IPM Sensitivity Runs

Memo

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

Final Rule

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Overview

This document supports the EPA's Final New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units and the Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units. As part of the Regulatory Impact Analysis (RIA) for this final rulemaking, EPA conducted modeling using the Integrated Planning Model (IPM)[1] to analyze compliance outcomes under the final rules. This document extends that modeling and describes a range of sensitivity scenarios aimed at highlighting the impacts of factors ranging from policy design choice to the impacts of input parameters on modeled compliance behavior.[2]

This document provides a summary of EPA's approach to developing sensitivity modeling and presents estimates of compliance costs for EGUs, as well as estimated impacts on emissions, generation, capacity, fuel use, and fuel price for select run years.

This document is organized as follows: an executive summary that describes key findings across the scenarios examined, followed by sections that provide detailed results for each of the sensitivity scenarios as compared to the final rules scenario and baseline included in the RIA for this rulemaking. Results are provided for 2028, 2030, 2035, 2040 and 2045 run years[3] and for the cumulative 2024-47 time period.[4]

Executive Summary

As outlined in Table E-1, this document outlines several sensitivity scenarios[5] that adjust a range of policy design and input parameters.

[1] Information on IPM can be found at the following link: https://www.epa.gov/power-sector-modeling.
[2] IPM run outputs for the four runs described in this document along with the updated gas supply curves are available in the docket for this rulemaking.
[3] 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 and 2029 to run year 2028, calendar years 2030-31 to run year 2030, calendar years 2032-37 to run year 2035, calendar years 2038-41 to run year 2040, calendar years 2042-47 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/power-sector-modeling
[4] EPA chose this time period as it estimates that some monitoring, reporting, and recordkeeping (MR&R) costs may be incurred in 2024. While MR&R costs analysis is presented beginning in the year 2024, the detailed assessment of costs, emissions impacts, and benefits begins in the year 2028. The analysis timeframe concludes in 2047, as this is the last year that may be represented with the analysis conducted for the specific year of 2045.
[5] For details of scenario specifications, please see Appendix.

Table E-1: List of Included Scenarios

Scenario Name	Description	Reflects Change in[6]	Detailed Results in Section
Baseline 1:	Baseline used for RIA evaluation: EPA's Power Sector Platform 2023 using IPM	N/A	1
Final Rules	Illustrative Final Rules Scenario used in RIA evaluation	N/A	1
Sensitivity: 40% co-firing	Illustrative scenario that features a BSER for existing coal-fired EGUs based on 40% natural gas co-firing for medium- and long-term coal-fired EGUs (no CCS-based BSER)	Policy Design	1
Sensitivity Low Gas: Baseline	Updated baseline that features lower LNG export volumes	Input Parameters	2
Sensitivity Low Gas: Final Rules	Updated final rules scenario that features lower LNG export volumes	Input Parameters	2
Sensitivity High Demand: Baseline	Updated baseline that features higher electricity demand projections	Input Parameters	3
Sensitivity High Demand: Final Rules	Updated final rules scenario that features higher electricity demand projections	Input Parameters	3
Sensitivity Vehicle Rules: Baseline	Updated baseline that includes higher demand from recently finalized EPA LDV, MDV and HDV vehicle rules	Input Parameters/ Policy Design	4
Sensitivity Vehicle Rules: Final Rules, ELG, MATS	Updated final rules scenario that includes higher demand from recently finalized vehicle rules, as well as ELG and MATS	Input Parameters/ Policy Design	4

Emissions and emission reduction estimates are provided in Table E-1a and Table E-1b below.

As outlined in Table E-1 above, the 40% co-firing sensitivity reflects a change in policy design, and not in the input parameters (i.e. macroeconomic conditions). Emission reductions under the 40% co-firing scenario remain very similar to the final rules scenario, since emission rate requirements consistent with 40% co-firing at coal-fired steam EGUs without a plan to cease operations by 2032 result in similar levels of CCS adoption and coal retirement as under the illustrative[7] final rules scenario, driven by the IRC section 45Q tax credits under the Inflation Reduction Act (IRA.).

Under the low gas sensitivities, reduced natural gas prices improve the economics of natural-gas fired generation relative to competing resources such as coal and renewable energy (RE). Through 2035 emissions are lower under the low gas sensitivity as natural gas offsets coal generation relative to the baseline, but after 2035 emissions are higher relative to the baseline, since lower gas prices reduce the penetration of RE sources in the longer term. Total emission reductions are therefore also lower under the low gas sensitivity.

[6] Changes noted reflect differences relative to Final 111 baseline and Final Rules Scenario used in the RIA.
[7] The energy impact estimates presented here reflect EPA's illustrative analysis of the final rules. 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.

Under the high demand sensitivity by 2040 annual electricity demand is about 11% higher and peak demand is 6% higher than under the baseline. This higher demand environment results in greater consumption of fossil fuel to generate electricity in the power sector, and therefore higher emissions under the high demand baseline. Consequently, emission reductions under the illustrative final rules under the high demand scenario are also higher than under the baseline.

Under the vehicle rules sensitivity, by 2040 annual electricity demand is about 7% higher and peak demand is 3% higher than under the baseline. This higher demand environment results in greater consumption of fossil fuel to generate electricity in the power sector, and therefore higher power sector emissions under the high demand baseline.[8] The policy scenario features the Final Rules, ELG, and MATS and final rules, and consequently, emission reductions are also higher relative to the Vehicle Rules baseline without these rules.

Table E-1a. CO_2 Emissions Summary

Annual CO_2	Total Emissions								
(Million Metric Tonnes)	Baseline	Final Rules	Sens: 40% co-firing	Sens Low Gas: Baseline	Sens Low Gas: Final Rules	Sens High Demand: Baseline	Sens High Demand: Final Rules	Sens Vehicle Rules: Baseline	Sens Vehicle Rules: Final Rules, ELG, MATS
2028	1,159	1,121	1,123	1,150	1,158	1,137	1,074	1,132	1,076
2030	1,098	1,048	1,054	1,093	1,081	1,119	1,025	1,087	1,008
2035	724	601	610	723	644	869	677	814	652
2040	459	406	409	564	517	544	460	510	441
2045	307	265	267	405	364	357	299	342	290
Cumulative 2028-47	12,538	11,156	11,250	13,509	12,594	14,041	11,897	13,416	11,583

Table E-1b. CO_2 Emissions Reductions Summary

Annual CO_2	Change from Relevant Baseline Run				
(Million Metric Tonnes)	Final Rules	Sensitivity: 40% co-firing[9]	Sensitivity Low Gas: Final Rules[10]	Sensitivity High Demand: Final Rules[11]	Sensitivity Vehicle Rules:

[8] Note – the emission changes here are specific to the power sector, and do not capture the emissions changes in the mobile sector due to reduced gasoline consumption.

[9] Relative to Baseline

[10] Relative to Sensitivity Low Gas: Baseline

[11] Relative to Sensitivity High Demand: Baseline

					Final Rules, ELG, MATS[12]
2028	-38	-36	8	-62	-56
2030	-50	-45	-12	-94	-79
2035	-123	-114	-79	-191	-162
2040	-54	-51	-46	-84	-70
2045	-42	-40	-42	-58	-52
Cumulative 2028-47	-1,382	-1,288	-915	-2,143	-1,833

Compliance cost estimates are provided in Table E-2 below, and are estimated as the difference between the total cost of meeting electricity demand in a baseline run and a corresponding policy scenario. IPM is populated with a range of constraints that model resource adequacy requirements – even under the higher demand environment, EPA projects that these requirements can be met, and the cost of compliance cited here is fully inclusive of the costs of meeting these constraints. Compliance costs are similar between the illustrative final rules scenario and the 40% co-firing sensitivity, reflecting similar compliance outcomes. Under the low gas sensitivity compliance costs are lower, reflecting the lower gas price environment which reduces the cost of increasing generation from natural-gas fired EGUs. The high demand sensitivity features higher costs since it features significantly higher levels of electricity demand relative to the baseline, and therefore increases the total amount of affected new and existing EGUs affected by the rules. Finally, compliance costs are highest under the vehicle rules sensitivity, since it features both higher electricity demand levels as well as requirements from MATS and ELG as well as the final rules. As in the case of the high demand sensitivity, resource adequacy constraints continue to be met in the vehicle rules, final rules, MATS and ELG sensitivity and the compliance costs fully reflect the costs of these constraints.

Table E-2. National Power Sector Compliance Cost Estimates (billions of 2019 dollars) for the Illustrative Scenarios

Billions of 2019$	Final Rules	Sensitivity: 40% co-firing	Sensitivity Low Gas: Final Rules	Sensitivity High Demand: Final Rules	Sensitivity Vehicle Rules: Final Rules, ELG, MATS
2028	-1.3	-1.3	0.1	-1.9	-1.2
2030	-0.2	0.2	0.4	-1.1	0.0
2035	1.3	1.3	0.7	1.2	1.6
2040	0.6	0.6	0.1	1.0	1.2
2045	3.3	3.0	2.9	5.0	4.0

[12] Relative to Sensitivity Vehicle Rules: Baseline

Present Value (2028-47)	13.44	13.19	12.15	16.58	18.50
Annualized (2028-47)	0.86	0.84	0.78	1.06	1.18

"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.[13] This does not include compliance costs beyond 2047. "2024 to 2047 (Net Present Value)" reflects total estimated annual compliance costs over the period 2024 through 2047

[13] 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. The PV of costs was then used to calculate the levelized annual value over a 23-year period (2024 to 2047) using the 3.76 percent rate as well.

Section 1: Estimated Impacts of the 40 percent co-firing sensitivity

Description of Scenario and Key Takeaways

Under the 40% co-firing sensitivity scenario, the final rules scenario was updated to allow for existing coal-fired steam EGUs greater than 25 MW without a plan to cease operation by the 2035 run year to either (1) co-fire natural gas equivalent to at least 40 percent of the heat input to the unit starting in run year 2030, or (2) install CCS with 90% capture by 2035. Hence this model run did not include the distinction of subcategories based on planned retirement date.[14] For details, please see Table A-2. Since none of the baseline parameters were updated, including capacity factors (unlike in RIA alternative 1 and alternative 2 scenarios, where the definition of annual capacity factor for baseload operation for new turbines is assumed to be 50 percent), the run is comparable to the baseline run and the illustrative final rules scenarios presented in the RIA.

Projected compliance behavior and compliance costs under the 40 percent co-firing scenario remains similar to that under the illustrative final rules scenario. In particular, under the 40 percent co-firing scenario:

1. National CO_2 emission reductions are roughly 93 percent of those observed under the illustrative final rules scenario, while projected compliance costs are approximately 2 percent lower.
2. 7 GW of coal-fired EGUs are projected to adopt gas co-firing under the 40 percent co-firing scenario as compared to 1 GW under the illustrative final rules scenario.
3. 18 GW of coal-fired EGUs are projected to adopt CCS under the 40 percent co-firing scenario as compared to 19 GW under the illustrative final rules scenario.
4. Under the baseline, 83 GW of coal retirements are projected by 2035, 92 GW are projected by 2040, and 105 GW are projected by 2045. Under the 40 percent co-firing scenario, 103 GW of coal retirements are projected by 2035, 103 GW are projected by 2040, and 121 GW by 2045. Under the illustrative final rules scenario coal retirements increase to 104 GW by 2035, 106 GW by 2040, and 124 GW by 2045.

Emissions Reduction Assessment

The EGU CO_2 emissions reductions are presented in this document from 2028 through 2045 and are based on IPM projections.[15] Table 1-1 presents the estimated reduction in power sector CO_2 emissions resulting from compliance with the evaluated illustrative scenarios.

[14] EPA utilized model run year 2035 as it reflects mapping of calender years 2032-2037, and it reflects the first model run year in which the rule's requirements for coal EGUs would be in place. As noted earlier, coal EGUs with no plans to cease operation by 2032 would face these additional mitigation measures.
[15] For detailed description of the Baseline and Final Rules compliance outcomes, please see Section 3 of the RIA for this rulemaking.

Table 1-1 EGU Annual CO_2 Emissions and Emissions Changes (million metric tons) from 2028 through 2045 [16]

Annual CO_2	Total Emissions			Change from Baseline	
(Million Metric Tonnes)	Baseline	Final Rules	Sensitivity: 40% co-firing	Final Rules	Sensitivity: 40% co-firing
2028	1,159	1,121	1,123	-38	-36
2030	1,098	1,048	1,054	-50	-45
2035	724	601	610	-123	-114
2040	459	406	409	-54	-51
2045	307	265	267	-42	-40
Cumulative (2028-47)	12,538	11,156	11,250	-1,382	-1,288

The 40% co-firing scenario is projected to result in 1,288 million metric tons of CO_2 reductions over the 2028-47 period, or roughly 93 percent of the reductions projected under the final rules scenario.

In addition to the projected annual CO_2 reductions, there are also projected reductions of other air emissions associated with EGUs burning fossil fuels that result from compliance strategies to reduce CO_2 emission rates. These other emissions include the annual total changes in emissions of NO_X, SO_2, and ozone season NO_X emissions changes. The emissions reductions are presented in Table 1-2 below. As with the CO_2 reductions, reductions of other pollutants under the 40% co-firing scenario remain similar to the reductions under the illustrative final rules scenario.

