline and policy cases. For all other measures, the change is expressed as the percentage change between the baseline and policy values.

b. Plants with operating status changes in either baseline or policy scenario have been excluded from general table calculations. Thus, for Option B, "N/A" reports 322 full and 52 partial baseline closures; 5 full closures as a result of the regulatory option; 3 avoided partial closures.

c. The change in variable production cost per MWh could not be developed for 58 plants with zero generation in either the baseline case or Option B policy case.

Source: U.S. EPA Analysis, 2024.

5.2.2.3.1 Findings for the Final Rule (Option B) in Model Year 2035

For the final rule, the analysis of changes in individual plants indicates that most plants experience only slight effects – *i.e.*, no change or less than a one percent reduction or one percent increase. Across the full set of steam electric plants modeled, 36 plants (5 percent) incur a reduction in generation of at least one percent; 17 of these plants (2.5 percent) are also estimated to incur a reduction in capacity utilization of at least one percent. Finally, only 12 plants (2 percent) are estimated incur an increase in variable production costs of at least one percent. For the set of 35 plants that incur costs under Option B, 4 plants incur a decrease in generation and 1 plant is estimated to have no change in generation. Of the plants that incur costs under Option B, three are estimated to increase electricity generation.

5.3 Estimated Effects of the Regulatory Options on New Capacity

IPM results show no new coal-fired capacity projected during the analysis period in the baseline. This continues to be the case for the final rule.

5.4 Uncertainties and Limitations

Despite EPA's use of the best available information and data, EPA's analyses of the electric power market and the overall economic impacts of the final rule involve several sources of uncertainty:

- *Length of capital recovery period.* Some of the EGUs estimated to incur ELG costs during the period of analysis have planned retirement dates in IPM that are less than 15 years after the year in which they are estimated to install wastewater treatment technologies to meet the revised limits. The early retirement of these EGUs in IPM relative to the length of the capital recovery period and the associated truncation of the annual charges results in ELG costs represented in the model that are lower than the total estimated capital costs for meeting ELG limits for these units.[72] Overall, IPM recognizes 87 percent of the estimated capital costs of the final rule. See ICF (2024) for details.

- *Steam electric power plant response to changes in production costs*: IPM includes information about announced retirements only to the extent that there is a high degree of certainty about the future implementation of the announced action (U.S. EPA, 2023a). To the extent that some utilities' business strategy and integrated resource plans call for the retirement of coal generation assets and transition toward other sources of energy such as renewables or natural gas that is separate from the factors modeled in IPM, then IPM may overstate retirements resulting from incremental costs under the final rule.

- *Demand for electricity*: IPM assumes that electricity demand at the national level will not change between the baseline and the final rule (generation within the regions is allowed to vary); this constraint is exogenous to the model. IPM v6 embeds a baseline energy demand forecast that is derived from the Department of Energy's *Annual Energy Outlook 2023* (EIA, 2023b). IPM does not capture changes in demand that may result from electricity price changes associated with the

72 EGUs with a planned retirement date are removed from the inventory of modeled units on that date irrespective of the modeled market conditions. The removal of such units pre-empts IPM from making any further decisions regarding the operational status or configuration of the units. It also stops any operating costs associated with the units.

final rule (*i.e.*, demand is inelastic with respect to price[73]). While this constraint may underestimate total demand in analyses of policy options that have lower compliance costs relative to the baseline, EPA assumes that relaxing the constraint would not affect the results analyzed. As described in Section 5.2.1 and Section 5.2.2, the price changes associated with the final rule in all NERC regions are very small (less than 0.11 $/MWh). EPA therefore concludes that the assumption of inelastic demand-responses over these changes in prices is reasonable.

- *Fuel prices*: Prices of fuels (*e.g.*, natural gas and coal) are determined endogenously within IPM. IPM modeling of fuel prices uses both short- and long-term price signals to balance supply of, and demand in, competitive markets for the fuel across the modeled time horizon. The model relies on AEO2023's electric demand forecast for the US and employs a set of EPA assumptions regarding fuel supplies and the performance and cost of electric generation technologies as well as pollution controls. Differences in actual fuel prices relative to those modeled by IPM, such as lower natural gas prices that may result from increased domestic production or short-term increases in natural gas prices resulting from Russia's invasion of Ukraine, would be estimated to affect the cost of electricity generation and therefore the amount of electricity generated by steam electric power plants, irrespective of the final rule. More generally, differences in fuel prices, and related changes in electricity production costs, can affect the modeled dispatch profiles, planning for new/repowered capacity, and contribute to differences in a number of policy-relevant parameters such as electricity production costs, prices, and emission changes.

- *Electricity imports*: IPM assumes that electricity imports from Canada and Mexico do not change between the baseline and the final rule. Holding international imports fixed potentially understates the impacts of changes in production costs and electricity prices in U.S. domestic markets. EPA does not expect that this assumption materially affects results, however, since IPM projects that only one of the eight NERC regions will import electricity (WECC) in 2035, and the level of imports compared to domestic generation in this region is very small (about 0.3 percent).

73 Electricity demand has been found to be inelastic with respect to price in the short-term. See, for example, Burke, P. J., & Abayasekara, A. (2018). The price elasticity of electricity demand in the United States: A three-dimensional analysis. *The Energy Journal*, *39*(2). and Bernstein, M. A., & Griffin, J. (2005). *Regional Differences in the Price-Elasticity of Demand For Energy*. RAND Corporation. https://www.rand.org/pubs/technical_reports/TR292.html .

6 Assessment of Impacts on Employment

6.1 Background and Context

In addition to addressing the costs and impacts of the regulatory options, EPA estimated the potential impacts of this rulemaking on employment, measured in terms of changes in full-time equivalent (FTE) labor inputs.[74] Evaluation of employment impacts is required by many environmental statutes, including the Clean Water Act (CWA section 507I, 33 U.S.C. § 1367I). This section first provides an overview of the analysis methodology. It then quantitatively presents the Agency's estimates of the potential impacts of the final rule on labor inputs at power plants and other relevant economic sectors.

6.2 Analysis Overview

This section describes the Agency's approach to quantitatively estimate the labor impacts (FTEs) of the final rule.[75] The agency is using an approach outlined in U.S. EPA (2018) to develop a bottom-up analysis that evaluates first order impacts, *i.e.*, the direct changes in the amount of labor needed in the power generation sector and in directly related sectors such as equipment manufacturing and fuel production. This analysis does not account for other indirect and induced effects of the rule on the broader economy due to, for example, changes in forecasted electricity prices. (As discussed in Chapter 7, the potential electricity price effects of the final rule are estimated to be small.)

6.2.1 Quantification of Projected Actions

EPA quantified two categories of actions resulting from the final rule that may affect labor inputs:

- The changes in the profile of electricity generation and in fuel consumption, based on electricity market modeling using IPM, as described in Chapter 5; and
- The ELG compliance technology expenditures (including total capital, initial one-time, and O&M costs) by steam electric power generating plants, as described in Chapter 3.

EPA conducted this analysis for regulatory Option B and the year 2030 to be consistent with the period when plants would comply with the final rule (2025-2029).

Table 6-1 presents the estimated changes in new generation capacity and retirements in 2030 due to Option B relative to the baseline. The Agency calculated the net change in generation capacity by subtracting the projected retirements, in terms of GW of generation capacity, from projected new generation capacity for each generation type. The net change in generation capacity is used in this analysis for determining the required resources of new generation capacity by generation type.

74 One FTE equals 2,080 labor hours per year.

75 Because the employment analysis is based, in part, on electricity market modeling using IPM, this analysis does not include the employment impacts associated with legacy wastewater limits or the treatment of unmanaged CRL.

Table 6-1: Estimated Change in Generating Capacity Under Option B Relative to Baseline in 2030

Generation Type[a]	New Generation (GW)[b]			Retirements (GW)[b]			Net Capacity Change (GW)[c]
	Baseline	Option B	Change	Baseline	Option B	Change	
Solar	11.06	12.05	1.00	0	0	0	1.00
Wind	77.77	78.85	1.08	0	0	0	1.08
Energy Storage	15.19	15.25	0.05	0	0	0	0.05
Combined Cycle (without CCS)	20.35	23.73	3.39	0.80	0.75	-0.04779	3.43
Combustion Turbine	13.91	14.39	0.48	0.95	0.95	0	0.48
Coal steam	0	0	0	56.44	62.05	5.62	-5.62
Oil & Natural Gas Steam	0	0	0	12.39	12.55	0.16	-0.16
Nuclear	0	0	0	2.69	2.69	0.00	0.00
Total	**138.28**	**144.28**	**6.00**	**73.26**	**78.99**	**5.73**	**0.27**

a. Only generation types with non-zero changes in new generation or retirements under Option B relative to the baseline are presented.

b. New generation capacity reported for analysis year 2030 is online in 2030, and retirements reported for analysis year 2030 are offline by 2030.

c. Net capacity change is calculated as new generation less retirements (in GW) under Option B relative to the baseline.

Source: U.S. EPA Analysis, 2024.

EPA also used IPM projections to estimate the quantity of new generation capacity being built in 2030. As described in Chapter 5, IPM outputs are reported for several analysis years, including 2030 and 2035. EPA assumed that the incremental change in new generation capacity between 2030 and 2035 is representative of capacity possibly under construction in 2030. Based on the build duration (years) for each type of generating capacity, EPA estimated the fraction of the incremental change in new capacity that would be under construction in each year. For example, construction for capacity with a build duration of 3 years that is not online by 2030 but is online by 2035 could begin in 2028, 2029, 2030, 2031, or 2032. Of these construction start years, only 2028, 2029, and 2030 would be under construction in 2030. For this example, EPA therefore assumes that 3/5 of the incremental change in new generation capacity would be under construction in 2030. Table 6-2 presents the Agency's estimates of the incremental change in new generation capacity under construction in 2030 for each generation type.

Table 6-2: Incremental Change in New Generation Capacity Under Construction in 2030

Generation Type	Incremental Change in New Generation Capacity (GW)
Solar	<0.01
Wind	0.08
Energy Storage	1.43
Combined Cycle (without CCS)	<0.01
Combustion Turbine	0.15
Total	1.66

Source: U.S. EPA Analysis, 2024.

Table 6-3 presents the estimated changes in consumption of natural gas and coal in 2030 under Option B relative the baseline. EPA calculated the net change in fuel consumption for Option B by subtracting the estimated fuel use under the baseline from the fuel use estimated under Option B in 2030. EPA used these estimates of net fuel consumption to determine the changes in labor inputs in associated sectors due to fuel use changes under the final rule relative to the baseline.

Table 6-3: Estimated Change in Fuel Consumption Under Option B Relative to Baseline in 2030

Fuel Type	Region				
	Appalachia	**Interior**	**Waste**	**West**	**All regions**
Baseline					
Coal (Million Short Tons)	34.54	34.17	7.15	142.53	218.39
Natural Gas (Trillion Cubic Feet)	N/A	N/A	N/A	N/A	11.70
Option B					
Coal (Million Short Tons)	38.75	35.07	7.15	141.49	222.46
Natural Gas (Trillion Cubic Feet)	N/A	N/A	N/A	N/A	11.70
Change in Fuel Consumption (Option B less Baseline)					
Coal (Million Short Tons)	-4.21	-0.91	0.00	1.04	-4.07
Natural Gas (Trillion Cubic Feet)	N/A	N/A	N/A	N/A	0.00

Source: U.S. EPA Analysis, 2024.

Table 6-4 presents the estimated capital and operating costs associated with installation and operation of the wastewater treatment technology used as basis for the final rule ELGs. EPA used these total cost estimates to determine the associated effects on labor inputs.

Table 6-4: Option B Technology Capital and Operation Costs (millions, 2023$)

Cost Type	Wastestream			
	BA	**FGD**	**CRL**	**Total**
Capital Costs	$165	$1,309	$1,700	$3,173
Pre-Tax Annualized O&M Costs	$8	$91	$113	$212

Source: U.S. EPA Analysis, 2024.

6.2.2 Resource Requirements of Changes in Projected Actions and Treatment Technology

EPA estimated the resource requirements associated with the changes in projected actions and new wastewater treatment technologies used as basis for the final rule in dollars. This section of the analysis is separated in four parts, described below:

1) Construction of new generation capacity;
2) Operation of new generation capacity and retirements;
3) Installation of new treatment technology; and
4) Operation of new wastewater treatment technology.

6.2.2.1 Construction of New Generation Capacity

EPA first estimated the costs associated with construction of new generation capacity for several different cost components *(e.g.*, equipment, materials, construction labor, and engineering services). EPA calculated the annual construction cost ($/year) as the product of the unit capital cost ($/kW) from U.S. EPA (2023b) and the estimated new capacity construction in 2030 (kW/year), as described in Section 6.2.1. EPA then calculated construction costs for specific cost components by multiplying the total capital costs associated with construction of new generation capacity by the estimated percentage of costs that correspond with each cost component based on information from U.S. EPA (2018). EPA further mapped each cost component to the most relevant NAICS sector. Table 6-5 displays the estimated percentage of costs for new generation capacity (for each relevant generation type) that corresponds with each cost component and associated NAICS sector.

Table 6-5: Capital and Labor Components for Construction of New Generation Capacity by Generation Type

Cost Component	NAICS Sector	NAICS Sector Description	Average % of Total Operation Costs		
			Renewables & Biomass	Combined Cycle	Combustion Turbine
Equipment	333	Machinery Manufacturing	54%	65%	65%
Material	33111	Iron and Steel Mills and Ferroalloy Manufacturing	6%	10%	10%
Labor	236210	Industrial Building Construction	31%	18%	18%
Engineering and Construction Management	541330	Engineering Services	9%	7%	7%

Source: U.S. EPA Analysis, 2024; U.S. EPA, 2018.

6.2.2.2 Operation of New Generation Capacity and Retirements

As described in Section 6.2.1, EPA used IPM projections to estimate the incremental quantity of generation capacity in operation in 2030 due to the final rule (see Table 6-1). EPA estimated the annual resource costs for operating new generation capacity, or reduction in resource costs from projected retirements, based on annual fixed operating and maintenance (FOM) costs, as reported in U.S. EPA (2023b). The Agency estimated annual FOM cost ($/year) by multiplying the FOM cost ($/kW-year) by the projected changed in capacity (kW). EPA then matched each generation type in the analysis to its corresponding NAICS electricity generation sector, as shown in Table 6-6.

Table 6-6: NAICS Sectors Associated with Operation of New Generation Capacity

NAICS Sector	NAICS Sector Description	Generation Type
221112	Fossil fuel electric power generation	Combined cycle
		Combustion turbine
		Coal steam
		Oil & natural gas steam
221113	Nuclear electric power generation	Nuclear
221114	Solar electric power generation	Wind
221115	Wind electric power generation	Solar

Source: U.S. EPA Analysis, 2024.

6.2.2.3 Installation of New Wastewater Treatment Technologies

The compliance years for installation of the wastewater treatment technologies used as basis for the final rule are between 2025-2029. As such, EPA does not expect plants to incur compliance costs from installation of new treatment technology in the analysis year of 2030. Thus, EPA estimated that there will be no employment impacts due to installation of new treatment technology in 2030. See Section 6.4 for additional discussion of the effects on labor inputs associated with the installation of new treatment technology prior to 2030.

6.2.2.4 Operation of New Wastewater Treatment Technologies

Plants will incur resource costs for operating and maintaining the wastewater treatment systems to meet the ELGs in the final rule, including operating labor, maintenance labor and materials, energy costs, and chemical purchases. EPA estimated the percentage of total annualized O&M costs that would be required for each of these cost components (Eastern Research Group, 2022). EPA applied these percentages to the total, pre-tax annualized O&M cost for each treatment technology to estimate the costs associated with each cost component. EPA associated each identified cost component with the most relevant NAICS sector. Table 6-7 presents the average percentage of total O&M costs and the relevant NAICS sector associated with each cost component.

Table 6-7: Operation and Labor Components for New Wastewater Treatment Technologies

Cost Component	NAICS Sector	NAICS Sector Description	Average % of Total O&M Costs (All Treatment Technologies)
Chemicals	3251	Basic Chemical Manufacturing	20%
Energy	22111	Electric power generation	5%
Monitoring	22111	Electric power generation	10%
Maintenance Materials	33111	Iron and Steel Mills and Ferroalloy Manufacturing	10%
Operating Labor	221112	Fossil fuel electric power generation	25%
Transportation Operation	484230	Specialized Freight (except Used Goods) Trucking, Long-Distance	5%
Disposal Operation	562211	Hazardous Waste Treatment and Disposal	15%
Maintenance Labor	811310	Commercial and Industrial Machinery and Equipment (except Automotive and Electronic) Repair and Maintenance	10%

Source: U.S. EPA Analysis, 2024; Eastern Research Group, 2022.

6.2.3 Estimation and Aggregation of Labor Impacts

To estimate the total labor impacts of the final rule, EPA converted the estimated resource costs from Section 6.2.2 into FTE estimates using the estimated labor productivity for each economic sector, based on U.S. Census Bureau Economic Census data (U.S. Census Bureau, 2021a; U.S. Census Bureau, 2012). Table 6-8 presents labor productivity estimates based on 2017 Economic Census data for the relevant sectors identified in Section 6.2.2.

Table 6-8: Base Labor Productivity by Relevant Sector

NAICS Sector	NAICS Sector Description	Value of shipments (2023$ Millions) [A] (2017)	Total employees [B] (2017)	Labor productivity [B/A] (2017)	Growth rate (2012-2017)
333	Machinery manufacturing	$410,800	1,029,068	2.51	3.0%
3251	Basic Chemical Manufacturing	$245,653	148,181	0.60	6.4%
22111	Electric power generation	$134,418	138,647	1.03	0.5%
33111	Iron and Steel Mills and Ferroalloy Manufacturing	$98,681	84,792	0.86	2.7%
221111	Hydroelectric power generation	$3,758	3,642	0.97	-3.6%
221112	Fossil fuel electric power generation	$85,041	76,058	0.89	1.5%
221113	Nuclear electric power generation	$32,699	48,521	1.48	0.3%
221114	Solar electric power generation	$2,030	2,163	1.07	-19.0%
221115	Wind electric power generation	$8,748	4,986	0.57	-8.1%
221116	Geothermal electric power generation	$1,097	1,214	1.11	1.3%
221117	Biomass electric power generation	$1,021	1,968	1.93	3.5%
221118	Other electric power generation	$24	95	4.04	-1.0%
236210	Industrial Building Construction	$28,689	71,562	2.49	0.6%
237130	Power and Communication Line and Related Structures Construction	$72,844	232,861	3.20	-5.3%
238910	Site Preparation Contractors	$109,842	385,177	3.51	-3.4%
335911	Storage battery manufacturing	$8,489	25,126	2.96	2.9%
484121	General Freight Trucking, Long-Distance, Truckload	$126,726	519,358	4.10	-0.5%
484230	Specialized Freight (except Used Goods) Trucking, Long-Distance	$46,023	174,571	3.79	-0.2%
541330	Engineering Services	$267,451	1,081,471	4.04	0.7%
562211	Hazardous Waste Treatment and Disposal	$9,819	34,035	3.47	0.3%
562212	Solid Waste Landfill	$8,492	20,525	2.42	-1.4%
811310	Commercial and Industrial Machinery and Equipment (except Automotive and Electronic) Repair and Maintenance	$44,245	202,493	4.58	-2.2%

Source: U.S. Census Bureau, 2012; U.S. Census Bureau, 2021a; U.S. EPA Analysis, 2024.

