ATTACHMENT A

Regulatory Impact Analysis for the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule

3 COMPLIANCE COSTS, EMISSIONS, AND ENERGY IMPACTS

3.1 Overview

This section reports the compliance costs, emissions, and energy analyses performed for the final NSPS and final Emission Guidelines. EPA used the Integrated Planning Model (IPM)[47] to conduct the electric generating units (EGU) analysis discussed in this section. As explained in detail below, this section presents analysis for three illustrative scenarios that differ in the level of EGU greenhouse gas (GHG) mitigation measures, and timing thereof in the lower 48 states subject to this action. The analysis for EGUs in the section includes effects from certain provisions of the Inflation Reduction Act (IRA) of 2022 in the baseline.[48] The analysis presented in this section reflects the combined effects of the final rules on new and existing sources. The impacts of each action independently are presented in Appendix D.

The section is organized as follows: following a summary of the illustrative scenarios analyzed and a summary of EPA's methodologies, we present estimates of compliance costs for EGUs, as well as estimated impacts on emissions, generation, capacity, fuel use, fuel price, and retail electricity price for select run years.[49]

3.2 Illustrative Scenarios

These rules establish GHG mitigation measures on certain fossil fuel-fired electric generating units. The EGUs covered by these rules are existing fossil fuel-fired steam generating

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[47] Information on IPM can be found at the following link: https://www.epa.gov/airmarkets/power-sector-modeling.

[48] The Inflation Reduction Act (IRA) contains tax credit provisions that affect power sector operations, details of which are incorporated into the IPM modeling. Details are included in the IPM documentation. The Clean Electricity Investment and Production Tax Credits (provisions 48E and 45Y of the IRA) are described in more detail in Section 4. The credit for Carbon Capture and Sequestration (provision 45Q) is described in Section 3. The impacts of the Zero-Emission Nuclear Power Production Credit (provision 45U) are reflected through modifying nuclear retirement limits, as described in Section 4. The Credit for the Production of Clean Hydrogen (provision 45V) is reflected through the inclusion of an exogenously delivered price of hydrogen fuel, see Section 9. The Advanced Manufacturing Production Tax Credit (45X) was reflected through adjustments to the short-term capital cost added for renewable technologies, see Section 4. Documentation available at: https://www.epa.gov/power-sector-modeling

[49] IPM uses model years to represent the full planning horizon being modeled. By mapping multiple calendar years to a run year, the model size is kept manageable. IPM considers the costs in all years in the planning horizon while reporting results only for model run years. For this analysis, IPM maps the calendar year 2028 to run year 2028, calendar years 2029-31 to run year 2030, calendar years 2032-37 to run year 2035, calendar years 2038-42 to run year 2040, calendar years 2043-47 to run year 2045 and calendar years 2048-52 to run year 2050. For model details, please see Chapter 2 of the IPM documentation, available at: https://www.epa.gov/airmarkets/power-sector-modeling

units greater than 25 MW, and new and reconstructed fossil fuel-fired combustion turbines that commence construction or reconstruction after the publication of this final regulation. For details on the source categories and the mitigation measures considered please see sections VII, VIII, and IX of the preamble.

This RIA evaluates the benefits, costs, and certain impacts of compliance with three illustrative scenarios: one scenario representing the final rules, and two scenarios representing alternative sets of requirements. To the extent possible, EPA evaluated the 111(b) final rule for new natural-gas fired EGUs and 111(d) final rule for existing coal fired EGUs in combination to better analyze the interactive effects of the final rules. For details of the controls modeled for each of the existing source categories starting in run year 2030 under the three illustrative scenarios please see Table 3-1 and Table 3-2 below.

Table 3-1 Summary of Modeled GHG Mitigation Measures for Existing Sources by Source Category under the Illustrative Final Rules and Alternative 1 Scenario[a,b,c]

Affected EGUs	Subcategory Definition	GHG Mitigation Measure
Long-term existing coal-fired steam generating units	Coal-fired steam generating units that have not elected to commit to permanently cease operations by 2040	CCS with 90% capture of CO_2, starting in 2035
Medium-term existing coal-fired steam generating units	Coal-fired steam generating units that have not elected to commit to permanently cease operations prior to 2035 but have committed to permanently ceasing operations by 2040	Natural gas co-firing at 40 percent of the heat input to the unit, starting in 2030

[a] All years shown in this table reflect IPM run years. Note that IPM run years encompass the specific calendar year requirements of BSER, details of which are available in Section VII of the preamble.
[b] Coal units that lack existing SCR controls must install these controls in addition to CCS to comply.
[c] Coal-fired EGUs that convert entirely to burn natural gas by 2030 are no longer subject to coal-fired EGU mitigation measures outlined above.

Table 3-2 Summary of Modeled GHG Mitigation Measures for Existing Sources by Source Category under the Illustrative Alternative 2 Scenario[a,b,c]

Affected EGUs	Subcategory Definition	GHG Mitigation Measure
Long-term existing coal-fired steam generating units	Coal-fired steam generating units that have not elected to commit to permanently cease operations by 2040	CCS with 90% capture of CO_2, starting in 2035
Medium-term existing coal-fired steam generating units	Coal-fired steam generating units that have not elected to commit to permanently cease operations prior to 2035 but have committed to permanently ceasing operations by 2040	Natural gas co-firing at 40 percent of the heat input to the unit, starting in 2035

[a] All years shown in this table reflect IPM run years. Note that IPM run years encompass the specific calendar year requirements of BSER, details of which are available in Section VII of the preamble.
[b] Coal units that lack existing SCR controls must install these controls in addition to CCS to comply.
[c] Coal-fired EGUs that convert entirely to burn natural gas by 2035 are no longer subject to coal-fired EGU mitigation measures outlined above.

Table 3-3 Summary of GHG Mitigation Measures for New Sources by Source Category under the Illustrative Final Rules, Alternative 1 and Alternative 2 Scenarios[a,b]

<table>
<tr><th>Affected EGUs</th><th>Subcategory Definition</th><th>Modeled Requirements During 1st Phase</th><th>Modeled Requirements During 2nd Phase (2035)</th><th>Baseload Definition: Alternative 1 and Alternative 2 Scenarios</th><th>Baseload Definition: Final Rules Scenario</th></tr>
<tr><td>Baseload Economic NGCC Additions</td><td>NGCC units that commence construction after 2023 and operate at greater than baseload annual capacity factor</td><td>Efficient generation</td><td>CCS or co-fire hydrogen at sufficient level to meet CCS emission rate</td><td rowspan="4">50%</td><td rowspan="4">40%</td></tr>
<tr><td>Intermediate Load Economic NGCC Additions</td><td>NGCC units that commence construction after 2023 and operate at an annual capacity factor of less than baseload</td><td colspan="2">Efficient generation</td></tr>
<tr><td>Intermediate load Economic NGCT Additions</td><td>NGCT units that commence construction after 2023 and operate at an annual capacity factor of more than 20%</td><td colspan="2">Emission rate consistent with NGCC operation</td></tr>
<tr><td>Peaking Economic NGCT Additions</td><td>NGCT units that commence construction after 2023 and operate at an annual capacity factor of less than 20%</td><td colspan="2">Efficient generation</td></tr>
</table>

[a] All years shown in this table reflect IPM run years. Note that IPM run years encompass the specific calendar year requirements of BSER, details of which are available in Section VII of the preamble.
[b] Delivered hydrogen price is assumed to be $1.15/kg in all years.
[c] The modeling does not reflect the requirements of the variable subcategory. We estimate this would have a limited impact on the results.

The illustrative compliance outcomes in this RIA represent EGU behavior in response to GHG mitigation measures applied to affected source categories in given IPM run years.[50] This RIA analyzes the final rules, as well as two alternative scenarios. The alternative 1 and alternative 2 scenarios assume the definition of annual capacity factor for baseload operation for new turbines is 50 percent, whereas under the final rules scenario baseload is defined as 40 percent annual capacity factor. The final rules and alternative 1 scenarios assume all medium-term existing coal-fired steam generating units must co-fire at least 40 percent natural gas by 2030[51], while the alternative 2 scenario assumes that all medium-term existing coal fired steam generating units must co-fire at least 40 percent natural gas by 2035.

The GHG mitigation measures in this RIA are illustrative since States are afforded flexibility to implement the final rules, and thus the impacts could be different to the extent states make different choices than those assumed in the illustrative analysis. Additionally, the way that EGUs comply with the GHG mitigation measures may differ from the methods forecast in the modeling for this RIA. See Section 3.4 for further discussion of the modeling approach used in the analysis presented below.

3.3 Monitoring, Reporting, and Recordkeeping Costs

EPA projected monitoring, reporting and recordkeeping (MR&R) costs for both state entities and affected EGUs for the years 2024 onwards. The MR&R cost estimates presented below apply to the three illustrative scenarios.

EPA estimates that industry will incur MR&R costs due to the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units. More specifically, we estimate costs associated with 40 CFR

[50] IPM uses model years to represent the full planning horizon being modeled. By mapping multiple calendar years to a run year, the model size is kept manageable. IPM considers the costs in all years in the planning horizon while reporting results only for model run years. For this analysis, IPM maps the calendar year 2028 to run year 2028, calendar years 2029-31 to run year 2030, calendar years 2032-37 to run year 2035, calendar years 2038-42 to run year 2040, calendar years 2043-47 to run year 2045 and calendar years 2048-52 to run year 2050. For model details, please see Chapter 2 of the IPM documentation, available at: https://www.epa.gov/airmarkets/power-sector-modeling

[51] CCS costs used in this analysis are developed by Sargent & Lundy and are outlined in Chapter 6 of the IPM documentation. These costs do not include the solvent acid or water washing costs. For details, please see: https://www.epa.gov/power-sector-modeling.

Part 60, Subpart TTTTa, as described in the supporting statement found in the docket. For purposes of RIA analysis, we assume that national costs in 2026 are approximately $35,000 in 2019 dollars, and then increase by approximately $35,000 in 2019 dollars each year thereafter to reflect costs associated with additional respondents.[52] We estimate that states will not incur MR&R costs associated with the Final New Source Performance Standards.

EPA estimates that industry will not incur incremental MR&R costs due to the Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units. We estimate that states will incur MR&R costs associated with this final rule. We estimate that this may affect 43 states, resulting in a total national annual burden of approximately 89,400 hours of labor, or approximately $11 million in 2019 dollars. For detailed information, see the Information Collection Request Support Statement for the Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units available in the docket for these actions. For purposes of this analysis, we estimate that these MR&R costs will be incurred over the three-year period of 2024 through 2026.

[52] For purposes of this regulatory impact analysis: (1) As described in the TTTTa supporting statement in the docket, we estimate there to be six new respondents in 2026; (2) We assume that these six respondents are simple cycle units, and that NGCC units would not incur MR&R costs incremental to existing TTTT requirements; (3) We assume that the number of new respondents would increase by six new respondents per year for each year over this analysis timeframe through 2047.