Table 1-2 EGU Annual Emissions and Emissions Changes for NO_X, SO_2, and Ozone NO_X 2028 to 2045

Annual NOx	Total Emissions			Change from Baseline	
(Thousand Tons)	Baseline	Final Rules	Sensitivity: 40% co-firing	Final Rules	Sensitivity: 40% co-firing
2028	461	441	443	-20	-17
2030	393	374	376	-20	-17
2035	259	210	212	-49	-47
2040	173	166	165	-6	-8
2045	107	83	84	-24	-23
Cumulative (2028-47)	4,590	4,048	4,072	-543	-519

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

Ozone Season[a] NOx	Total Emissions			Change from Baseline	
(Thousand Tons)	Baseline	Final Rules	Sensitivity: 40% co-firing	Final Rules	Sensitivity: 40% co-firing
2028	189	183	183	-6	-6
2030	175	168	168	-7	-7
2035	119	100	102	-19	-17
2040	88	82	82	-6	-6
2045	59	45	45	-14	-13
Cumulative (2028-47)	2,148	1,897	1,917	-251	-231
Annual SO2	**Total Emissions**			**Change from Baseline**	
(Thousand Tons)	**Baseline**	**Final Rules**	**Sensitivity: 40% co-firing**	**Final Rules**	**Sensitivity: 40% co-firing**
2028	454	420	426	-34	-29
2030	334	313	313	-20	-20
2035	240	150	146	-90	-94
2040	143	139	130	-4	-12
2045	55	13	15	-41	-39
Cumulative (2028-47)	3,913	3,006	2,968	-908	-945

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

Compliance Cost Assessment

The estimates of the changes in the cost of supplying electricity for the illustrative integrated final rules scenario are presented below in Table 1-3.[17] Since compliance with the final 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 1-3 National Power Sector Compliance Cost Estimates (billions of 2019 dollars) for the Illustrative Integrated Final Rules Scenario

Billions of 2019$	Final Rules	Sensitivity: 40% co-firing
2028 (annual)	-1.3	-1.3
2030 (annual)	-0.2	0.2
2035 (annual)	1.3	1.3
2040 (annual)	0.6	0.6
2045 (annual)	3.3	3.0

[17] 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.

Present Value (2024-47)	13.4	13.2
Annualized (2024-47)	0.86	0.84

"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.[18] This does not include compliance costs beyond 2047. "2024 to 2047 (Net Present Value)" reflects total estimated annual compliance costs 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.[19]

In general, projected compliance costs under the 40 percent co-firing scenario track closely with the illustrative final rules scenario. In 2028 costs are lower as a result of fewer SCR installations in response to the Good Neighbor Plan (GNP) and early renewable builds[20], whereas in 2030 costs are higher as a result of additional investment in gas co-firing at coal-fired EGUs. In 2035 costs are reflective of a similar level of CCS adoption in the 40 percent co-firing sensitivity as in the illustrative final rules scenario – this result is driven by the availability of tax credits for sequestration under the IRA which promote CCS adoption. By 2045 costs are lower under the 40 percent co-firing sensitivity since coal EGUs that are co-firing natural gas are not limited to those with committed retirements by the 2040 run year.

In addition to evaluating annual compliance cost impacts, EPA believes that a fuller understanding of this illustrative scenario is achieved through an evaluation of annualized costs over the 2028 to 2047 timeframe. Starting with the estimated annual cost time series, it is possible to estimate the net present value (PV) of that stream, and then estimate a levelized annual cost associated with compliance under each illustrative final rules scenario.[21] For this analysis we first calculate the PV of the cost streams from 2024 through 2047[22] using a 3.76 percent discount rate. In this cost annualization, we use a 3.76 percent discount rate to be 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 investors are willing to sacrifice present consumption for future consumption and is based on a Weighted Average Cost of Capital (WACC).[23] 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 1-3[24]

[18] 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. The PV of costs was then used to calculate the levelized annual value over a 24-year period (2024 to 2047) using the 3.76 percent rate as well.

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

[20] For details, please see Section 3 of the RIA for this rulemaking.

[21] 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.

[22] 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.

[23] The IPM Baseline run documentation (Section 10.4.1 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."

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

Impacts on Fuel Use, Prices and Generation Mix

The final rules are expected to result in significant GHG emissions reductions. The rules are also expected to have some impact on fuel use, fuel prices, generation, and capacity in the power sector. In this section we discuss the estimated changes in fuel use, fuel prices, generation by fuel type, and capacity by fuel type for the 2028, 2030, 2035, 2040 and 2045 IPM model run years.

Table 1-4 and Table 1-5**Table 1-5 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Natural Gas UseTable 1-5 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Natural Gas Use** present the percentage changes in national coal and natural gas usage by EGUs in the 2028, 2030, 2035, 2040 and 2045 run years. As outlined in the RIA, baseline coal consumption is projected to fall significantly over the forecast period, as the coal fleet continues to age and retirements continue consistent with recent historical patterns. Under the illustrative final rule modeling these trends accelerate. Consumption patterns are similar under the 40 percent co-firing scenario, with coal consumption ticking up briefly in both cases in 2040 reflecting greater levels of CCS adoption relative to the baseline. Similarly, gas consumption is projected to decline over the forecast period under the baseline, reflecting the greater cost competitiveness of renewable resources and increasing natural gas prices driven by increasing LNG exports. Under both the illustrative final rules scenario and the 40 percent co-firing scenario, gas consumption remains at similar levels – while there is an increase in the amount of coal EGUs co-firing natural gas, this remains a relatively small amount relative to total gas consumption.

Table 1-4 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Coal Use

	Total Power Sector Coal Consumption (Million Tons)			Percentage change from Baseline	
	Baseline	**Final Rules**	**Sensitivity: 40% co-firing**	**Final Rules**	**Sensitivity: 40% co-firing**
2028	251	234	235	-7%	-6%
2030	223	195	197	-13%	-12%
2035	147	111	112	-25%	-24%
2040	93	103	100	11%	8%
2045	28	3	4	-89%	-87%

Table 1-5 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Natural Gas Use

	Total Power Sector Gas Consumption (Trillion Cubic Feet)			Percentage change from Baseline	
	Baseline	**Final Rules**	**Sensitivity: 40% co-firing**	**Final Rules**	**Sensitivity: 40% co-firing**
2028	11.6	11.5	11.5	-1%	-1%
2030	11.7	11.7	11.7	0%	0%

2035	9.3	9.7	9.7	4%	4%
2040	6.4	6.4	6.4	0%	0%
2045	4.2	4.3	4.3	1%	1%

Table 1-6 and Table 1-7 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 final rules scenarios and the 40% co-firing sensitivity. In 2030 and 2035, gas prices are higher, which is reflective of higher gas consumption as a result of the imposition of the final Emission Guidelines for coal-fired steam generating units. In 2035 and 2040, the second phase of the NSPS are assumed to be active, resulting in less gas consumption and lower prices. Results remain similar between the final rules scenario and the 40 percent co-firing scenario.

Table 1-6 2028, 2030, 2035, 2040 and 2045 Projected Delivered Coal Price (2019 dollars)

	Delivered Coal Price (2019$/MMBtu)			Percentage change from Baseline	
	Baseline	Final Rules	Sensitivity: 40% co-firing	Final Rules	Sensitivity: 40% co-firing
2028	1.5	1.5	1.5	-1%	-1%
2030	1.6	1.5	1.5	-2%	-1%
2035	1.5	1.5	1.5	0%	-1%
2040	1.6	1.6	1.6	1%	0%
2045	1.4	0.9	1.2	-32%	-14%

Table 1-7 2028, 2030, 2035, 2040 and 2045 Projected Henry Hub Natural Gas Price (2019 dollars)

	Henry Hub Natural Gas Price (2019$/MMBtu)			Percentage change from Baseline	
	Baseline	Final Rules	Sensitivity: 40% co-firing	Final Rules	Sensitivity: 40% co-firing
2028	2.8	2.7	2.7	-2%	-2%
2030	2.9	2.9	2.9	0%	2%
2035	2.9	3.0	3.0	3%	3%
2040	2.8	2.8	2.8	-1%	-1%
2045	3.0	3.0	3.0	0%	0%

Table 1-8 presents the projected percentage changes in the amount of electricity generation in 2028, 2030, 2035, 2040 and 2045 by fuel type. Consistent with the fuel use projections and emissions trends described above, EPA projects an overall shift from coal to gas and renewables under the baseline, and these trends persist under the illustrative final rules scenarios analyzed.

The projected impacts are highest in 2035 reflecting the imposition of the final Emission Guidelines and are smaller thereafter. The IRC section 45Q tax credit is available for 12 years within the modeling, after which point units no longer receive tax credits and must dispatch based on unsubsidized operating costs. Projected generation use by fuel type remains very similar between the illustrative final rules scenario and the 40% co-firing sensitivity.

Table 1-8 2028, 2030, 2035, 2040 and 2045 Projected U.S. Generation by Fuel Type

		Generation (TWh)			Percent Change from Baseline	
	Year	Baseline	Final Rules	Sensitivity: 40% co-firing	Final Rules	Sensitivity: 40% co-firing
Unabated Coal	2028	472	441	443	-7%	-6%
Coal & CCS		0	0	0	0%	0%
Coal & Nat. Gas co-firing		0	0	0	0%	0%
Unabated Nat. Gas		1,652	1,631	1,630	-1%	-1%
Nat. Gas & CCS		0	0	0	0%	0%
Nuclear		774	776	776	0%	0%
Hydro		293	293	293	0%	0%
Non-Hydro RE		1,151	1,199	1,198	4%	4%
Oil/Gas Steam		3	3	3	1%	1%
Other		70	71	71	1%	1%
Total		4,415	4,414	4,414	0%	0%
Unabated Coal	2030	407	355	347	-13%	-15%
Coal & CCS		3	5	5	71%	63%
Coal & Nat. Gas co-firing		0	2	25	0%	0%
Unabated Nat. Gas		1,670	1,660	1,650	-1%	-1%
Nat. Gas & CCS		0	0	0	0%	0%
Nuclear		749	751	750	0%	0%
Hydro		298	299	299	0%	0%
Non-Hydro RE		1,355	1,404	1,402	4%	3%
Oil/Gas Steam		4	6	5	36%	15%
Other		70	71	71	1%	1%
Total		4,557	4,553	4,554	0%	0%
Unabated Coal	2035	160	0	0	-100%	-100%
Coal & CCS		76	133	127	74%	66%
Coal & Nat. Gas co-firing		0	4	23	0%	0%
Unabated Nat. Gas		1,341	1,379	1,369	3%	2%
Nat. Gas & CCS		3	7	7	105%	105%

Nuclear		674	674	674	0%	0%
Hydro		319	317	317	-1%	-1%
Non-Hydro RE		2,336	2,402	2,400	3%	3%
Oil/Gas Steam		1	1	1	79%	57%
Other		68	70	70	2%	2%
Total		4,978	4,987	4,986	0%	0%
Unabated Coal	2040	61	0	0	-100%	-100%
Coal & CCS		76	128	122	68%	60%
Coal & Nat. Gas co-firing		0	0	6	0%	0%
Unabated Nat. Gas		933	919	915	-2%	-2%
Nat. Gas & CCS		3	7	7	105%	105%
Nuclear		619	618	618	0%	0%
Hydro		336	336	336	0%	0%
Non-Hydro RE		3,252	3,275	3,277	1%	1%
Oil/Gas Steam		1	1	1	126%	94%
Other		65	66	66	1%	1%
Total		5,345	5,350	5,349	0%	0%
Unabated Coal	2045	45	0	0	-100%	-100%
Coal & CCS		4	3	3	-7%	-8%
Coal & Nat. Gas co-firing		0	0	2	0%	0%
Unabated Nat. Gas		614	612	610	0%	-1%
Nat. Gas & CCS		3	6	6	103%	103%
Nuclear		475	477	477	0%	0%
Hydro		343	342	342	0%	0%
Non-Hydro RE		4,275	4,336	4,335	1%	1%
Oil/Gas Steam		0	1	1	106%	67%
Other		63	64	64	1%	1%
Total		5,823	5,841	5,841	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 1-9 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 are assumed to be in effect under both scenarios. Under the baseline, coal retirements are projected to be 83 GW. This increases to 104 GW under the illustrative final rules scenario and 103 GW under the 40 percent co-firing scenario. By 2045 the baseline projects coal retirements to be 105 GW, while the illustrative final rules scenario projects 124 GW and the 40 percent co-firing scenario projects 121 GW. 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.[25]

Under the illustrative final rules scenario, 1 GW of natural gas co-firing is projected by 2030, whereas under the 40 percent co-firing scenario 7 GW of co-firing is projected by 2030.

Under the baseline, 11 GW of coal EGUs are projected to install CCS by 2035, while under the illustrative final rules scenario this increases to 19 GW, and under the co-firing scenario 18 GW of coal EGUs are projected to install CCS by 2035.

Under the baseline, 12 GW of coal to gas conversions are projected by 2030, while under the illustrative final rules scenario, 20 GW are projected by 2030, and under the 40 percent co-firing scenario 17 GW are projected by 2030.