EPA calculated the compound annual growth rate of labor productivity in each sector using U.S. Census data from a five-year period (2012 to 2017). EPA estimated the labor productivity in 2030 using this calculated growth rate. Due to uncertainty surrounding future labor productivity rates, EPA presents the results of the employment analysis as a range: using the 2017 labor productivity rate, assuming labor productivity remains constant between 2017 and 2030, and using a projected 2030 labor productivity rate assuming labor productivity grows between 2017 and 2030 at the same compound annual growth rate observed from 2012 to 2017. EPA multiplied the estimated costs by NAICS sector (Section 6.2.2) by the estimated labor productivity to estimate employment effects.

To estimate FTE changes associated with fuel consumption (*e.g.*, coal, natural gas), EPA used 2022 regional coal mining productivity estimates from EIA (EIA, 2023i) and 2021 natural gas production and employment estimates from EIA (EIA, 2023f; EIA, 2023e) and U.S. Census Bureau's County Business Patterns (U.S. Census Bureau, 2023), respectively (Table 6-9). EPA divided the projected changes in coal and natural gas use (by region for coal consumption) by the labor productivity estimates for coal and natural gas to obtain the total labor hours required for fuel production. EPA converted labor hours to employees assuming one FTE equals 2,080 labor hours per year. Total employment in the coal mining industry in 2022 was 43,582 (EIA, 2023i). Total employment for the natural gas extraction industry was 28,547, respectively (NAICS code 21113; U.S. Census Bureau, 2023).

Table 6-9: Coal and Natural Gas Labor Productivity Estimates

Resource	Labor productivity	Unit	Data vintage
Coal – Appalachian region	2.7	Short tons per labor hour	2022
Coal – Interior region	5.87	Short tons per labor hour	2022
Coal – Western region	16.04	Short tons per labor hour	2022
Coal – Waste	6.11	Short tons per labor hour	2022
Natural gas	728	Million Btu per labor hour	2021

Source: EIA, 2023e; EIA, 2023f; EIA, 2023i; U.S. Census Bureau, 2023; U.S. EPA Analysis 2024.

6.3 Estimated Impacts of the Final Rule in 2030

6.3.1 New Generation Capacity

Table 6-10 and Table 6-11 present the results of EPA's analysis of the impacts on labor inputs of changes in generation capacity, by generation type and NAICS sector. In each sector identified and for both labor productivity rates, EPA estimated increased FTEs associated with construction of new generation capacity. Using the 2017 and adjusted 2030 labor productivity rates, the storage battery manufacturing sector (NAICS code 335911) is expected to see the second greatest rise in FTE. In total, the Agency estimated an increase of 3,786 to 5,450 FTEs using the 2017 and adjusted 2030 labor productivity rates, respectively.

Table 6-10: Changes in Labor Inputs from Construction of New Generation Capacity in 2030 FTE)

Labor Productivity Rates	NAICS Sector	NAICS Sector Description	Generation Type: Combined Cycle	Wind	Solar	Combustion Turbine	Energy Storage	All Types
2017	333	Machinery Manufacturing	<0.01	37	<0.01	87	0	123
	33111	Iron and Steel Mills and Ferroalloy Manufacturing	<0.01	1	<0.01	5	0	6
	236210	Industrial Building Construction	<0.01	21	<0.01	24	0	45

Table 6-10: Changes in Labor Inputs from Construction of New Generation Capacity in 2030 FTE)								
Labor Productivity Rates	NAICS Sector	NAICS Sector Description	Generation Type					
			Combined Cycle	Wind	Solar	Combustion Turbine	Energy Storage	All Types
	335911	Storage Battery Manufacturing	0	0	0	0	3,587	3,587
	541330	Engineering Services	<0.01	10	<0.01	15	0	25
	Total	-	<0.01	69	<0.01	130	3,587	3,786
Adjusted 2030	333	Machinery Manufacturing	<0.01	54	<0.01	127	0	181
	33111	Iron and Steel Mills and Ferroalloy Manufacturing	<0.01	2	<0.01	6	0	8
	236210	Industrial Building Construction	<0.01	23	<0.01	26	0	49
	335911	Storage Battery Manufacturing	0	0	0	0	5,185	5,185
	541330	Engineering Services	<0.01	11	<0.01	17	0	27
	Total	-	<0.01	89	<0.01	176	5,185	5,450

a. Only generation types with non-zero changes in new generation capacity are reported.

Source: U.S. EPA Analysis, 2024.

EPA estimated that overall labor inputs for operation of new generation capacity would decrease by 148 to 247 FTEs using the 2017 and adjusted 2030 labor productivity rates, respectively (Table 6-11). Under both sets of labor productivity rates, labor inputs are expected to increase for certain generation types and decrease for others. FTEs are expected to increase in sectors involved in combined cycle, combustion turbine, wind, and solar. The increases for these generation types are a result of additional generation capacity due to the final rule relative to the baseline. For combined turbine, a minority of increases in FTEs are due to avoided retirements. Using the 2017 labor productivity rate, labor inputs are expected to increase the most for wind and solar generation with 44 and 19 FTEs, respectively. Using the adjusted 2030 labor productivity rate, labor inputs are expected to increase the most for combined cycle and combustion turbine with 14 and 12 FTEs, respectively. By contrast, the analysis shows estimated decreases in FTEs associated with coal steam and oil and natural gas steam generation with the greatest decrease occurring from reduced capacity of coal steam generation. Decreases for coal steam and oil and natural gas steam generation are the result of capacity retirements due to the final rule. The total changes in labor inputs for all generation types are small relative to overall employment in the electric power generation sector (138,647 employees in 2017; see Table 6-8).

Table 6-11: Changes in Labor Inputs from Operation of New Generation Capacity and Retirements in 2030 (# FTEs)

Labor Productivity Rates	Generation Type [a, b]							
	Combined Cycle	Wind	Solar	Combustion Turbine	Coal Steam	Oil & Natural Gas Steam	Nuclear	All Types
2017	12	44	19	10	-228	-4	0	-148
Adjusted 2030	14	3	6	12	-277	-5	0	-247

a. Results are presented as the net employment generated from new generation capacity minus retirements.

b. Only generation types with non-zero changes in employment are reported. Estimated employment impacts from hydro, biomass, geothermal, landfill gas, and energy storage (pumped storage) were zero.

Source: U.S. EPA Analysis, 2024.

6.3.2 New Treatment Technology

Table 6-12 presents the impacts of new wastewater treatment technologies used as basis for the ELGs in the final rule. Estimates of impacts on labor inputs are presented by wastestream and NAICS sectors involved in operation of new treatment technology (see Section 6.4 for construction impacts).

EPA estimated that labor inputs would increase by 371 to 402 FTEs using the 2017 and 2030 adjusted labor productivity rates, respectively due to operation of new treatment technologies, with all NAICS sectors seeing an increase. Operation of CRL treatment technology is estimated to have the greatest increase on labor inputs using either the 2017 and 2030 labor productivity rates (197 and 214 FTEs, respectively) followed by FGD (160 and 173 FTEs, respectively) and BA (14 and 15 FTEs, respectively). Additionally, the sector with the highest associated labor increases under both labor productivity rates is the hazardous waste treatment and disposal sector (NAICS code 562211) with 110 and 114 FTEs, respectively. Using 2017 labor productivity rates, the sector with the second highest increase is the repair and maintenance for commercial and industrial machinery and equipment (except automotive and electronic) sector (NAICS code 811310) with 97 FTEs. Using adjusted 2030 labor productivity rates, the sector with the second highest increase is the electric power generation sector (NAICS code 22111) with 93 FTEs.

Table 6-12: Changes in Labor Inputs from Operation of New Technology in 2030 (# FTEs)

Labor Productivity Rates	NAICS Sector	NAICS Sector Description	Wastestream			
			FGD	BA	CRL	Total
2017	3251	Basic Chemical Manufacturing	11	1	14	26
	22111	Electric Power Generation	35	3	43	80
	33111	Iron and Steel Mills and Ferroalloy Manufacturing	8	1	10	18
	484230	Specialized Freight (except Used Goods) Trucking, Long-Distance	17	2	21	40
	562211	Hazardous Waste Treatment and Disposal	47	4	59	110
	811310	Commercial and Industrial Machinery and Equipment (except Automotive and Electronic) Repair and Maintenance	42	4	52	97
	Total	**-**	**160**	**14**	**197**	**371**

Table 6-12: Changes in Labor Inputs from Operation of New Technology in 2030 (# FTEs)						
Labor Productivity Rates	NAICS Sector	NAICS Sector Description	Wastestream			
			FGD	BA	CRL	Total
Adjusted 2030	3251	Basic Chemical Manufacturing	25	2	30	57
	22111	Electric Power Generation	40	4	49	93
	33111	Iron and Steel Mills and Ferroalloy Manufacturing	11	1	14	26
	484230	Specialized Freight (except Used Goods) Trucking, Long-Distance	17	1	21	39
	562211	Hazardous Waste Treatment and Disposal	49	4	61	114
	811310	Commercial and Industrial Machinery and Equipment (except Automotive and Electronic) Repair and Maintenance	31	3	39	73
	Total	-	**173**	**15**	**214**	**402**

Source: U.S. EPA Analysis, 2024.

6.3.3 Fuel Consumption Changes

Table 6-13 presents the impacts on labor inputs associated with changes in fuel consumption for electricity generation, by region and fuel type. Overall, EPA estimated a net reduction of 793 FTEs. The Appalachia region is estimated to experience the greatest reduction in labor input associated with coal production, followed by the Interior region. EPA estimated a negligible change in labor input associated with coal production in the West region and a negligible change in national labor input associated with natural gas extraction.

Table 6-13: Labor Demand from Fuel Use Changes (# Employees)							
Fuel Type	NAICS Sector	NAICS Sector Description	Coal Region			Waste Coal	Total
			Appalachia	Interior	West		
Coal	2121	Coal Mining	-750	-74	0	31	-793
Natural gas	21113	Natural Gas Extraction	0	0	0	0	<0.01

Source: U.S. EPA Analysis, 2024.

6.3.4 Total Impacts of the Final Rule by Industry

Table 6-14 presents the total estimated impacts by NAICS sector. The number of FTEs is expected to increase or remain the same in every relevant sector identified in the analysis except for the coal mining and electric power generation sectors (NAICS codes 2121 and 22111, respectively). The Agency estimated that the coal mining sector will experience a decrease in FTEs due to a decline in fuel consumption for electricity generation. The Agency also estimated that the decrease in FTEs in the electric power generation sector is driven by retirements of coal steam generation. Overall, EPA estimated the final rule to increase labor inputs by 3,218 to 4,813 FTEs using the 2017 and adjusted 2030 labor productivity rates, respectively. The sector with the greatest estimated increase in labor inputs under both labor productivity rates is the storage batter manufacturing sector (NAICS code 335910). Using both labor productivity rates, the sector with the second greatest increase in labor inputs is the machinery manufacturing sector (NAICS code 333) followed by the hazardous waste treatment and disposal sector (NAICS code 562211).

The analysis estimates changes in labor inputs at power generating plants, coal mining, natural gas extraction, and in the sectors involved most directly in generation capacity additions or wastewater treatment technologies. Even though this final rule may affect many sectors, the overall impacts on labor, both positive and negative, are quite small. Furthermore, this impact assessment does not reach a quantitative estimate of the overall effects of the final rule on employment or even whether the net effect will be positive or negative. However, given that the modeled increase in electricity production costs is small (0.5 percent, based on IPM projections of Option B for 2030), the magnitude of all effects combined can also be expected to be small.

Table 6-14: Total Effects on Labor Inputs by NAICS Sector in 2030 (# FTEs)

NAICS Sector[a]	NAICS Sector Description	Labor Productivity Rates	
		2017	Adjusted 2030
333	Machinery Manufacturing	123	181
2121	Coal Mining[a]	-793	-793
3251	Basic Chemical Manufacturing	26	57
21113	Natural Gas Extraction[a]	0	0
22111	Electric Power Generation	-66	-154
33111	Iron and Steel Mills and Ferroalloy Manufacturing	24	34
236210	Industrial Building Construction	45	49
237130	Power and Communication Line and Related Structures Construction	0	0
238910	Site Preparation Contractors	0	0
335911	Storage Battery Manufacturing	3,587	5,185
484121	General Freight Trucking, Long-Distance, Truckload	0	0
484230	Specialized Freight (except Used Goods) Trucking, Long-Distance	40	39
541330	Engineering Services	25	27
562211	Hazardous Waste Treatment and Disposal	110	114
562212	Solid Waste Landfill	0	0
811310	Commercial and Industrial Machinery and Equipment (except Automotive and Electronic) Repair and Maintenance	97	73
Total	**-**	**3,218**	**4,813**

a. EPA identified NAICS Sector 2121 (coal mining) and 21113 (natural gas extraction) as the relevant sectors that would incur impacts from changes in fuel consumption for electricity generation.

Source: U.S. EPA Analysis, 2024.

6.4 Estimated Impacts from Installation of Wastewater Treatment Technologies

Installation of wastewater treatment technologies used as basis for ELGs in the final rule is projected to occur before the analysis year of 2030. In this section, EPA reports the estimated impacts on labor inputs associated with the installation of each treatment technology during the compliance years of 2025 to 2029.

EPA calculated the resource requirements, in dollars, for different cost components of installation of new treatment technology (*e.g.*, materials, construction labor, engineering services). Table 6-15 presents the average percentage of total capital costs associated with each cost component, applicable to all wastestreams (Eastern Research Group, 2022).

Table 6-15: Capital and Labor Components for New Treatment Technology

Cost Component	NAICS Sector	NAICS Sector Description	Average % of Total Capital Costs
Installation Materials[a]	332	Fabricated Metal Product Manufacturing	43%
Equipment	333	Machinery manufacturing	25%
Indirect Capital Labor (Construction/Installation)	23829	Other Building Equipment Contractors	10%
Indirect Capital Labor (Site Preparation)	238910	Site Preparation Contractors	10%
Indirect capital labor (Engineering Services)	541330	Engineering Services	10%
Disposal Capital Cost	562212	Solid Waste Landfill	2%

a. Installation materials refers to the labor required for the manufacturing of materials required for installation of new treatment technology.

Source: Eastern Research Group, 2022; U.S. EPA Analysis, 2024.

Table 6-16 presents the estimated impacts associated with installation of wastewater treatment technologies in the final rule. These impacts include the employment impacts related to the initial one-time cost incurred by plants to comply with recordkeeping and monitoring under the final rule. Overall, EPA estimated that labor inputs would increase due to installation of new treatment technologies by 10,484 FTEs using the 2017 labor productivity rates and by 11,366 FTEs using the adjusted 2030 labor productivity rates. Under both labor productivity rates, the number of FTEs is estimated to increase the most, by 4,828 to 5,506 FTEs, in the fabricated metal product manufacturing sector (NAICS code 332). The sector with the second greatest increase in labor input is machinery manufacturing (NAICS code 333), followed by the engineering services sector (NAICS code 541330).

Table 6-16: Total FTE Changes from Installation of New Technology

Labor Productivity	NAICS Sector	NAICS Sector Description	Wastestream			
			FGD	BA	CRL	Total
2017	332	Fabricated Metal Product Manufacturing	1,991	250	2,586	4,828
	333	Machinery manufacturing	819	103	1,064	1,987
	23829	Other Building Equipment Contractors	461	58	599	1,118
	221112[a]	Fossil Fuel Electric Power Generation	1	0	2	3
	238910	Site Preparation Contractors	459	58	596	1,113
	484121	General Freight Trucking, Long-Distance, Truckload	0	0	0	0
	541330	Engineering Services	529	67	687	1,283
	562212	Solid Waste Landfill	63	8	82	153
	Total	-	**4,324**	**543**	**5,617**	**10,484**
Adjusted 2030	332	Fabricated Metal Product Manufacturing	2,271	285	2,949	5,506
	333	Machinery manufacturing	1,203	151	1,562	2,917
	23829	Other Building Equipment Contractors	285	36	370	691

Table 6-16: Total FTE Changes from Installation of New Technology

Labor Productivity	NAICS Sector	NAICS Sector Description	Wastestream			
			FGD	BA	CRL	Total
	221112[a]	Fossil Fuel Electric Power Generation	1	0	2	4
	238910	Site Preparation Contractors	293	37	381	711
	484121	General Freight Trucking, Long-Distance, Truckload	0	0	0	0
	541330	Engineering Services	582	73	755	1,410
	562212	Solid Waste Landfill	52	7	68	127
	Total	**-**	**4,688**	**589**	**6,089**	**11,366**

a. EPA estimated impacts related to initial one-time recordkeeping and monitoring costs using the labor productivity rate for the fossil fuel electric power generation sector.

Source: U.S. EPA Analysis, 2024.

6.5 Uncertainties and Limitations

Despite EPA's use of the best available information and data, EPA's analysis of the potential impacts of the final rule on labor input involves several sources of uncertainty:

- EPA used a bottom-up engineering analysis to estimate direct FTE impacts. This analysis does not account for other indirect and induced effects of the rule on the broader economy due to, for example, changes in forecasted electricity prices. However, EPA expects these effects to be small given the relatively small changes in electricity production costs modeled in IPM (see Chapter 5) and small potential electricity price effects (see Chapter 7).

- EPA estimated FTE impacts based on projected changes in electricity generation for a single year (2030) to correspond to the detailed outputs of the market analysis in Chapter 5, but the final rule also has incremental effects in other years.

- Labor productivity in the analysis year 2030 is unknown. To the extent that labor productivity in 2030 diverges from recent trends, this analysis may over- or underestimate employment impacts.