Table 3-4 Summary of State and Industry Annual Respondent Cost of Reporting and Recordkeeping Requirements (million 2019 dollars)

	Final NSPS for New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units		Final EGs for Existing Fossil Fuel-Fired Electric Generating Units		Total
	Industry	State[a]	Industry[b]	State	Total
2024	-	-	-	11	11
2025	-	-	-	11	11
2026	0.035	-	-	11	11
2027	0.07	-	-	-	0.070
2028	0.11	-	-	-	0.11
2029	0.14	-	-	-	0.14
2030	0.18	-	-	-	0.18
2031	0.21	-	-	-	0.21
2032	0.25	-	-	-	0.25
2033	0.28	-	-	-	0.28
2034	0.32	-	-	-	0.32
2035	0.35	-	-	-	0.35
2036	0.39	-	-	-	0.39
2037	0.42	-	-	-	0.42
2038	0.46	-	-	-	0.46
2039	0.49	-	-	-	0.49
2040	0.53	-	-	-	0.53
2041	0.56	-	-	-	0.56
2042	0.60	-	-	-	0.60
2043	0.63	-	-	-	0.63
2044	0.67	-	-	-	0.67
2045	0.70	-	-	-	0.70
2046	0.74	-	-	-	0.74
2047	0.77	-	-	-	0.77

[a] EPA estimates that states will not incur MR&R costs for the Final NSPS for New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units.
[b] EPA estimates that industry will not incur MR&R costs for the Final EGs for Existing Fossil Fuel-Fired Electric Generating Units.

3.4 Power Sector Modeling Framework

IPM is a state-of-the-art, peer-reviewed, dynamic linear programming model that can be used to project power sector behavior under future business-as-usual conditions and to examine prospective air pollution control policies throughout the contiguous United States for the entire electric power system. EPA used IPM to project likely future electricity market conditions with and without the final NSPS and Emission Guidelines.

IPM, developed by the consultancy ICF, is a multi-regional, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. It provides estimates of least cost capacity expansion, electricity dispatch, and emissions control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. The model accounts for all major electric regions throughout the country, including transmission capabilities and constraints between them. This ensures that key transmission constraints are represented in IPM and that each individual IPM region has less internal transmission congestion based on today's loads and resource mix.

EPA has used IPM for almost three decades to better understand power sector behavior under future business-as-usual conditions and to evaluate the economic and emissions impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions discussed here as well as all other model assumptions and inputs.[53]

The model incorporates a detailed representation of the fossil-fuel supply system that is used to estimate equilibrium fuel prices. The model uses natural gas fuel supply curves and regional gas delivery costs (basis differentials) to simulate the fuel price associated with a given level of gas consumption within the system. These inputs are derived using ICF's Gas Market Model (GMM), a supply/demand equilibrium model of the North American gas market.[54]

IPM also endogenously models the partial equilibrium of coal supply and EGU coal demand levels throughout the contiguous U.S., taking into account assumed non-power sector demand and imports/exports. IPM reflects 36 coal supply regions, 14 coal grades, and the coal transport network, which consists of over four thousand linkages representing rail, barge, and truck and conveyer linkages. The coal supply curves in IPM were developed during a thorough bottom-up, mine-by-mine approach that depicts the coal choices and associated supply costs that power plants would face if selecting that coal over the modeling time horizon. The IPM

[53] Detailed information and documentation of EPA's Baseline run using IPM (v6), including all the underlying assumptions, data sources, and architecture parameters can be found on EPA's website at: https://www.epa.gov/power-sector-modeling.
[54] See Chapter 8 of EPA's Baseline run using IPM v6 documentation, available at: https://www.epa.gov/power-sector-modeling

documentation outlines the methods and data used to quantify the economically recoverable coal reserves, characterize their cost, and build the 36 coal regions' supply curves.[55]

To estimate the annualized costs of additional capital investments in the power sector, EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. The CRF is derived from estimates of the power sector's cost of capital (i.e., private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital.[56] It is important to note that there is no single CRF factor applied in the model; rather, the CRF varies across technologies, book life of the capital investments, and regions in the model in order to better simulate power sector decision-making.[57]

EPA has used IPM extensively over the past three decades to analyze options for reducing power sector emissions. Previously, the model has been used to estimate the costs, emission changes, and power sector impacts for the Clean Air Interstate Rule (U.S. EPA, 2005), the Cross-State Air Pollution Rule (U.S. EPA, 2011a), the Mercury and Air Toxics Standards (U.S. EPA, 2011b), the Clean Power Plan for Existing Power Plants (U.S. EPA, 2015b), the Cross-State Air Pollution Update Rule (U.S. EPA, 2016), the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units (U.S. EPA, 2019), and the Revised Cross-State Air Pollution Update Rule (U.S. EPA, 2021), and the Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (U.S. EPA, 2023). EPA has also used IPM to estimate the air pollution reductions and power sector impacts of water and waste regulations affecting EGUs, including contributing to RIAs for the Cooling Water Intakes (316(b)) Rule (U.S. EPA, 2014a), the Disposal of Coal Combustion Residuals from Electric Utilities rule (U.S. EPA, 2015c), the Steam Electric Effluent Limitation Guidelines (U.S. EPA, 2015a), and the Steam Electric Reconsideration Rule (U.S. EPA, 2020)

The model and EPA's input assumptions undergo periodic formal peer review. The rulemaking process also provides opportunity for expert review and comment by a variety of

[55] See Chapter 7 of the IPM documentation, available at: https://www.epa.gov/power-sector-modeling
[56] See Chapter 10 of the IPM documentation, available at: https://www.epa.gov/airmarkets/power-sector-modeling
[57] Costs modeled in IPM reflect the costs faced by industry, and therefore are net of subsidies included in the IRA

stakeholders, including owners and operators of capacity in the electricity sector that is represented by the model, public interest groups, and other developers of U.S. electricity sector models. The feedback that the Agency receives provides a highly detailed review of key input assumptions, model representation, and modeling results. IPM has received extensive review by energy and environmental modeling experts in a variety of contexts. For example, in September 2019 U.S. EPA commissioned a peer review of EPA Baseline version 6, and in October 2014 U.S. EPA commissioned a peer review of EPA Baseline version 5.13 using the Integrated Planning Model.[58] Additionally, and in the late 1990s, the Science Advisory Board reviewed IPM as part of the CAA Amendments Section 812 prospective studies.[59] The Agency has also used the model in a number of comparative modeling exercises sponsored by Stanford University's Energy Modeling Forum over the past 20 years. IPM has also been employed by states (e.g., for the Regional Greenhouse Gas Initiative, the Western Regional Air Partnership, Ozone Transport Assessment Group), other Federal and state agencies, environmental groups, and industry.

3.5 EPA's Power Sector Modeling of the Baseline Run and Three Illustrative Scenarios

The IPM "baseline" for any regulatory impact analysis is a business-as-usual scenario that represents expected behavior in the electricity sector under market and regulatory conditions in the absence of a regulatory action. As such, an IPM baseline represents an element of the baseline for this RIA.[60] EPA frequently updates the IPM baseline to reflect the latest available electricity demand forecasts from the U.S. Energy Information Administration (EIA) as well as expected costs and availability of new and existing generating resources, fuels, emission control technologies, and regulatory requirements. The IPM baseline also includes power-sector related provisions from the IRA.[61]

[58] See Response and Peer Review Reports, available at: https://www.epa.gov/power-sector-modeling/ipm-peer-reviews.

[59] http://www2.epa.gov/clean-air-act-overview/benefits-and-costs-clean-air-act

[60] As described in Chapter 5 of EPA's *Guidelines for Preparing Economic Analyses*, the baseline "should incorporate assumptions about exogenous changes in the economy that may affect relevant benefits and costs (e.g., changes in demographics, economic activity, consumer preferences, and technology), industry compliance rates, other regulations promulgated by EPA or other government entities, and behavioral responses to the proposed rule by firms and the public" (U.S. EPA, 2014b).

[61] A wide variety of modeling teams have assessed baselines with IRA. The baseline estimated here is generally in line with these other estimates. See Bistline, et al. (2023). "Power Sector Impacts of the Inflation Reduction Act of 2022," In Preparation.

3.5.1 EPA's IPM Baseline Run v7.23

For our analysis of the final NSPS, and the final Emissions Guidelines, EPA used EPA's Power Sector Platform 2023 using IPM, as well as a companion updated database of EGU units (the National Electricity Energy Data System or NEEDS 12-04-23) that is used in EPA's modeling applications of IPM.[62] The IPM Baseline includes the CSAPR (2011a), CSAPR Update (2016), the Revised CSAPR Update (2021), and the proposed Good Neighbor Plan for 2015 Ozone NAAQS (2023), as well as the Mercury and Air Toxics Standards (2020). The baseline also includes the 2015 Effluent Limitation Guidelines (ELG) and the 2015 Coal Combustion Residuals (CCR), and the finalized 2020 ELG and CCR rules.[63] Finalized in December 2021, the impacts of the 2023 and Later Model Year Light-Duty Vehicle GHG Emissions Standards are also captured in the baseline; the rule includes requirements for model years 2023 through 2026. The impacts of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review are not captured in the baseline.[64] The proposed GNP Supplemental Rule (2023), the proposed Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles (2023), the proposed Heavy-duty Greenhouse Gas "Phase 3" for Model Years 2027 and Later (2023), the proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (2023), and the proposed Steam Electric Power Generating Effluent Guidelines (2023) were not included. Additionally, the model was also updated to account for recent updates to state and federal legislation affecting the power sector, including Public Law 117-169, 136 Stat. 1818 (August 16, 2022), commonly known as the Inflation Reduction Act of 2022 (IRA). The Integrated Planning Model (IPM) Documentation includes a summary of all legislation reflected in this version of the model as well as a description of how that legislation is implemented in the model. The IPM documentation provides details on the provisions of the IRA that were incorporated into this analysis, including provisions relating to tax subsidies for non-emitting

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[62] https://www.epa.gov/power-sector-modeling
[63] For a full list of modeled policy parameters, please see:
https://www.epa.gov/airmarkets/power-sector-modeling
[64] Available at: https://www.federalregister.gov/documents/2021/11/15/2021-24202/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for

generation, energy storage, and CCS.[65] The model runs for the main RIA analysis examine the combined effects of the final NSPS, and the final Emissions Guidelines. Appendix C examines the impact of the two rules independently. The analysis of power sector cost and impacts presented in this section is based on a single IPM Baseline run, and represents incremental impacts projected solely as a result of compliance with the GHG mitigation measures presented in Table 3-1, Table 3-2, and Table 3-3.

3.5.2 Methodology for Evaluating the Illustrative Scenarios

To estimate the costs, benefits, and economic and energy market impacts of the final NSPS, and the final Emissions Guidelines, EPA conducted quantitative analysis of the three illustrative scenarios: one scenario representing the final rules, and two scenarios representing alternative sets of requirements. Details about these illustrative scenarios as analyzed in this RIA, are provided above in Section 3.2.