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.[26] Additionally, IPM models operating reserves at the regional level, and can account for the impact of solar and wind on operating reserves requirements.[27]

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 (i.e., lower capacity factors), due to the increase in low-emitting generation. These trends persist under the illustrative scenarios.

Table 1-9 2028, 2030, 2035, 2040 and 2045 Projected U.S. Capacity by Fuel Type

		Capacity (GW)			Percent Change from Baseline	
	Year	**Baseline**	**Final Rules**	**Sensitivity: 40% co-firing**	**Final Rule**	**Option 2**
Unabated Coal	2028	106	101	102	-4%	-4%
Coal & CCS		0	0	0	0%	0%
Coal & Nat. Gas co-firing		0	0	0	0%	0%
Unabated Nat. Gas		471	472	472	0%	0%
Nat. Gas & CCS		0	0	0	0%	0%
Nuclear		146	147	147	1%	1%
Hydro		102	102	102	0%	0%
Non-Hydro RE		434	447	447	3%	3%
Oil/Gas Steam		11	11	11	0%	0%

[25] For further discussion of how the rule is anticipated to integrate into the ongoing power sector transition while not impacting resource adequacy, see section XII.F of the preamble, and the Resource Adequacy Analysis TSD included in the docket.
[26] For details, please see chapter 4 of the IPM documentation, available at: https://www.epa.gov/power-sector-modeling.
[27] For details, please see chapter 3 of the IPM documentation, available at: https://www.epa.gov/power-sector-modeling.

Other		12	12	12	1%	1%
Total		1,282	1,292	1,292	1%	1%
Unabated Coal	2030	85	72	69	-15%	-18%
Coal & CCS		0	1	1	72%	64%
Coal & Nat. Gas co-firing		0	1	7	0%	0%
Unabated Nat. Gas		479	480	479	0%	0%
Nat. Gas & CCS		0	0	0	0%	0%
Nuclear		143	144	144	1%	1%
Hydro		104	104	104	0%	0%
Non-Hydro RE		492	505	504	3%	2%
Oil/Gas Steam		12	20	17	60%	36%
Other		12	12	12	1%	1%
Total		1,327	1,338	1,337	1%	1%
Unabated Coal	2035	41	0	0	-100%	-100%
Coal & CCS		11	19	18	74%	66%
Coal & Nat. Gas co-firing		0	1	7	0%	0%
Unabated Nat. Gas		476	484	483	2%	1%
Nat. Gas & CCS		0	1	1	104%	104%
Nuclear		126	131	131	3%	3%
Hydro		107	107	107	0%	0%
Non-Hydro RE		806	830	829	3%	3%
Oil/Gas Steam		12	19	16	49%	25%
Other		12	12	12	1%	1%
Total		1,591	1,603	1,603	1%	1%
Unabated Coal	2040	31	0	0	-99%	-99%
Coal & CCS		11	18	18	68%	60%
Coal & Nat. Gas co-firing		0	0	6	0%	0%
Unabated Nat. Gas		516	525	523	2%	1%
Nat. Gas & CCS		0	1	1	104%	104%
Nuclear		122	126	126	4%	4%
Hydro		112	112	112	0%	0%
Non-Hydro RE		1,077	1,087	1,088	1%	1%
Oil/Gas Steam		11	17	14	53%	27%
Other		12	12	12	1%	1%
Total		1,892	1,899	1,900	0%	0%
Unabated Coal	2045	29	0	0	-99%	-99%
Coal & CCS		1	1	1	-5%	-5%
Coal & Nat. Gas co-firing		0	0	6	0%	0%
Unabated Nat. Gas		565	581	577	3%	2%
Nat. Gas & CCS		0	1	1	104%	104%

Nuclear		107	112	112	4%	4%
Hydro		112	112	112	0%	0%
Non-Hydro RE		1,402	1,422	1,421	1%	1%
Oil/Gas Steam		11	17	14	53%	27%
Other		12	12	12	1%	1%
Total		2,240	2,257	2,257	1%	1%

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

Section 2: Estimated Impacts of the low gas sensitivity

Description of Scenario and Key Takeaways

Under the low gas sensitivities, the gas supply curves were updated[28] to exclude the incremental amount of future LNG export capacity assumed between AEO 2022 and AEO 2023, resulting in lower natural gas prices. This was a major change in the baseline assumptions between proposal and final, and to test its impact, EPA conducted this sensitivity analysis. For details, please see Table A-4. Since the baseline parameters were updated, the run is compared with an updated baseline run.

Under theLow Gas Export sensitivities, the baseline shifts significantly, and compliance behavior is also affected. In particular:

1. Lower natural gas prices improve the relative economics of natural gas-fired generation and reduce the competitiveness of competing resources such as coal and RE. Through 2035 emissions are lower under the low gas sensitivity as natural gas offsets coal generation relative to the baseline, but after 2035 emissions are higher relative to the baseline since lower gas prices reduce the penetration of RE sources in the longer term.
2. As a result, reductions of CO_2 emissions from the illustrative final rules under the low gas export scenario (915 MMT) are lower than under the final rules scenario (1,382 MMT).
3. Levels of CCS adoption at coal fired EGUs from the illustrative final rules is similar under the low gas export case (17 GW by 2035) and the illustrative final rules case (19 GW by 2035).

Emissions Reduction Assessment

The EGU CO_2 emissions reductions are presented in this document from 2028 through 2045 and are based on IPM projections.[29] Table 2-1 presents the estimated reduction in power sector CO_2 emissions resulting from compliance with the evaluated illustrative scenarios.

[28] The updated gas supply curves used in this analysis are available in the docket for this rulemaking. The analysis described in this document is illustrative, in that the approach does not include use of the Gas Market Model to account for subnational pricing impacts of decreased LNG exports.
[29] For detailed description of the Baseline and Final Rules compliance outcomes, please see Section 3 of the RIA for this rulemaking.

Table 2-1 EGU Annual CO_2 Emissions and Emissions Changes (million metric tons) from 2028 through 2045 [30]

Annual CO_2	Total Emissions (Million Metric Tonnes)		Change from Baseline	Total Emissions		Change from Baseline
	Baseline	**Final Rules**	**Final Rules**	**Sensitivity Low Gas: Baseline**	**Sensitivity Low Gas: Final Rules**	**Sensitivity Low Gas: Final Rules**
2028	1,159	1,121	-38	1,150	1,158	8
2030	1,098	1,048	-50	1,093	1,081	-12
2035	724	601	-123	723	644	-79
2040	459	406	-54	564	517	-46
2045	307	265	-42	405	364	-42
Cumulative 2028-47	12,538	11,156	-1,382	13,509	12,594	-915

Lower natural gas prices improve the relative economics of natural gas-fired generation and reduce the competitiveness of competing resources such as coal and RE. Through 2035 emissions are lower under the low gas sensitivity as natural gas offsets coal generation relative to the baseline, but after 2035 emissions are higher relative to the baseline, since lower gas prices reduce the penetration of RE sources. The final rules include requirements on existing coal-fired steam EGUs and new combustion turbines. Under the low gas sensitivity, the baseline projects lower levels of coal-fired steam generation and higher levels of natural gas-fired generation relative to the expected baseline. As a result, CO_2 reductions are also lower than under the final rules scenario as modeled under the expected gas market environment.

In addition to the projected annual CO_2 reductions, there are also projected reductions of other air emissions associated with EGUs burning fossil fuels that result from compliance strategies to reduce CO_2 emission rates. These other emissions include the annual total changes in emissions of NO_X, SO_2, and ozone season NO_X emissions changes. The emissions reductions are presented in Table 2-2 below. As with the CO_2 reductions, reductions of other pollutants are generally lower than under the illustrative final rules scenario as modeled under the expected gas market environment.

Table 2-2 EGU Annual Emissions and Emissions Changes for NO_X, SO_2, and Ozone NO_X 2028 to 2045

Annual NOx	Total Emissions (Thousand Tons)		Change from Baseline	Total Emissions		Change from Baseline
	Baseline	**Final Rules**	**Final Rules**	**Sensitivity Low Gas: Baseline**	**Sensitivity Low Gas: Final Rules**	**Sensitivity Low Gas: Final Rules**
2028	461	441	-20	447	452	5

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

2030	393	374	-20	382	380	-2
2035	259	210	-49	238	208	-29
2040	173	166	-6	184	175	-9
2045	107	83	-24	118	99	-19
Cumulative (2028-47)	4,590	4,048	-543	4,524	4,206	-318
Ozone Season NOx	**Total Emissions**		**Change from Baseline**	**Total Emissions**		**Change from Baseline**
(Thousand Tons)	**Baseline**	**Final Rules**	**Final Rules**	**Sensitivity Low Gas: Baseline**	**Sensitivity Low Gas: Final Rules**	**Sensitivity Low Gas: Final Rules**
2028	189	183	-6	183	185	2
2030	175	168	-7	170	170	0
2035	119	100	-19	112	101	-11
2040	88	82	-6	90	86	-4
2045	59	45	-14	64	53	-11
Cumulative (2028-47)	2,148	1,897	-251	2,124	1,983	-141
Annual SO2	**Total Emissions**		**Change from Baseline**	**Total Emissions**		**Change from Baseline**
(Thousand Tons)	**Baseline**	**Final Rules**	**Final Rules**	**Sensitivity Low Gas: Baseline**	**Sensitivity Low Gas: Final Rules**	**Sensitivity Low Gas: Final Rules**
2028	454	420	-34	413	422	9
2030	334	313	-20	307	301	-6
2035	240	150	-90	176	130	-46
2040	143	139	-4	131	123	-8
2045	55	13	-41	43	11	-32
Cumulative (2028-47)	3,913	3,006	-908	3,278	2,786	-492

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

Compliance Cost Assessment

The estimates of the changes in the cost of supplying electricity for the illustrative integrated final rules scenario are presented below in Table 2-3.[31] Since compliance with the final 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.

[31] 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.

Table 2-3 National Power Sector Compliance Cost Estimates (billions of 2019 dollars) for the Illustrative Integrated Final Rules Scenario

Billions of 2019$	Final Rules	Sensitivity Low Gas: Final Rules
2028	-1.3	0.1
2030	-0.2	0.4
2035	1.3	0.7
2040	0.6	0.1
2045	3.3	2.9
Present Value (2028-47)	13.44	12.15
Annualized (2028-47)	0.86	0.78

"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.[32] This does not include compliance costs beyond 2047. "2024 to 2047 (Net Present Value)" reflects total estimated annual compliance costs 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.[33]

Since the natural gas price environment is lower under the low gas sensitivity as compared to the expected baseline scenario, the compliance costs are also lower, reflecting lower baseline costs for the production of electricity from natural gas.

In addition to evaluating annual compliance cost impacts, EPA believes that a fuller understanding of this illustrative scenario is achieved through an evaluation of annualized costs over the 2028 to 2047 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 under each illustrative scenario.[34] For this analysis we first calculated the PV of the cost streams from 2024 through 2047[35] using a 3.76 percent discount rate. In this cost annualization, we use a 3.76 percent discount rate to be 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 investors are willing to sacrifice present consumption for future consumption and is based on a

[32] 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. The PV of costs was then used to calculate the levelized annual value over a 23-year period (2024 to 2047) using the 3.76 percent rate as well.

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

[34] 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.

[35] 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.

Weighted Average Cost of Capital (WACC).[36] 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 2-3**Table 1-3 National Power Sector Compliance Cost Estimates (billions of 2019 dollars) for the Illustrative Integrated Table 1-3 National Power Sector Compliance Cost Estimates (billions of 2019 dollars) for the Illustrative Integrated** .[37]

Impacts on Fuel Use, Prices and Generation Mix

The final rules are expected to result in significant GHG emissions reductions. The rules are also expected to have some impact on fuel use, fuel prices, generation, and capacity in the power sector. In this section we discuss the estimated changes in fuel use, fuel prices, generation by fuel type, and capacity by fuel type for the 2028, 2030, 2035, 2040 and 2045 IPM model run years.

Table 2-4 and Table 2-5**Table 1-5 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Natural Gas UseTable 1-5 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Natural Gas Use** present the percentage changes in national coal and natural gas usage by EGUs in the 2028, 2030, 2035, 2040 and 2045 run years. As outlined in the RIA, baseline coal consumption is projected to fall significantly over the forecast period, as the coal fleet continues to age and retirements occur consistent with recent historical patterns. Under the low gas sensitivity these trends accelerate further, as natural gas fired generation sees improved economics relative to coal-fired generation. Under the illustrative final rule modeling these trends are further accentuated. The reduction in consumption patterns is therefore similar under the illustrative final rules scenario as under both the expected gas environment and the low gas sensitivity, with coal consumption ticking up briefly in both cases in 2040 reflecting greater levels of CCS adoption relative to the baseline, but lower in other years where the rules are in effect.

Similarly, gas consumption is projected to decline over the forecast period under the expected baseline, reflecting the greater cost competitiveness of renewable resources and increasing natural gas prices driven by increasing LNG exports. Under the low gas sensitivity, gas consumption also declines over the forecast period but at a lower rate since the relative economics of RE are weakened by the lower gas price environment.

The illustrative final rules scenario under the low gas sensitivity projects gas consumption declining to a greater extent after 2035, since the low gas sensitivity baseline features more new combustion turbine builds than the expected baseline, and the requirements on new combustion turbines therefore have a greater impact.