- EPA mapped cost components to the most relevant NAICS sectors, but FTEs in other NAICS sectors may be affected. In addition, if those NAICS sectors have different labor productivity rates, this analysis may over- or underestimate FTE impacts.

7 Assessment of Potential Electricity Price Effects

7.1 Analysis Overview

EPA assessed the potential impacts of regulatory options A through C on electricity prices. Following the methodology EPA used to analyze the 2015 and 2020 rules, and 2023 proposal (U.S. EPA, 2015, 2020, 2023d), the Agency conducted this analysis in two parts:

- An assessment of the potential annual increase in electricity costs per MWh of total electricity sales (Section 7.2)
- An assessment of the potential annual increase in household electricity costs (Section 7.3).

As is the case with the plant-level and parent entity-level cost-to-revenue screening analyses discussed in Chapter 4 (Economic Impact Screening Analyses), this analysis of electricity price effects uses a historical snapshot of electricity generation against which to assess the relative impacts of the regulatory options. However, unlike the plant- and entity-level screening analyses which assume that steam electric power plants and their parent entities would absorb 100 percent of the compliance burden (zero cost pass-through), this electricity price impact assessment assumes the opposite: 100 percent pass-through of compliance costs through electricity prices (*i.e.*, full cost pass-through).

Although this convenient analytical simplification does not reflect actual market conditions,[76] EPA judges this assumption appropriate for two reasons: (1) the majority of steam electric power plants operate under a cost-of-service framework and *may be* able to recover increases in their production costs through increased electricity prices and (2) for plants operating in states where electric power generation has been deregulated, it would not be possible to estimate this consumer price effect at the state level. Thus, this 100 percent cost pass-through assumption represents a "worst-case" impact scenario from the perspective of the electricity consumers. To the extent that all compliance-related costs are *not* passed forward to consumers but are absorbed, at least in part, by electric power generators, this analysis overstates consumer impacts.

It is also important to note that, if the full cost pass-through condition assumed in this analysis were to occur, then the screening analyses assessed in Chapter 4 would overstate the impacts to plants and owners of these plants because the two conditions (full cost pass-through and no cost pass-through) could not simultaneously occur for the same steam electric power plant.

76 Plants located in states where electricity prices remain regulated under the traditional cost-of-service rate regulation framework may be able to recover compliance cost-based increases in their production costs through increased electricity rates, depending on the business operation model of the plant owner(s), the ownership and operating structure of the plant itself, and the role of market mechanisms used to sell electricity. In contrast, in states in which electric power generation has been deregulated, cost recovery is not guaranteed. While plants operating within deregulated electricity markets *may be* able to recover some of their additional production costs in increased revenue, it is not possible to determine the extent of cost recovery ability for each plant. Moreover, even though individual plants may not be able to recover all of their compliance costs through increased revenues, the market-level effect may still be that consumers would see higher overall electricity prices because of changes in the cost structure of electricity supply and resulting changes in market-clearing prices in deregulated generation markets.

7.2 Assessment of Impact of Compliance Costs on Electricity Prices

EPA assessed the potential increase in electricity prices to the four electricity consumer groups: residential, commercial, industrial, and transportation.

7.2.1 Analysis Approach and Data Inputs

For this analysis, EPA assumed that compliance costs would be fully passed through as increased electricity prices and allocated these costs among consumer groups (residential, commercial, industrial, and transportation) in proportion to the historical quantity of electricity consumed by each group. EPA performed this analysis at the level of the NERC region. Using the NERC region as the basis for this analysis is appropriate given the structure and functioning of sub-national electricity markets, around which NERC regions are defined. The analysis, which uses the exact same approach as used for the 2015 and 2020 rules and 2023 proposal analyses, involves the following steps (for additional details, see Chapter 7 in U.S. EPA, 2015):

- EPA summed weighted pre-tax plant-level annualized compliance costs by NERC region.[77, 78]
- EPA estimated the approximate average price impact per unit of electricity consumption by dividing total annualized compliance costs by the projected total MWh of sales in 2024 by NERC region, from AEO2023 (EIA, 2023b).
- EPA compared the estimated average price effect to the projected electricity price by consumer group and NERC region for 2024 from AEO2023 (EIA, 2023b).

7.2.2 Key Findings for Regulatory Options

As reported in Table 7-1, the compliance costs per unit of sales are very small for all analyzed regulatory options; the maximum cost per kWh is a fraction of a cent. Under all three regulatory options, the regions with the greatest cost per kWh are RF and SERC under both the lower and upper bound scenarios.

Table 7-1: Compliance Cost per KWh Sales by NERC Region and Regulatory Option in 2024 (2023$) – Lower Bound

NERC[a]	Total Electricity Sales (at 2024; MWh)	National Pre-Tax Compliance Costs (at 2024; 2023$)	Costs per Unit of Sales (2023¢/kWh Sales)
Option A			
MRO	456,121,788	$54,026,214	0.012¢
NPCC	253,369,049	$5,992,572	0.002¢
RF	732,859,497	$146,301,472	0.020¢
SERC	1,324,847,581	$228,184,395	0.017¢
TRE	389,170,380	$7,931,750	0.002¢

77 These compliance costs are in 2023 dollars as of a given technology implementation year (2025 through 2029) and discounted to 2024 at 3.76 percent. This analysis accounts for the different years in which plants are estimated to implement the compliance technologies in order to reflect the effect of differences in timing of these electricity price impacts in terms of cost to household ratepayers and society. Costs and ratepayer effects occurring farther in the future (*e.g.*, in the last year of the technology implementation period) have a lower present value of impact than those that occur sooner following rule promulgation. Estimating the cost and ratepayer effect as of the assumed technology implementation year (2025 through 2029) and then discounting these effects to a single analysis year (2024) accounts for this consideration.

78 For this analysis, EPA brought compliance costs forward to a given compliance year using the CCI and ECI.

Table 7-1: Compliance Cost per KWh Sales by NERC Region and Regulatory Option in 2024 (2023$) – Lower Bound			
NERC[a]	**Total Electricity Sales (at 2024; MWh)**	**National Pre-Tax Compliance Costs (at 2024; 2023$)**	**Costs per Unit of Sales (2023¢/kWh Sales)**
WECC	691,321,258	$36,218,573	0.005¢
US	**3,868,347,589**	**$479,230,884**	**0.012¢**
		Option B	
MRO	456,121,788	$69,824,715	0.015¢
NPCC	253,369,049	$6,122,629	0.002¢
RF	732,859,497	$208,025,785	0.028¢
SERC	1,324,847,581	$256,608,152	0.019¢
TRE	389,170,380	$9,215,116	0.002¢
WECC	691,321,258	$44,513,228	0.006¢
US	**3,868,347,589**	**$594,885,534**	**0.015¢**
		Option C	
MRO	456,121,788	$76,979,491	0.017¢
NPCC	253,369,049	$6,122,629	0.002¢
RF	732,859,497	$235,300,734	0.032¢
SERC	1,324,847,581	$305,278,400	0.023¢
TRE	389,170,380	$14,139,636	0.004¢
WECC	691,321,258	$55,553,917	0.008¢
US	**3,868,347,589**	**$693,950,715**	**0.018¢**

a. ELG compliance costs are zero in the AK and HICC regions and these regions are therefore omitted from the presentation. Because of this, the sum of electricity sales for all regions do not sum to the total for the United States.

Source: U.S. EPA Analysis, 2024.

Table 7-2: Compliance Cost per KWh Sales by NERC Region and Regulatory Option in 2024 (2023$) – Upper Bound			
NERC[a]	**Total Electricity Sales (at 2024; MWh)**	**National Pre-Tax Compliance Costs (at 2024; 2023$)**	**Costs per Unit of Sales (2023¢/kWh Sales)**
		Option A	
MRO	456,121,788	$118,176,904	0.026¢
NPCC	253,369,049	$6,405,553	0.003¢
RF	732,859,497	$245,175,269	0.033¢
SERC	1,324,847,581	$518,050,509	0.039¢
TRE	389,170,380	$16,758,365	0.004¢
WECC	691,321,258	$140,691,334	0.020¢
US	**3,868,347,589**	**$1,047,696,932**	**0.027¢**
		Option B	
MRO	456,121,788	$133,975,405	0.029¢
NPCC	253,369,049	$6,535,610	0.003¢
RF	732,859,497	$306,899,583	0.042¢
SERC	1,324,847,581	$546,474,267	0.041¢
TRE	389,170,380	$18,041,731	0.005¢
WECC	691,321,258	$148,985,988	0.022¢
US	**3,868,347,589**	**$1,163,351,581**	**0.030¢**
		Option C	
MRO	456,121,788	$141,130,180	0.031¢
NPCC	253,369,049	$6,535,610	0.003¢
RF	732,859,497	$334,174,531	0.046¢

Table 7-2: Compliance Cost per KWh Sales by NERC Region and Regulatory Option in 2024 (2023$) – Upper Bound

NERC[a]	Total Electricity Sales (at 2024; MWh)	National Pre-Tax Compliance Costs (at 2024; 2023$)	Costs per Unit of Sales (2023¢/kWh Sales)
SERC	1,324,847,581	$595,144,514	0.045¢
TRE	389,170,380	$22,966,251	0.006¢
WECC	691,321,258	$160,026,678	0.023¢
US	**3,868,347,589**	**$1,262,416,762**	**0.033¢**

a. ELG compliance costs are zero in the AK and HICC regions and these regions are therefore omitted from the presentation. Because of this, the sum of electricity sales for all regions do not sum to the total for the United States.

Source: U.S. EPA Analysis, 2024.

To determine the relative significance of compliance costs on electricity prices across consumer groups, EPA compared the per kWh compliance cost to retail electricity prices projected by EIA (EIA, 2023b) by consuming group and for the average of the groups. This analysis is presented in Table 7-3 and Table 7-4 for the lower and upper bound scenarios, respectively.

Looking across the four consumer groups and assuming that any price change would apply equally to all consumer groups, under all scenarios industrial consumers are estimated to experience the highest price changes relative to the electricity price basis, while residential consumers are estimated to experience the lowest price changes, shown in Table 7-3. The comparably higher relative price changes to industrial consumers are due to their lower electricity rates and EPA's assumption of uniform changes across all consumer groups; they do not reflect differential distribution of the incremental costs across consumer groups.

Table 7-3: Projected 2024 Price (Cents per kWh of Sales) and Potential Price Increase Due to Compliance Costs by NERC Region and Regulatory Option (2023$) – Lower Bound

NERC[b]	Compliance Costs (2023¢ /kWh)	Residential		Commercial		Industrial		Transportation		All Sectors Average	
		EIA Price Basis (2023¢ /kWh)	% Change [a]	EIA Price Basis (2023¢ /kWh)	% Change [a]	EIA Price Basis (2023¢ /kWh)	% Change [a]	EIA Price Basis (2023¢ /kWh)	% Change [a]	EIA Price Basis (2023¢ /kWh)	% Change [a]
Option A											
MRO	0.012¢	11.58¢	0.10%	9.48¢	0.12%	6.59¢	0.18%	11.00¢	0.11%	9.15¢	0.13%
NPCC	0.002¢	20.94¢	0.01%	17.15¢	0.01%	12.12¢	0.02%	13.96¢	0.02%	17.95¢	0.01%
RF	0.020¢	14.33¢	0.14%	12.07¢	0.17%	8.90¢	0.22%	10.13¢	0.20%	12.05¢	0.17%
SERC	0.017¢	12.42¢	0.14%	10.22¢	0.17%	6.65¢	0.26%	11.45¢	0.15%	10.30¢	0.17%
TRE	0.002¢	12.08¢	0.02%	10.47¢	0.02%	7.59¢	0.03%	9.13¢	0.02%	10.22¢	0.02%
WECC	0.005¢	16.15¢	0.03%	14.34¢	0.04%	9.81¢	0.05%	18.17¢	0.03%	13.91¢	0.04%
US	**0.012¢**	**13.90¢**	**0.09%**	**11.94¢**	**0.10%**	**7.95¢**	**0.16%**	**13.84¢**	**0.09%**	**11.67¢**	**0.11%**
Option B											
MRO	0.015¢	11.58¢	0.13%	9.48¢	0.16%	6.59¢	0.23%	11.00¢	0.14%	9.15¢	0.17%
NPCC	0.002¢	20.94¢	0.01%	17.15¢	0.01%	12.12¢	0.02%	13.96¢	0.02%	17.95¢	0.01%
RF	0.028¢	14.33¢	0.20%	12.07¢	0.24%	8.90¢	0.32%	10.13¢	0.28%	12.05¢	0.24%
SERC	0.019¢	12.42¢	0.16%	10.22¢	0.19%	6.65¢	0.29%	11.45¢	0.17%	10.30¢	0.19%
TRE	0.002¢	12.08¢	0.02%	10.47¢	0.02%	7.59¢	0.03%	9.13¢	0.03%	10.22¢	0.02%

Table 7-3: Projected 2024 Price (Cents per kWh of Sales) and Potential Price Increase Due to Compliance Costs by NERC Region and Regulatory Option (2023$) – Lower Bound											
		Residential		Commercial		Industrial		Transportation		All Sectors Average	
NERC[b]	Compliance Costs (2023¢ /kWh)	EIA Price Basis (2023¢ /kWh)	% Change [a]	EIA Price Basis (2023¢ /kWh)	% Change [a]	EIA Price Basis (2023¢ /kWh)	% Change [a]	EIA Price Basis (2023¢ /kWh)	% Change [a]	EIA Price Basis (2023¢ /kWh)	% Change [a]
WECC	0.006¢	16.15¢	0.04%	14.34¢	0.04%	9.81¢	0.07%	18.17¢	0.04%	13.91¢	0.05%
US	**0.015¢**	**13.90¢**	**0.11%**	**11.94¢**	**0.13%**	**7.95¢**	**0.19%**	**13.84¢**	**0.11%**	**11.67¢**	**0.13%**
Option C											
MRO	0.017¢	11.58¢	0.15%	9.48¢	0.18%	6.59¢	0.26%	11.00¢	0.15%	9.15¢	0.18%
NPCC	0.002¢	20.94¢	0.01%	17.15¢	0.01%	12.12¢	0.02%	13.96¢	0.02%	17.95¢	0.01%
RF	0.032¢	14.33¢	0.22%	12.07¢	0.27%	8.90¢	0.36%	10.13¢	0.32%	12.05¢	0.27%
SERC	0.023¢	12.42¢	0.19%	10.22¢	0.23%	6.65¢	0.35%	11.45¢	0.20%	10.30¢	0.22%
TRE	0.004¢	12.08¢	0.03%	10.47¢	0.03%	7.59¢	0.05%	9.13¢	0.04%	10.22¢	0.04%
WECC	0.008¢	16.15¢	0.05%	14.34¢	0.06%	9.81¢	0.08%	18.17¢	0.04%	13.91¢	0.06%
US	**0.018¢**	**13.90¢**	**0.13%**	**11.94¢**	**0.15%**	**7.95¢**	**0.23%**	**13.84¢**	**0.13%**	**11.67¢**	**0.15%**

a. The rate impact analysis assumes full pass-through of all compliance costs to electricity consumers.

b. ELG compliance costs are zero in the AK and HICC regions and these regions are therefore omitted from the presentation.

Sources: U.S. EPA Analysis, 2024; EIA, 2022c, 2023b.

Table 7-4: Projected 2024 Price (Cents per kWh of Sales) and Potential Price Increase Due to Compliance Costs by NERC Region and Regulatory Option (2023$) – Upper Bound											
		Residential		Commercial		Industrial		Transportation		All Sectors Average	
NERC[b]	Compliance Costs (2023¢ /kWh)	EIA Price Basis (2023¢ /kWh)	% Change [a]	EIA Price Basis (2023¢ /kWh)	% Change [a]	EIA Price Basis (2023¢ /kWh)	% Change [a]	EIA Price Basis (2023¢ /kWh)	% Change [a]	EIA Price Basis (2023¢ /kWh)	% Change [a]
Option A											
MRO	0.026¢	11.58¢	0.22%	9.48¢	0.27%	6.59¢	0.39%	11.00¢	0.24%	9.15¢	0.28%
NPCC	0.003¢	20.94¢	0.01%	17.15¢	0.01%	12.12¢	0.02%	13.96¢	0.02%	17.95¢	0.01%
RF	0.033¢	14.33¢	0.23%	12.07¢	0.28%	8.90¢	0.38%	10.13¢	0.33%	12.05¢	0.28%
SERC	0.039¢	12.42¢	0.31%	10.22¢	0.38%	6.65¢	0.59%	11.45¢	0.34%	10.30¢	0.38%
TRE	0.004¢	12.08¢	0.04%	10.47¢	0.04%	7.59¢	0.06%	9.13¢	0.05%	10.22¢	0.04%
WECC	0.020¢	16.15¢	0.13%	14.34¢	0.14%	9.81¢	0.21%	18.17¢	0.11%	13.91¢	0.15%
US	**0.027¢**	**13.90¢**	**0.19%**	**11.94¢**	**0.23%**	**7.95¢**	**0.34%**	**13.84¢**	**0.20%**	**11.67¢**	**0.23%**
Option B											
MRO	0.029¢	11.58¢	0.25%	9.48¢	0.31%	6.59¢	0.45%	11.00¢	0.27%	9.15¢	0.32%
NPCC	0.003¢	20.94¢	0.01%	17.15¢	0.02%	12.12¢	0.02%	13.96¢	0.02%	17.95¢	0.01%
RF	0.042¢	14.33¢	0.29%	12.07¢	0.35%	8.90¢	0.47%	10.13¢	0.41%	12.05¢	0.35%
SERC	0.041¢	12.42¢	0.33%	10.22¢	0.40%	6.65¢	0.62%	11.45¢	0.36%	10.30¢	0.40%
TRE	0.005¢	12.08¢	0.04%	10.47¢	0.04%	7.59¢	0.06%	9.13¢	0.05%	10.22¢	0.05%
WECC	0.022¢	16.15¢	0.13%	14.34¢	0.15%	9.81¢	0.22%	18.17¢	0.12%	13.91¢	0.15%
US	**0.030¢**	**13.90¢**	**0.22%**	**11.94¢**	**0.25%**	**7.95¢**	**0.38%**	**13.84¢**	**0.22%**	**11.67¢**	**0.26%**

Table 7-4: Projected 2024 Price (Cents per kWh of Sales) and Potential Price Increase Due to Compliance Costs by NERC Region and Regulatory Option (2023$) – Upper Bound

		Residential		Commercial		Industrial		Transportation		All Sectors Average	
NERC[b]	Compliance Costs (2023¢ /kWh)	EIA Price Basis (2023¢ /kWh)	% Change [a]	EIA Price Basis (2023¢ /kWh)	% Change [a]	EIA Price Basis (2023¢ /kWh)	% Change [a]	EIA Price Basis (2023¢ /kWh)	% Change [a]	EIA Price Basis (2023¢ /kWh)	% Change [a]
Option C											
MRO	0.031¢	11.58¢	0.27%	9.48¢	0.33%	6.59¢	0.47%	11.00¢	0.28%	9.15¢	0.34%
NPCC	0.003¢	20.94¢	0.01%	17.15¢	0.02%	12.12¢	0.02%	13.96¢	0.02%	17.95¢	0.01%
RF	0.046¢	14.33¢	0.32%	12.07¢	0.38%	8.90¢	0.51%	10.13¢	0.45%	12.05¢	0.38%
SERC	0.045¢	12.42¢	0.36%	10.22¢	0.44%	6.65¢	0.68%	11.45¢	0.39%	10.30¢	0.44%
TRE	0.006¢	12.08¢	0.05%	10.47¢	0.06%	7.59¢	0.08%	9.13¢	0.06%	10.22¢	0.06%
WECC	0.023¢	16.15¢	0.14%	14.34¢	0.16%	9.81¢	0.24%	18.17¢	0.13%	13.91¢	0.17%
US	**0.033¢**	**13.90¢**	**0.23%**	**11.94¢**	**0.27%**	**7.95¢**	**0.41%**	**13.84¢**	**0.24%**	**11.67¢**	**0.28%**

a. The rate impact analysis assumes full pass-through of all compliance costs to electricity consumers.

b. ELG compliance costs are zero in the AK and HICC regions and these regions are therefore omitted from the presentation.