Before undertaking power sector analysis to evaluate compliance with the illustrative scenarios, EPA first considered available GHG mitigation strategies that could be implemented by the 2035 run year. EPA considered the following GHG control strategies: Carbon Capture and Storage (CCS), efficient generation practices, natural gas co-firing at existing coal-fired EGUs and hydrogen co-firing at new combined cycle and combustion turbine EGUs. EPA then developed subcategory definitions that assigned GHG mitigation measures to the appropriate affected sources.[66] This RIA projects the system-wide least-cost strategies for complying with the assigned GHG mitigation measures. Least-cost compliance may lead to the application of different control strategies at a given source, which is in keeping with the cost-saving compliance flexibility afforded by this rulemaking.

[65] The Inflation Reduction Act (IRA) contains a number of tax credit provisions that affect power sector operations. The Clean Electricity Investment and Production Tax Credits (provisions 48E and 45Y of the IRA) are described in more detail in Section 4. The credit for Carbon Capture and Sequestration (provision 45Q) is described in Section 3. The impacts of the Zero-Emission Nuclear Power Production Credit (provision 45U) are reflected through modifying nuclear retirement limits, as described in Section 4. The Credit for the Production of Clean Hydrogen (provision 45V) is reflected through the inclusion of an exogenously delivered price of hydrogen fuel, see Section 9. The Advanced Manufacturing Production Tax Credit (45X) was reflected through adjustments to the short-term capital cost added for renewable technologies, see Section 4. For a discussion of the uncertainties around the modeling of the impacts of the IRA including CCS and market conditions, please see the Limitations Discussion in Section 3.7. Documentation is available at: https://www.epa.gov/power-sector-modeling

[66] For details, please see sections VII, VIII and X of the preamble.

While CCS at new and existing sources and co-firing natural gas at existing coal facilities[67] are captured endogenously within IPM v6.21, hydrogen co-firing at new gas EGUs is at present represented exogenously, but alternative representations are likely to be considered in future modeling.

Hydrogen is an exogenous input to the model, represented as a fuel that is available at affected sources at a delivered cost of $1.15/kg, inclusive of $3/kg subsidies under the IRA. These costs are consistent with DOE projections of 2030 for delivered costs of electrolytic low-GHG hydrogen in the range of $0.70/kg to $1.15/kg for power sector applications, given R&D advancements and economies of scale.[68] A growing number of studies are demonstrating more efficient and less expensive techniques to produce low-GHG electrolytic hydrogen; and, tax credits and market forces are expected to accelerate innovation and drive down costs even further over the next decade.[69] [70] [71]

We also note the model does not track upstream emissions associated with the production of the hydrogen (or any other modeled fuels such as coal and natural gas), nor any incremental electricity demand associated with its production. Under the illustrative Final Rules scenario, incremental electricity demand from hydrogen production in 2035 is estimated at about 0.1 GWh, or less than 0.001 percent of the total projected nationwide generation.

As noted in Section 5.2, IPM estimates compliance costs incurred by regulated firms, but because of the availability of subsidy payments, there are also real resource costs to the economy outside of the regulated sector. IPM provides EPA's best estimate of the costs of the final rules to the electricity sector and related energy sectors (i.e., natural gas, coal mining). To estimate the social costs for the economy as a whole, EPA has used information from IPM as an input into the

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[67] For details on CCS modeling in IPM, please see Chapter 6 of the documentation, available at: https://www.epa.gov/power-sector-modeling. Additionally, EPA has summarized the CCS costs for affected existing coal-fired steam generating units in the "GHG Mitigation Measures for Steam EGUs" Technical Support Document. For the universe of coal-fired steam generating units that have not committed to retirement or convert to gas by 2039, assuming a 12 year amortization period and an 80% capacity factor, EPA estimates the average abatement cost to be -$5/ton, inclusive of 45Q tax subsidies.

[68] DOE Pathways to Commercial Liftoff: Clean Hydrogen, March 2023 See: https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf

[69] "Sound waves boost green hydrogen production," Power Engineering, January 4, 2023.

[70] "Direct seawater electrolysis by adjusting the local reaction environment of a catalyst," Nature Energy, January 30, 2023.

[71] Hydrogen from Next-generation Electrolyzers of Water (H2NEW) | H2NEW (energy.gov)

Agency's computable general equilibrium model, SAGE. The economy-wide analysis is considered a complement to the more detailed evaluation of sector costs produced by IPM.

The annualized social cost estimated in SAGE for the finalized rules is approximately $1.32 billion (2019 dollars) between 2024 and 2047 using a 4.5 percent discount rate that is consistent with the internal discount rate in the model. Under the assumption that compliance costs from IPM in 2056 continue until 2081, the equivalent annualized value for social costs in the SAGE model is $1.51 billion (2019 dollars) over the period from 2024 to 2081, again using a 4.5 percent discount rate that is consistent with the internal discount rate of the model. The social cost estimate reflects the combined effect of the finalized rules' requirements and interactions with IRA subsidies for specific technologies that are expected to see increased use in response to the finalized rules. We are not able to identify their relative roles at this time. Note that SAGE does not currently estimate changes in emissions nor account for environmental benefits. See Section 5.2 for more discussion on the economy-wide analysis with SAGE and estimates of private and social costs.

3.5.3 Methodology for Estimating Compliance Costs

This section describes EPA's approach to quantify estimated compliance costs in the power sector associated with the three illustrative scenarios, which include estimates projected directly by the model, and costs estimated outside the model framework. The model projections capture the costs associated with installation of GHG mitigation measures at affected sources as well as the resulting effects on dispatch as the relative operating costs for units are affected. Additionally, EPA estimates monitoring, reporting and recordkeeping (MR&R) costs for affected EGUs for the timeframe of 2024 to 2047, and these costs are added to the estimated change in the total system production cost projected by IPM.

3.6 Estimated Impacts of the Illustrative Scenarios

3.6.1 Emissions Reduction Assessment

As indicated in Section 3.2, the EGU CO_2 emissions reductions are presented in this RIA from 2028 through 2045 and are based on IPM projections. Table 3-5 presents the estimated reduction in power sector CO_2 emissions resulting from compliance with the evaluated illustrative scenarios. The alternative scenarios produce smaller emissions reductions than the final rules.

Table 3-5 EGU Annual CO_2 Emissions and Emissions Changes (million metric tons) for the Baseline and the Illustrative Scenarios from 2028 through 2045 [72]

Annual CO_2		Total Emissions			Change from Baseline		
(million metric tons)	Baseline	Final Rules	Alternative 1	Alternative 2	Final Rules	Alternative 1	Alternative 2
2028	1,159	1,121	1,123	1,127	-38	-36	-32
2030	1,098	1,048	1,050	1,071	-50	-48	-27
2035	724	601	601	603	-123	-124	-122
2040	459	406	406	406	-54	-53	-53
2045	307	265	267	267	-42	-40	-40

Within the compliance modeling, sources within each subcategory are subject to GHG mitigation measures beginning in 2030. Since IPM is forward looking, investment decisions prior to the start of the program are influenced by how those assets would fare under the policy assumed. Hence, we see small reductions in 2028, prior to the imposition of the policy in 2030. Emission reductions peak in 2035 across all scenarios, reflective of the start of the requirements on existing coal-fired EGUs. Under the alternative 1 and alternative 2 scenarios, the baseload definition is assumed to be 50 percent under the NSPS, while the final rules scenario assumes a 40 percent baseload definition. The final rules and alternative 1 scenarios assume all medium-term existing coal-fired steam generating units must co-fire at least 40 percent natural gas by 2030, while the alternative 2 scenario assumes that all medium-term existing coal fired steam generating units must co-fire at least 40 percent natural gas by 2035.

The impact of the IRA is to increase the cost-competitiveness of low-emitting technology, with the result that emissions are projected to fall significantly over the forecast period under the baseline. Hence reductions from the rules are highest in 2035 relative to the baseline and also decline over time. For details on the EGU emissions controls assumed in each of the illustrative scenarios, please see Table 3-1, Table 3-2, and Table 3-3.

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

In addition to the annual CO_2 reductions, there will also be reductions of other air emissions associated with EGUs burning fossil fuels that result from compliance strategies to reduce annual CO_2 emissions. These other emissions include the annual total changes in emissions of NO_X, SO_2, direct $PM_{2.5}$, and ozone season NO_X emissions changes. The emissions reductions are presented in Table 3-6.

Table 3-6 EGU Annual Emissions and Emissions Changes for NO_X, SO_2, $PM_{2.5}$, Hg and Ozone NO_X for the Illustrative Scenarios for 2028 to 2045

Annual NO_X	Total Emissions				Change from Baseline		
(Thousand Tons)	Baseline	Final Rule	Alt 1	Alt 2	Final Rule	Alt 1	Alt 2
2028	461	441	442	444	-20	-19	-17
2030	393	374	374	382	-20	-20	-11
2035	259	210	207	211	-49	-51	-48
2040	173	166	166	167	-6	-7	-5
2045	107	83	83	83	-24	-24	-24
Ozone Season NO_X[a]	**Total Emissions**				**Change from Baseline**		
(Thousand Tons)	**Baseline**	**Final Rule**	**Alt 1**	**Alt 2**	**Final Rule**	**Alt 1**	**Alt 2**
2028	189	183	183	184	-6	-6	-5
2030	175	168	168	171	-7	-7	-4
2035	119	100	99	101	-19	-20	-18
2040	88	82	82	82	-6	-6	-6
2045	59	45	45	45	-14	-14	-14
Annual SO_2	**Total Emissions**				**Change from Baseline**		
(Thousand Tons)	**Baseline**	**Final Rule**	**Alt 1**	**Alt 2**	**Final Rule**	**Alt 1**	**Alt 2**
2028	454	420	424	426	-34	-30	-28
2030	334	313	317	319	-20	-16	-15
2035	240	150	150	146	-90	-90	-94
2040	143	139	139	135	-4	-4	-8
2045	55	13	13	14	-41	-41	-41
Annual Mercury	**Total Emissions**				**Change from Baseline**		
(Tons)	**Baseline**	**Final Rule**	**Alt 1**	**Alt 2**	**Final Rule**	**Alt 1**	**Alt 2**
2028	3.1	3.0	3.0	3.0	-0.1	-0.1	-0.1
2030	2.9	2.8	2.8	2.9	-0.1	-0.1	0.0
2035	2.5	2.4	2.4	2.4	-0.1	-0.1	-0.1
2040	2.0	2.3	2.3	2.3	0.2	0.2	0.3
2045	1.4	1.2	1.2	1.2	-0.2	-0.2	-0.1
Direct $PM_{2.5}$	**Total Emissions**				**Change from Baseline**		
(Thousand Tons)	**Baseline**	**Final Rule**	**Alt 1**	**Alt 2**	**Final Rule**	**Alt 1**	**Alt 2**
2028	71	69	69	69	-2	-2	-1
2030	66	65	65	65	-2	-2	-1
2035	51	49	49	49	-1	-2	-1
2040	37	39	39	39	2	1	2
2045	24	22	22	22	-2	-2	-2

[a] Ozone season is the May through September period in this analysis.