[36] The IPM Baseline run documentation (Section 10.4.1 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.”
[37] The PMT() function in Microsoft Excel for Windows 365 is used to calculate the level annualized cost from the estimated PV.

Table 2-4 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Coal Use

	Total Power Sector Coal Consumption (Million Tons)		Percentage change from Baseline	Total Power Sector Coal Consumption		Percentage change from Baseline
	Baseline	Final Rules	Final Rules	Sensitivity Low Gas: Baseline	Sensitivity Low Gas: Final Rules	Sensitivity Low Gas: Final Rules
2028	251	234	-7%	233	234	1%
2030	223	195	-13%	204	188	-8%
2035	147	111	-25%	110	96	-13%
2040	93	103	11%	84	89	5%
2045	28	3	-89%	20	3	-86%

Table 2-5 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Natural Gas Use

	Total Power Sector Gas Consumption (Trillion Cubic Feet)		Percentage change from Baseline	Total Power Sector Gas Consumption		Percentage change from Baseline
	Baseline	Final Rules	Final Rules	Sensitivity Low Gas: Baseline	Sensitivity Low Gas: Final Rules	Sensitivity Low Gas: Final Rules
2028	11.6	11.5	-1%	12.2	12.2	0%
2030	11.7	11.7	0%	12.3	12.5	2%
2035	9.3	9.7	4%	10.5	10.6	1%
2040	6.4	6.4	0%	8.6	8.5	-1%
2045	4.2	4.3	1%	6.2	6.1	-2%

Table 2-6 and Table 2-7 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. Fuel prices generally follow consumption trends outlined earlier. Fewer LNG exports mean that even though total power sector gas consumption is higher in the low gas sensitivity, natural gas prices are lower.

Table 2-6 2028, 2030, 2035, 2040 and 2045 Projected Delivered Coal Price (2019 dollars)

	Delivered Coal Price (2019$/MMBtu)		Percentage change from Baseline	National Average Minemouth Coal Price		Percentage change from Baseline
	Baseline	Final Rules	Final Rules	Sensitivity Low Gas: Baseline	Sensitivity Low Gas: Final Rules	Sensitivity Low Gas: Final Rules
2028	1.5	1.5	-1%	1.5	1.5	0%
2030	1.6	1.5	-2%	1.5	1.5	-1%
2035	1.5	1.5	0%	1.5	1.5	2%

2040	1.6	1.6	1%	1.6	1.6	0%
2045	1.4	0.9	-32%	1.2	0.9	-20%

Table 2-7 2028, 2030, 2035, 2040 and 2045 Projected Henry Hub Natural Gas Price (2019 dollars)

	Henry Hub		Percentage change from Baseline	Henry Hub Gas Price		Percentage change from Baseline
(2019$/MMBtu)	Baseline	Final Rules	Final Rules	Sensitivity Low Gas: Baseline	Sensitivity Low Gas: Final Rules	Sensitivity Low Gas: Final Rules
2028	2.8	2.7	-2%	2.7	2.7	0%
2030	2.9	2.9	0%	2.7	2.7	0%
2035	2.9	3.0	3%	2.3	2.4	2%
2040	2.8	2.8	-1%	2.3	2.3	-2%
2045	3.0	3.0	0%	2.4	2.4	0%

Table 2-8 presents the projected percentage changes in the amount of electricity generation in 2028, 2030, 2035, 2040 and 2045 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 Emission Guidelines and are smaller thereafter. The IRC section 45Q tax credit is available for 12 years within the modeling, after which point units no longer receive tax credits and must dispatch based on unsubsidized operating costs.

Under the low gas export sensitivity, generation at coal-fired EGUs is lower than under the expected baseline. As a result there are fewer reductions in coal-fired generation as a result of the illustrative final rules. However, in the longer-term reductions in gas-fired generation are higher under the low gas export final rules sensitivity than the expected final rules scenario, reflecting greater impact of the requirements on new combustion turbines in the lower gas price environment.

Table 2-8 2028, 2030, 2035, 2040 and 2045 Projected U.S. Generation by Fuel Type

		Generation (TWh)		Percent Change from Baseline	Generation (TWh)		Percent Change from Baseline
	Year	Baseline	Final Rules	Final Rules	Sensitivity Low Gas: Baseline	Sensitivity Low Gas: Final Rules	Sensitivity Low Gas: Final Rules
Unabated Coal	2028	472	441	-7%	430	440	2%
Coal & CCS		0	0	0%	0	0	0%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		1,652	1,631	-1%	1,738	1,726	-1%
Nat. Gas & CCS		0	0	0%	0	0	0%
Nuclear		774	776	0%	777	778	0%
Hydro		293	293	0%	293	293	0%
Non-Hydro RE		1,151	1,199	4%	1,106	1,103	0%
Oil/Gas Steam		3	3	1%	3	3	1%
Other		70	71	1%	66	68	4%
Total		4,415	4,414	0%	4,413	4,413	0%
Unabated Coal	2030	407	355	-13%	369	341	-8%
Coal & CCS		3	5	71%	3	5	45%
Coal & Nat. Gas co-firing		0	2	0%	0	3	0%
Unabated Nat. Gas		1,670	1,660	-1%	1,758	1,772	1%
Nat. Gas & CCS		0	0	0%	0	0	0%
Nuclear		749	751	0%	749	752	0%
Hydro		298	299	0%	298	299	0%
Non-Hydro RE		1,355	1,404	4%	1,308	1,306	0%
Oil/Gas Steam		4	6	36%	5	8	83%
Other		70	71	1%	66	68	4%
Total		4,557	4,553	0%	4,555	4,554	0%
Unabated Coal	2035	160	0	-100%	88	0	-100%
Coal & CCS		76	133	74%	75	115	53%
Coal & Nat. Gas co-firing		0	4	0%	0	3	0%
Unabated Nat. Gas		1,341	1,379	3%	1,504	1,477	-2%
Nat. Gas & CCS		3	7	105%	5	17	235%
Nuclear		674	674	0%	682	681	0%
Hydro		319	317	-1%	317	316	0%
Non-Hydro RE		2,336	2,402	3%	2,231	2,294	3%
Oil/Gas Steam		1	1	79%	4	6	47%
Other		68	70	2%	64	67	5%
Total		4,978	4,987	0%	4,970	4,978	0%

Unabated Coal	2040	61	0	-100%	44	0	-100%
Coal & CCS		76	128	68%	75	110	47%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		933	919	-2%	1,239	1,200	-3%
Nat. Gas & CCS		3	7	105%	5	17	235%
Nuclear		619	618	0%	625	626	0%
Hydro		336	336	0%	334	336	1%
Non-Hydro RE		3,252	3,275	1%	2,922	2,961	1%
Oil/Gas Steam		1	1	126%	1	1	98%
Other		65	66	1%	62	65	4%
Total		5,345	5,350	0%	5,307	5,315	0%
Unabated Coal	2045	45	0	-100%	30	0	-100%
Coal & CCS		4	3	-7%	2	3	42%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		614	612	0%	902	857	-5%
Nat. Gas & CCS		3	6	103%	5	13	179%
Nuclear		475	477	0%	505	494	-2%
Hydro		343	342	0%	337	340	1%
Non-Hydro RE		4,275	4,336	1%	3,886	3,979	2%
Oil/Gas Steam		0	1	106%	1	1	71%
Other		63	64	1%	60	63	4%
Total		5,823	5,841	0%	5,728	5,750	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 2-9 presents the projected percentage changes in the amount of generating capacity in 2028, 2030, 2035, 2040 and 2045 by primary fuel type.

Under the low gas sensitivity, baseline coal capacity is projected to be 8 GW lower in 2035 and baseline natural gas capacity is projected to be 7 GW higher in 2035 than under the expected baseline.

Under the low gas sensitivity, the illustrative final rules scenario projects 18 GW of incremental coal retirements in 2035, and 13 GW of incremental coal retirements relative to the low gas sensitivity baseline values (89 GW in 2035 and 112 GW in 2045). These values 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.[38]

[38] For further discussion of how the rule is anticipated to integrate into the ongoing power sector transition while not impacting resource adequacy, see section XII.F of the preamble, and the Resource Adequacy Analysis TSD included in the docket.

Under the illustrative final rules scenario under both natural gas environments, 1 GW of natural gas co-firing is projected by 2030.

Under the low gas sensitivity, the illustrative final rules scenario projects 17 GW of CCS installations at coal-fired EGUs (11 GW under low gas baseline) and 2 GW of CCS installations at new gas-fired EGUs (0.5 GW under low gas baseline). Under the expected gas scenario, the illustrative final rules scenario projects 19 GW of CCS installations at coal-fired EGUs (11 GW under expected gas baseline) and 1 GW of CCS installations at new gas-fired EGUs (0.5 GW under expected gas baseline).

Table 2-9 2028, 2030, 2035, 2040 and 2045 Projected U.S. Capacity by Fuel Type

		Capacity (GW)		Percent Change from Baseline	Capacity (GW)		Percent Change from Baseline
	Year	**Baseline**	**Final Rules**	**Final Rules**	**Sensitivity Low Gas: Baseline**	**Sensitivity Low Gas: Final Rules**	**Sensitivity Low Gas: Final Rules**
Unabated Coal	2028	106	101	-4%	101	102	2%
Coal & CCS		0	0	0%	0	0	0%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		471	472	0%	479	477	0%
Nat. Gas & CCS		0	0	0%	0	0	0%
Nuclear		146	147	1%	146	147	1%
Hydro		102	102	0%	102	102	0%
Non-Hydro RE		434	447	3%	423	422	0%
Oil/Gas Steam		11	11	0%	11	11	1%
Other		12	12	1%	11	12	3%
Total		1,282	1,292	1%	1,273	1,273	0%
Unabated Coal	2030	85	72	-15%	79	71	-10%
Coal & CCS		0	1	72%	0	1	46%
Coal & Nat. Gas co-firing		0	1	0%	0	1	0%
Unabated Nat. Gas		479	480	0%	486	486	0%
Nat. Gas & CCS		0	0	0%	0	0	0%
Nuclear		143	144	1%	143	145	1%
Hydro		104	104	0%	104	104	0%
Non-Hydro RE		492	505	3%	479	478	0%
Oil/Gas Steam		12	20	60%	13	20	54%
Other		12	12	1%	11	12	3%
Total		1,327	1,338	1%	1,317	1,317	0%
Unabated Coal	2035	41	0	-100%	33	0	-99%

Coal & CCS		11	19	74%	11	17	52%
Coal & Nat. Gas co-firing		0	1	0%	0	1	0%
Unabated Nat. Gas		476	484	2%	483	488	1%
Nat. Gas & CCS		0	1	104%	1	2	235%
Nuclear		126	131	3%	130	132	1%
Hydro		107	107	0%	107	107	0%
Non-Hydro RE		806	830	3%	770	799	4%
Oil/Gas Steam		12	19	49%	14	19	37%
Other		12	12	1%	11	12	4%
Total		1,591	1,603	1%	1,560	1,577	1%
Unabated Coal	2040	31	0	-99%	27	0	-99%
Coal & CCS		11	18	68%	11	16	47%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		516	525	2%	527	535	2%
Nat. Gas & CCS		0	1	104%	1	2	235%
Nuclear		122	126	4%	126	127	1%
Hydro		112	112	0%	111	112	0%
Non-Hydro RE		1,077	1,087	1%	976	991	1%
Oil/Gas Steam		11	17	53%	13	18	41%
Other		12	12	1%	11	12	3%
Total		1,892	1,899	0%	1,803	1,813	1%
Unabated Coal	2045	29	0	-99%	21	0	-99%
Coal & CCS		1	1	-5%	0	0	46%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		565	581	3%	581	591	2%
Nat. Gas & CCS		0	1	104%	1	2	235%
Nuclear		107	112	4%	111	113	1%
Hydro		112	112	0%	111	112	1%
Non-Hydro RE		1,402	1,422	1%	1,282	1,305	2%
Oil/Gas Steam		11	17	53%	13	18	41%
Other		12	12	1%	11	12	4%
Total		2,240	2,257	1%	2,132	2,154	1%

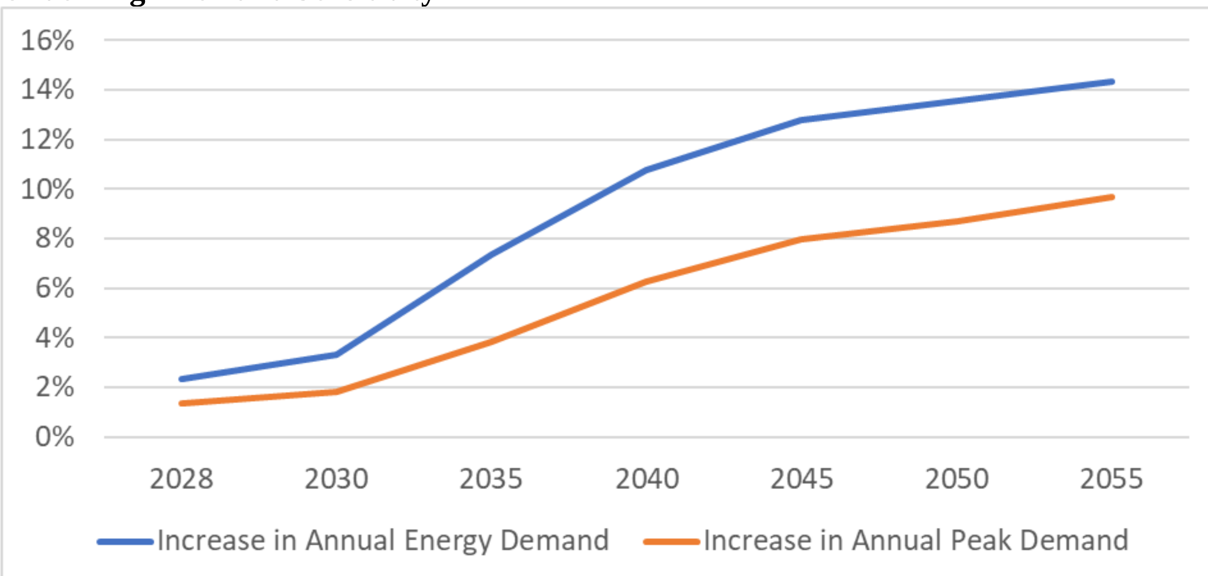
Note: In this table, “Non-Hydro RE” includes biomass, geothermal, landfill gas, solar, and wind

Section 3: Estimated Impacts of the High Demand Sensitivity

Description of Scenario and Key Takeaways

Under the high demand sensitivity, power sector demand was updated to account for the EV electricity demand associated with the LDV, MDV and HDV rulemakings (Vehicle Rules) as well as the non-EV load from the AEO 23 High Economic Growth Case. The percentage increase relative to the baseline is shown in Figure 3-1 below. Since the baseline parameters were updated, the illustrative final rules scenario is compared with an updated baseline run as well as the final rules scenario presented in the RIA.