Sources: U.S. EPA Analysis, 2024; EIA, 2022c, 2023b.

7.2.3 Uncertainties and Limitations

As noted above, the assumption of 100 percent pass-through of compliance costs to electricity prices represents a worst-case scenario from the perspective of consumers. To the extent that some steam electric power plants do not pass their compliance costs to consumers through higher electricity rates, this analysis may overstate the potential impact of the regulatory options on electricity consumers.

In addition, this analysis assumes that costs would be passed on in the form of a flat-rate price increase per unit of electricity, to be applied equally to all consumer groups. This assumption is appropriate to assess the general magnitude of potential price increases. The allocation of costs to different consumer groups could be higher or lower than estimated by this approach.

7.3 Assessment of Impact of Compliance Costs on Household Electricity Costs

EPA also assessed the potential increases in the cost of electricity to residential households.

7.3.1 Analysis Approach and Data Inputs

For this analysis, EPA again assumed that compliance costs would be fully passed through as increased electricity prices and allocated these costs to residential households in proportion to the baseline electricity consumption. EPA analyzed the potential impact on annual electricity costs at the level of the 'average' household, using the estimated household electricity consumption quantity by NERC region. Following the approach used in analyzing the 2015 and 2020 rules and 2023 proposal (U.S. EPA, 2015, 2020, 2023d), the steps in this calculation are as follows:

- As done for the electricity price analysis discussed in Section 7.2, to estimate total annual cost in each NERC region, EPA summed weighted pre-tax, plant-level annualized compliance costs by NERC region.[79]

- As was done for the analysis of impact of compliance costs on electricity prices, EPA divided total compliance costs by the total MWh of sales reported for each NERC region. EPA used electricity sales (in MWh) for 2024 from AEO2023 (EIA, 2023b).[80]

- To calculate average annual electricity sales per household, EPA divided the total quantity of *residential* sales (in MWh) for 2021 in each NERC region by the number of households in that region; the Agency obtained both the quantity of residential sales and the number of households from the 2021 EIA-861 database (EIA, 2022a). For this analysis, EPA assumed that the average quantity of electricity sales per household by NERC region would remain the same in 2024 as in 2021.

- To assess the potential annual cost impact per household, EPA multiplied the estimated average price impact by the average quantity of electricity sales per household in 2021 by NERC region.

7.3.2 Key Findings for Regulatory Options A through C

Table 7-5 and Table 7-6 report the upper and lower bound scenario results of this analysis by NERC region for each regulatory option, and overall for the United States.[81]

Table 7-5: Average Incremental Annual Cost per Household in 2024 by NERC Region and Regulatory Option (2023$) – Lower Bound

NERC[b]	Total Electricity Sales (MWh)	Residential Electricity Sales (MWh)	Number of Households	Residential Sales per Residential Household (MWh/year)	Total Pre-Tax Compliance Costs (at 2024; 2023$/year)	Total Compliance Costs per Unit of Sales (2023$/MWh)	Total Compliance Costs per Residential Household (2023$/year)
				Option A			
MRO	456,121,788	119,927,337	10,807,443	11.10	54,026,214	$0.12	$1.31
NPCC	253,369,049	111,525,266	14,886,378	7.49	5,992,572	$0.02	$0.18
RF	732,859,497	320,906,246	32,782,678	9.79	146,301,472	$0.20	$1.95
SERC	1,324,847,581	501,406,381	38,022,008	13.19	228,184,395	$0.17	$2.27
TRE	389,170,380	79,238,157	6,202,682	12.77	7,931,750	$0.02	$0.26
WECC	691,321,258	252,010,889	29,828,524	8.45	36,218,573	$0.05	$0.44
US[b]	**3,861,716,503**	**1,389,584,033**	**133,240,696**	**10.43**	**479,230,884**	**$0.12**	**$1.29**
				Option B			
MRO	456,121,788	119,927,337	10,807,443	11.10	69,824,715	$0.15	$1.70
NPCC	253,369,049	111,525,266	14,886,378	7.49	6,122,629	$0.02	$0.18

79 Compliance costs in the ASCC and HICC regions are zero and EPA therefore did not include these regions in its analysis.

80 AEO does not provide information for HICC and ASSC. None of the plants estimated to incur compliance costs as a result of the final ELG, however, are located in these two NERC regions.

81 Average annual cost per residential household is zero in ASCC and HICC for the baseline and the three options and these regions are therefore omitted from the details. They are included in the U.S. totals.

Table 7-5: Average Incremental Annual Cost per Household in 2024 by NERC Region and Regulatory Option (2023$) – Lower Bound

NERC[b]	Total Electricity Sales (MWh)	Residential Electricity Sales (MWh)	Number of Households	Residential Sales per Residential Household (MWh/year)	Total Pre-Tax Compliance Costs (at 2024; 2023$/year)	Total Compliance Costs per Unit of Sales (2023$/MWh)	Total Compliance Costs per Residential Household (2023$/year)
RF	732,859,497	320,906,246	32,782,678	9.79	208,025,785	$0.28	$2.78
SERC	1,324,847,581	501,406,381	38,022,008	13.19	256,608,152	$0.19	$2.55
TRE	389,170,380	79,238,157	6,202,682	12.77	9,215,116	$0.02	$0.30
WECC	691,321,258	252,010,889	29,828,524	8.45	44,513,228	$0.06	$0.54
US[b]	**3,861,716,503**	**1,389,584,033**	**133,240,696**	**10.43**	**594,885,534**	**$0.15**	**$1.61**
Option C							
MRO	456,121,788	119,927,337	10,807,443	11.10	76,979,491	$0.17	$1.87
NPCC	253,369,049	111,525,266	14,886,378	7.49	6,122,629	$0.02	$0.18
RF	732,859,497	320,906,246	32,782,678	9.79	235,300,734	$0.32	$3.14
SERC	1,324,847,581	501,406,381	38,022,008	13.19	305,278,400	$0.23	$3.04
TRE	389,170,380	79,238,157	6,202,682	12.77	14,139,636	$0.04	$0.46
WECC	691,321,258	252,010,889	29,828,524	8.45	55,553,917	$0.08	$0.68
US[b]	**3,861,716,503**	**1,389,584,033**	**133,240,696**	**10.43**	**693,950,715**	**$0.18**	**$1.87**

a. This analysis assumes full pass-through of all compliance costs to electricity consumers.

b. ELG compliance costs are zero in the AK and HICC regions and these regions are therefore omitted from the presentation. For this reason, electricity sales shown for the United States is greater than the total for NERC regions included in the table.

Sources: U.S. EPA Analysis, 2024; EIA, 2022c, 2023b.

Table 7-6: Average Incremental Annual Cost per Household in 2024 by NERC Region and Regulatory Option (2023$) – Upper Bound

NERC[b]	Total Electricity Sales (MWh)	Residential Electricity Sales (MWh)	Number of Households	Residential Sales per Residential Household (MWh/year)	Total Pre-Tax Compliance Costs (at 2024; 2023$/year)	Total Compliance Costs per Unit of Sales (2023$/MWh)	Total Compliance Costs per Residential Household (2023$/year)
Option A							
MRO	456,121,788	119,927,337	10,807,443	11.10	118,176,904	$0.26	$2.88
NPCC	253,369,049	111,525,266	14,886,378	7.49	6,405,553	$0.03	$0.19
RF	732,859,497	320,906,246	32,782,678	9.79	245,175,269	$0.33	$3.27
SERC	1,324,847,581	501,406,381	38,022,008	13.19	518,050,509	$0.39	$5.16
TRE	389,170,380	79,238,157	6,202,682	12.77	16,758,365	$0.04	$0.55
WECC	691,321,258	252,010,889	29,828,524	8.45	140,691,334	$0.20	$1.72
US[b]	**3,861,716,503**	**1,389,584,033**	**133,240,696**	**10.43**	**1,047,696,932**	**$0.27**	**$2.83**
Option B							
MRO	456,121,788	119,927,337	10,807,443	11.10	133,975,405	$0.29	$3.26
NPCC	253,369,049	111,525,266	14,886,378	7.49	6,535,610	$0.03	$0.19
RF	732,859,497	320,906,246	32,782,678	9.79	306,899,583	$0.42	$4.10
SERC	1,324,847,581	501,406,381	38,022,008	13.19	546,474,267	$0.41	$5.44
TRE	389,170,380	79,238,157	6,202,682	12.77	18,041,731	$0.05	$0.59
WECC	691,321,258	252,010,889	29,828,524	8.45	148,985,988	$0.22	$1.82
US[b]	**3,861,716,503**	**1,389,584,033**	**133,240,696**	**10.43**	**1,163,351,581**	**$0.30**	**$3.14**

Table 7-6: Average Incremental Annual Cost per Household in 2024 by NERC Region and Regulatory Option (2023$) – Upper Bound

NERC[b]	Total Electricity Sales (MWh)	Residential Electricity Sales (MWh)	Number of Households	Residential Sales per Residential Household (MWh/year)	Total Pre-Tax Compliance Costs (at 2024; 2023$/year)	Total Compliance Costs per Unit of Sales (2023$/MWh)	Total Compliance Costs per Residential Household (2023$/year)
Option C							
MRO	456,121,788	119,927,337	10,807,443	11.10	141,130,180	$0.31	$3.43
NPCC	253,369,049	111,525,266	14,886,378	7.49	6,535,610	$0.03	$0.19
RF	732,859,497	320,906,246	32,782,678	9.79	334,174,531	$0.46	$4.46
SERC	1,324,847,581	501,406,381	38,022,008	13.19	595,144,514	$0.45	$5.92
TRE	389,170,380	79,238,157	6,202,682	12.77	22,966,251	$0.06	$0.75
WECC	691,321,258	252,010,889	29,828,524	8.45	160,026,678	$0.23	$1.96
US[b]	**3,861,716,503**	**1,389,584,033**	**133,240,696**	**10.43**	**1,262,416,762**	**$0.33**	**$3.41**

a. This analysis assumes full pass-through of all compliance costs to electricity consumers.

b. ELG compliance costs are zero in the AK and HICC regions and these regions are therefore omitted from the presentation. For this reason, electricity sales shown for the United States is greater than the total for NERC regions included in the table.

Sources: U.S. EPA Analysis, 2024; EIA, 2022c, 2023b.

To address concerns that cost increase may affect households served by certain types of operators more than others, the Agency also estimated the potential increases in electricity costs for households by plant ownership type for the final rule. In this analysis, the Agency estimated the potential increase in electricity costs for the average household under each plant ownership type based on the average household electricity sales (10.43 MWh/year) in Table 7-5 and Table 7-6 and the compliance costs per MWh under each plant ownership type.[82] The analysis shows that the compliance costs per average residential consumer are relatively similar under each plant ownership type with an average of $3.57 and $6.48 in the lower and upper bound scenarios, respectively.[83] The compliance costs of the final rule per average residential consumer were greatest for cooperatives (between $6.73 and $19.26) and lowest for federal entities (between $0.62 and $1.63).

7.3.3 Uncertainties and Limitations

As noted above, the assumption of 100 percent pass-through of compliance costs to electricity prices represents a worst-case scenario from the perspective of households. To the extent that some steam electric power plants do not pass their compliance costs to consumers through higher electricity rates, this analysis may overstate the potential impact of the regulatory options on households.

This analysis also assumes that costs would be passed on in the form of a flat-rate price increase per unit of electricity, an assumption EPA concluded is reasonable to characterize the magnitude of compliance

82 The Agency estimated compliance costs per MWh for each plant ownership type by dividing the total compliance costs incurred by plants under each ownership type by the sum of retail sales (MWh) and sales for resale (MWh) for the utilities associated with plants under each ownership type from EIA-861 2021 data (U.S. Energy Information Administration. (2022a). *Annual Electric Power Industry Report, Form EIA-861 detailed data files: Final 2021 Data*).

83 The compliance costs per average residential consumer are different from what is reported in Table 7-5 because only a subset of utilities incurred compliance costs under the final rule (Option B).

costs relative to household electricity consumption. The allocation of costs to the residential class could be higher or lower than estimated by this approach.

7.4 Distribution of Electricity Cost Impact on Household

In general, lower-income households spend less, in the absolute, on energy than do higher-income households, but energy expenditures represent a larger *share* of their income. Therefore, electricity price increases tend to have a relatively larger effect on lower-income households, compared to higher-income households. In analyzing the impacts of the 2015 rule, EPA conducted a distributional analysis of the 2015 rule to assess (1) whether an increase in electricity rates that may occur under the 2015 rule would disproportionately affect lower-income households and (2) whether households would be able to pay for these electricity rate increases without experiencing economic hardship (*i.e.*, whether the increase is affordable). The analysis provided additional insight on the distribution of impacts among residential electricity consumers to help respond to concerns regarding the impacts of the rule on utilities and cooperatives in service areas that include a relatively high proportion of low-income households.

In the 2015 analysis, EPA had concluded that even when looking at a worst-case scenario of 100 percent pass through of the compliance costs, the "incremental economic burden of any final rule based on the regulatory options in the proposal on households is small both relative to income and relative to the baseline energy burden of households in different income ranges. While the incremental burden relative to income is not distributionally neutral, *i.e.*, any increase would affect lower-income households to a greater extent than higher-income households, the small impacts may be further moderated by existing pricing structures (see Section 7.4 in U.S. EPA, 2015)." As presented in the preceding sections, EPA estimates that regulatory options A through C would result in compliance costs for FGD wastewater, BA transport water, and CRL treatment. To the extent that these costs are in turn passed through to electricity consumers in the form of higher prices, the resulting higher electricity prices may have a larger negative effect on lower-income households. However, given the small increase to household electricity costs corresponding to the incremental compliance costs for the rule (between $1.61 and $3.14 per household per year for Option B), EPA finds that the earlier conclusion of small impacts from the 2015 rule still holds given the lower compliance costs of the three regulatory options relative to the 2015 rule.

8 Assessment of Potential Impact of the Regulatory Options on Small Entities – Regulatory Flexibility Act (RFA) Analysis

The Regulatory Flexibility Act (RFA) of 1980, as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996, requires federal agencies to consider the impact of their rules on small entities, to analyze alternatives that minimize those impacts,[84] and to make their analyses available for public comments. The RFA is concerned with three types of small entities: small businesses, small nonprofits, and small government jurisdictions.

The RFA describes the regulatory flexibility analyses and procedures that must be completed by federal agencies unless they certify that the rule, if promulgated, would not have a significant economic impact on a substantial number of small entities. This certification must be supported by a statement of factual basis, *e.g.*, addressing the number of small entities affected by the final rule, estimated cost impacts on these entities, and evaluation of the economic impacts.

In accordance with RFA requirements and as it has consistently done in developing effluent limitations guidelines and standards, EPA assessed whether the regulatory options would have “a significant impact on a substantial number of small entities” (SISNOSE). Following the approach used in the analysis of the 2015 and 2020 rules and 2023 proposal (U.S. EPA, 2015, 2020, 2023d), this assessment involved the following steps:

- Identifying the domestic parent entities of steam electric power plants.
- Determining which of those domestic parent entities are small entities, based on SBA size criteria.
- Assessing the change in potential impact of the regulatory options on those small entities by comparing the estimated entity-level annualized compliance cost to entity-level revenue; the cost-to-revenue ratio indicates the magnitude of economic impacts. Following EPA guidance (U.S. EPA, 2006), EPA used threshold compliance costs of one percent or three percent of entity-level revenue to categorize the degree of *significance* of the economic impacts on small entities.
- Assessing the change in whether those small entities incurring potentially significant impacts represent a substantial number of small entities. Following EPA guidance (U.S. EPA, 2006), EPA determined whether the number of small entities impacted is *substantial* based on (1) the estimated *absolute numbers* of small entities incurring potentially significant impacts according to the two cost impact criteria, and (2) the *percentage of small entities* in the relevant entity categories that are estimated to incur these impacts.

EPA performed this assessment for each of the regulatory options. This chapter describes the analytic approach (Section 8.1), summarizes the findings of EPA’s RFA assessment (Section 8.2), and reviews

84 Section 603(c) of the RFA provides examples of such alternatives as: (1) the establishment of differing compliance or reporting requirements or timetables that take into account the resources available to small entities; (2) the clarification, consolidation, or simplification of compliance and reporting requirements under the rule for such small entities; (3) the use of performance rather than design standards; and (4) an exemption from coverage of the rule, or any part thereof, for such small entities.

uncertainties and limitations in the analysis (Section 8.3). The chapter also discusses how regulatory options developed by EPA served to mitigate the impact of the regulatory options on small entities (Section 8.4).

8.1 Analysis Approach and Data Inputs

EPA used the same methodology and assumptions used for the analysis of the 2015, 2020, and proposed 2023 rules (U.S. EPA, 2015, 2020, 2023d), but updated input data to reflect more recent information about plant ownership, entity size, and compliance costs as described in the sections below.