3.6.2 Compliance Cost Assessment

The estimates of the changes in the cost of supplying electricity for the illustrative scenarios presented in Table 3-7.[73] Since the rules are estimated to result in additional recordkeeping, monitoring or reporting requirements, the costs associated with compliance, monitoring, recordkeeping, and reporting requirements are included within the estimates in this table.

Table 3-7 National Power Sector Compliance Cost Estimates (billions of 2019 dollars) for the Illustrative Scenarios

	Final Rules	Alternative 1	Alternative 2
2024 to 2042 (Annualized)	0.43	0.46	0.38
2024 to 2047 (Annualized)	0.86	0.88	0.85
2028 (Annual)	-1.30	-1.08	-1.06
2030 (Annual)	-0.22	-0.05	-0.72
2035 (Annual)	1.28	1.21	1.16
2040 (Annual)	0.59	0.64	0.60
2045 (Annual)	3.34	3.26	3.59

"2024 to 2042 (Annualized)" reflects total estimated annual compliance costs levelized over the period 2024 through 2042 and discounted using a 3.76 real discount rate.[74] This does not include compliance costs beyond 2042. "2024 to 2047 (Annualized)" reflects total estimated annual compliance costs levelized over the period 2024 through 2047 and discounted using a 3.76 real discount rate. This does not include compliance costs beyond 2047. "2028 (Annual)" through "2045 (Annual)" costs reflect annual estimates in each of those run years.[75]

There are several notable aspects of the results presented in Table 3-7. One notable result in Table 3-7 is that the estimated annual compliance costs for the three scenarios are negative (i.e., a cost reduction) in 2028 and 2030, although these illustrative scenarios reduce CO_2 emissions as shown in Table 3-5. While seemingly counterintuitive, estimating negative compliance costs in a single year is possible given the assumption of perfect foresight. IPM's

[73] Reported yearly costs reflect costs incurred in IPM run year mapped to respective calendar year. For details, please see Chapter 2 of the IPM documentation.

[74] This table reports compliance costs consistent with expected electricity sector economic conditions. The PV of costs was calculated using a 3.76 percent real discount rate consistent with the rate used in IPM's objective function for cost-minimization. This discount rate is meant to capture the observed equilibrium market rate at which investors are willing to sacrifice present consumption for future consumption and is based on a Weighted Average Cost of Capital (WACC). The PV of costs was then used to calculate the levelized annual value over a 19-year period (2024 to 2042) and a 24-year period (2024 to 2047) using the 3.76 percent rate as well. Table 3-7 reports the PV of the annual stream of costs from 2024 to 2047 using 3 percent and 7 percent consistent with OMB guidance.

[75] Cost estimates include financing charges on capital expenditures that would reflect a transfer and would not typically be considered part of total social costs.

objective function is to minimize the discounted present value (PV) of a stream of annual total cost of generation over a multi-decadal time period.[76] Under the baseline, the proposed GNP rule results in installation of SCR controls in the 2030 run year on some coal-fired EGUs that currently lack them. Under the scenarios modeled, a subset of these facilities retires rather than retrofit, since they would face additional requirements under the GHG regulations modeled. This in turn results in lower capital costs in the first run year and is balanced by higher costs in later years. Additionally, renewable costs are assumed to decline over the forecast period. Given IPM's perfect foresight, the model choses to wait to build incremental RE until later in the period when costs are lower. Under the illustrative policy scenarios the model builds this capacity sooner, which results in lower costs in the years built, but higher costs in future years.

Costs peak in 2035 across all scenarios, reflecting the date of imposition of the final Emission Guidelines for coal-fired steam generating units and tightening NSPS requirements. The final rules scenario results in the greatest early buildout of RE, resulting in the lowest near-term costs and higher longer-term costs. As a result, over the 2024 - 2047 time period, the final rules scenario shows slightly lower costs than alternative 1 and alternative 2. However, over the entire forecast period, costs are higher under the final rules.[77]

In addition to evaluating annual compliance cost impacts, EPA believes that a full understanding of these three illustrative scenarios benefits from an evaluation of annualized costs over the 2028 to 2045 timeframe. Starting with the estimated annual cost time series, it is possible to estimate the net present value of that stream, and then estimate a levelized annual cost associated with compliance with each illustrative scenario.[78] For this analysis we first calculated the PV of the stream of costs from 2024 through 2045[79] using a 3.76 percent discount rate. In this cost annualization, we use a 3.76 percent discount rate, which is consistent with the rate used in IPM's objective function for minimizing the PV of the stream of total costs of electricity generation. This discount rate is meant to capture the observed equilibrium market rate at which

[76] For more information, please see Chapter 2 of the IPM documentation.

[77] The present value of costs over the 2024-57 time period using a 3.76 percent discount rate are $18.6 billion for the alternative 1, $18.8 billion for the final rules, and $18.1 billion for the alternative 2.

[78] The XNPV() function in Microsoft Excel for Windows 365 was used to calculate the PV of the variable stream of costs, and the PMT() function in Microsoft Excel for Windows 365 is used to calculate the level annualized cost from the estimated PV.

[79] Consistent with the relationship between IPM run years and calendar years, EPA assigned run year compliance cost estimates to all calendar years mapped to that run year. For more information, see Chapter 7 of the IPM Documentation.

investors are willing to sacrifice present consumption for future consumption and is based on a Weighted Average Cost of Capital (WACC).[80] After calculating the PV of the cost streams, the same 3.76 percent discount rate and 2024 to 2047 time period are used to calculate the levelized annual (i.e., annualized) cost estimates shown in Table 3-7.[81] The same approach was used to develop the annualized cost estimates for the 2024 to 2047 timeframe.

3.6.3 Impacts on Fuel Use, Prices, and Generation Mix

The final NSPS, and the final Emissions Guidelines are expected to result in significant GHG emissions reductions. The rules are also expected to have some impacts to the economics of the power sector. Consideration of these potential impacts is an important component of assessing the relative impact of the illustrative scenarios. In this section we discuss the estimated changes in fuel use, fuel prices, generation by fuel type, capacity by fuel type, and retail electricity prices for the 2028, 2030, 2035, 2040, and 2045 IPM model run years.

Table 3-8 and Table 3-9 present the percentage changes in national coal and natural gas usage by EGUs in the 2028, 2030, 2035, 2040 and 2045 run years. These fuel use estimates reflect some power companies choosing natural gas and renewables over coal in 2030 rather than implement available cost-reasonable controls as a result of the imposition of GHG mitigation measures under the final Emissions Guidelines for coal-fired steam generating units.

Under the baseline, current market trends persist and are accentuated by the IRA. Hence coal capacity continues to decline over the forecast period, and there is continued penetration of non-emitting resources such as wind and solar.

Of the 181 GW of coal-fired capacity active in 2023, only 80 GW have not announced retirement or coal to gas conversion by 2040. Furthermore, of these 80 GW, by 2040 56 GW will be 53 years or older (which is the average retirement age for coal EGUs over the 2015-22 time

[80] The IPM Baseline run documentation (Appendix B.4.1 Introduction to Discount Rate Calculations) states "The real discount rate for all expenditures (capital, fuel, variable operations and maintenance, and fixed operations and maintenance costs) in the EPA Platform v6 is 3.76 percent."

[81] The PMT() function in Microsoft Excel for Windows 365 is used to calculate the level annualized cost from the estimated PV.

period).[82] EPA projects that under the baseline, 42 GW of coal are projected to be active in 2040. Coal consumption declines consistent with this decrease in capacity over the forecast period.

At the same time, tighter natural gas markets as a result of increased LNG exports results in declining gas consumption over the forecast period, particularly after 2035, when improved renewable cost and performance consistent with NREL ATB 2023 further erode gas generation share. In the baseline, increases in LNG exports reach their highest levels by 2040, resulting in tighter natural gas markets. At the same time, RE cost and performance improvements mean that RE becomes more competitive. This results in less gas and more RE deployment, driving down emissions. In other words, emissions decline over the forecast period in the baseline, and decline faster in 2040 and 2045. Steam retirements continue over the forecast period. As a result in the policy scenario, requirements on existing steam generation result in large reductions in 2035 driven by lower thermal generation and increased adoption of BSER technology but then emissions begin to converge back to baseline levels.

Under the illustrative scenarios, increases in gas demand are highest in 2035, driven by reductions in coal-fired generation as a result of the existing source standards. After 2035, the absolute increases in gas consumption are smaller, consistent with baseline trends towards declining gas consumption and higher levels of RE deployment. In 2030, increases in gas consumption are lowest under the alternative 2 scenario, consistent with shifting the requirements on medium-term coal fired electricity generating steam units assumed from 2030 under the final rules and alternative 1 to 2035 in the alternative 2 scenario.

To put these reductions into context, under the Baseline, power sector coal consumption is projected to decrease from 251 million tons in 2028 to 222 million tons in 2030 (5 percent annually between 2028-2030), and to 147 million tons in 2035 (7 percent annually between 2030-2035). Under the final rules, coal consumption is projected to decrease from 234 million tons in 2028 to 194 million tons in 2030 (8 percent annually between 2028-2030), and 111 million tons in 2035 (9 percent annually between 2030-2035). Between 2015 and 2020, annual coal consumption in the electric power sector fell between 8 and 19 percent annually.[83] Coal

[82] The annual average retirement age for coal-fired EGUs between 2000-2022 ranged between 47 and 61 years old, and the average retirement age over that period was 53 years. Similarly, the average age for retiring coal-fired EGUs between 2015-2022 was 53 years, demonstrating the consistency of retirement ages throughout the years.

[83] U.S. EIA Monthly Energy Review, Table 6.2, January 2022.

consumption falls by the greatest amount in 2035, consistent with the imposition of the requirements on existing coal-fired steam generating units. For units that adopt CCS, 45Q tax credits result in higher levels of dispatch and therefore coal consumption at those sources relative to the baseline. These sources consume different types of coal depending on location and relative cost, resulting in non-uniform subnational coal consumption impacts (i.e. production declines in some regions and increases in others).