Figure 3-1 Percentage Increase in National Electricity Demand Relative to Baseline Under High Demand Sensitivity



Under the high demand sensitivity, the baseline shifts significantly, and compliance behavior is also affected. In particular:

1. Demand is significantly higher relative to the expected baseline, and the percentage increase in peak demand is less than the percentage increase in energy demand, reflecting a change in the demand profile as a result of increased end-use electrification. By 2040 energy demand is 11% higher and peak demand is 6% higher than under the baseline.
2. As a result, reductions of CO_2 emissions from the illustrative final rules under the high demand sensitivity (2,143 MMT) are larger than under the baseline demand scenario (1,382 MMT) as are compliance costs for the final rules (PV of 16.6 billion 2019$ under the high demand sensitivity and13.4 billion 2019$ under the baseline demand).
3. IPM includes various constraints that model resource adequacy requirements – even under the higher demand environment, EPA projects that these requirements can be met, and the cost of compliance cited here is fully inclusive of the costs of meeting these constraints.
4. Levels of CCS adoption at coal fired EGUs is similar under the illustrative final rules scenario under both the high demand case (20 GW by 2035) and the baseline demand (19 GW by 2035).

Emissions Reduction Assessment

The EGU CO_2 emissions reductions are presented in this document from 2028 through 2045 and are based on IPM projections.[39] Table 3-1 presents the estimated reduction in power sector CO_2 emissions resulting from compliance with the evaluated illustrative scenarios.

Table 3-1 EGU Annual CO_2 Emissions and Emissions Changes (million metric tons) from 2028 through 2045 [40]

Annual CO_2	Total Emissions		Change from Baseline	Total Emissions		Change from Baseline
(Million Metric Tonnes)	Baseline	Final Rules	Final Rules	Sensitivity High Demand: Baseline	Sensitivity High Demand: Final Rules	Sensitivity High Demand: Final Rules
2028	1,159	1,121	-38	1,137	1,074	-62
2030	1,098	1,048	-50	1,119	1,025	-94
2035	724	601	-123	869	677	-191
2040	459	406	-54	544	460	-84
2045	307	265	-42	357	299	-58
Cumulative 2028-47	12,538	11,156	-1,382	14,041	11,897	-2,143

Higher electricity demand results in an improvement in the relative economics of existing thermal resources and new RE. Since total electricity demand is higher, total emissions under the baseline are also generally higher. Similarly, total CO_2 reductions from the illustrative final rules under the high demand sensitivity are also higher than under the illustrative final rules scenario. IPM includes capital cost-step adders through 2035 that increase the cost of new capacity if annual deployment exceeds certain upper bounds. Renewable cost and performance assumptions in the model are derived using NREL 2023 ATB values, which assume significant improvements over the forecast period. As a result, in the baseline the model waits to build RE capacity till later in the forecast horizon to take advantage of lower cost options. Under the high demand scenario the model builds more of this capacity earlier, resulting in emissions under the high demand sensitivity being slightly lower in 2028, but generally higher thereafter. Moreover higher gas consumption in the high demand scenarios pushes up gas prices, incentivizing greater dispatch at more efficient gas turbines and greater levels of NGCC builds than under the baseline.

In addition to the projected annual CO_2 reductions, there are also projected reductions of other air emissions associated with EGUs burning fossil fuels that result from compliance strategies to reduce CO_2 emission rates. These other emissions include the annual total changes in emissions of NO_X, SO_2, and ozone season NO_X emissions changes. The emissions reductions

[39] For detailed description of the Baseline and Final Rules compliance outcomes, please see Section 3 of the RIA for this rulemaking.
[40] This analysis is limited to the geographically contiguous lower 48 states.

are presented in Table 3-2 below. As with the CO_2 reductions, reductions of other pollutants are also generally higher than under the high demand scenario.

Table 3-2 EGU Annual Emissions and Emissions Changes for NO_X, SO_2, and Ozone NO_X 2028 to 2045

Annual NOx	Total Emissions		Change from Baseline	Total Emissions		Change from Baseline
(Thousand Tons)	Baseline	Final Rules	Final Rules	Sensitivity High Demand: Baseline	Sensitivity High Demand: Final Rules	Sensitivity High Demand: Final Rules
2028	461	441	-20	443	417	-26
2030	393	374	-20	383	350	-33
2035	259	210	-49	289	219	-70
2040	173	166	-6	184	171	-13
2045	107	83	-24	115	87	-29
Cumulative (2028-47)	4,590	4,048	-543	4,816	4,053	-763
Ozone Season NOx	**Total Emissions**		**Change from Baseline**	**Total Emissions**		**Change from Baseline**
(Thousand Tons)	**Baseline**	**Final Rules**	**Final Rules**	**Sensitivity High Demand: Baseline**	**Sensitivity High Demand: Final Rules**	**Sensitivity High Demand: Final Rules**
2028	189	183	-6	182	173	-9
2030	175	168	-7	171	158	-13
2035	119	100	-19	132	104	-28
2040	88	82	-6	95	85	-11
2045	59	45	-14	65	47	-18
Cumulative (2028-47)	2,148	1,897	-251	2,267	1,905	-362
Annual SO2	**Total Emissions**		**Change from Baseline**	**Total Emissions**		**Change from Baseline**
(Thousand Tons)	**Baseline**	**Final Rules**	**Final Rules**	**Sensitivity High Demand: Baseline**	**Sensitivity High Demand: Final Rules**	**Sensitivity High Demand: Final Rules**
2028	454	420	-34	439	382	-58
2030	334	313	-20	350	288	-62
2035	240	150	-90	304	150	-154
2040	143	139	-4	161	134	-28
2045	55	13	-41	61	14	-47

Cumulative (2028-47)	3,913	3,006	-908	4,411	2,857	-1,555

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

Compliance Cost Assessment

The estimates of the changes in the cost of supplying electricity for the illustrative integrated final rules scenario are presented below in Table 3-3.[41] Since compliance with the final 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 3-3 National Power Sector Compliance Cost Estimates (billions of 2019 dollars) for the Illustrative Integrated Final Rules Scenario

Billions of 2019$	Final Rules	Sensitivity High Demand: Final Rules
2028	-1.3	-1.9
2030	-0.2	-1.1
2035	1.3	1.2
2040	0.6	1.0
2045	3.3	5.0
Present Value (2028-47)	13.44	16.58
Annualized (2028-47)	0.86	1.06

"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.[42] This does not include compliance costs beyond 2047. "2024 to 2047 (Net Present Value)" reflects total estimated annual compliance costs 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.[43]

Under the higher demand sensitivity annual electricity demand is around 11% higher by 2040, resulting in a higher total baseline production cost in this scenario. Consequently, the compliance costs are also higher – going from 13.4 billion 2019$ under the illustrative final rules under the baseline to 16.6 billion 2019$ under the illustrative final rules under the high demand baseline.

In addition to evaluating annual compliance cost impacts, EPA believes that a fuller understanding of this illustrative scenario is achieved through an evaluation of annualized costs

[41] 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.
[42] 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. The PV of costs was then used to calculate the levelized annual value over a 23-year period (2024 to 2047) using the 3.76 percent rate as well.
[43] Cost estimates include financing charges on capital expenditures that would reflect a transfer and would not typically be considered part of total social costs.

over the 2028 to 2047 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 under each illustrative scenario.[44] For this analysis we first calculated the PV of the cost streams from 2024 through 2047[45] using a 3.76 percent discount rate. In this cost annualization, we use a 3.76 percent discount rate to be 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 investors are willing to sacrifice present consumption for future consumption and is based on a Weighted Average Cost of Capital (WACC).[46] 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 3-3**Table 1-3 National Power Sector Compliance Cost Estimates (billions of 2019 dollars) for the Illustrative Integrated Table 1-3 National Power Sector Compliance Cost Estimates (billions of 2019 dollars) for the Illustrative Integrated** .[47]

Impacts on Fuel Use, Prices and Generation Mix

The final rules are expected to result in significant GHG emissions reductions. The rules are also expected to have some impact on fuel use, fuel prices, generation, and capacity in the power sector. In this section we discuss the estimated changes in fuel use, fuel prices, generation by fuel type, and capacity by fuel type for the 2028, 2030, 2035, 2040 and 2045 IPM model run years.

Table 3-4 and Table 3-5**Table 1-5 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Natural Gas UseTable 1-5 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Natural Gas Use** present the percentage changes in national coal and natural gas usage by EGUs in the 2028, 2030, 2035, 2040 and 2045 run years. As outlined in the RIA, baseline coal consumption is projected to fall significantly over the forecast period, as the coal fleet continues to age and retirements occur consistent with recent historical patterns.

Under the high demand sensitivity there are higher levels of near term RE additions, but in general greater levels of fossil fuel consumption than under the baseline scenario. However, the same trends persist, as both coal and natural gas consumption are projected to decline over the forecast horizon.

[44] 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.

[45] 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.

[46] The IPM Baseline run documentation (Section 10.4.1 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."

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

Under the high demand sensitivity, the illustrative final rules are projected to lead to a similar pattern of reductions as under the baseline.

Table 3-4 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Coal Use

	Total Power Sector Coal Consumption (Million Tons)		Percentage change from Baseline	Total Power Sector Coal Consumption		Percentage change from Baseline
	Baseline	Final Rules	Final Rules	Sensitivity High Demand: Baseline	Sensitivity High Demand: Final Rules	Sensitivity High Demand: Final Rules
2028	251	234	-7%	238	212	-11%
2030	223	195	-13%	233	182	-22%
2035	147	111	-25%	181	116	-36%
2040	93	103	11%	101	107	6%
2045	28	3	-89%	37	4	-90%

Table 3-5 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Natural Gas Use

	Total Power Sector Gas Consumption (Trillion Cubic Feet)		Percentage change from Baseline	Total Power Sector Gas Consumption		Percentage change from Baseline
	Baseline	Final Rules	Final Rules	Sensitivity High Demand: Baseline	Sensitivity High Demand: Final Rules	Sensitivity High Demand: Final Rules
2028	11.6	11.5	-1%	11.7	11.4	-2%
2030	11.7	11.7	0%	11.8	11.7	-1%
2035	9.3	9.7	4%	10.4	11.0	6%
2040	6.4	6.4	0%	7.4	7.4	0%
2045	4.2	4.3	1%	4.9	4.9	1%

Table 3-6 and Table 3-7 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. Fuel prices generally follow consumption trends outlined earlier.

Table 3-6 2028, 2030, 2035, 2040 and 2045 Projected Delivered Coal Price (2019 dollars)

	Delivered Coal Price (2019$/MMBtu)	Percentage change from Baseline	National Average Minemouth Coal Price	Percentage change from Baseline

	Baseline	Final Rules	Final Rules	Sensitivity High Demand: Baseline	Sensitivity High Demand: Final Rules	Sensitivity High Demand: Final Rules
2028	1.5	1.5	-1%	1.5	1.5	-3%
2030	1.6	1.5	-2%	1.6	1.5	-4%
2035	1.5	1.5	0%	1.6	1.6	0%
2040	1.6	1.6	1%	1.6	1.6	1%
2045	1.4	0.9	-32%	1.4	1.0	-30%

Table 3-7 2028, 2030, 2035, 2040 and 2045 Projected Henry Hub Natural Gas Price (2019 dollars)

	Henry Hub		Percentage change from Baseline	Henry Hub Gas Price		Percentage change from Baseline
(2019$/MMBtu)	Baseline	Final Rules	Final Rules	Sensitivity High Demand: Baseline	Sensitivity High Demand: Final Rules	Sensitivity High Demand: Final Rules
2028	2.8	2.7	-2%	2.8	2.7	-3%
2030	2.9	2.9	0%	2.9	2.9	0%
2035	2.9	3.0	3%	3.1	3.2	3%
2040	2.8	2.8	-1%	3.0	3.0	0%
2045	3.0	3.0	0%	3.1	3.2	2%

Table 3-8 presents the projected percentage changes in the amount of electricity generation in 2028, 2030, 2035, 2040 and 2045 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 Emission Guidelines and are smaller thereafter. The IRC section 45Q tax credit is available for 12 years within the modeling, after which point units no longer receive tax credits and must dispatch based on unsubsidized operating costs.