8.1.1 Determining Parent Entity of Steam Electric Power Plants

Consistent with the entity-level cost-to-revenue analysis (see Chapter 4), EPA conducted the RFA analysis at the highest level of domestic ownership, referred to as the “domestic parent entity” or “domestic parent firm”, including only entities with the largest share of ownership (majority owner)[85] in at least one of the estimated 858 steam electric power plants in the steam electric point source category. As was done for the entity-level cost-to-revenue analysis in Section 4.3, EPA identified the majority owner for each plant using 2022 databases published by EIA (EIA, 2022c), Dun and Bradstreet (Dun & Bradstreet, 2021), Experian (Experian, 2023), corporate and financial websites, information provided in the comments on the 2023 proposed rule, and the Steam Electric Survey (U.S. EPA, 2010).

8.1.2 Determining Whether Parent Entities of Steam Electric Power Plants Are Small

EPA identified the size of each parent entity using the SBA size threshold guidelines in effect as of March 17, 2023 (SBA, 2023). The criteria for entity size determination vary by the organization/operation category of the parent entity, as follows:

- **Privately owned (non-government) entities**: Privately owned entities include investor-owned utilities, nonutility entities, and entities with a primary business other than electric power generation. For entities with electric power generation as a primary business, small entities are those with less than the threshold number of employees specified by SBA for each of the relevant North American Industry Classification System (NAICS) sectors (NAICS 2211) (see *Table 8-1*). For entities with a primary business other than electric power generation, the relevant size criteria are based on revenue or number of employees by NAICS sector.[86]

- **Publicly owned entities**: Publicly owned entities include federal, State, municipal, and other political subdivision entities. The federal and State governments were considered to be large; municipalities and other political units with population less than 50,000 were considered to be small.

85 Throughout the analyses, EPA refers to the owner with the largest ownership share as the “majority owner” even when the ownership share is less than 51 percent.

86 Certain steam electric power plants are owned by entities whose primary business is not electric power generation. EPA determined the NAICS code of each privately owned entity based on Dun and Bradstreet (Dun & Bradstreet. (2021). *Hoovers Data Services* Version [Data set]).).

- **Rural Electric Cooperatives**: Small entities are those with less than the threshold number of employees specified by SBA for each of the relevant NAICS sectors, depending on the type of electricity generation (see *Table 8-1*).

Table 8-1: NAICS Codes and SBA Size Standards for Non-government Majority Owners Entities of Steam Electric Power Plants

NAICS Code[a]	NAICS Description	SBA Size Standard[b]
212114	Surface Coal Mining	1,250 Employees
221111	Hydroelectric Power Generation	750 Employees
221112	Fossil Fuel Electric Power Generation	950 Employees
221113	Nuclear Electric Power Generation	1,150 Employees
221114[c]	Solar Electric Power Generation	250 Employees
221115[c]	Wind Electric Power Generation	250 Employees
221116[c]	Geothermal Electric Power Generation	250 Employees
221117[c]	Biomass Electric Power Generation	250 Employees
221118[c]	Other Electric Power Generation	250 Employees
221121	Electric Bulk Power Transmission and Control	950 Employees
221122	Electric Power Distribution	1,100 Employees
221210	Natural Gas Distribution	1,150 Employees
221310	Water Supply and Irrigation Systems	$41.0 million in revenue
237130	Power and Communication Line and Related Structures Construction	$45.0 million in revenue
332410	Power Boiler and Heat Exchanger Manufacturing	750 Employees
333611	Turbine and Turbine Generator Set Unit Manufacturing	1,500 Employees
523940	Portfolio Management and Investment Advice	$47.0 million in revenue
524113	Direct Life Insurance Carriers	$47.0 million in revenue
524126	Direct Property and Casualty Insurance Carriers	1,500 employees
541614	Process, Physical Distribution and Logistics Consulting Services	$20.0 million in revenue
551112	Offices of Other Holding Companies	$45.5 million in revenue
562219	Other Nonhazardous Waste Treatment and Disposal	$47.0 million in revenue

a. Certain plants affected by this rulemaking are owned by non-government entities whose primary business is not electric power generation.

b. Based on size standards effective at the time EPA conducted this analysis (SBA size standards, effective March 17, 2023).

c. NAICS code used as proxy for determining size threshold for entities categorized in NAICS 221119.

Source: SBA, 2023.

To determine whether a majority owner is a small entity according to these criteria, EPA compared the relevant entity size criterion value estimated for each parent entity to the SBA threshold value. EPA used the following data sources and methodology to estimate the relevant size criterion values for each parent entity:

- **Employment**: EPA used entity-level employment values from Dun and Bradstreet, Experian, or corporate/financial websites, if those values were available.

- **Revenue**: EPA used entity-level revenue values from Dun and Bradstreet, Experian, or corporate/financial website, if those values were available.

- **Population**: Population data for municipalities and other non-state political subdivisions were obtained from the U.S. Census Bureau (estimated population for 2021) (U.S. Census Bureau, 2021b).

Parent entities for which the relevant measure is less than the SBA size criterion were identified as small entities and carried forward in the RFA analysis.

As discussed in Chapter 4, EPA estimated the number of small entities owning steam electric power plants as a range, based on alternative assumptions about the possible ownership of electric power plants that fall within the definition of the point source category. Following the approach used in the analysis of the 2015, 2020, proposed 2023 rules, EPA analyzed two cases that provide a range of estimates for (1) the number of firms incurring compliance costs and (2) the costs incurred by any firm owning a regulated plant (U.S. EPA, 2015, 2020, 2023d).

Table 8-2 presents the total number of entities with steam electric power plants as well as the number and percentage of those entities determined to be small. Table 8-3 presents the distribution of steam electric power plants by ownership type and owner size. Analysis results are presented by ownership type for each of the regulatory options under the lower (Case 1) and upper (Case 2) bound estimates of the number of entities owning steam electric power plants.

As reported in Table 8-2 and Table 8-3, EPA estimates that between 220 and 391 entities own 858 steam electric power plants (for Case 1 and Case 2, respectively).[87] A typical parent entity on average is estimated to own four steam electric power plants (for both Case 1 and Case 2). The Agency estimates that between 117 (53 percent) and 202 (51 percent) parent entities are small (Table 8-2), and these small entities own 267 steam electric power plants (Table 8-3), or approximately 31 percent of all steam electric power plants. Across ownership types, cooperative entities have the largest share of small entities (86 and 89 percent, for Case 1 and Case 2 respectively) and the largest share of steam electric power plants owned by small entities (88 percent).

Table 8-2: Number of Entities by Sector and Size (assuming two different ownership cases)

Ownership Type	Small Entity Size Standard	Case 1: Lower bound estimate of number of entities owning steam electric power plants[a]			Case 2: Upper bound estimate of number of entities owning steam electric power plants[a]		
		Total	Small	% Small	Total	Small	% Small
Cooperative	number of employees	22	19	86.4%	28	25	89.3%
Federal	assumed large	2	0	0.0%	7	0	0.0%
Investor-owned	number of employees[d]	57	17	29.8%	88	22	24.6%
Municipality	50,000 population served	50	22	44.0%	84	30	35.6%
Nonutility	number of employees[d]	76	57	75.0%	160	123	77.3%

87 As described in Chapter 8 in the 2015 RIA (U.S. Environmental Protection Agency. (2015). *Regulatory Impact Analysis for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*. (EPA-821-R-15-004).), Case 1 assumed that any entity owning a surveyed plant(s) owns the known surveyed plant(s) and all of the sample weight associated with the surveyed plant(s). This case minimizes the count of affected entities, while tending to maximize the potential cost burden to any single entity. Case 2 assumed (1) that an entity owns only the surveyed plant(s) that it is known to own from the Steam Electric Survey and (2) that this pattern of ownership, observed for surveyed plants and their owning entities, extends over the entire plant population. This case minimizes the possibility of multi-plant ownership by a single entity and thus maximizes the count of affected entities, but also minimizes the potential cost burden to any single entity.

Table 8-2: Number of Entities by Sector and Size (assuming two different ownership cases)

Ownership Type	Small Entity Size Standard	Case 1: Lower bound estimate of number of entities owning steam electric power plants[a]			Case 2: Upper bound estimate of number of entities owning steam electric power plants[a]		
		Total	Small	% Small	Total	Small	% Small
Other Political Subdivision[c]	50,000 population served	11	2	18.2%	23	2	8.9%
State	assumed large	2	0	0.0%	2	0	0.0%
Total[b]		**220**	**117**	**53.2%**	**391**	**202**	**51.7%**

a. Eight plants are owned by a joint venture of two entities.

b. Of these entities, 68 entities, 28 of which are small, own steam electric power plants that are estimated to incur compliance technology costs under Option B under both Case 1 and Case 2 under the lower bound scenario. Under the upper bound scenario, 81 entities, 32 of which are small, own steam electric power plants that are estimated to incur compliance technology costs under Option B under both Case 1 and Case 2.

c. EPA was unable to determine the size of 11 parent entities; for this analysis, these entities are assumed to be small.

d. Entity size may be based on revenue, depending on the NAICS sector (see *Table 8-1*).

Source: U.S. EPA Analysis, 2024.

Table 8-3: Steam Electric Power Plants by Ownership Type and Size

Ownership Type	Small Entity Size Standard	Number of Steam Electric Power Plants[a,b,c]		
		Total	Small	% Small
Cooperative	number of employees	59	52	88.1%
Federal	assumed large	23	0	0.0%
Investor-owned	number of employees[e]	320	44	13.9%
Municipality	50,000 population served	111	31	28.0%
Nonutility	number of employees[e]	308	134	43.6%
Other Political Subdivisions	50,000 population served	33	6	18.5%
State	assumed large	4	0	0.0%
Total[d]		**858**	**267**	**31.2%**

a. Numbers may not add up to totals due to independent rounding.

b. The number of plants is calculated on a sample-weighted basis.

c. Plant size was determined based on the size of the owner with the largest share in the plant. In case of multiple owners with equal ownership shares (*e.g.*, two entities with 50/50 shares), a plant was assumed to be small if it is owned by at least one small entity.

d. Of these, 142 steam electric power plants are estimated to incur compliance costs under Option B; 33 of the 142 steam electric power plants are owned by small entities under the lower bound. Under the upper bound, 171 steam electric power plants are estimated to incur compliance costs under Option B; 39 of the 171 steam electric power plants are owned by small entities.

e. Entity size may be based on revenue, depending on the NAICS sector (see *Table 8-1*).

Source: U.S. EPA Analysis, 2024.

8.1.3 Significant Impact Test for Small Entities

As outlined in the introduction to this chapter, two criteria are assessed in determining whether the regulatory options would qualify for a no-SISNOSE finding:

- Is the *absolute number* of small entities estimated to incur a potentially significant impact, as described above, *substantial*?

and

- Do these *significant impact* entities represent a *substantial* fraction of small entities in the electric power industry that could potentially be within the scope of a regulation?

A measure of the potential impact of the regulatory options on small entities is the fraction of small entities that have the potential to incur a significant impact. For example, if a high percentage of potentially small entities incur significant impacts *even though the absolute number of significant impact entities is low*, then the rule could represent a substantial burden on small entities.

To assess the extent of economic/financial impact on small entities, EPA compared estimated compliance costs to estimated entity revenue (also referred to as the "sales test"). The analysis is based on the ratio of estimated annualized after-tax compliance costs to annual revenue of the entity. For this analysis, EPA categorized entities according to the magnitude of economic impacts that entities would incur due to the regulatory options. EPA identified entities for which annualized compliance costs are at least one percent and three percent of revenue. EPA then evaluated the absolute number and the percent of entities in each impact category, and by type of ownership. The Agency assumed that entities incurring costs below one percent of revenue are unlikely to face significant economic impacts, while entities with costs of at least one percent of revenue have a higher chance of facing significant economic impacts, and entities incurring costs of at least three percent of revenue have a still higher probability of significant economic impacts. Consistent with the parent-level cost-to-revenue analysis discussed in Chapter 4, EPA assumed that steam electric power plants, and consequently, their parents, would not be able to pass any of the increase in their production costs to consumers (zero cost pass-through). This assumption is used for analytic convenience and provides a worst-case scenario of regulatory impacts to steam electric power plants.

A detailed summary of how EPA developed these entity-level compliance cost and revenue values is presented in Chapter 3 and Chapter 4.

8.2 Key Findings for Regulatory options

As described above, EPA developed estimates of the number of small parent entities in the specified cost-to-revenue impact ranges. Table 8-4 and Table 8-5 summarize the results of the analysis based on lower and upper bound costs. In terms of *number* of entities in each of the impact categories, analysis results for each option are the same under Case 1 and Case 2; however, these numbers represent different percentages of all small entities owning steam electric power plants under each weighting case.

In the lower bound scenario, EPA estimates that 3 small cooperatives, 4 small nonutilities, and 3 small municipalities owning steam electric power plants would incur costs exceeding one percent of revenue (Table 8-4), under the final rule (Option B). On the basis of *percentage*, the 3 small cooperatives represent approximately 12 to 16 percent of the number of small cooperatives owning steam electric power plants. The 4 small nonutilities represent approximately 3 to 7 percent of the number of small nonutilities owning steam electric power plants. The 3 small municipalities represents approximately 10 to 14 percent of the number of small municipalities owning steam electric power plants. These small entities represent approximately 5 to 8.5 percent of the total number of small entities owning steam electric power plants.

In the upper bound scenario, EPA estimates that 4 small cooperatives, 5 small nonutilities, and 3 small municipalities owning steam electric power plants would incur costs exceeding one percent of revenue (Table 8-5), under the final rule (Option B). On the basis of *percentage*, the 4 small cooperatives represent approximately 16 to 21 percent of the number of small cooperatives owning steam electric power plants. The 5 small nonutilities represent approximately 4 to 9 percent of the number of small nonutilities owning steam electric power plants. The 3 small municipalities represents approximately 10 to 14 percent of the number of small municipalities owning steam electric power plants. These small entities represent approximately 6 to 10 percent of the total number of small entities owning steam electric power plants.

In the lower bound scenario, the analysis shows 5 small businesses (2 small cooperatives, 2 small nonutilities, and 1 small municipality) entity incurring costs greater than three percent of revenue under all regulatory options. These small entities represent approximately 2.5 to 4 percent of the small entities owning steam electric power plants. Overall, this worst-case screening-level analysis suggests that the analyzed regulatory options are unlikely to have a significant economic impact on a substantial impact on small entities. In the upper bound scenario, the analysis shows 7 small businesses (3 small cooperatives, 2 small nonutilities, and 2 small municipalities) entity incurring costs greater than three percent of revenue under all regulatory options. These small entities represent approximately 3.5 to 6 percent of the small entities owning steam electric power plants. Overall, this worst-case screening-level analysis suggests that the analyzed regulatory options are unlikely to have a significant economic impact on a substantial impact on small entities under the lower and upper bound scenario.

Table 8-4: Estimated Cost-To-Revenue Impact on Small Parent Entities, by Entity Type and Ownership Category – Lower Bound

Entity Type/Ownership Category	Case 1: Lower bound estimate of number of entities owning steam electric power plants (out of total of 117 small entities)				Case 2: Upper bound estimate of number of entities owning steam electric power plants (out of total of 202 small entities)			
	≥1%		≥3%[a]		≥1%		≥3%[a]	
	Number of small entities	% of all small entities[b]	Number of small entities	% of all small entities[b]	Number of small entities	% of all small entities[b]	Number of small entities	% of all small entities[b]
Option A								
Small Business								
Cooperative	2	10.5%	2	10.5%	2	8.0%	2	8.0%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Nonutility	2	3.5%	2	3.5%	2	1.6%	2	1.6%
Small Government								
Municipality	3	13.6%	1	4.5%	3	10.0%	1	3.3%
Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	**7**	**6.0%**	**5**	**4.3%**	**7**	**3.5%**	**5**	**2.5%**
Option B								
Small Business								
Cooperative	3	15.8%	2	10.5%	3	12.0%	2	8.0%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Nonutility	4	7.0%	2	3.5%	4	3.2%	2	1.6%
Small Government								
Municipality	3	13.6%	1	4.5%	3	10.0%	1	3.3%
Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	**10**	**8.5%**	**5**	**4.3%**	**10**	**5.0%**	**5**	**2.5%**
Option C								
Small Business								
Cooperative	3	15.8%	2	10.5%	3	12.0%	2	8.0%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Nonutility	4	7.0%	2	3.5%	4	3.2%	2	1.6%
Small Government								
Municipality	3	13.6%	1	4.5%	3	10.0%	1	3.3%
Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	**10**	**8.5%**	**5**	**4.3%**	**10**	**5.0%**	**5**	**2.5%**

a. The number of entities with cost-to-revenue impact of at least three percent is a subset of the number of entities with such ratios exceeding one percent.

b. Percentage values were calculated relative to the total of 117 (Case 1) and 202 (Case 2) small entities owning steam electric power plants regardless of whether these plants are estimated to incur compliance technology costs under any of the regulatory options.

Source: U.S. EPA Analysis, 2024.

Table 8-5: Estimated Cost-To-Revenue Impact on Small Parent Entities, by Entity Type and Ownership Category – Upper Bound

Entity Type/Ownership Category	Case 1: Lower bound estimate of number of entities owning steam electric power plants (out of total of 117 small entities)				Case 2: Upper bound estimate of number of entities owning steam electric power plants (out of total of 202 small entities)			
	≥1%		≥3%[a]		≥1%		≥3%[a]	
	Number of small entities	% of all small entities[b]	Number of small entities	% of all small entities[b]	Number of small entities	% of all small entities[b]	Number of small entities	% of all small entities[b]
Option A								
Small Business								
Cooperative	3	15.8%	3	15.8%	3	12.0%	3	12.0%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Nonutility	3	5.3%	2	3.5%	3	2.4%	2	1.6%
Small Government								
Municipality	3	13.6%	2	9.1%	3	10.0%	2	6.7%
Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	**9**	**7.7%**	**7**	**6.0%**	**9**	**4.5%**	**7**	**3.5%**
Option B								
Small Business								
Cooperative	4	21.1%	3	15.8%	4	16.0%	3	12.0%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Nonutility	5	8.8%	2	3.5%	5	4.1%	2	1.6%
Small Government								
Municipality	3	13.6%	2	9.1%	3	10.0%	2	6.7%
Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	**12**	**10.3%**	**7**	**6.0%**	**12**	**5.9%**	**7**	**3.5%**
Option C								
Small Business								
Cooperative	4	21.1%	3	15.8%	4	16.0%	3	12.0%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Nonutility	5	8.8%	2	3.5%	5	4.1%	2	1.6%
Small Government								
Municipality	3	13.6%	2	9.1%	3	10.0%	2	6.7%
Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	**12**	**10.3%**	**7**	**6.0%**	**12**	**5.9%**	**7**	**3.5%**

a. The number of entities with cost-to-revenue impact of at least three percent is a subset of the number of entities with such ratios exceeding one percent.

b. Percentage values were calculated relative to the total of 117 (Case 1) and 202 (Case 2) small entities owning steam electric power plants regardless of whether these plants are estimated to incur compliance technology costs under any of the regulatory options.