Table 3-10 presents the projected hydrogen power sector consumption under the Baseline and the Illustrative Scenarios.[84]

Table 3-8 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Coal Use for the Baseline and the Illustrative Scenarios

		Million Tons				Percent Change from Baseline		
	Year	Baseline	Final	Alt. 1	Alt. 2	Final	Alt. 1	Alt. 2
Appalachia	2028	40	37	36	37	-7%	-8%	-7%
Interior		38	35	36	36	-7%	-5%	-4%
Waste Coal		7	7	7	7	0%	0%	0%
West		166	155	156	156	-7%	-6%	-6%
Total		251	234	235	237	-7%	-6%	-6%
Appalachia	2030	39	39	39	39	0%	1%	0%
Interior		35	36	36	34	1%	2%	-2%
Waste Coal		7	7	7	7	0%	0%	0%
West		141	113	113	133	-20%	-20%	-6%
Total		222	194	195	214	-13%	-12%	-4%
Appalachia	2035	32	19	19	19	-40%	-40%	-40%
Interior		19	25	25	25	30%	30%	30%
Waste Coal		7	3	3	3	-53%	-53%	-53%
West		89	63	63	67	-29%	-29%	-25%
Total		147	111	111	114	-25%	-25%	-22%
Appalachia	2040	19	19	19	19	1%	1%	0%
Interior		10	25	25	25	150%	150%	150%
Waste Coal		3	3	3	3	0%	0%	0%
West		61	56	56	59	-8%	-8%	-3%
Total		93	103	103	106	11%	11%	14%
Appalachia	2045	4	0	0	0	-100%	-100%	-100%
Interior		1	0	0	0	-100%	-100%	-85%
Waste Coal		3	0	0	0	-100%	-100%	-100%
West		20	3	3	3	-85%	-85%	-84%
Total		28	3	3	3	-89%	-90%	-88%

[84] Please note that hydrogen consumption is rounded to the nearest trillion Btu.

Table 3-9 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Natural Gas Use for the Baseline and the Illustrative Scenarios

	Trillion Cubic Feet				Percent Change from Baseline		
Year	**Baseline**	**Final**	**Alt. 1**	**Alt. 2**	**Final**	**Alt. 1**	**Alt. 2**
2028	11.6	11.5	11.5	11.5	-1.0%	-1.0%	-1.0%
2030	11.7	11.7	11.7	11.5	0.0%	0.0%	-1.7%
2035	9.3	9.7	9.7	9.7	4.3%	4.4%	4.4%
2040	6.4	6.4	6.4	6.4	-0.1%	0.0%	0.0%
2045	4.2	4.3	4.3	4.3	1.1%	1.9%	1.8%

Table 3-10 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Hydrogen Use for the Baseline and the Illustrative Scenarios

	Trillion Btu			
Year	**Baseline**	**Final**	**Alt. 1**	**Alt. 2**
2028	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00
2040	0.00	0.00	0.00	0.00
2045	0.22	0.45	0.49	0.44

Table 3-11 and Table 3-12 present the projected coal and natural gas prices in 2028, 2030, 2035, 2040 and 2045, as well as the percent change from the baseline projected due to the illustrative scenarios. In 2028, earlier RE builds result in lower gas consumption and higher gas prices. By 2030, reductions in coal generation stemming from requirements on medium-term coal fired electricity generating steam units result in higher gas consumption and prices. In 2035, increases in gas consumption are highest relative to the baseline, stemming from the requirements on long-term coal fired electricity generating steam units and the NSPS. Impacts lessen in 2040 onwards as the system approaches baseline levels with higher levels of RE generation, and less gas and coal generation.

Under the alternative 2, gas prices remain similar to baseline levels in 2030 as a result of the requirements on medium-term coal fired electricity generating steam units assumed to take place in 2035. Under the final rules scenario, the lower baseload threshold results in lower amounts of generation from new gas, resulting in smaller increases in gas generation relative to baseline levels than under the alternative 1 and alternative 2 illustrative scenarios.

Growing LNG exports result in tighter natural gas markets, particularly in 2035 and beyond, while RE cost and performance continues to improve. At the same time, requirements on new combustion turbines result in fewer new NGCCs that run at baseload levels. This means that as steam generation falls, it is filled by a combination of higher existing gas and new RE generation, tamping down on the increase in gas consumption.

Table 3-11 2028, 2030, 2035, 2040 and 2045 Projected Minemouth and Power Sector Delivered Coal Price (2019 dollars) for the Baseline and the Illustrative Scenarios

		$/MMBtu				Percent Change from Baseline		
		Baseline	**Final**	**Alt. 1**	**Alt. 2**	**Final**	**Alt. 1**	**Alt. 2**
Minemouth	2028	0.98	0.97	0.97	0.97	-1%	-1%	-1%
Delivered		1.54	1.52	1.52	1.52	-1%	-1%	-1%
Minemouth	2030	1.02	1.05	1.05	1.02	3%	3%	0%
Delivered		1.56	1.53	1.53	1.54	-2%	-2%	-1%
Minemouth	2035	1.07	1.10	1.10	1.09	3%	3%	2%
Delivered		1.55	1.55	1.55	1.54	0%	0%	0%
Minemouth	2040	1.17	1.22	1.22	1.21	4%	4%	3%
Delivered		1.59	1.60	1.60	1.60	1%	1%	0%
Minemouth	2045	1.37	1.50	1.50	1.50	9%	9%	9%
Delivered		1.38	0.94	0.94	0.94	-32%	-32%	-32%

Table 3-12 2028, 2030, 2035, 2040 and 2045 Projected Henry Hub and Power Sector Delivered Natural Gas Price (2019 dollars) for the Baseline and the Illustrative Scenarios

		$/MMBtu				Percent Change from Baseline		
		Baseline	Final	Alt. 1	Alt. 2	Final	Alt. 1	Alt. 2
Henry Hub	2028	2.78	2.72	2.74	2.74	-2%	-2%	-2%
Delivered		2.84	2.78	2.80	2.80	-2%	-2%	-2%
Henry Hub	2030	2.89	2.90	2.91	2.87	0%	1%	-1%
Delivered		2.95	2.97	2.98	2.93	1%	1%	0%
Henry Hub	2035	2.87	2.95	2.95	2.95	3%	3%	3%
Delivered		2.88	2.97	2.97	2.97	3%	3%	3%
Henry Hub	2040	2.82	2.79	2.81	2.81	-1%	0%	0%
Delivered		2.79	2.77	2.79	2.79	-1%	0%	0%
Henry Hub	2045	2.95	2.95	2.95	2.95	0%	0%	0%
Delivered		2.94	2.94	2.94	2.94	0%	0%	0%

Gas capacity is higher as a result of greater NGCT buildout. These NGCT units operate at low capacity factors, which means gas consumption is similar between the two scenarios, as is natural gas price.

Table 3-13 presents the projected percentage changes in the amount of electricity generation in 2028, 2030, 2035 and 2040 by fuel type. Consistent with the fuel use projections and emissions trends above, EPA projects an overall shift from coal to gas and renewables under the baseline, and these trends persist under the illustrative scenarios analyzed. The projected impacts are highest in 2035 reflecting the imposition of the final Emissions Guidelines and are smaller thereafter. 45(q) is available for 12 years within the modeling,[85] after which point units no longer receive tax credits and must dispatch based on unsubsidized operating costs.

[85] EPA assumes a 12-year booklife for CCS consistent with the duration of the 45(q) tax credit

Table 3-13 2028, 2030, 2035, 2040 and 2045 Projected U.S. Generation by Fuel Type for the Baseline and the Illustrative Scenarios

		Generation (TWh)				Percent Change from Baseline		
	Year	Baseline	Baseline	Final	Alt. 1	Final	Alt. 1	Alt. 2
Unabated Coal		472	441	443	447	-7%	-6%	-5%
Coal & CCS		0	0	0	0	-	-	-
Coal with Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		1,652	1,631	1,634	1,633	-1%	-1%	-1%
Nat. Gas & CCS		0	0	0	0	-	-	-
Nuclear	2028	751	751	751	751	0%	0%	0%
Hydro		293	293	293	293	0%	0%	0%
Non-Hydro RE		1,141	1,191	1,186	1,182	4%	4%	4%
Oil/Gas Steam		26	28	27	27	8%	7%	7%
Other		31	31	31	31	0%	0%	0%
Grand Total		4,365	4,366	4,365	4,365	0%	0%	0%
Unabated Coal		407	355	357	391	-13%	-12%	-4%
Coal & CCS		3	5	5	3	71%	76%	0%
Coal with Nat. Gas co-firing		0	2	2	0	-	-	-
Unabated Nat. Gas		1,670	1,660	1,664	1,642	0%	0%	-1%
Nat. Gas & CCS		0	0	0	0	-	-	-
Nuclear	2030	729	729	729	729	0%	0%	0%
Hydro		298	299	298	298	0%	0%	0%
Non-Hydro RE		1,329	1,381	1,377	1,373	4%	4%	3%
Oil/Gas Steam		25	28	27	25	12%	11%	3%
Other		31	31	31	31	0%	0%	0%
Grand Total		4,491	4,491	4,491	4,491	0%	0%	0%
Unabated Coal		160	0	0	0	-100%	-100%	-100%
Coal & CCS		76	133	133	136	74%	74%	78%
Nat. Gas co-firing		0	4	4	6	-	-	-
Unabated Nat. Gas		1,341	1,379	1,386	1,384	4%	4%	4%
Nat. Gas & CCS		3	7	6	6	105%	64%	64%
Nuclear	2035	667	666	666	666	0%	0%	0%
Hydro		319	317	317	317	-1%	-1%	-1%
Non-Hydro RE		2,229	2,286	2,281	2,278	3%	2%	2%
Oil/Gas Steam		8	9	9	9	21%	16%	17%
Other		31	30	30	30	0%	0%	0%
Grand Total		4,834	4,831	4,833	4,832	0%	0%	0%
Unabated Coal	2040	61	0	0	0	-100%	-100%	-100%
Coal & CCS		76	128	128	131	68%	68%	73%

Coal with Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		933	919	924	924	0%	0%	0%
Nat. Gas & CCS		3	7	6	6	105%	64%	64%
Nuclear		614	613	613	613	0%	0%	0%
Hydro		336	336	336	336	0%	0%	0%
Non-Hydro RE		3,097	3,119	3,114	3,111	1%	1%	0%
Oil/Gas Steam		5	6	6	6	28%	27%	27%
Other		29	29	29	29	0%	0%	0%
Grand Total		5,154	5,157	5,156	5,155	0%	0%	0%
Unabated Coal	2045	45	0	0	0	-100%	-100%	-100%
Coal & CCS		4	3	3	4	-7%	-9%	4%
Coal with Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		614	612	620	619	1%	2%	2%
Nat. Gas & CCS		3	6	5	5	103%	65%	65%
Nuclear		471	472	473	473	0%	0%	0%
Hydro		343	342	342	342	0%	0%	0%
Non-Hydro RE		4,032	4,089	4,081	4,081	1%	1%	1%
Oil/Gas Steam		4	6	6	6	25%	25%	25%
Other		28	27	27	27	0%	0%	0%
Grand Total		5,544	5,557	5,557	5,556	0%	0%	0%

Note: In this table, "Non-Hydro RE" includes biomass, geothermal, landfill gas, solar, and wind. Oil/Gas steam category includes coal to gas conversions.