Under the high demand sensitivity, generation at coal-fired EGUs and new turbines is higher than under the baseline. There are greater reductions from these sources as a result of the illustrative final rules.

Table 3-8 2028, 2030, 2035, 2040 and 2045 Projected U.S. Generation by Fuel Type

		Generation (TWh)		Percent Change from Baseline	Generation (TWh)		Percent Change from Baseline
	Year	Baseline	Final Rules	Final Rules	Sensitivity High Demand: Baseline	Sensitivity High Demand: Final Rules	Sensitivity High Demand: Final Rules
Unabated Coal	2028	472	441	-7%	447	400	-10%
Coal & CCS		0	0	0%	0	0	0%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		1,652	1,631	-1%	1,670	1,627	-3%
Nat. Gas & CCS		0	0	0%	0	0	0%
Nuclear		774	776	0%	774	777	0%
Hydro		293	293	0%	292	291	0%
Non-Hydro RE		1,151	1,199	4%	1,256	1,340	7%
Oil/Gas Steam		3	3	1%	3	4	41%
Other		70	71	1%	71	70	-1%
Total		4,415	4,414	0%	4,512	4,510	0%
Unabated Coal	2030	407	355	-13%	423	331	-22%
Coal & CCS		3	5	71%	4	5	37%
Coal & Nat. Gas co-firing		0	2	0%	0	7	0%
Unabated Nat. Gas		1,670	1,660	-1%	1,700	1,669	-2%
Nat. Gas & CCS		0	0	0%	0	0	0%
Nuclear		749	751	0%	746	750	1%
Hydro		298	299	0%	298	302	2%
Non-Hydro RE		1,355	1,404	4%	1,454	1,554	7%
Oil/Gas Steam		4	6	36%	4	6	68%
Other		70	71	1%	71	70	-1%
Total		4,557	4,553	0%	4,698	4,694	0%
Unabated Coal	2035	160	0	-100%	243	1	-100%
Coal & CCS		76	133	74%	64	137	115%
Coal & Nat. Gas co-firing		0	4	0%	0	8	0%
Unabated Nat. Gas		1,341	1,379	3%	1,514	1,555	3%
Nat. Gas & CCS		3	7	105%	2	7	339%
Nuclear		674	674	0%	677	679	0%
Hydro		319	317	-1%	318	318	0%
Non-Hydro RE		2,336	2,402	3%	2,449	2,555	4%
Oil/Gas Steam		1	1	79%	1	2	236%
Other		68	70	2%	69	70	1%

Total		4,978	4,987	0%	5,336	5,333	0%
Unabated Coal	2040	61	0	-100%	94	0	-100%
Coal & CCS		76	128	68%	64	132	108%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		933	919	-2%	1,075	1,050	-2%
Nat. Gas & CCS		3	7	105%	2	7	339%
Nuclear		619	618	0%	623	620	0%
Hydro		336	336	0%	336	336	0%
Non-Hydro RE		3,252	3,275	1%	3,645	3,699	1%
Oil/Gas Steam		1	1	126%	1	1	168%
Other		65	66	1%	66	67	0%
Total		5,345	5,350	0%	5,906	5,913	0%
Unabated Coal	2045	45	0	-100%	60	0	-100%
Coal & CCS		4	3	-7%	4	4	8%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		614	612	0%	713	703	-1%
Nat. Gas & CCS		3	6	103%	1	5	550%
Nuclear		475	477	0%	477	473	-1%
Hydro		343	342	0%	344	346	0%
Non-Hydro RE		4,275	4,336	1%	4,922	5,006	2%
Oil/Gas Steam		0	1	106%	0	1	143%
Other		63	64	1%	65	64	0%
Total		5,823	5,841	0%	6,586	6,602	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 3-9 presents the projected percentage changes in the amount of generating capacity in 2028, 2030, 2035, 2040 and 2045 by primary fuel type.

Under the high demand sensitivity, baseline coal capacity is projected to be 9 GW higher in 2035 and baseline natural gas capacity is projected to be 10 GW higher in 2035 than under the expected baseline.

Under the high demand sensitivity, the illustrative final rules scenario projects 26 GW of incremental coal retirements in 2035, and 17 GW of incremental coal retirements relative to the high demand sensitivity baseline values (75 GW in 2035 and 87 GW in 2045). 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.[48]

[48] For further discussion of how the rule is anticipated to integrate into the ongoing power sector transition while not impacting resource adequacy, see section XII.F of the preamble, and the Resource Adequacy Analysis TSD included in the docket.

Under the illustrative final rules scenario under both demand environments, 1 GW of natural gas co-firing is projected by 2030.

Under the high demand sensitivity, the illustrative final rules scenario projects 20 GW of CCS installations at coal-fired EGUs (9 GW under high demand baseline) and 0.8 GW of CCS installations at new gas-fired EGUs (0.1 GW under high demand baseline). Under the baseline scenario, the illustrative final rules scenario projects 19 GW of CCS installations at coal-fired EGUs (11 GW under baseline) and 1 GW of CCS installations at new gas-fired EGUs (0.5 GW under baseline).

Under the high demand sensitivity, the illustrative final rules scenario projects 269 GW of cumulative new wind additions by 2035 (246 GW under high demand baseline), 135 GW of cumulative new solar installations by 2035 (131 GW under high demand baseline), and 81 GW of cumulative new storage installations by 2035 (75 GW under high demand baseline).

Under the baseline, the illustrative final rules scenario projects 232 GW of cumulative new wind additions by 2035 (220 GW under baseline), 130 GW of cumulative new solar installations by 2035 (127 GW under baseline), and 79 GW of cumulative new storage installations by 2035 (70 GW under baseline).

Table 3-9 2028, 2030, 2035, 2040 and 2045 Projected U.S. Capacity by Fuel Type

		Capacity (GW)		Percent Change from Baseline	Capacity (GW)		Percent Change from Baseline
	Year	Baseline	Final Rules	Final Rules	Sensitivity High Demand: Baseline	Sensitivity High Demand: Final Rules	Sensitivity High Demand: Final Rules
Unabated Coal	2028	106	101	-4%	103	93	-10%
Coal & CCS		0	0	0%	0	0	0%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		471	472	0%	482	483	0%
Nat. Gas & CCS		0	0	0%	0	0	0%
Nuclear		146	147	1%	148	150	1%
Hydro		102	102	0%	102	102	0%
Non-Hydro RE		434	447	3%	460	484	5%
Oil/Gas Steam		11	11	0%	11	12	13%
Other		12	12	1%	12	12	-1%
Total		1,282	1,292	1%	1,318	1,335	1%
Unabated Coal	2030	85	72	-15%	85	64	-24%
Coal & CCS		0	1	72%	1	1	37%
Coal & Nat. Gas co-firing		0	1	0%	0	1	0%

Unabated Nat. Gas		479	480	0%	489	490	0%
Nat. Gas & CCS		0	0	0%	0	0	0%
Nuclear		143	144	1%	146	146	0%
Hydro		104	104	0%	104	105	1%
Non-Hydro RE		492	505	3%	517	543	5%
Oil/Gas Steam		12	20	60%	12	21	72%
Other		12	12	1%	12	12	-1%
Total		1,327	1,338	1%	1,364	1,383	1%
Unabated Coal	2035	41	0	-100%	51	0	-100%
Coal & CCS		11	19	74%	9	20	114%
Coal & Nat. Gas co-firing		0	1	0%	0	1	0%
Unabated Nat. Gas		476	484	2%	486	504	4%
Nat. Gas & CCS		0	1	104%	0	1	335%
Nuclear		126	131	3%	135	136	1%
Hydro		107	107	0%	107	108	1%
Non-Hydro RE		806	830	3%	840	873	4%
Oil/Gas Steam		12	19	49%	12	20	65%
Other		12	12	1%	12	12	0%
Total		1,591	1,603	1%	1,653	1,676	1%
Unabated Coal	2040	31	0	-99%	39	0	-100%
Coal & CCS		11	18	68%	9	19	107%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		516	525	2%	555	571	3%
Nat. Gas & CCS		0	1	104%	0	1	335%
Nuclear		122	126	4%	131	132	1%
Hydro		112	112	0%	112	112	0%
Non-Hydro RE		1,077	1,087	1%	1,191	1,210	2%
Oil/Gas Steam		11	17	53%	11	19	67%
Other		12	12	1%	12	12	0%
Total		1,892	1,899	0%	2,060	2,076	1%
Unabated Coal	2045	29	0	-99%	36	0	-100%
Coal & CCS		1	1	-5%	1	1	25%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		565	581	3%	619	644	4%
Nat. Gas & CCS		0	1	104%	0	1	335%
Nuclear		107	112	4%	117	117	1%
Hydro		112	112	0%	112	113	0%
Non-Hydro RE		1,402	1,422	1%	1,592	1,619	2%
Oil/Gas Steam		11	17	53%	11	19	67%
Other		12	12	1%	12	12	0%

Total		2,240	2,257	1%	2,500	2,526	1%

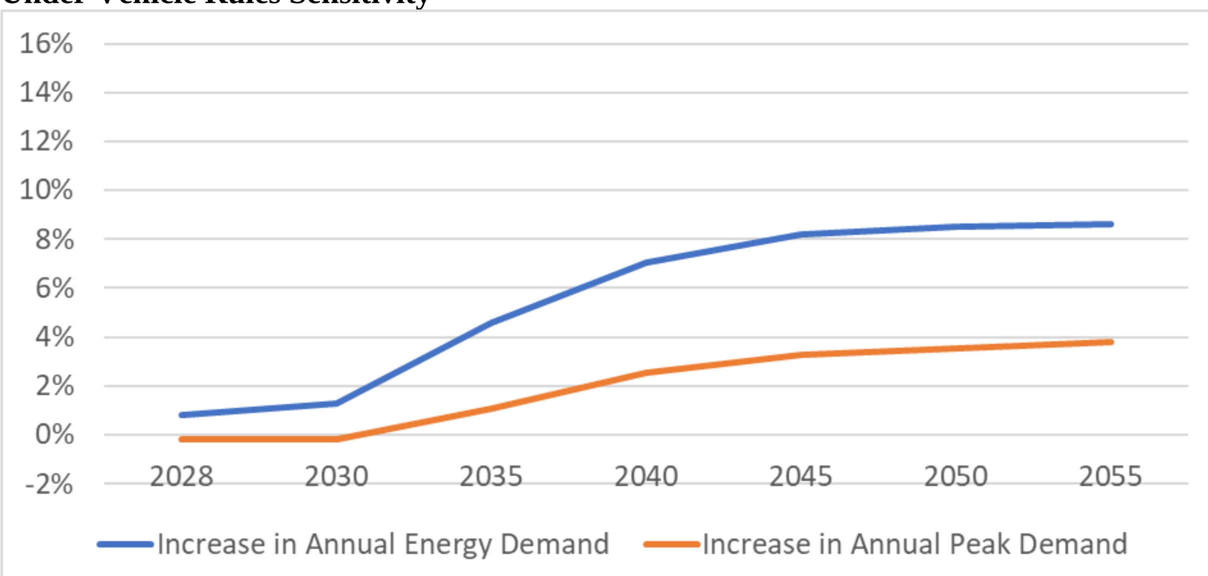
Note: In this table, "Non-Hydro RE" includes biomass, geothermal, landfill gas, solar, and wind

Section 4: Estimated Impacts of the Vehicle Rules, Final Rules, MATS and ELG Sensitivity

Description of Scenario and Key Takeaways

Under the Vehicle Rules sensitivity, power sector demand was updated to account for the EV electricity demand associated with the LDV, MDV and HDV rulemakings ("Vehicle Rules"). Additionally, this baseline is used to project compliance with the final rules, as well as the recently finalized ELG and MATS rules. The percentage increase relative to the baseline is shown in Figure 4-1 below, while the ELG and MATS requirements are outlined in Table A-7 and A-8. Since the baseline parameters were updated, the illustrative final rules scenario is compared with an updated baseline run as well as the final rules scenario presented in the RIA.