Source: U.S. EPA Analysis, 2024.

8.3 Uncertainties and Limitations

Despite EPA's use of the best available information and data, the RFA analysis discussed in this chapter has sources of uncertainty, including:

- None of the sample-weighting approaches used for this analysis accounts precisely for the number of parent-entities and compliance costs assigned to those entities simultaneously. EPA assesses the values presented in this chapter as reasonable estimates of the numbers of small entities that could incur a significant impact according to the cost-to-revenue metric.
- In cases where available information was insufficient to determine the size of an entity, the Agency assumed the entity to be small. EPA was unable to determine the size of nine parent entities and assumed all to be small for this analysis.
- As discussed in Chapter 4, the zero cost pass-through assumption represents a worst-case scenario from the perspective of the plants and parent entities. To the extent that some entities are able to pass at least some compliance costs to consumers through higher electricity prices, this analysis may overstate potential impact of regulatory options A through C on small entities.

8.4 Small Entity Considerations in the Development of Rule Options

As described in the introduction to this chapter, the RFA requires federal agencies to consider the impact of their regulatory actions on small entities and to analyze alternatives that minimize those impacts. As EPA explicitly states in the final rule, the implementation period built into the rule is another way for permit writers to consider the needs of small entities, as these entities may need additional time to plan and finance capital improvements.

9 Unfunded Mandates Reform Act (UMRA) Analysis

Title II of the Unfunded Mandates Reform Act of 1995, Pub. L. 104-4, requires that federal agencies assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under UMRA section 202, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that might result in expenditures by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100 million (adjusted annually for inflation) or more in any one year (*i.e.*, about $198 million in 2023 dollars). Before promulgating a regulation for which a written statement is needed, UMRA section 205 generally requires EPA to "identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule." (2 U.S.C. 1535(a) The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative, if the Administrator publishes with the rule an explanation of why that alternative was not adopted. Before EPA establishes any regulatory requirements that might significantly or uniquely affect small governments, including Tribal governments, it must develop a small government agency plan, under UMRA section 203. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant intergovernmental mandates, and informing, educating, and advising small governments on compliance with regulatory requirements.

EPA estimated the compliance costs associated with each of the regulatory options for different categories of entities. The Agency estimates that the *maximum* compliance cost *in any one year* to government entities (excluding federal government) range from $155 million under the lower bound cost scenario to $220 million under the upper bound cost scenario.[88,89] The *maximum* compliance cost *in any given year* to the private sector range from $1,380 million under the lower bound cost scenario to $3,156 million under the upper bound cost scenario. From these compliance cost values, EPA determined that the final rule does contain a mandate that may result in expenditures of $198 million (in 2023 dollars) or more for the public (including State, local, and Tribal governments) and private sectors in any one year.

This chapter contains additional information to support the above statements, including information on compliance and administrative costs, and on impacts to small governments. Following the approach used for the analysis of the 2015 and 2020 rules and 2023 proposal (U.S. EPA, 2015, 2020, 2023d; see Chapter 9), the annualized costs presented in this UMRA analysis are calculated using the social cost framework presented in Chapter 12 of the BCA (U.S. EPA, 2024a). Specifically, this analysis uses costs in 2024 stated in 2023 dollars and accounts for costs in the year they are anticipated to be incurred between 2025 and 2049. The discounted stream of costs is then annualized over a 25-year period. As discussed in Chapter 10 (Other Administrative Requirements; see Section 10.7) in this document, the reporting and recordkeeping requirements in this final rule would increase the reporting and recordkeeping burden for the review, oversight, and administration of the rule relative to baseline requirements. NPDES permitting authorities are required to review notices of planned participation (NOPPs), leachate groundwater

88 Maximum costs are costs incurred by the entire universe of steam electric power plants in a given year of occurrence under a given regulatory option.

89 For this analysis, rural electric cooperatives are considered to be a part of the private sector.

information reports (LGIRs), and progress reports associates with EPA's voluntary incentive program (VIP) to administer this rule. Government entities owning steam electric power plants would potentially incur costs as the result of this rule associated with the cost to implement control technologies at power plants they own. For more details on how social costs were developed, see Chapter 12 in the BCA.

9.1 UMRA Analysis of Impact on Government Entities

This part of the UMRA analysis assesses the compliance cost burden to State, local, and Tribal governments that own existing steam electric power plants. The use of the phrase "government entities" in this section does *not* include the federal government, which owns 23 of the 858 steam electric power plants; three of these plants incur compliance costs under the regulatory options. Additionally, in evaluating the magnitude of the impact of the options on government entities, EPA analyzed only *compliance costs* incurred by government entities owning steam electric power plants. EPA estimated that government entities will not incur significant incremental *administrative costs* to implement the rule, regardless of whether or not they own steam electric power plants. As discussed in Section 10.7, EPA estimated some increase in the burden associated with this rule. In the case of plant owners, EPA estimated new reporting burdens from notices of planned participation (NOPPs), annual progress reports, leachate function equivalency reports, annual combustion residual leachate monitoring reports, and website posting of all of these documents.

Table 9-1 summarizes the number of State, local and Tribal government entities and the number of steam electric power plants they own. The determination of owning entities, their type, and their size is detailed in Section 4.3 and Chapter 8 (*Assessment of Potential Impact of the Regulatory Options on Small Entities – Regulatory Flexibility Act (RFA) Analysis*).

Table 9-1: Government-Owned Steam Electric Power Plants and Their Parent Entities

Entity Type	Parent Entities[a]	Steam electric power plants[b]
Municipality	50	111
Other Political Subdivision	11	33
State	2	4
Tribal	0	0
Total	**63**	**148**

a. Counts of entities under weighting Case 1, which provides an upper bound of total compliance costs for any given parent entity. For details see Chapter 8.

b. Plant counts are relative to the estimated 858 plants covered under the point source category.

Source: U.S. EPA Analysis, 2024.

Out of 858 steam electric power plants, 148 are owned by 63 government entities.[90] The majority (75 percent) of these government-owned plants are owned by municipalities, followed by other political subdivisions (22 percent), and State governments (3 percent).

Table 9-2 and Table 9-3 show upper and lower bound compliance costs for government entities owning steam electric power plants. Compliance costs to government entities under the final rule range from

90 Counts exclude federal government entities and steam electric power plants they own. The owning entity is determined based on the entity with the largest ownership share in each plant, as described in Chapter 4.

approximately $40 million to $66 million in the aggregate. Average annualized costs per plant are $0.3 million under the lower bound cost scenario and $0.5 million under the upper bound cost scenario. The maximum annualized compliance costs range from $8.65 million to $12.54 million.

Table 9-2: Estimated Compliance Costs to Government Entities Owning Steam Electric Power Plants (2023$) – Lower Bound

Ownership Type	Number of Steam Electric Power Plants (weighted)[a]	Total Weighted, Annualized Pre-Tax Cost (Millions)[a]	Average Annualized Cost per MW of Capacity[b]	Average Annualized Cost per Plant (Millions)[c]	Maximum Annualized Cost per Plant (Millions)[d]
Option A					
Municipality	111	$20	$592	$0.2	$7.79
Other Political Subdivision	33	$5	$266	$0.2	$1.93
State	4	$2	$363	$0.4	$1.16
Total	**148**	**$28**	**$462**	**$0.2**	**$7.79**
Option B					
Municipality	111	$28	$804	$0.3	$8.65
Other Political Subdivision	33	$7	$354	$0.2	$2.48
State	4	$5	$959	$1.2	$2.65
Total	**148**	**$40**	**$663**	**$0.3**	**$8.65**
Option C					
Municipality	111	$29	$842	$0.3	$8.65
Other Political Subdivision	33	$7	$354	$0.2	$2.48
State	4	$14	$2,936	$3.6	$11.57
Total	**148**	**$51**	**$845**	**$0.3**	**$11.57**

a. Plant counts are relative to the estimated 858 plants covered under the point source category.

b. Average cost per MW values were calculated using total compliance costs and capacity for all steam electric power plants owned by entities in a given ownership category. In case of multiple ownership structure where parent entities of a given plant have equal ownership shares and are in different ownership categories, compliance costs and capacity were allocated to appropriate ownership categories in accordance with ownership shares.

c. Average cost per plant values were calculated using the total number of steam electric power plants owned by entities in a given ownership category.

d. Reflects maximum of un-weighted costs to surveyed plants only.

Source: U.S. EPA Analysis, 2024.

Table 9-3: Estimated Compliance Costs to Government Entities Owning Steam Electric Power Plants (2023$) – Upper Bound

Ownership Type	Number of Steam Electric Power Plants (weighted)[a]	Total Weighted, Annualized Pre-Tax Cost (Millions)[a]	Average Annualized Cost per MW of Capacity[b]	Average Annualized Cost per Plant (Millions)[c]	Maximum Annualized Cost per Plant (Millions)[d]
Option A					
Municipality	111	$43	$1,261	$0.4	$11.67
Other Political Subdivision	33	$7	$350	$0.2	$1.93
State	4	$4	$795	$1.0	$2.04
Total	**148**	**$54**	**$912**	**$0.4**	**$11.67**

Table 9-3: Estimated Compliance Costs to Government Entities Owning Steam Electric Power Plants (2023$) – Upper Bound					
Ownership Type	**Number of Steam Electric Power Plants (weighted)[a]**	**Total Weighted, Annualized Pre-Tax Cost (Millions)[a]**	**Average Annualized Cost per MW of Capacity[b]**	**Average Annualized Cost per Plant (Millions)[c]**	**Maximum Annualized Cost per Plant (Millions)[d]**
Option B					
Municipality	111	$50	$1,472	$0.5	$12.54
Other Political Subdivision	33	$9	$438	$0.3	$2.48
State	4	$7	$1,392	$1.7	$4.09
Total	**148**	**$66**	**$1,113**	**$0.5**	**$12.54**
Option C					
Municipality	111	$52	$1,511	$0.5	$12.54
Other Political Subdivision	33	$9	$438	$0.3	$2.48
State	4	$16	$3,369	$4.1	$12.23
Total	**148**	**$77**	**$1,295**	**$0.5**	**$12.54**

a. Plant counts are relative to the estimated 858 plants covered under the point source category.

b. Average cost per MW values were calculated using total compliance costs and capacity for all steam electric power plants owned by entities in a given ownership category. In case of multiple ownership structure where parent entities of a given plant have equal ownership shares and are in different ownership categories, compliance costs and capacity were allocated to appropriate ownership categories in accordance with ownership shares.

c. Average cost per plant values were calculated using the total number of steam electric power plants owned by entities in a given ownership category.

d. Reflects maximum of un-weighted costs to surveyed plants only.

Source: U.S. EPA Analysis, 2024.

9.2 UMRA Analysis of Impact on Small Governments

As part of the UMRA analysis, EPA also assessed whether the regulatory options would significantly and uniquely affect small governments. To assess whether the regulatory options would affect small governments in a way that is disproportionately burdensome in comparison to the effect on large governments, EPA compared total incremental costs and costs per plant estimated to be incurred by small governments with those values estimated to be incurred by large governments. EPA also compared the changes in per plant costs incurred for small government-owned plants with those incurred by non-government-owned plants. The Agency evaluated costs per plant on the basis of both average and maximum annualized incremental cost per plant.

Table 9-4 presents the distribution of plants by entity type and size. Out of 148 government-owned steam electric power plants, EPA identified 37 plants that are owned by 24 small government entities. These 37 plants constitute approximately 25 percent of all government-owned plants.[91]

91 Counts exclude federal government entities and steam electric power plants they own.

Table 9-4: Counts of Government-Owned Plants and Their Parent Entities, by Size

Entity Type	Entities[a]			Steam Electric Power Plants[b]		
	Large	Small	Total	Large	Small	Total
Municipality	28	22	50	80	31	111
Other Political Subdivision	9	2	11	27	6	33
State	2	0	2	4	0	4
Total	**39**	**24**	**63**	**111**	**37**	**148**

a. Counts of entities under weighting Case 1, which provides an upper bound of total compliance costs for any given parent entity. For details see Chapter 8.

b. Plant counts are relative to the estimated 858 plants covered under the point source category.

Source: U.S. EPA Analysis, 2024.

As presented in Table 9-5 and Table 9-6, under the final rule, overall compliance costs range from $633 million in the lower bound cost scenario to $1,245 million in the upper bound cost scenario.

Table 9-5: Estimated Incremental Compliance Costs for Electric Generators by Ownership Type and Size (2023$) – Lower Bound

Ownership Type	Entity Size	Number of Plants [a]	Total Annualized Pre-Tax Costs (Millions)[a]	Average Annualized Pre-tax Cost per MW of Capacity[b]	Average Annualized Pre-tax Cost per Plant (Millions)[c]	Maximum Annualized Pre-tax Cost per Plant (Millions)
Option A						
Government (excl. federal)	Small	37	$9	$1,385	$0.24	$2.6
	Large	111	$19	$350	$0.17	$7.8
Private	Small	230	$117	$1,104	$0.51	$40.8
	Large	457	$355	$1,011	$0.78	$42.8
All Plants		**858**	**$509**	**$805**	**$0.59**	**$42.8**
Option B						
Government (excl. federal)	Small	37	$10	$1,566	$0.27	$2.6
	Large	111	$30	$553	$0.27	$8.7
Private	Small	230	$132	$1,245	$0.57	$42.7
	Large	457	$452	$1,285	$0.99	$77.5
All Plants		**858**	**$633**	**$1,001**	**$0.74**	**$77.5**
Option C						
Government (excl. federal)	Small	37	$10	$1,566	$0.27	$2.6
	Large	111	$40	$757	$0.37	$11.6
Private	Small	230	$133	$1,258	$0.58	$42.7
	Large	457	$537	$1,528	$1.18	$77.5
All Plants		**858**	**$734**	**$1,160**	**$0.86**	**$77.5**

a. Plant counts are relative to the estimated 858 plants covered under the point source category.

b. Average cost per MW values were calculated using total compliance costs and capacity for all steam electric power plants owned by entities in a given ownership category, *including plants that incur zero costs*. In case of multiple ownership structure where parent entities of a given plant have equal ownership shares and are in different ownership categories, compliance costs and capacity were allocated to appropriate ownership categories in accordance with ownership shares.

c. Average cost per plant values were calculated using total number of steam electric power plants owned by entities in a given ownership category. As a result, plants with multiple majority owners are represented more than once in the denominator of relevant cost per plant calculations.

Source: U.S. EPA Analysis, 2024.

Table 9-6: Estimated Incremental Compliance Costs for Electric Generators by Ownership Type and Size (2023$) – Upper Bound

Ownership Type	Entity Size	Number of Plants [a]	Total Annualized Pre-Tax Costs (Millions)[a]	Average Annualized Pre-tax Cost per MW of Capacity[b]	Average Annualized Pre-tax Cost per Plant (Millions)[c]	Maximum Annualized Pre-tax Cost per Plant (Millions)
Option A						
Government (excl. federal)	Small	37	$20	$3,046	$0.53	$10.5
	Large	111	$35	$652	$0.31	$11.7
Private	Small	230	$306	$2,884	$1.33	$173.9
	Large	457	$735	$2,090	$1.61	$127.2
All Plants		**858**	**$1,121**	**$1,772**	**$1.31**	**$173.9**
Option B						
Government (excl. federal)	Small	37	$21	$3,227	$0.57	$10.5
	Large	111	$46	$856	$0.41	$12.5
Private	Small	230	$321	$3,025	$1.39	$175.8
	Large	457	$831	$2,364	$1.82	$128.8
All Plants		**858**	**$1,245**	**$1,968**	**$1.45**	**$175.8**
Option C						
Government (excl. federal)	Small	37	$21	$3,227	$0.57	$10.5
	Large	111	$57	$1,060	$0.51	$12.5
Private	Small	230	$322	$3,038	$1.40	$175.8
	Large	457	$917	$2,607	$2.01	$130.6
All Plants		**858**	**$1,346**	**$2,126**	**$1.57**	**$175.8**

a. Plant counts are relative to the estimated 858 plants covered under the point source category.

b. Average cost per MW values were calculated using total compliance costs and capacity for all steam electric power plants owned by entities in a given ownership category, *including plants that incur zero costs*. In case of multiple ownership structure where parent entities of a given plant have equal ownership shares and are in different ownership categories, compliance costs and capacity were allocated to appropriate ownership categories in accordance with ownership shares.

c. Average cost per plant values were calculated using total number of steam electric power plants owned by entities in a given ownership category. As a result, plants with multiple majority owners are represented more than once in the denominator of relevant cost per plant calculations.

Source: U.S. EPA Analysis, 2024.

9.3 UMRA Analysis of Impact on the Private Sector

As the final part of the UMRA analysis, this section reports the compliance costs projected to be incurred by private entities.

Table 9-7 and Table 9-8 summarize the lower and upper bound total annualized costs, maximum one-year costs, and the year when maximum costs are incurred by type of owner. EPA estimates the final rule to have total annualized pre-tax compliance costs for private entities ranging from $603 million under the lower bound cost scenario to $1,207 million under the upper bound cost scenario.

Table 9-7: Compliance Costs for Electric Generators by Ownership Type (2023$) – Lower Bound

Ownership Type	Total Annualized Costs (Millions)	Maximum One-Year Costs (Millions)	Year of Maximum Costs[a]
Option A			
Government (excl. federal)	$28	$135	2026
Private	$490	$1,096	2028
Option B			
Government (excl. federal)	$40	$155	2026
Private	$603	$1,380	2028
Option C			
Government (excl. federal)	$51	$256	2026
Private	$693	$1,596	2028

a. The year when the maximum cost occurs is driven by the modeled technology implementation schedule and is determined based on the renewal of individual NPDES permits for plants owned by the different categories of entities. See Section 3.1.3 in this report and Chapter 11 in the BCA for more details on the technology implementation years and assumptions on the timing of cost incurrence.

Source: U.S. EPA Analysis, 2024.