Table 3-14 presents the projected percentage changes in the amount of generating capacity in 2028, 2030, 2035, 2040 and 2045 by primary fuel type. In 2035, the final Emission Guidelines is assumed to be in effect under all three scenarios. Under the final rules, 104 GW of coal-fired EGUs have committed retirements by 2035 (21 GW incremental to baseline). One GW of coal-fired EGUs who have committed to retirement by 2040 are medium-term existing coal-fired steam generating units and, as such, install 40 percent natural gas co-firing requirement. 19 GW of coal-fired EGUs who plan to operate past 2040 are subject to the long-term existing coal-fired steam generating unit subcategory and, as such, install CCS (reflecting 8 GW incremental to the baseline). Finally, 19 GW of coal-fired EGUs undertake coal to gas conversion (6 GW incremental to the baseline).

Under the baseline, total coal retirements between 2028 and 2035 are projected to be 84 GW (or 12 GW annually). Under the final rules, total coal retirements between 2028 and 2035 are projected to be 104 GW (or 15 GW annually). This is compared to an average recent historical retirement rate of 11 GW per year from 2015 – 2020.[86]

By 2030 the final rules are projected to result in an additional 5 GW of coal retirements, by 2035 an incremental 21 GW of coal retirements and by 2040 an incremental 14 GW of coal retirements relative to the baseline. These compliance decisions reflect EGU operators making least-cost decisions on how to achieve efficient compliance with the rules while maintaining sufficient generating capacity to maintain resource adequacy.[87]

IPM endogenously estimates the capacity credit (i.e. the accredited capacity that can count towards meeting the resource adequacy constraints within the model) for wind, solar, and storage as a function of penetration.[88] Additionally, IPM models operating reserves at the regional level, and can account for the impact of solar and wind on operating reserves requirements.[89]

An incremental 15 GW of renewable capacity additions (consisting of an incremental 3 GW of solar and 12 GW of wind builds) and 9 GW of storage is projected by 2035 in the illustrative final rule. Under the final rules, 18 GW of economic NGCC additions occur by 2035 (1 GW less than the baseline), and 24 GW of economic NGCT additions occur by 2035 (10 GW incremental to the baseline). These builds partially reflect early action, i.e., builds that would otherwise have occurred later in the forecast period under the baseline. Of these units, 870 MW of NGCCs install CCS in 2035.

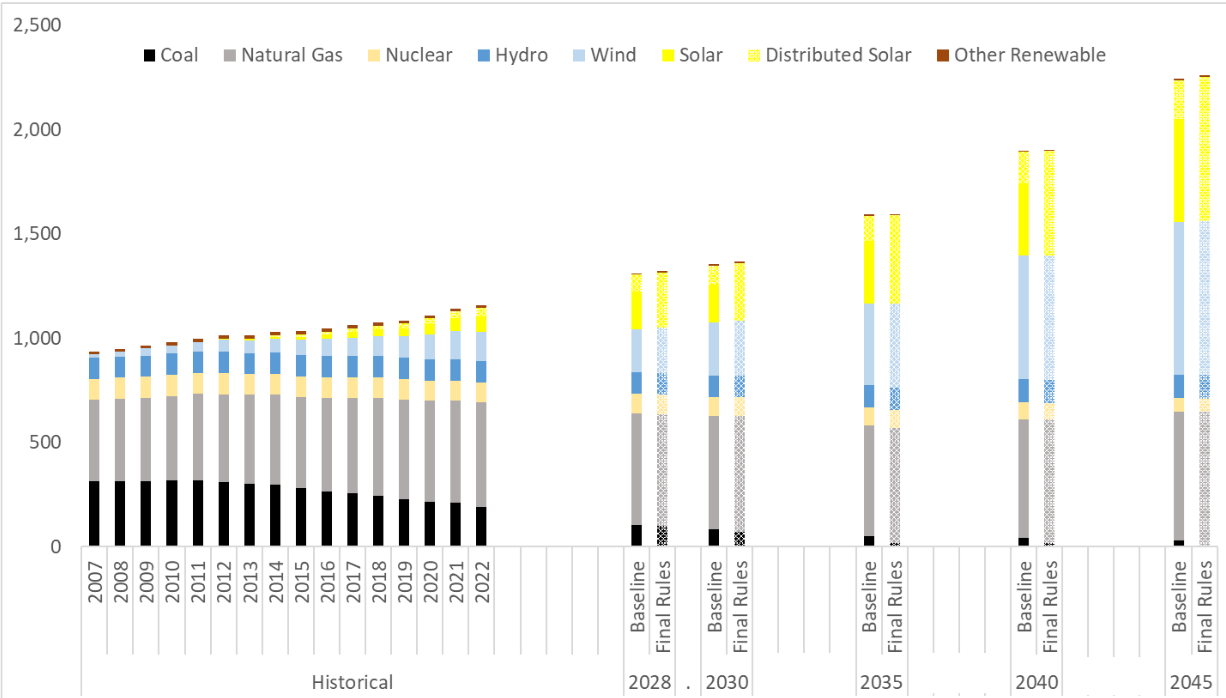
Under the baseline, the reduction in generation from natural-gas and coal fired facilities is greater than the reduction in their capacities over time. Hence thermal resources tend to be operated less frequently over time, due to the increase in low-emitting generation. These trends persist under the illustrative scenarios.

As shown in Figure 3.2 below, The coal-fired generation share was 49 percent in 2007 and 20 percent in 2022, and is projected to fall to 3 percent in 2040 under the baseline and 1 percent

[86] See EIA's Today in Energy: https://www.eia.gov/todayinenergy/detail.php?id=50838.
[87] For further discussion of how the rule is anticipated to integrate into the ongoing power sector transition while not impacting resource adequacy, see section XIV(F) of the preamble, and the Resource Adequacy Assessment TSD included in the docket.
[88] For details, please see chapter 4 of the IPM documentation, available at: https://www.epa.gov/power-sector-modeling
[89] For details, please see chapter 3 of the IPM documentation, available at: https://www.epa.gov/power-sector-modeling

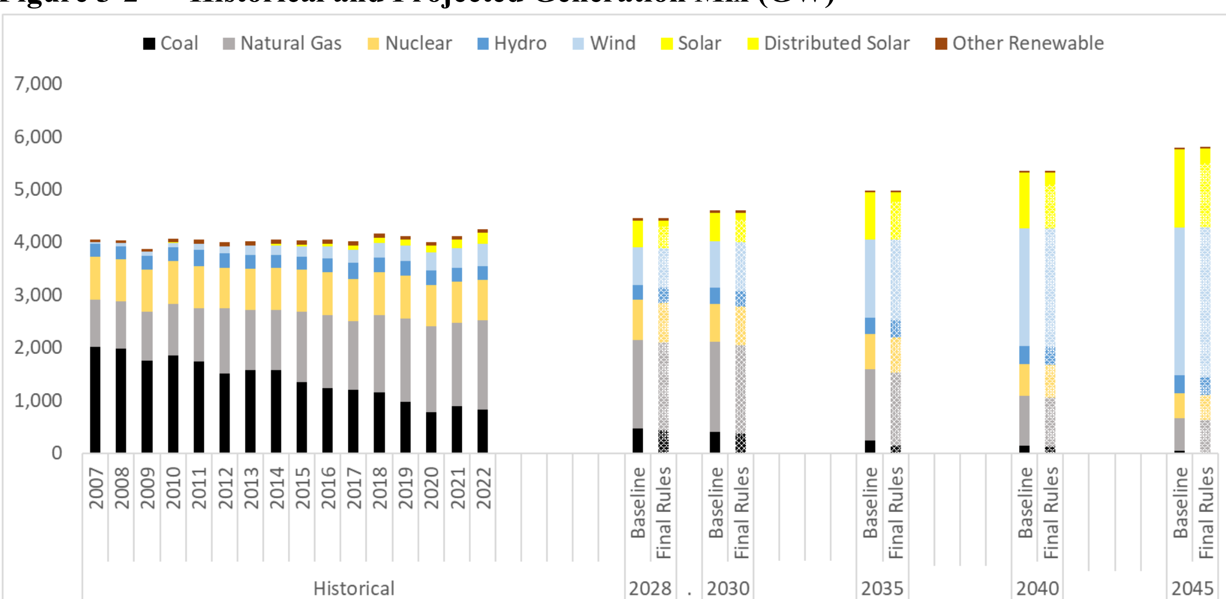
by 2045. Under the final rules scenario, coal-fired generation share is projected to fall to 2 percent by 2040 and less than 1 percent in 2045. The natural gas-fired generation share was 22 percent in 2007 and 39 percent in 2022 and is projected to fall to 18 percent in 2040 under the baseline and 11 percent by 2045. Under the final rules scenario, natural gas-fired generation share is projected to fall to 17 percent by 2040 and 11 percent in 2045. The wind and solar generation share was 1 percent in 2007 and 13 percent in 2022 and is projected to grow to 57 percent in 2040 under the baseline and 69 percent by 2045. Under the final rules scenario, wind and solar generation share is projected to grow to 58 percent by 2040 and 69 percent in 2045.

Figure 3-1 Historical and Projected Capacity Mix (GW)



Sources: EIA Power Annual and EPA projections

Figure 3-2 Historical and Projected Generation Mix (GW)



Sources: EIA Power Annual and EPA projections

Table 3-14 2028, 2030, 2035, 2040 and 2045 Projected U.S. Capacity by Fuel Type for the Baseline and the Illustrative Scenarios

		Capacity (GW)				Percent Change from Baseline		
	Year	Baseline	Final Rules	Alt. 1	Alt. 2	Final Rules	Alt. 1	Alt. 2
Unabated Coal	2028	106	101	101	102	-4%	-4%	-4%
Coal & CCS		0	0	0	0	-	-	-
Coal with Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		471	472	473	472	0%	0%	0%
Nat. Gas & CCS		0	0	0	0	-	-	-
Nuclear		94	94	94	94	0%	0%	0%
Hydro		102	102	102	102	0%	0%	0%
Non-Hydro RE		394	407	406	405	3%	3%	3%
Oil/Gas Steam		63	64	64	64	2%	2%	2%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,236	1,246	1,246	1,245	1%	1%	1%
Unabated Coal	2030	85	72	72	80	-15%	-15%	-5%
Coal & CCS		0	1	1	0	72%	77%	0%
Coal with Nat. Gas co-firing		0	1	1	0	-	-	-
Unabated Nat. Gas		479	480	481	480	1%	1%	1%
Nat. Gas & CCS		0	0	0	0	-	-	-
Nuclear		91	91	91	91	0%	0%	0%
Hydro		104	104	104	104	0%	0%	0%
Non-Hydro RE		440	454	453	452	3%	3%	3%
Oil/Gas Steam		64	73	73	66	13%	13%	3%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,269	1,281	1,281	1,280	1%	1%	1%
Unabated Coal	2035	41	0	0	0	-100%	-100%	-100%
Coal & CCS		11	19	19	20	74%	74%	78%
Coal with Nat. Gas co-firing		0	1	1	1	-	-	-
Unabated Nat. Gas		476	484	484	484	2%	2%	2%
Nat. Gas & CCS		0	1	1	1	104%	63%	63%
Nuclear		84	84	84	84	0%	0%	0%
Hydro		107	107	107	107	0%	0%	0%
Non-Hydro RE		699	714	713	711	2%	2%	2%
Oil/Gas Steam		55	66	66	66	19%	19%	20%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,479	1,482	1,481	1,481	0%	0%	0%