Figure 4-1 Percentage Increase in National Electricity Demand Relative to Baseline Under Vehicle Rules Sensitivity



Under the Vehicle Rules, Final Rules, MATS, and ELG Sensitivity, the baseline shifts significantly, and compliance behavior is also affected. In particular:

1. Demand is higher relative to the expected baseline, and the percentage increase in peak demand is less than the percentage increase in energy demand, reflecting a change in the demand profile as a result of increased end-use electrification. By 2040 energy demand is 7% higher and peak demand is 3% higher than under the baseline.
2. In addition to featuring higher demand, the vehicle rules scenario includes impacts of ELG, MATS and the final rules. As a result, reductions of CO_2 emissions from the illustrative final rules under the vehicle rules scenario (1,833 MMT) are larger than under the final rules scenario (1,382 MMT).
3. Levels of CCS adoption at coal fired EGUs is similar under the illustrative final rules scenario under both the vehicle rules scenario (20 GW by 2035) and the expected demand case (19 GW by 2035).

4. IPM is populated with a range of constraints that reflect resource adequacy requirements – even under the higher demand environment, EPA projects that these requirements can be met, and the cost of compliance cited here is fully inclusive of the costs of meeting these constraints

Emissions Reduction Assessment

The EGU CO_2 emissions reductions are presented in this document from 2028 through 2045 and are based on IPM projections.[49] Table 4-1 presents the estimated reduction in power sector CO_2 emissions resulting from compliance with the evaluated illustrative scenarios.

Table 4-1 EGU Annual CO_2 Emissions and Emissions Changes (million metric tons) from 2028 through 2045 [50]

Annual CO_2	**Total Emissions**		**Change from Baseline**	**Total Emissions**		**Change from Baseline**
(Million Metric Tonnes)	**Baseline**	**Final Rules**	**Final Rules**	**Sensitivity Vehicle Rules: Baseline**	**Sensitivity Vehicle Rules: Final Rules, ELG, MATS**	**Sensitivity Vehicle Rules: Final Rules, ELG, MATS**
2028	1,159	1,121	-38	1,132	1,076	-56
2030	1,098	1,048	-50	1,087	1,008	-79
2035	724	601	-123	814	652	-162
2040	459	406	-54	510	441	-70
2045	307	265	-42	342	290	-52
Cumulative 2028-47	12,538	11,156	-1,382	13,416	11,583	-1,833

Higher electricity demand results in an improvement in the relative economics of existing thermal resources and new RE. Since total electricity demand is higher, total emissions under the baseline are also generally higher. Similarly, total CO_2 reductions from the illustrative final rules, ELG and MATS under the vehicle sensitivity are also higher than under the illustrative final rules scenario (which also does not include the ELG and MATS requirements). IPM includes capital cost-step adders through 2035 that increase the cost of new capacity if annual deployment exceeds certain upper bounds. Renewable cost and performance assumptions in the model are derived using NREL 2023 ATB values, which assume significant improvements over the forecast period. As a result, in the baseline the model waits to build RE capacity till later in the forecast horizon to take advantage of lower cost options. Under the Vehicle Rules sensitivity the model builds more of this capacity earlier, resulting in emissions under the vehicle rules sensitivity being slightly lower in 2028, but generally higher thereafter. Moreover higher gas

[49] For detailed description of the Baseline and Final Rules compliance outcomes, please see Section 3 of the RIA for this rulemaking.

[50] This analysis is limited to the geographically contiguous lower 48 states. All emissions are power sector specific and do not reflect emission changes in the mobile sector from reduced gasoline consumption under Vehicle Rules.

consumption in the higher demand environment pushes up gas prices, incentivizing greater dispatch at more efficient gas turbines and greater levels of NGCC builds than under the baseline.

In addition to the projected annual CO_2 reductions, there are also projected reductions of other air emissions associated with EGUs burning fossil fuels that result from compliance strategies to reduce CO_2 emission rates. These other emissions include the annual total changes in emissions of NO_X, SO_2, and ozone season NO_X emissions changes. The emissions reductions are presented in Table 4-2 below. As with the CO_2 reductions, reductions of other pollutants are also generally higher than under the Vehicle and Power Sector Rules scenario.

Table 4-2 EGU Annual Emissions and Emissions Changes for NO_X, SO_2, and Ozone NO_X 2028 to 2045

Annual NOx	Total Emissions		Change from Baseline	Total Emissions		Change from Baseline
(Thousand Tons)	Baseline	Final Rules	Final Rules	Sensitivity Vehicle Rules: Baseline	Sensitivity Vehicle Rules: Final Rules, ELG, MATS	Sensitivity Vehicle Rules: Final Rules, ELG, MATS
2028	461	441	-20	442	411	-30
2030	393	374	-20	391	354	-37
2035	259	210	-49	309	229	-80
2040	173	166	-6	192	178	-14
2045	107	83	-24	119	87	-32
Cumulative (2028-47)	4,590	4,048	-543	4,999	4,138	-861
Ozone Season NOx	**Total Emissions**		**Change from Baseline**	**Total Emissions**		**Change from Baseline**
(Thousand Tons)	**Baseline**	**Final Rules**	**Final Rules**	**Sensitivity Vehicle Rules: Baseline**	**Sensitivity Vehicle Rules: Final Rules, ELG, MATS**	**Sensitivity Vehicle Rules: Final Rules, ELG, MATS**
2028	189	183	-6	181	170	-11
2030	175	168	-7	174	160	-14
2035	119	100	-19	139	109	-30
2040	88	82	-6	101	88	-13
2045	59	45	-14	69	47	-21
Cumulative (2028-47)	2,148	1,897	-251	2,359	1,953	-406

Annual SO2	Total Emissions		Change from Baseline	Total Emissions		Change from Baseline
(Thousand Tons)	Baseline	Final Rules	Final Rules	Sensitivity Vehicle Rules: Baseline	Sensitivity Vehicle Rules: Final Rules, ELG, MATS	Sensitivity Vehicle Rules: Final Rules, ELG, MATS
2028	454	420	-34	435	375	-60
2030	334	313	-20	397	308	-89
2035	240	150	-90	360	158	-203
2040	143	139	-4	177	140	-37
2045	55	13	-41	65	14	-51
Cumulative (2028-47)	3,913	3,006	-908	4,921	2,953	-1,967

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

Compliance Cost Assessment

The estimates of the changes in the cost of supplying electricity for the illustrative integrated final rules scenario are presented below in Table 4-3.[51] Since compliance with the final 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 4-3 National Power Sector Compliance Cost Estimates (billions of 2019 dollars) for the Illustrative Integrated Final Rules Scenario

	Final Rules	Sensitivity Vehicle Rules: Final Rules, ELG, MATS
2028	-1.3	-1.2
2030	-0.2	0.0
2035	1.3	1.6
2040	0.6	1.2
2045	3.3	4.0
Present Value (2028-47)	13.44	18.50
Annualized (2028-47)	0.86	1.18

[51] 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.

"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.[52] This does not include compliance costs beyond 2047. "2024 to 2047 (Net Present Value)" reflects total estimated annual compliance costs 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.[53]

Under the Vehicle Rules sensitivity annual electricity demand is around 7% higher by 2040, resulting in a higher total baseline production cost in this scenario. Additionally, the run also includes the ELG and MATS rule requirements in addition to the requirements of the Final Rules. Consequently the compliance costs are also higher – going from 13.4 billion 2019$ under the illustrative final rules under in the baseline to 18.5 billion 2019$ under in the illustrative final rules, ELG, and MATS under in the vehicle rules baseline.

In addition to evaluating annual compliance cost impacts, EPA believes that a fuller understanding of this illustrative vehicle rules and power sector rules scenario is achieved through an evaluation of annualized costs over the 2028 to 2047 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 under each illustrative scenario.[54] For this analysis we first calculated the PV of the cost streams from 2024 through 2047[55] using a 3.76 percent discount rate. In this cost annualization, we use a 3.76 percent discount rate to be 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 investors are willing to sacrifice present consumption for future consumption and is based on a Weighted Average Cost of Capital (WACC).[56] 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 4-3[57]

Impacts on Fuel Use, Prices and Generation Mix

The illustrative, MATS, and ELG final rules are expected to result in significant GHG emissions reductions. They are also expected to have some impact on fuel use, fuel prices, generation, and capacity in the power sector. In this section we discuss the estimated changes in

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[52] 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. The PV of costs was then used to calculate the levelized annual value over a 23-year period (2024 to 2047) using the 3.76 percent rate as well.

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

[54] 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.

[55] 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.

[56] The IPM Baseline run documentation (Section 10.4.1 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."

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

fuel use, fuel prices, generation by fuel type, and capacity by fuel type for the 2028, 2030, 2035, 2040 and 2045 IPM model run years.

Table 4-4 and Table 4-5**Table 1-5 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Natural Gas UseTable 1-5 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Natural Gas Use** present the percentage changes in national coal and natural gas usage by EGUs in the 2028, 2030, 2035, 2040 and 2045 run years. As outlined in the RIA, baseline coal consumption is projected to fall significantly over the forecast period, as the coal fleet continues to age and retirements occur consistent with recent historical patterns.

Under the Vehicle Rules sensitivity there are higher levels of near term RE additions, but in general greater levels of fossil fuel consumption than under the baseline scenario. However, the same trends persist, as both coal and natural gas consumption are projected to decline over the forecast horizon.

Under the Vehicle Rules sensitivity, the illustrative power sector rules are projected to lead to a similar pattern of reductions in coal use as under the baseline in 2035 and beyond, whereas the requirements under the ELG and MATS rules yield greater reductions in coal use in 2028 and 2030.

Table 4-4 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Coal Use

	Total Power Sector Coal Consumption (Million Tons)		Percentage change from Baseline	Total Power Sector Coal Consumption		Percentage change from Baseline
	Baseline	**Final Rules**	**Final Rules**	**Sensitivity Vehicle Rules: Baseline**	**Sensitivity Vehicle Rules: Final Rules, ELG, MATS**	**Sensitivity Vehicle Rules: Final Rules, ELG, MATS**
2028	251	234	-7%	240	213	-11%
2030	223	195	-13%	218	176	-19%
2035	147	111	-25%	168	111	-34%
2040	93	103	11%	97	103	7%
2045	28	3	-89%	33	4	-89%

Table 4-5 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Natural Gas Use

	Total Power Sector Gas Consumption (Trillion Cubic Feet)		Percentage change from Baseline	Total Power Sector Gas Consumption		Percentage change from Baseline
	Baseline	**Final Rules**	**Final Rules**	**Sensitivity Vehicle Rules: Baseline**	**Sensitivity Vehicle Rules: Final Rules, ELG, MATS**	**Sensitivity Vehicle Rules: Final Rules, ELG, MATS**

2028	11.6	11.5	-1%	11.5	11.4	-1%
2030	11.7	11.7	0%	11.7	11.7	0%
2035	9.3	9.7	4%	10.0	10.6	6%
2040	6.4	6.4	0%	7.1	7.0	0%
2045	4.2	4.3	1%	4.7	4.7	1%

Table 4-6 and Table 4-7 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. Fuel prices generally follow consumption trends outlined earlier.

Table 4-6 2028, 2030, 2035, 2040 and 2045 Projected Delivered Coal Price (2019 dollars)

	Delivered Coal Price (2019$/MMBtu)		Percentage change from Baseline	National Average Minemouth Coal Price		Percentage change from Baseline
	Baseline	Final Rules	Final Rules	Sensitivity Vehicle Rules: Baseline	Sensitivity Vehicle Rules: Final Rules, ELG, MATS	Sensitivity Vehicle Rules: Final Rules, ELG, MATS
2028	1.5	1.5	-1%	1.5	1.5	-2%
2030	1.6	1.5	-2%	1.5	1.5	-3%
2035	1.5	1.5	0%	1.6	1.5	-2%
2040	1.6	1.6	1%	1.6	1.6	-1%
2045	1.4	0.9	-32%	1.4	1.0	-29%

Table 4-7 2028, 2030, 2035, 2040 and 2045 Projected Henry Hub Natural Gas Price (2019 dollars)

	Henry Hub (2019$/MMBtu)		Percentage change from Baseline	Henry Hub Gas Price		Percentage change from Baseline
	Baseline	Final Rules	Final Rules	Sensitivity Vehicle Rules: Baseline	Sensitivity Vehicle Rules: Final Rules, ELG, MATS	Sensitivity Vehicle Rules: Final Rules, ELG, MATS
2028	2.8	2.7	-2%	2.8	2.7	-2%
2030	2.9	2.9	0%	2.9	2.9	1%

2035	2.9	3.0	3%	3.0	3.1	3%
2040	2.8	2.8	-1%	2.9	2.9	0%
2045	3.0	3.0	0%	3.1	3.1	1%

Table 4-8 presents the projected percentage changes in the amount of electricity generation in 2028, 2030, 2035, 2040 and 2045 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 Emission Guidelines and are smaller thereafter. The IRC section 45Q tax credit is available for 12 years within the modeling, after which point units no longer receive tax credits and must dispatch based on unsubsidized operating costs.

Under the Vehicle Rules sensitivity, generation at coal-fired EGUs and new turbines is higher than under the expected baseline over the full time period. As a result, there are greater reductions in generation and associated emissions from these sources as a result of the illustrative final rules, ELG, and MATS.