Table 9-8: Compliance Costs for Electric Generators by Ownership Type (Millions of 2023$) – Upper Bound

Ownership Type	Total Annualized Costs (Millions)	Maximum One-Year Costs (Millions)	Year of Maximum Costs[a]
Option A			
Government (excl. federal)	$55	$200	2026
Private	$1,095	$2,872	2028
Option B			
Government (excl. federal)	$67	$220	2026
Private	$1,207	$3,156	2028
Option C			
Government (excl. federal)	$78	$320	2026
Private	$1,298	$3,372	2028

a. The year when the maximum cost occurs is driven by the modeled technology implementation schedule and is determined based on the renewal of individual NPDES permits for plants owned by the different categories of entities. See Section 3.1.3 in this report and Chapter 11 in the BCA for more details on the technology implementation years and assumptions on the timing of cost incurrence.

Source: U.S. EPA Analysis, 2024.

9.4 UMRA Analysis Summary

EPA estimated that State and local government entities would incur expenditures of greater than $198 million, in the aggregate, in any one year under the final rule, Option B, in the upper bound scenario only. Additionally, the Agency estimated that the private sector would incur expenditures of greater than $198 million, in the aggregate, in any one year under all regulatory options, under the upper and lower scenario. Furthermore, as discussed above, neither permitted plants nor permitting authorities are estimated to incur significant additional administrative costs as the result of the regulatory options.

Consistent with Section 205, EPA presents three regulatory options which would all result in compliance costs to governments and the private sector. For Option B, the final rule, the maximum compliance costs incurred by the private sector in any one year range from $1,380 million to $3,156 million in 2028 whereas total annualized compliance costs for plants owned by private sector entities range from $603 million to $1,207 million. The implementation period built into this final rule is one way that EPA accounted for the site-specific needs of steam electric power plants.

10 Other Administrative Requirements

This chapter presents analyses conducted in support of the regulatory options to address the requirements of applicable Executive Orders and Acts. These analyses complement EPA's assessment of the compliance costs, economic impacts, and economic achievability of the final rule, and other analyses done in accordance with the RFA and UMRA, presented in previous chapters.

10.1 Executive Order 12866: Regulatory Planning and Review, Executive Order 13563: Improving Regulation and Regulatory Review, and Executive Order 14094: Modernizing Regulatory Review

Under Executive Order (E.O.) 12866 (58 FR 51735, October 4, 1993), as amended by E.O. 13563 (76 FR 3821, January 21, 2011) and E.O. 14094 (88 FR 21879, April 11, 2023), EPA must determine whether the regulatory action is "significant" and therefore subject to review by the Office of Management and Budget (OMB) and other requirements of the Executive Order. The order defines a "significant regulatory action" as one that is likely to result in a regulation that may:

- Have an annual effect on the economy of $200 million or more (adjusted every 3 years by the Administrator of the Office of Information and Regulatory Affairs (OIRA) for changes in gross domestic product), or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or Tribal governments or communities; or

- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; or

- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

- Raise novel legal or policy issues for which centralized review would meaningfully further the President's priorities or the principles set forth in the Executive Order, as specifically authorized in a timely manner by the Administrator of OIRA in each case.

Pursuant to the terms of Executive Order 12866, as amended by E.O. 14094, EPA determined that the final rule (Option B) is a "significant regulatory action" because the action is likely to have an annual effect on the economy of $200 million or more. As such, the action is subject to review by OMB. Any changes made during this period of review will be documented in the docket for this action.

EPA prepared an analysis of the potential benefits and costs associated with this action; this analysis is described in Chapter 13 of the BCA (U.S. EPA, 2024a).

As detailed in earlier chapters of this report, EPA also assessed the impacts of the regulatory options on the wholesale price of electricity (Chapter 5: Electricity Market Analyses), retail electricity prices by consumer group (Chapter 7: Electricity Price Effects), and on employment or labor markets (Chapter 6: Employment Effects).

10.2 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, Executive Order 14008: Tackling the Climate Crisis at Home and Abroad, and Executive Order 14096: Revitalizing our Nation's Commitment to Environmental Justice for All

E.O. 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States. E.O. 14008 (86 FR 7619, February 1, 2021) expands on the policy objectives established in E.O.12898 and directs federal agencies to develop programs, policies, and activities to address the disproportionately high and adverse human health, environmental, climate-related and other cumulative impacts on disadvantaged communities, as well as the accompanying economic challenges of such impacts.

EPA's analysis showed that the human health or environmental risk addressed by this final rule will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income, or indigenous populations. The results of this evaluation are contained in the EJA (U.S. EPA, 2024c).

10.3 Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

E.O. 13045 (62 FR 19885, April 23, 1997) applies to any rule that (1) is determined to be "economically significant" as defined under E.O. 12866 and (2) concerns an environmental health or safety risk that EPA has reason to believe might have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health and safety effects of the planned rule on children and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

As detailed in the EA and BCA (U.S. EPA, 2024a, 2024b), EPA identified several ways in which the regulatory options would affect children, including by potentially reducing health risk from exposure to pollutants present in steam electric power plant discharges. The reductions are estimated to be relatively small and arise from more stringent limits under the regulatory options as compared to the baseline. EPA quantified neurological changes, as measured by Intellectual Quotient (IQ) points, from lead exposure among pre-school children and from mercury exposure *in-utero* resulting from maternal fish consumption under the regulatory options, as compared to the baseline. EPA also estimated changes in the number of children with very high blood lead concentrations (above 20 ug/dL) and IQs less than 70 who may require compensatory education tailored to their specific needs.

EPA estimated that the final rule could benefit children. The analysis shows relatively small potential changes in lead exposure (from fish consumption) for an average of 1.55 million children annually, and in mercury exposure (from maternal fish consumption) for an average of 201,850 infants born annually. However, EPA estimates the resulting health impacts to be relatively small. EPA estimated that the final rule (Option B) would lead to slight reductions in lead and mercury exposure, decreasing IQ losses by less than 1 point from lead exposure and 1,377 points from mercury exposure over the entire exposed population. The annualized social welfare effects from reduced IQ loss associated with children's exposure to lead and mercury are $2.0 million using a 2 percent discount rate, with most of these benefits associated with reduced mercury exposure. Chapter 5 in the BCA provides further details, including results for the other regulatory options (U.S. EPA, 2024a). EPA did not quantify additional benefits to children from changes in exposure to steam electric pollutant discharges due to data limitations, but discussed them qualitatively. These include changes in the incidence or severity of other health effects from exposure to lead, mercury, and other pollutants including arsenic, boron, cadmium, copper, nickel, selenium, thallium, and zinc. They also include potential effects from reductions in exposure to disinfection byproducts in households served by drinking water systems that use source waters downstream of steam electric power plant outfalls.

10.4 Executive Order 13132: Federalism

E.O. 13132 (64 FR 43255, August 10, 1999) requires EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." Policies that have federalism implications are defined in the Executive Order to include regulations that 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."

Under section 6 of E.O. 13132, EPA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute unless the federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments or unless EPA consults with State and local officials early in the process of developing the regulation. EPA also may not issue a regulation that has federalism implications and that preempts State law, unless the Agency consults with State and local officials early in the process of developing the regulation.

EPA has concluded that this action will have federalism implications, because it may impose substantial direct compliance costs on State or local governments, and the Federal government would not provide the funds necessary to pay those costs. As discussed in earlier chapters of this document, EPA anticipates that the final rule will not impose a significant incremental administrative burden on States from issuing, reviewing, and overseeing compliance with discharge requirements.

Specifically, EPA has identified 148 steam electric power plants that are owned by State or local government entities or other political subdivisions. EPA estimates that the maximum compliance cost in any one year to governments (excluding federal government) ranges from $155 million to $220 million under the final rule (Option B) (see Chapter 9, *Unfunded Mandates Reform Act (UMRA)*, for details). Annualized compliance costs incurred by governments are $40 million to $67 million under the final rule (Option B).

10.5 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

E.O. 13175 (65 FR 67249, November 6, 2000) requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." "Policies that have tribal implications" is defined in the Executive Order to include regulations that have "substantial direct effects on one or more Indian Tribes, on the relationship between the Federal government and the Indian Tribes, or on the distribution of power and responsibilities between the federal government and Indian Tribes."

EPA assessed potential tribal implications for the regulatory options arising from three main changes, as described below: (1) direct compliance costs incurred by plants; (2) impacts on drinking water systems downstream from steam electric power plants; and (3) administrative burden on governments that implement the NPDES program.

- Direct compliance costs: EPA's analyses show that no plant estimated to be affected by the regulatory options is owned by tribal governments.
- Impacts on drinking water systems: EPA identified one public water system (PWS) operated by tribal governments that may be affected by bromide and iodine discharges from steam electric power plants.[92] In total, this systems serves approximately 6,800 people. EPA estimated small reductions in bromide and iodine concentrations in the source waters of this PWS under the final rule, providing health benefits to the populations served by the PWS. The analysis is detailed in Chapter 4 of the BCA (U.S. EPA, 2024a). Due to data limitations, EPA was not able to quantify the potential drinking water treatment cost savings for this system in the analysis detailed in Chapter 9 of the BCA (U.S. EPA, 2024a).
- Administrative burden: No tribal governments are currently authorized pursuant to section 402(b) of the CWA to implement the NPDES program.

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

E.O. 13211 requires Agencies to prepare a Statement of Energy Effects when undertaking certain agency actions. Such Statements of Energy Effects shall describe the effects of certain regulatory actions on energy supply, distribution, or use, notably: (i) any adverse effects on energy supply, distribution, or use (including a shortfall in supply, price increases, and increased use of foreign supplies) should the proposal be implemented, and (ii) reasonable alternatives to the action with adverse energy effects and the estimated effects of such alternatives on energy supply, distribution, and use.

The OMB implementation memorandum for E.O. 13211 outlines specific criteria for assessing whether a regulation constitutes a "significant energy action" and would have a "significant adverse effect on the supply, distribution or use of energy."[93] Those criteria include:

- Reductions in crude oil supply in excess of 10,000 barrels per day;
- Reductions in fuel production in excess of 4,000 barrels per day;
- Reductions in coal production in excess of 5 million tons per year;

92 EPA included public water systems identified in EPA's Safe Drinking Water Information System as having a tribe as the primacy agency and one tribe-operated system with the state of Oklahoma as the primacy agency.

93 Executive Order 13211 was issued May 18, 2002. The OMB later released an Implementation Guidance memorandum on July 13, 2002.

- Reductions in natural gas production in excess of 25 million mcf per year;
- Reductions in electricity production in excess of 1 billion kilowatt-hours per year, or in excess of 500 megawatts of installed capacity;
- Increases in the cost of energy production in excess of 1 percent;
- Increases in the cost of energy distribution in excess of 1 percent;
- Significant increases in dependence on foreign supplies of energy; or
- Having other similar adverse outcomes, particularly unintended ones.

None of the criteria above regarding potential significant adverse effects on the supply, distribution, or use of energy (listed above) apply to this final rule. While the regulatory options might affect (1) the production of electricity, (2) the amount of installed capacity, (3) the cost of energy production, and (4) the dependence on foreign supplies of energy, as described below and demonstrated by the results from the national electricity market analyses conducted for the final rule (see Chapter 5),[94] changes for the first three factors are smaller than the thresholds of concern specified by OMB.

10.6.1 Impact on Electricity Generation

The electricity market analyses (Chapter 5) estimate that the final rule will decrease coal-fired generation, including generation from power plants to which the final rule applies, by 3.8 percent to approximately 0.7 percent in 2028 through 2050, relative to baseline generation. The changes in coal-fired generation would be offset by roughly corresponding changes in production from other plants, resulting in no net decrease in overall production; electricity generated in 2035 increases by 1,693 GWh, which is approximately 0.3 percent of baseline generation. These changes are very small and support EPA's assessment that the final rule does not constitute a "significant energy action" in terms of overall impact on electricity generation.

10.6.2 Impact on Electricity Generating Capacity

As documented in Chapter 5, the Agency's electricity market analysis estimated that the final rule would result in net cumulative capacity decrease of 370 MW of generating capacity by 2045. This is the largest projected decrease in generating capacity in the analysis years.

10.6.3 Cost of Energy Production

Based on the IPM analysis results, EPA estimated that the final rule will not significantly affect the total cost of electricity production. At the national level, total electricity generation costs (fuel, variable O&M, fixed O&M, capital, and CCS) under the final rule are projected to increase by 0.2 percent. At the regional level, the change in electricity generation costs varies. Table 5-4 in Chapter *5* summarizes changes projected in IPM for the 2035 run year and shows range from an increase of 0.9 percent in MRO

94 As described in Chapter 5, this analysis does not consider the costs associated with legacy wastewater limits or the treatment of unmanaged CRL.

to a decrease of 0.1 percent in the RF and NPCC regions under the final rule. None of the NERC regions show increases approaching 1 percent.

Consequently, no region would experience net energy price increases greater than the 1 percent threshold as a result of the final rule in either the short or the long run. This supports EPA's assessment that the final rule does not constitute a "significant energy action" in terms of estimated potential effects on the cost of energy production.

10.6.4 Dependence on Foreign Supply of Energy

EPA's electricity market analyses did not support explicit consideration of the effects of the regulatory options on foreign imports of energy. However, the regulatory options directly affect electric power plants, which generally do not face significant foreign competition. Only Canada and Mexico are connected to the U.S. electricity grid, and transmission losses are substantial when electricity is transmitted over long distances. In addition, the effects on installed capacity and electricity prices are estimated to be small.

Table 10-1 presents IPM projected generating capacity and generation by type in 2035 under the baseline and the final rule. The final rule is estimated to decrease coal-based electricity generation by 9 percent, while generation using several other sources of energy is estimated to either increase (natural gas, wind, solar, and landfill gas), or decrease (*i.e.*, hydro, landfill gas, oil/gas steam). Apart from coal generation and oil/gas steam generation, and natural gas, changes are less than 1 percent across all generation types.

Table 10-1: Total Market-Level Capacity and Generation by Type for the Final Rule in Model Year 2035

Type	Generating Capacity (GW)			Electricity Generation (Thousand GWh)		
	Baseline	Option B	% Change	Baseline	Option B	% Change
Hydro	107.3	107.3	0.00%	319.3	318.7	-0.17%
Biomass	0.2	0.2	0.00%	0.4	0.4	0.00%
Geothermal	3.2	3.2	0.00%	21.3	21.3	0.00%
Landfill Gas	3.0	3.0	0.00%	19.1	19.1	-0.08%
Solar	298.2	299.2	0.33%	705.5	708.0	0.35%
Wind	394.0	395.2	0.31%	1,482.7	1,487.3	0.31%
Coal	51.6	46.0	-10.94%	235.7	214.5	-9.00%
Nuclear	83.7	83.7	0.00%	667.0	667.0	0.00%
Natural Gas	476.0	480.2	0.89%	1,344.4	1,359.3	1.11%
Oil/Gas Steam	55.3	55.1	-0.20%	7.7	7.1	-7.67%
Other[b]	6.5	6.5	0.00%	30.5	30.5	-0.02%
Total[a]	**1,478.9**	**1,479.6**	0.05%	**4,833.5**	**4,833.2**	-0.01%

a. Numbers may not add up due to rounding.

b. Values for energy storage are reported in the "Other" category.

Source: U.S. EPA Analysis, 2024.

Table 10-2 presents the corresponding projections of the quantity of fuel used for power generation. Changes are consistent with changes in generation presented in Table 10-1 with less coal (6.97 percent) and more natural gas (0.83 percent) consumed under the final rule. Changes are less than 1 percent for natural gas, lignite and subbituminous coal. However, bituminous coal consumption decreases by 21.82 percent.

Table 10-2: Total Market-Level Fuel Use by Fuel Type for the Final Rule in Model Year 2035

	Fuel Consumption		
Fuel Type	**Baseline**	**Option B**	**% Change**
Coal (million tons)	141	131	-6.97%
Bituminous Coal (million tons)	42	33	-21.82%
Subbituminous Coal (million tons)	74	74	-0.81%
Lignite (million tons)	24	24	0.07%
Natural Gas (trillion cubic feet)	9	9	0.83%

Source: U.S. EPA Analysis, 2024.

Given the very small changes in coal and other fuels use under the final rule, it is reasonable to assume that any increase in demand for fuel used in electricity generation would be met through domestic supply, thereby not increasing U.S. dependence on foreign supply of energy. Consequently, EPA assesses that the final rule does not constitute a "significant energy action" from the perspective of energy independence.

10.6.5 Overall Executive Order 13211 Finding

From these analyses and the electricity markets analysis in Chapter 5, EPA concludes that the final rule would not have a *significant adverse effect* at a national or regional level under E.O. 13211. Specifically, the Agency's analysis found that the rule would not reduce net electricity production in excess of 1 billion kilowatt hours per year nor or installed capacity in excess of 500 megawatts, nor would the rule increase U.S. dependence on foreign supply of energy. As such, the final rule does not constitute a significant regulatory action under E.O. 13211 and EPA did not prepare a Statement of Energy Effects.

10.7 Paperwork Reduction Act of 1995

The Paperwork Reduction Act of 1995 (PRA) (superseding the PRA of 1980) is implemented by OMB and requires that agencies submit a supporting statement to OMB for any information collection that solicits the same data from more than nine parties. The PRA seeks to ensure that Federal agencies balance their need to collect information with the paperwork burden imposed on the public by the collection.

The definition of "information collection" includes activities required by regulations, such as permit development, monitoring, record keeping, and reporting. The term "burden" refers to the "time, effort, or financial resources" the public expends to provide information to or for a Federal agency, or to otherwise fulfill statutory or regulatory requirements. PRA paperwork burden is measured in terms of annual time and financial resources the public devotes to meet one-time and recurring information requests (44 U.S.C. 3502(2); 5 C.F.R. 1320.3(b)). Information collection activities may include:

- reviewing instructions;
- using technology to collect, process, and disclose information;
- adjusting existing practices to comply with requirements;
- searching data sources;
- completing and reviewing the response; and
- transmitting or disclosing information.

Agencies must provide information to OMB on the parties affected, the annual reporting burden, the annualized cost of responding to the information collection, and whether the request significantly impacts a substantial number of small entities. An agency may not conduct or sponsor, and a person is not required to respond to, an information collection unless it displays a currently valid OMB control number.

OMB has previously approved the information collection requirements contained in the existing regulations 40 CFR part 423 under the provisions of the Paperwork Reduction Act.[95]

EPA is finalizing several changes to the individual reporting and recordkeeping requirements of section 423.19 for specific subcategories of plants and/or plants that have certain types of discharges. EPA is adding reporting and recordkeeping requirements to plants in the permanent cessation of coal combustion by 2034 subcategory and for plants that discharge unmanaged CRL. EPA is also removing reporting and recordkeeping requirements for low-utilization electric generating units and finalizing a new requirement for plants to post reports to a publicly available website. EPA estimates it would take a total annual average of 24,300 hours and $2,540,000 for 236 affected steam electric power plants to collect and report the information in the final rule. These costs are in addition to those detailed in Chapter 3.3 through Chapter 9 of this document.