Unabated Coal	2040	31	0	0	0	-99%	-99%	-99%
Coal & CCS		11	18	18	19	68%	68%	73%
Coal with Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		516	525	525	525	2%	2%	2%
Nat. Gas & CCS		0	1	1	1	104%	63%	63%
Nuclear		79	79	79	79	0%	0%	0%
Hydro		112	112	112	112	0%	0%	0%
Non-Hydro RE		943	952	951	950	1%	1%	1%
Oil/Gas Steam		54	65	65	65	19%	19%	20%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,7 53	1,759	1,757	1,757	0%	0%	0%
Unabated Coal	2045	29	0	0	0	-99%	-99%	-99%
Coal & CCS		1	1	1	1	-5%	-7%	13%
Coal with Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		565	581	581	580	3%	3%	3%
Nat. Gas & CCS		0	1	1	1	104%	63%	63%
Nuclear		65	65	65	65	0%	0%	0%
Hydro		112	112	112	112	0%	0%	0%
Non-Hydro RE		1,2 32	1,250	1,248	1,248	1%	1%	1%
Oil/Gas Steam		54	64	64	65	19%	19%	20%
Other		7	7	7	7	0%	0%	0%
Grand Total		2,0 65	2,080	2,078	2,078	1%	1%	1%

Note: In this table, "Non-Hydro RE" includes biomass, geothermal, landfill gas, solar, and wind

EPA estimated the change in the retail price of electricity (2019 dollars) using the Retail Price Model (RPM).[90] The RPM was developed by ICF for EPA and uses the IPM estimates of changes in the cost of generating electricity to estimate the changes in average retail electricity prices. The prices are average prices over consumer classes (i.e., consumer, commercial, and industrial) and regions, weighted by the amount of electricity used by each class and in each region. The RPM combines the IPM annual cost estimates in each of the 64 IPM regions with

[90] See documentation available at: https://www.epa.gov/airmarkets/retail-price-model

EIA electricity market data for each of the 25 electricity supply regions in the electricity market module of the National Energy Modeling System (NEMS).[91]

Table 3-15, Table 3-16, Table 3-17, and Table 3-18 present the projected percentage changes in the retail price of electricity for the three illustrative scenarios in 2030, 2035, 2040 and 2045, respectively. Consistent with other projected impacts presented above, average retail electricity prices at both the national and regional level are projected to experience the largest impacts in 2035. Consistent with the decline in total production cost in 2030[92] National electricity rates are projected to fall 0.5 percent below baseline levels in 2030, or a decrease of 0.47 mills/kWh (2019 dollars). In 2035, EPA estimates that these rules will result in a 1 percent increase in national average retail electricity price, or by about 1.33 mills/kWh (2019 dollars). In 2040, EPA estimates that these rules will result in a 0.2 percent increase in national average retail electricity price, or by about 0.15 mills/kWh. In 2045, EPA estimates that these rules will result in a 0.7 percent increase in national average retail electricity price, or by about 0.63 mills/kWh.

[91] See documentation available at: https://www.eia.gov/outlooks/aeo/nems/documentation/electricity/pdf/EMM_2022.pdf

[92] Under the baseline, the proposed GNP rule results in installation of SCR controls in the 2030 run year on some coal-fired EGUs that currently lack them. Under the scenarios modeled, a subset of these facilities retires rather than retrofit, since they would face additional requirements under the GHG regulations modeled. This in turn results in lower capital costs in the first run year and is balanced by higher costs in later years. Additionally, renewable costs are assumed to decline over the forecast period. Given IPM's perfect foresight, the model choses to wait to build incremental RE until later in the period when costs are lower. Under the illustrative policy scenarios the model builds this capacity sooner, which results in lower costs in the years built, but higher costs in future years.

Table 3-15 Average Retail Electricity Price by Region for the Baseline and the Illustrative Scenarios, 2030

All Sector	2030 Average Retail Electricity Price (2019 mills/kWh)				Percent Change from Baseline		
Region	**Baseline**	**Final Rules**	**Alt. 1**	**Alt. 2**	**Final Rules**	**Alt. 1**	**Alt. 2**
TRE	73	73	73	73	-1%	-1%	-1%
FRCC	98	98	98	97	0%	0%	0%
MISW	93	93	93	93	0%	0%	-1%
MISC	91	91	91	91	0%	0%	-1%
MISE	109	107	107	107	-2%	-2%	-2%
MISS	86	83	83	83	-3%	-3%	-3%
ISNE	157	157	156	156	0%	0%	0%
NYCW	210	211	211	211	0%	0%	0%
NYUP	126	126	126	126	0%	0%	0%
PJME	110	107	107	106	-3%	-3%	-3%
PJMW	97	97	96	96	0%	-1%	-1%
PJMC	89	87	87	87	-3%	-3%	-3%
PJMD	76	77	76	76	0%	-1%	-1%
SRCA	92	92	92	92	0%	0%	0%
SRSE	95	95	95	95	0%	0%	0%
SRCE	71	71	71	71	0%	0%	0%
SPPS	78	78	78	77	0%	1%	-1%
SPPC	97	97	96	97	-1%	-1%	-1%
SPPN	65	66	66	65	1%	1%	0%
SRSG	102	102	102	102	0%	0%	0%
CANO	143	142	142	142	0%	-1%	-1%
CASO	174	173	173	173	0%	0%	-1%
NWPP	82	81	81	81	-1%	-1%	-1%
RMRG	101	100	100	100	0%	-1%	-1%
BASN	96	97	97	97	1%	1%	1%
NATIONAL	100	99	99	99	-0.5%	-1%	-1%

Table 3-16 Average Retail Electricity Price by Region for the Baseline and the Illustrative Scenarios, 2035

All Sector	2035 Average Retail Electricity Price (2019 mills/kWh)				Percent Change from Baseline		
Region	**Baseline**	**Final Rules**	**Alt. 1**	**Alt. 2**	**Final Rules**	**Alt. 1**	**Alt. 2**
TRE	78	80	80	80	2%	2%	2%
FRCC	92	92	92	92	1%	1%	1%
MISW	84	85	85	85	1%	1%	1%
MISC	81	82	82	82	1%	1%	1%
MISE	96	99	98	98	3%	3%	3%
MISS	79	81	81	81	2%	2%	2%
ISNE	156	156	156	156	0%	0%	0%
NYCW	209	210	210	210	0%	0%	0%
NYUP	125	126	125	125	1%	1%	1%
PJME	108	113	112	112	4%	3%	3%
PJMW	92	95	94	94	3%	3%	3%
PJMC	75	79	79	79	6%	5%	5%
PJMD	71	74	74	74	4%	3%	3%
SRCA	89	90	90	90	0%	0%	0%
SRSE	90	91	91	91	1%	1%	1%
SRCE	67	67	67	67	0%	0%	0%
SPPS	69	70	70	70	1%	1%	1%
SPPC	80	80	80	80	-1%	-1%	0%
SPPN	63	64	64	64	1%	1%	1%
SRSG	103	104	104	104	0%	0%	0%
CANO	140	141	141	141	1%	1%	1%
CASO	173	173	173	173	0%	0%	0%
NWPP	79	79	79	79	0%	0%	0%
RMRG	93	95	95	95	2%	2%	2%
BASN	97	96	96	96	-1%	-1%	-1%
NATIONAL	96	97	97	97	1%	1%	1%

Table 3-17 Average Retail Electricity Price by Region for the Baseline and the Illustrative Scenarios, 2040

All Sector	2040 Average Retail Electricity Price (2019 mills/kWh)				Percent Change from Baseline		
Region	**Baseline**	**Final Rules**	**Alt. 1**	**Alt. 2**	**Final Rules**	**Alt. 1**	**Alt. 2**
TRE	74	73	73	73	0%	0%	0%
FRCC	88	89	89	89	0%	0%	0%
MISW	79	80	80	80	1%	1%	1%
MISC	73	73	73	73	0%	0%	0%
MISE	98	98	98	98	0%	0%	0%
MISS	74	75	75	74	1%	1%	0%
ISNE	167	168	168	168	1%	1%	1%
NYCW	236	235	235	235	0%	0%	0%
NYUP	138	138	138	138	0%	0%	0%
PJME	117	117	117	117	0%	0%	0%
PJMW	89	90	89	90	0%	0%	0%
PJMC	78	78	78	78	0%	0%	0%
PJMD	74	74	74	74	0%	0%	0%
SRCA	87	87	87	87	0%	0%	0%
SRSE	84	84	84	84	0%	0%	0%
SRCE	66	66	66	66	0%	0%	0%
SPPS	66	66	66	66	1%	1%	1%
SPPC	76	76	76	76	0%	0%	0%
SPPN	62	62	62	62	0%	0%	0%
SRSG	98	98	98	98	0%	0%	0%
CANO	144	145	145	145	0%	0%	0%
CASO	172	173	173	173	0%	0%	0%
NWPP	81	80	80	80	-1%	-1%	-1%
RMRG	88	88	88	88	1%	1%	0%
BASN	96	95	95	95	-1%	-1%	-1%
NATIONAL	95	95	95	95	0.2%	0.2%	0.1%

Table 3-18 Average Retail Electricity Price by Region for the Baseline and the Illustrative Scenarios, 2045

All Sector	2045 Average Retail Electricity Price (2019 mills/kWh)				Percent Change from Baseline		
Region	Baseline	Final Rules	Alt. 1	Alt. 2	Final Rules	Alt. 1	Alt. 2
TRE	66	66	66	66	1%	1%	1%
FRCC	86	86	86	86	0%	0%	0%
MISW	77	78	78	78	1%	1%	1%
MISC	70	71	71	71	1%	1%	1%
MISE	94	95	95	95	1%	1%	1%
MISS	69	68	69	69	0%	0%	0%
ISNE	161	161	161	161	0%	0%	0%
NYCW	227	229	229	229	1%	1%	1%
NYUP	128	129	129	129	1%	1%	1%
PJME	116	116	116	116	0%	0%	0%
PJMW	87	87	87	87	1%	1%	1%
PJMC	76	77	77	77	0%	0%	0%
PJMD	74	74	74	74	0%	0%	0%
SRCA	87	87	87	87	0%	0%	0%
SRSE	84	85	85	85	1%	1%	1%
SRCE	64	65	65	65	1%	1%	1%
SPPS	65	66	66	66	1%	1%	2%
SPPC	70	71	71	71	1%	1%	1%
SPPN	63	65	65	66	3%	3%	3%
SRSG	94	95	95	95	1%	1%	1%
CANO	141	141	141	141	0%	0%	0%
CASO	171	171	171	171	0%	0%	0%
NWPP	82	84	84	84	3%	3%	3%
RMRG	83	85	85	85	2%	2%	2%
BASN	94	95	95	95	2%	1%	2%
NATIONAL	92	93	93	93	0.7%	0.6%	0.7%