Table 4-8 2028, 2030, 2035, 2040 and 2045 Projected U.S. Generation by Fuel Type

		Generation (TWh)		Percent Change from Baseline	Generation (TWh)		Percent Change from Baseline
	Year	Baseline	Final Rules	Final Rules	Sensitivity Vehicle Rules: Baseline	Sensitivity Vehicle Rules: Final Rules, ELG, MATS	Sensitivity Vehicle Rules: Final Rules, ELG, MATS
Unabated Coal	2028	472	441	-7%	452	400	-12%
Coal & CCS		0	0	0%	0	0	0%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		1,652	1,631	-1%	1,641	1,628	-1%
Nat. Gas & CCS		0	0	0%	0	0	0%
Nuclear		774	776	0%	773	776	0%
Hydro		293	293	0%	292	292	0%
Non-Hydro RE		1,151	1,199	4%	1,217	1,279	5%
Oil/Gas Steam		3	3	1%	2	3	13%

Other		70	71	1%	71	71	0%
Total		4,415	4,414	0%	4,447	4,447	0%
Unabated Coal	2030	407	355	-13%	397	315	-21%
Coal & CCS		3	5	71%	3	7	127%
Coal & Nat. Gas co-firing		0	2	0%	0	2	0%
Unabated Nat. Gas		1,670	1,660	-1%	1,676	1,669	0%
Nat. Gas & CCS		0	0	0%	0	0	0%
Nuclear		749	751	0%	747	749	0%
Hydro		298	299	0%	297	302	2%
Non-Hydro RE		1,355	1,404	4%	1,415	1,488	5%
Oil/Gas Steam		4	6	36%	4	6	44%
Other		70	71	1%	71	71	0%
Total		4,557	4,553	0%	4,610	4,609	0%
Unabated Coal	2035	160	0	-100%	209	1	-100%
Coal & CCS		76	133	74%	71	133	88%
Coal & Nat. Gas co-firing		0	4	0%	0	4	0%
Unabated Nat. Gas		1,341	1,379	3%	1,454	1,504	3%
Nat. Gas & CCS		3	7	105%	1	7	453%
Nuclear		674	674	0%	676	678	0%
Hydro		319	317	-1%	318	319	0%
Non-Hydro RE		2,336	2,402	3%	2,403	2,489	4%
Oil/Gas Steam		1	1	79%	1	1	105%
Other		68	70	2%	69	70	1%
Total		4,978	4,987	0%	5,202	5,205	0%
Unabated Coal	2040	61	0	-100%	77	0	-100%
Coal & CCS		76	128	68%	70	128	82%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		933	919	-2%	1,030	1,006	-2%
Nat. Gas & CCS		3	7	105%	1	7	453%
Nuclear		619	618	0%	622	622	0%
Hydro		336	336	0%	336	335	0%
Non-Hydro RE		3,252	3,275	1%	3,515	3,558	1%
Oil/Gas Steam		1	1	126%	1	1	145%
Other		65	66	1%	67	67	0%
Total		5,345	5,350	0%	5,718	5,723	0%
Unabated Coal	2045	45	0	-100%	54	0	-100%
Coal & CCS		4	3	-7%	4	4	7%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		614	612	0%	687	677	-2%
Nat. Gas & CCS		3	6	103%	1	5	511%

Nuclear		475	477	0%	477	476	0%
Hydro		343	342	0%	344	344	0%
Non-Hydro RE		4,275	4,336	1%	4,684	4,753	1%
Oil/Gas Steam		0	1	106%	0	1	108%
Other		63	64	1%	65	65	0%
Total		5,823	5,841	0%	6,316	6,325	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 4-9 presents the projected percentage changes in the amount of generating capacity in 2028, 2030, 2035, 2040 and 2045 by primary fuel type.

Under the Vehicle Rules sensitivity baseline coal capacity is projected to be 4 GW higher in 2035 and Vehicle Rules sensitivity baseline natural gas capacity is projected to be 1 GW lower in 2035 than under the baseline.

Under the vehicle rules sensitivity, the illustrative final rules, MATS and ELG scenario projects 24 GW of incremental coal retirements in 2035, and 16 GW of incremental coal retirements relative to the vehicle rules sensitivity baseline values (79 GW in 2035 and 90 GW in 2045). 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.[58]

Under the illustrative final rules scenario and the Sensitivity Vehicle Rules: Final Rules, ELG, MATS , 1 GW of natural gas co-firing is projected by 2030.

Under the Vehicle Rules sensitivity, the illustrative final rules, ELG, and MATS scenario projects 19 GW of CCS installations at coal-fired EGUs (10 GW under vehicle baseline) and 0.8 GW of CCS installations at new gas-fired EGUs (0.1 GW under high demand baseline). Under the baseline scenario, the illustrative final rules scenario projects 19 GW of CCS installations at coal-fired EGUs (11 GW under baseline) and 1 GW of CCS installations at new gas-fired EGUs (0.5 GW under baseline).

Under the Sensitivity Vehicle Rules: Final Rules, ELG, MATS scenario projects 254 GW of cumulative new wind additions by 2035 (237 GW under vehicle rules baseline), 133 GW of cumulative new solar installations by 2035 (128 GW under vehicle rules baseline), and 79 GW of cumulative new storage installations by 2035 (71 GW under vehicle rues baseline).

Under the baseline, the illustrative final rules scenario projects 232 GW of cumulative new wind additions by 2035 (220 GW under baseline), 130 GW of cumulative new solar installations by 2035 (127 GW under baseline), and 79 GW of cumulative new storage installations by 2035 (70 GW baseline).

[58] For further discussion of how the rule is anticipated to integrate into the ongoing power sector transition while not impacting resource adequacy, see section XII.F of the preamble, and the Resource Adequacy Analysis TSD included in the docket.

Table 4-9 2028, 2030, 2035, 2040 and 2045 Projected U.S. Capacity by Fuel Type

		Capacity (GW)		Percent Change from Baseline	Capacity (GW)		Percent Change from Baseline
	Year	Baseline	Final Rules	Final Rules	Sensitivity Vehicle Rules: Baseline	Sensitivity Vehicle Rules: Final Rules, ELG, MATS	Sensitivity Vehicle Rules: Final Rules, ELG, MATS
Unabated Coal	2028	106	101	-4%	102	93	-9%
Coal & CCS		0	0	0%	0	0	0%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		471	472	0%	472	474	0%
Nat. Gas & CCS		0	0	0%	0	0	0%
Nuclear		146	147	1%	146	148	1%
Hydro		102	102	0%	102	102	0%
Non-Hydro RE		434	447	3%	451	469	4%
Oil/Gas Steam		11	11	0%	10	11	4%
Other		12	12	1%	12	12	0%
Total		1,282	1,292	1%	1,295	1,308	1%
Unabated Coal	2030	85	72	-15%	83	62	-25%
Coal & CCS		0	1	72%	0	1	125%
Coal & Nat. Gas co-firing		0	1	0%	0	1	0%
Unabated Nat. Gas		479	480	0%	478	481	1%
Nat. Gas & CCS		0	0	0%	0	0	0%
Nuclear		143	144	1%	143	144	1%
Hydro		104	104	0%	104	105	1%
Non-Hydro RE		492	505	3%	506	526	4%
Oil/Gas Steam		12	20	60%	12	20	68%
Other		12	12	1%	12	12	0%
Total		1,327	1,338	1%	1,338	1,352	1%
Unabated Coal	2035	41	0	-100%	45	0	-100%
Coal & CCS		11	19	74%	10	19	87%
Coal & Nat. Gas co-firing		0	1	0%	0	1	0%
Unabated Nat. Gas		476	484	2%	475	485	2%
Nat. Gas & CCS		0	1	104%	0	1	446%
Nuclear		126	131	3%	129	134	4%

Hydro		107	107	0%	107	108	1%
Non-Hydro RE		806	830	3%	824	854	4%
Oil/Gas Steam		12	19	49%	12	19	61%
Other		12	12	1%	12	12	0%
Total		1,591	1,603	1%	1,616	1,634	1%
Unabated Coal	2040	31	0	-99%	35	0	-100%
Coal & CCS		11	18	68%	10	18	81%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		516	525	2%	529	540	2%
Nat. Gas & CCS		0	1	104%	0	1	446%
Nuclear		122	126	4%	125	130	4%
Hydro		112	112	0%	112	112	0%
Non-Hydro RE		1,077	1,087	1%	1,152	1,169	1%
Oil/Gas Steam		11	17	53%	11	18	62%
Other		12	12	1%	12	12	0%
Total		1,892	1,899	0%	1,987	1,999	1%
Unabated Coal	2045	29	0	-99%	32	0	-99%
Coal & CCS		1	1	-5%	1	1	25%
Coal & Nat. Gas co-firing		0	0	0%	0	0	0%
Unabated Nat. Gas		565	581	3%	585	603	3%
Nat. Gas & CCS		0	1	104%	0	1	446%
Nuclear		107	112	4%	111	116	5%
Hydro		112	112	0%	112	112	0%
Non-Hydro RE		1,402	1,422	1%	1,520	1,542	1%
Oil/Gas Steam		11	17	53%	11	18	62%
Other		12	12	1%	12	12	0%
Total		2,240	2,257	1%	2,384	2,405	1%

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

Appendix

Table A1. Summary of Modeled GHG Mitigation Measures for Existing Sources by Subcategory under the Illustrative Final Rules [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 A2. Summary of Modeled GHG Mitigation Measures for Existing Sources by Source Category under the 40% co-firing Scenario [a,b,c]

Subcategory Definition	GHG Mitigation Measure
Coal-fired steam generating units that have not elected to commit to permanently cease operations prior to 2035	Natural gas co-firing at 40 percent of the heat input to the unit, starting in 2030
Coal-fired steam generating units that have not elected to commit to permanently cease operations prior to 2035, and not commenced co-firing 40% gas by 2030	CCS with 90% capture of CO_2, 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 2030 are no longer subject to coal-fired EGU mitigation measures outlined above.

Table A3. Summary of GHG Mitigation Measures for New Sources by Source Category under the Illustrative Final Rules [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: 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">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 40%</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 40%</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 VIII of the preamble.
[b] Delivered hydrogen price is assumed to be $1.15/kg in all years.

Table A4. Gas Supply Curve Adjustment for Low Gas Sensitivity

Trillion Cubic Feet of Natural Gas Supply	2028	2030	2035	2040	2045	2050
Liquefied Natural Gas Exports: AEO 2023 Reference case	6.0	6.9	9.5	10.0	10.0	10.0
Liquefied Natural Gas Exports: AEO2022 Reference case	5.0	5.4	5.9	5.9	5.9	5.9
Adjustment to IPM Gas Supply:	1.0	1.5	3.6	4.1	4.1	4.1

Note: The updated gas supply curves used in this analysis are available in the docket for this rulemaking. The analysis described in this document is illustrative, in that the approach does not include use of the Gas Market Model to account for subnational pricing impacts of decreased LNG exports.

Table A5. Comparisons of National Annual Energy Demand Between Baseline, High Demand Sensitivity, and Vehicle Rules Sensitivity

Annual Energy Demand (TWh)	2028	2030	2035	2040	2045
Baseline	4,459	4,597	4,939	5,254	5,576
Vehicle Rules Sensitivity	4,496	4,657	5,165	5,625	6,032
High Demand Sensitivity	4,565	4,749	5,301	5,818	6,287
Percentage increase above Baseline					
Vehicle Rules Sensitivity	1%	1%	5%	7%	8%
High Demand Sensitivity	2%	3%	7%	11%	13%

Table A6. Comparisons of National Peak Energy Demand Between Baseline, High Demand Sensitivity, and Vehicle Rules Sensitivity

Annual Peak Demand (GW)	2028	2030	2035	2040	2045
Baseline	820	841	901	966	1,040
Vehicle Rules Sensitivity	818	840	911	991	1,074
High Demand Sensitivity	831	856	936	1,027	1,122
Percentage increase above Baseline					
Vehicle Rules Sensitivity	0%	0%	1%	3%	3%
High Demand Sensitivity	1%	2%	4%	6%	8%

Table A7. Modeled MATS RTR requirements

Provision	Regulatory Option Modeled
FPM Standard (Surrogate Standard for Non-mercury HAP metals)	Revised fPM standard of 0.010 lb/MMBtu
Mercury Standard	Revised mercury standard for lignite-fired EGUs of 1.2 lb/TBtu
Continuous Emissions Monitoring Systems (PM CEMS)	Require installation of PM CEMS to demonstrate compliance

Table A8. Modeled ELG requirements

Wastestream	Subcategory	Technology Basis for BAT/PSES Regulatory Options[a]
FGD Wastewater	NA (default unless in subcategory)[b]	ZLD
	Boilers permanently ceasing the combustion of coal by 2028	SI
	Boilers permanently ceasing the combustion of coal by 2034	CP + Bio
	High FGD Flow Facilities or Low Utilization Boilers	NS
BA Transport Water	NA (default unless in subcategory)[b]	ZLD
	Boilers permanently ceasing the combustion of coal by 2028	SI
	Boilers permanently ceasing the combustion of coal by 2034	HRR
	Low Utilization Boilers	NS
CRL	NA (default)[b]	ZLD
	Discharges of unmanaged CRL	CP
	Boilers permanently ceasing the combustion of coal by 2034	CP
Legacy wastewater	Operate after 2024	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. For a description of these technologies please see: U.S. Environmental Protection Agency. (2024f). Technical Development Document for Supplemental Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category. (821-R-24-004).

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