EPA estimates it would take a total annual average of 3,230 hours and $273,000 for permitting or control authorities to review the information submitted by plants. EPA estimates that there would be no start-up or capital costs associated with the information described above. Here also, these costs are in addition to those detailed in Chapter 3.3 through Chapter 9 of this document.

10.8 National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995, Pub L. No. 104-113, Sec. 12(d) directs EPA to use voluntary consensus standards in its regulatory activities unless doing so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standard bodies. The NTTAA directs EPA to provide Congress, through the OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

The regulatory options do not involve technical standards, for example in the measurement of pollutant loads. Nothing in the regulatory options would prevent the use of voluntary consensus standards for such measurement where available, and EPA encourages permitting authorities and regulated entities to do so. Therefore, EPA did not include any voluntary consensus standards in the final rule.

95 OMB has assigned control number 2040-0281 to the information collection requirements under 40 CFR part 423.

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A Summary of Changes to Costs and Economic Impact Analysis

Table A-1 summarizes the principal methodological changes EPA made to analyses of the costs and economic impacts of this final ELG rule as compared to the analyses of the 2020 rule and the 2023 proposal (U.S. EPA, 2020, 2023d).

Table A-1: Changes to Costs and Economic Impacts Analysis Since 2020 Rule and 2023 Proposed Rule

Cost or Impact Category	Analysis Component (2020 Rule Analysis)	Change from 2020 Rule to 2023 Proposed Rule	Change from 2023 Proposed Rule to 2024 Final Rule
General inputs for screening-level analyses	Compliance costs discounted and annualized (7 percent)	No change	Compliance costs discounted and annualized using a weighted average cost of capital for the power sector of 3.76 percent
	Generation, plant revenue, and estimated electricity prices using EIA-861 and EIA-923 databases; six-year (2013-2018) average values	Updated with data from more current EIA-861 and EIA-923 databases to use more recent six-year [2015-2020] average values	Updated with data from more current EIA-861 and EIA-923 databases to use more recent six-year [2016-2021] average values
	Generating capacity from 2018 EIA-860	Updated using 2020 EIA-860	Updated using 2021 EIA-860
	NERC regions from 2017 EIA-860	Updated using 2020 EIA-860	Updated using 2021 EIA-860
	Electricity revenue, sales, and number of consumers by consumer class (residential, industrial, commercial, and transportation) for ASCC and HICC regions from EIA-861 for [2018]	Updated to use data from EIA-861 for [2020]	Updated to use data from EIA-861 for [2021]
	Electricity revenue, sales, and number of consumers by consumer class (residential, industrial, commercial, and transportation) for NERC regions other than ASCC and HICC regions from [2019] AEO projections	Updated using [2021] AEO projections	Updated using [2023] AEO projections
Industry profile	Total count of plants (914 plants)	Updated universe of 871 plants reflects information on actual, planned, and announced unit retirements through the end of 2028	Updated universe of 858 plants reflects information on actual, planned, and announced unit retirements through the end of 2028
	Industry data (*i.e.*, capacity, generation, number of plants, etc.) from 2018 EIA databases	Updated using 2020 EIA databases	Updated using 2021 EIA databases

Table A-1: Changes to Costs and Economic Impacts Analysis Since 2020 Rule and 2023 Proposed Rule

Cost or Impact Category	Analysis Component (2020 Rule Analysis)	Change from 2020 Rule to 2023 Proposed Rule	Change from 2023 Proposed Rule to 2024 Final Rule
Screening-level plant impacts	Cost-to-revenue impact indicators (1% and 3%) based on 6-year (2013-2018) average values of electricity generation and electricity prices (to estimate plant-level revenue)	Updated to use average electricity generation and electricity prices for [2015-2020]	Updated to use average electricity generation and electricity prices for [2016-2021]
Market-level impacts (IPM)	The Baseline includes existing regulatory requirements as of January 2020, plus the final CCR Part A rule and an updated representation of the 2015 ELG based on 2020 data.	The Baseline includes existing regulatory requirements as of August 2021 and an updated representation of the 2020 ELG based on 2021 data.	The Baseline includes regulatory requirements as of March 2023 including the Inflation Reduction Act of 2022.
Potential electricity price effects	Projected total electricity sales in [2020] from [AEO 2019]	Projected total electricity sales in [2024] from [AEO 2021]	Projected total electricity sales in [2024] from [AEO 2023]
	Electricity sales data by consumer group from [2018] EIA-860 database	Electricity sales data by consumer group from [2020] EIA-860 database	Electricity sales data by consumer group from [2021] EIA-860 database
Owner-level impacts and RFA/SBREFA	Owners identified in EIA-860 [2018]	Owners identified in EIA-860 [2020]	Owners identified in EIA-860 [2021]
	Small business size determination metrics [Dun and Bradstreet for private entities; Census ACS 2017 for governments]	Small business size determination metrics [Dun and Bradstreet for private entities; Census ACS 2019 for governments]	Small business size determination metrics [Dun and Bradstreet for private entities; Census ACS 2021 for governments]

B Comparison of Incremental Costs and Pollutant Removals

This appendix describes EPA's analysis of the incremental costs and pollutant removals of the regulatory options. The information provides insight into how regulatory options compare to each other in terms of reducing toxic pollutant discharges to surface waters.

B.1 Methodology

Cost-effectiveness is defined as the incremental annualized cost of a pollution control option in an industry or industry subcategory per incremental pound equivalent of pollutant (*i.e.*, pound of pollutant adjusted for toxicity) removed by that control option. The analysis compares removals for pollutants directly regulated by the ELGs and incidentally removed along with regulated pollutants.

As described for the 2015 and 2020 rules and 2023 proposed rule, EPA's cost-effectiveness analysis involves the following steps to generate input data and calculate the desired values (for details, see Appendix F in U.S. EPA, 2015):

1. Determine the pollutants considered for regulation.
2. For each pollutant, obtain relative toxic weights and POTW removal factors.
3. Define the regulatory pollution control options.
4. Calculate pollutant removals and toxic-weighted pollutant removals for each control option and for each of direct and indirect discharges. For indirect dischargers, the calculations include applying a factor that reflects the ability of a POTW or sewage treatment plant to remove pollutants prior to discharge to water. See TDD (U.S. EPA, 2024e) for details.
5. Determine the total annualized compliance cost for each control option and for direct and indirect dischargers.
6. Adjust the cost obtained in step 5 to 1981 dollars.[96]
7. Calculate the cost-effectiveness ratios for each control option and for direct and indirect dischargers.

EPA calculated the cost-effectiveness ratios for the final rule regulatory options, but did not include the costs or loading reductions resulting from the unmanaged CRL limits. EPA only estimated changes in total dissolved solids and total suspended solids for unmanaged CRL discharges. Since these broad parameters cannot be easily translated into toxic pollutants, EPA did not include the costs associated with treatment of unmanaged CRL discharges to be consistent. The next section provides results for steps 1 through 5, where the total annualized compliance costs calculated in step 5 are relative to the 2020 rule baseline.

96 Adjustment of costs to 1981 dollars is a convention to facilitate comparison of cost-effectiveness values across rules. Since EPA is not estimating cost-effectiveness ratios in this analysis, this adjustment was not needed.

B.2 Results

Toxic Weights of Pollutants and POTW Removal

The TDD provides information on the pollutants addressed by the regulatory options (U.S. EPA, 2024e). The pollutants include several metals (*e.g.*, arsenic, mercury, selenium), various non-metal compounds (*e.g.*, chloride, fluoride, sulfate), nutrients, and conventional pollutants (*e.g.*, oil and grease, biochemical oxygen demand.)

The toxic weighted pound equivalent (TWPE) analysis involves multiplying the changes in loadings of each pollutant by a pollutant-specific toxic weighting factor (TWF) that represents the toxic effect level relative to the toxicity of copper. For indirect dischargers, the changes are multiplied by a second factor that reflects the ability of a POTW or sewage treatment plant to remove pollutants prior to discharge to waters.

Evaluated Options

EPA analyzed Options A through C summarized in Table 1-1.

Pollutant Removals and Pound Equivalent Calculations

Table B-1, below, presents estimated annual reduction in the mass loading of pollutant anticipated from direct and indirect dischargers for each regulatory option, relative to the baseline. The toxic weighted removals account for pollutant toxicity and, for indirect dischargers,[97] for POTW removals. The calculations do not account for the removal of pollutants that do not have TWFs, either because data are not available to set a TWF or toxicity is not the pollutant's primary environmental impact (*e.g.*, nutrients contributing to eutrophication, bromide contributing to formation of disinfection byproducts). Furthermore, the pound equivalent pollutant removal analysis does not address routes of potential environmental damage and human exposure, and therefore potential benefits from reducing pollutant exposure.

Annualized Compliance Costs

EPA developed costs for technology controls to address each of the wastestreams present at each steam electric power plant. The TDD provides additional details on the methods used to estimate the costs of meeting the limitations and standards under the baseline and each of the regulatory options (U.S. EPA, 2024e). The method used to calculate the incremental annualized compliance costs is described in greater detail in Chapter 3, *Compliance Costs*. EPA categorized these annualized compliance costs as either direct or indirect based on the discharge associated with each wastestream at each plant. Table B-1 summarizes the annualized compliance costs of the regulatory options relative to the baseline.

Cost Effectiveness

Table B-1 summarizes the cost-effectiveness ratios for the regulatory options, calculated as the annual cost of that option divided by to the pound-equivalents removed by that option. The incremental effectiveness of progressively more stringent regulatory options can be assessed both in comparison to the baseline scenario and to another regulatory option. By convention, EPA presents the cost-effectiveness

97 Plants that discharge pollutants to a POTW.

values in 1981 dollars per pound-equivalent removed. Figure B-1 compares the pollutant removals and costs of the regulatory options graphically.

Table B-1: Estimated Pollutant Removal and Costs of Regulatory Options by Discharger Category

Discharger Category	Option[c]	Total Annual TWF-Weighted Pollutant Removals (lb-eq.)[a]		Total Annual Pre-tax Compliance Costs (million, 2023$)		Cost-Effectiveness (1981$/lb-eq.)[b]	
		Total[d]	Incremental[e]	Total[d]	Incremental[e]	Total[d]	Incremental[e]
Direct	A	199,121	199,121	$317.81	$317.81	$422	$422
	B	247,191	48,070	$432.45	$114.64	$463	$631
	C	271,621	24,430	$529.11	$96.66	$515	$1,047
Indirect	A	2,989	2,989	$9.45	$9.45	$837	$837
	B	3,194	205	$10.15	$0.70	$841	$900
	C	3,214	20	$12.56	$2.41	$1,034	$31,302

a. The Agency estimated zero TWPE but non-zero BA compliance costs for one plant in this analysis. EPA included the costs for this plant in this analysis even though there are no corresponding removals.

b. Compliance costs adjusted to 1981 dollars using the CCI (3,535 / 13,358 = 0.265)

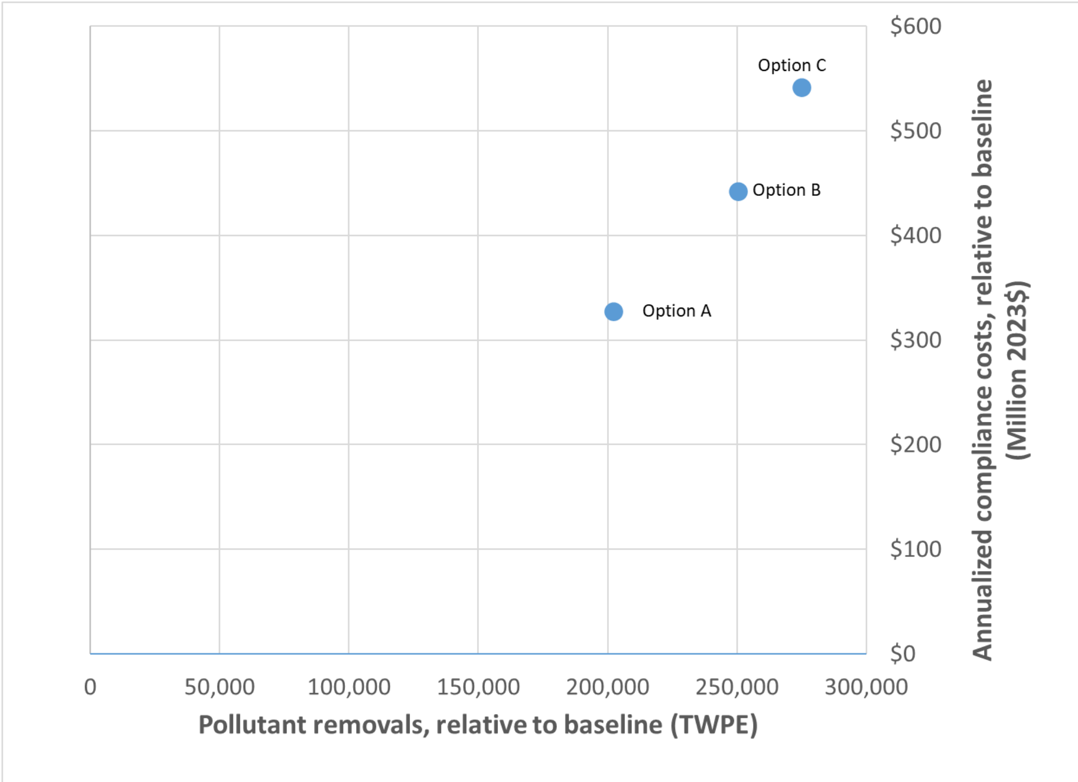
c. Options are listed in increasing order of pollutant removals, relative to the baseline.

d. Total removals and costs are compared to those for the baseline.

e. Incremental removals and costs are compared to those for the next least stringent option in the order listed in the table. For direct dischargers, the incremental removals and costs under Option A are calculated relative to the baseline, the incremental removals and costs for Option B are calculated relative to those of Option A, etc.

Source: U.S. EPA Analysis, 2024

Figure B-1: Estimated Removals and Costs of the Regulatory Options, Relative to Baseline.



Source: U.S. EPA Analysis, 2024.

C Total Costs Based on 7 Percent Discount Rate

Table C-1 and Table C-2 present compliance cost estimates for the regulatory options, and Table and Table C-4 show the breakout of total compliance costs for each option by wastestream, based on the 7 percent discount rate that was previously used for the 2023 proposed rule analysis as representing the private cost of capital (U.S. EPA, 2023d). For comparison, the tables include values from Table 3-1 and Table 3-3 estimated using the 3.76 percent discount rate used as the revised estimate of the private cost of capital.

Table C-1: Estimated Total Annualized Compliance Costs (in millions, 2023$, at 2024) – Lower

Regulatory Option	Pre-Tax Compliance Costs				After-Tax Compliance Costs			
	Capital Technology	Other Initial One-Time	Total O&M	Total	Capital Technology	Other Initial One-Time	Total O&M	Total
3.76% Discount Rate								
Option A	$232	$0.1	$247	$479	$186	$0.1	$200	$386
Option B	$284	$0.2	$312	$596	$229	$0.1	$250	$479
Option C	$336	$0.2	$359	$695	$270	$0.2	$286	$557
7% Discount Rate								
Option A	$271	$0.1	$228	$499	$218	$0.1	$184	$401
Option B	$325	$0.2	$282	$608	$262	$0.2	$226	$488
Option C	$385	$0.2	$325	$711	$310	$0.2	$259	$569

Source: U.S. EPA Analysis, 2024.

Table C-2: Estimated Total Annualized Compliance Costs (in millions, 2023$, at 2024) – Upper

Regulatory Option	Pre-Tax Compliance Costs				After-Tax Compliance Costs			
	Capital Technology	Other Initial One-Time	Total O&M	Total	Capital Technology	Other Initial One-Time	Total O&M	Total
3.76% Discount Rate								
Option A	$453	$0.1	$595	$1,048	$372	$0.1	$490	$863
Option B	$505	$0.2	$659	$1,164	$415	$0.1	$541	$956
Option C	$557	$0.2	$706	$1,263	$456	$0.2	$577	$1,033
7% Discount Rate								
Option A	$526	$0.1	$543	$1,069	$432	$0.1	$447	$878
Option B	$580	$0.2	$597	$1,177	$476	$0.2	$489	$965
Option C	$640	$0.2	$640	$1,281	$524	$0.2	$522	$1,046

Source: U.S. EPA Analysis, 2024.

Table C-3: Estimated Total Annualized Compliance Costs, by Wastestream (in millions, 2023$, at 2024) – Lower

Regulatory Option	Pre-Tax Compliance Costs					After-Tax Compliance Costs				
	BA Transport Water	FGD Wastewater	CRL	Legacy	Net Total Costs	BA Transport Water	FGD Wastewater	CRL	Legacy	Net Total Costs
3.76% Discount Rate										
Option A	$19	$179	$281	$0	$479	$15	$139	$232	$0	$386
Option B	$19	$179	$370	$28	$596	$15	$139	$302	$23	$479
Option C	$30	$205	$433	$28	$695	$23	$160	$350	$23	$557
7% Discount Rate										
Option A	$20	$190	$289	$0	$499	$16	$147	$238	$0	$401
Option B	$20	$190	$381	$17	$608	$16	$147	$310	$14	$488
Option C	$31	$216	$446	$17	$711	$25	$170	$360	$14	$569

Source: U.S. EPA Analysis, 2024.

Table C-4: Estimated Total Annualized Compliance Costs, by Wastestream (in millions, 2023$, at 2024) – Upper

Regulatory Option	Pre-Tax Compliance Costs					After-Tax Compliance Costs				
	BA Transport Water	FGD Wastewater	CRL	Legacy	Net Total Costs	BA Transport Water	FGD Wastewater	CRL	Leg acy	Net Total Costs
3.76% Discount Rate										
Option A	$19	$179	$849	$0	$1,048	$15	$139	$709	$0	$863
Option B	$19	$179	$939	$28	$1,164	$15	$139	$778	$23	$956
Option C	$30	$205	$1,001	$28	$1,263	$23	$160	$826	$23	$1,033
7% Discount Rate										
Option A	$20	$190	$859	$0	$1,069	$16	$147	$715	$0	$878
Option B	$20	$190	$950	$17	$1,177	$16	$147	$787	$14	$965
Option C	$31	$216	$1,016	$17	$1,281	$25	$170	$838	$14	$1,046

Source: U.S. EPA Analysis, 2024.