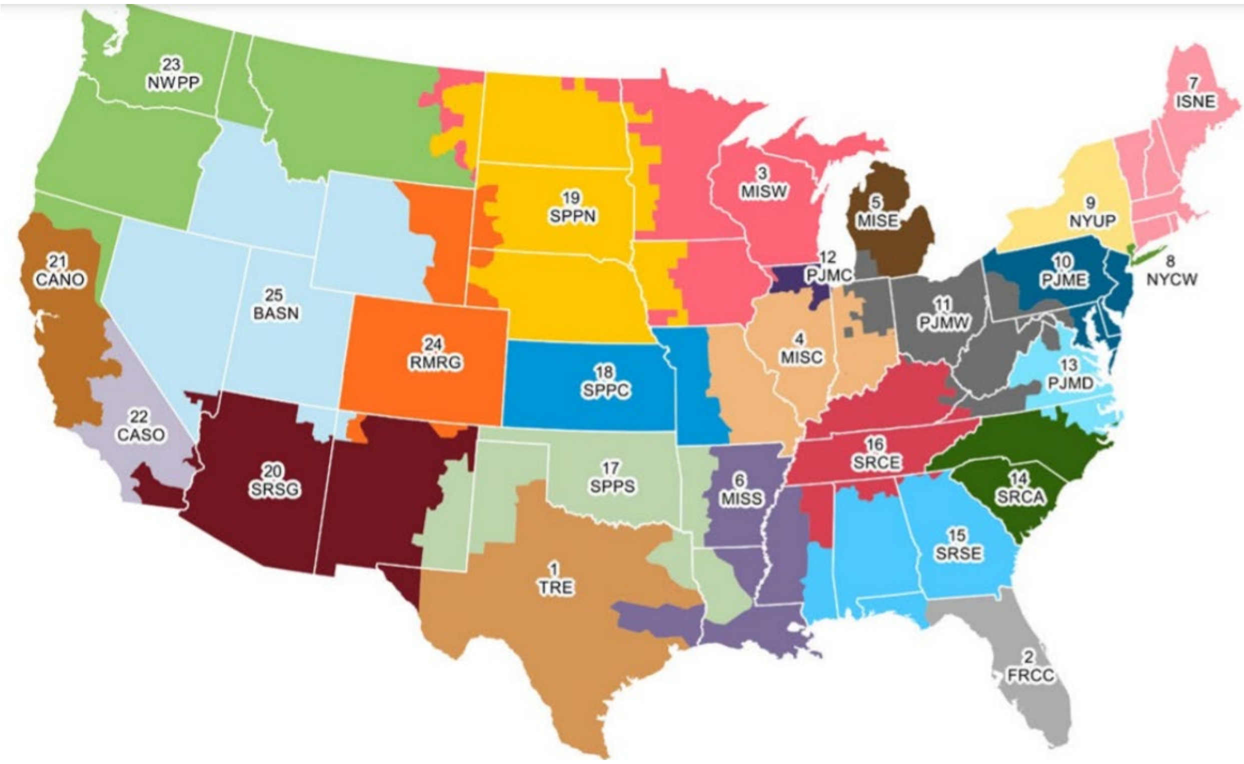


Figure 3-3 Electricity Market Module Regions
Source: EIA (http://www.eia.gov/forecasts/aeo/pdf/nerc_map.pdf)

3.7 Limitations

EPA's modeling is based on expert judgment of various input assumptions for variables whose outcomes are uncertain. As a general matter, the Agency reviews the best available information from engineering studies of air pollution controls and new capacity construction costs to support a reasonable modeling framework for analyzing the cost, emission changes, and other impacts of regulatory actions for EGUs. The annualized cost of the rules for EGUs, as quantified here, is EPA's best assessment of the cost of implementing the rules for the power sector. These costs are generated from rigorous economic modeling of anticipated changes in the power sector due to implementation of the rule.

There are several key areas of uncertainty related to the electric power sector that are worth noting, including:

• Electric demand: The analysis includes an assumption for future electric demand. This is based on AEO 2023 reference case with incremental demand from EPA's OTAQ's on the books rules that are not captured in AEO 2023 reference case projections.[93] To the extent electric demand is higher or lower, it may increase/decrease the projected future thermal/renewable composition of the fleet. Hence higher demand, all else equal, may result in fewer baseline retirements, while a different load shape could incentivize different levels of RE penetration.

• Natural gas supply and demand: The baseline includes significant growth in LNG exports, driving tighter natural gas prices relative to the forecast used to estimate the impacts of the final rules. To the extent prices are higher or lower, it would influence the use of natural gas for electricity generation and overall competitiveness of other EGUs (e.g., coal, RE and nuclear units).

• Longer-term planning by utilities: Many utilities have announced long-term clean energy and/or climate commitments, with a phasing out of large amounts of coal capacity by 2030 and continuing through 2050. These announcements, some of which are not legally binding, are not necessarily reflected in the baseline, and may alter the amount of coal capacity projected in the baseline that would be covered under this rule.

• Inflation Reduction Act (IRA): The IRA was passed in August of 2022. In order to illustrate the impact of the IRA on this rulemaking, EPA included a baseline that incorporates key provisions of the IRA as well as imposing the final rules as modeled in this RIA on that baseline. However, additional effects of the IRA beyond those modeled in this RIA could result in a change in projected system compliance costs and emissions outcomes.[94]

• Hydrogen production: Currently, hydrogen is an exogenous input to the model, represented as a fuel that is available at affected sources at a delivered cost of $1.15/kg. The model does not track any upstream emissions[95] associated with the production of the hydrogen, nor any incremental electricity demand associated with its production.[96] The incorporation of these effects could change the amount of hydrogen selected as a compliance measure. The model

[93] For details, see chapter 3 of the IPM documentation available at: https://www.epa.gov/power-sector-modeling

[94] For details of IRA representation in this analysis please see IPM documentation, available at: https://www.epa.gov/power-sector-modeling

[95] IPM does not track upstream emissions for any modeled fuels.

[96] Potential impacts associated with hydrogen production and utilization are discussed in preamble Sections VII(F)(3), and XIV(E)(3). These include water use in hydrogen production, combustibility, and potential increased NO_X emissions from combustion of higher percentages of hydrogen in natural gas blends. Analysis in this RIA does not assess these potential impacts, nor the potential impacts of hydrogen gas release on climate or air quality through atmospheric chemical reactions.

also does not account for any possible increases in NO_X emission rates at higher levels of hydrogen blending.[97] For details on hydrogen modeling assumptions, please see Section 3.5.2.

The baseline includes modeling to capture the finalized 2020 Effluent Limitation Guidelines (ELG), and it also incorporates information provided by owners of affected facilities to state permitting authorities in October 2021 that indicate their likely compliance pathway, including retirement by 2028. Potential future incorporation of this information may result in additional coal plant retirements in an updated baseline scenario, which could affect modeled costs and benefits of the rules depending on the extent that these retirements occur before compliance deadlines for this action. Similarly, the baseline accounts for the effect of expected compliance methods for the 2020 CCR Rule. It is possible that the waste streams of coal plants are subject to multiple rules listed above, and that the interactions between these requirements may alter compliance behavior that would likely occur under any of the rules in isolation, i.e. plants may adopt compliance methods that are different than those represented in the baseline. In order to estimate the impact of recently finalized EPA regulations, sensitivity analysis was performed using IPM and included in the docket for this rulemaking that included a characterization of the LDV, MDV and HDV (2024) vehicle rules, ELG (2024), and MATS (2024) rules in addition to the final carbon rules presented in this RIA.

The impact of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review[98] are also not included in this analysis. Inclusion of these standards would likely increase the price of natural gas modestly as a result of limitations on the usage of reciprocating internal combustion engines in the pipeline transportation of natural gas. All else equal, inclusion of this program would likely result in a modest increase in the total cost of compliance for this rule. The proposed GNP Supplemental Rule (2023), the proposed Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles (2023), the proposed Heavy-duty Greenhouse Gas “Phase 3” for Model Years 2027 and Later (2023), the proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility

[97] For details on the possible increases in NOx emission rates at higher levels of hydrogen blending, please see the *Hydrogen in Combustion Turbine Electricity Generating Units TSD,* available in the docket for this rulemaking.

[98] Available at: https://www.federalregister.gov/documents/2021/11/15/2021-24202/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for

Steam Generating Units Review of the Residual Risk and Technology Review (2023), and the proposed Steam Electric Power Generating Effluent Guidelines (2023) were not included. Inclusion of these rules may result in changes projected compliance outcomes. Additionally, EPA performed a variety of sensitivity analysis looking at lower natural gas prices, higher electricity demand and also higher electricity demand coupled with EPA's additional Power Sector Rules (MATS, ELG and the Final Rules). These sensitivity analyses continue to show that the Final Rules, in the context of higher demand and other pending power sector rules, still demonstrate compliance pathways that respect these NERC reliability considerations and constraints, while achieving significant emissions reductions at reasonable costs. These results are discussed in "IPM Sensitivities Technical MEMO" and "The Resource Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG, and MATS Technical MEMO" in the docket for this rulemaking.

The IPM modeling of CCS is inclusive of the cost of installation and operating capture technology and includes heat rate and capacity penalties to account for the parasitic load of the capture equipment. The costs also reflect the cost of transport and storage of captured CO_2 based on the distance between CO_2 production and storage sites. One possible area of uncertainty is delays in the time taken to receive necessary permits, which are not modeled in IPM. As laid out in the preamble, EPA has provided flexibilities in order to manage any delays in the process.

These are key uncertainties that may affect the overall composition of electric power generation fleet and could thus have an effect on the estimated costs and impacts of this action. However, these uncertainties would largely affect the modeling of the baseline and illustrative scenarios similarly, and therefore, the impact on the incremental projections (reflecting the potential costs/benefits of the regulatory alternatives) would be more limited and are not likely to result in notable changes to the assessment of the final NSPS and Emission Guidelines found in this section. While it is important to recognize these key areas of uncertainty, they do not change EPA's overall confidence in the estimated impacts of the illustrative regulatory alternatives presented in this section. EPA continues to monitor industry developments and makes appropriate updates to the modeling platforms in order to reflect the best and most current data available.

3.8 References

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