INTEGRATED PROPOSAL MODELING AND UPDATED BASELINE ANALYSIS

Memo to the Docket

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

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U.S. Environmental Protection Agency
Office of Air and Radiation
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MEMO SUPPORTING INTEGRATED PROPOSAL MODELING AND UPDATED BASELINE ANALYSIS

Overview

As part of the Regulatory Impact Analysis (RIA) for this proposed rulemaking, EPA conducted modeling using the Integrated Planning Model (IPM)[1] to project the impacts of the first two phases of the proposed NSPS for combustion turbines as well as the requirements in the proposed emission guidelines for existing steam generating units. EPA also presented a separate spreadsheet-based analysis that estimated the impacts of the proposed third phase of the NSPS for combustion turbines and the requirements in the proposed emission guidelines for existing combustion turbines. This document presents integrated proposal modeling that incorporates all requirements under the proposed rules. Additionally, this document presents updated IPM results that incorporate updated assumptions regarding liquified natural gas (LNG) exports from the Energy Information Administration's (EIA) Annual Energy Outlook 2023 (AEO 2023).

This document provides a summary of EPA's approach to developing integrated proposal 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.[2] Separate results are then presented using a baseline that incorporates updated LNG export assumptions.[3]

Illustrative Integrated Proposal Scenario

These proposed rules propose to establish standards of performance and emission guidelines to limit GHG emissions from certain fossil fuel-fired electric generating units. The EGUs covered by these proposed rules are existing fossil fuel-fired EGUs (both steam generating

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

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

[3] 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.

EGUs and stationary combustion turbines) and new fossil-fuel fired stationary combustion turbine EGUs that commence construction or reconstruction after May 23, 2023, the date of publication of these proposed regulations. For details on the source categories and the GHG mitigation measures considered please see sections VII, X and XI of the preamble (*See* 88 FR 33240).

This memo outlines the projected costs and certain impacts of compliance under an illustrative integrated proposal modeling scenario. To the extent possible, EPA evaluated the 111(b) proposal for new natural gas-fired EGUs and 111(d) proposal for existing coal-fired EGUs and existing natural gas fired EGUs in combination to better analyze the interactive effects of the proposals. For details of the controls modeled for each of the source categories starting in run year 2030 under the illustrative scenario please see Table 1 and Table 2 below.

Table 1 Summary of GHG Mitigation Measures for Existing Steam Generating EGUs under the Illustrative Integrated Proposal Scenario[a,b,c]

Affected EGUs	Modeled Subcategory Definition	Modeled GHG Mitigation Measures
Long-term existing coal-fired steam generating units	Coal-fired steam generating units without committed retirement prior to 2040	CCS with 90 percent capture of CO_2, starting in 2030
Medium-term existing coal-fired steam generating units	Coal-fired steam generating units with a committed retirement by 2040 that are less than 500 MW, and that are not a near-term/low utilization unit	Natural gas co-firing at 40 percent of the heat input to the unit, starting in 2030
Near-term existing coal-fired steam generating units	Coal-fired steam generating units with a committed retirement prior to 2035 that operate with annual capacity factors less than 20 percent in 2030	Routine methods of operation
Imminent-term existing coal-fired steam generating units	Coal-fired steam generating units with a federally enforceable retirement commitment prior to 2030	Routine methods of operation

[a] All years shown in this table reflect IPM run years.
[b] Coal units that lack existing SCR controls must also install these controls in addition to CCS to comply.
[c] Coal-fired EGUs that convert entirely to burn natural gas are no longer subject to coal-fired EGU mitigation measures outlined above.

Table 2 Summary of GHG Mitigation Measures for Combustion Turbines by Source Category under the Illustrative Integrated Proposal Scenario[a,b,c]

Affected EGUs	Modeled Subcategory Definition	1st Component GHG Mitigation Measure	2nd Component GHG Mitigation Measure	3rd Component GHG Mitigation Measure	Second Phase Begins:	Third Phase Begins:
Baseload Economic NGCC Additions, and existing NGCC units > 300 MW[d]	NGCC units that commence construction after 2023, and existing NGCC units >300 MW that operate at an annual capacity factor of more than 50%	Efficient generation	30% by volume hydrogen co-firing or CCS	96% by volume hydrogen co-firing or CCS	2035	2040
Intermediate Load Economic NGCC Additions, and existing NGCC units > 300 MW	NGCC units that commence construction after 2023, and existing NGCC units >300 MW that operate at an annual capacity factor of less than 50%	Efficient generation	Efficient generation	Efficient generation		
Intermediate load Economic NGCT Additions, and existing NGCT units > 300 MW	NGCT units that commence construction after 2023, and existing NGCT units >300 MW that operate at an annual capacity factor of more than 20%	Efficient generation	30% by volume hydrogen co-firing[e]	96% by volume hydrogen co-firing[e]		
Peaking Economic NGCT Additions, and existing NGCT units > 300 MW	NGCT units that commence construction after 2023, or existing NGCT units >300 MW and operate at an annual capacity factor of less than 20%	Efficient generation	Efficient generation	Efficient generation		

[a] All years shown in this table reflect IPM run years.
[b] Delivered hydrogen price is assumed to be $0.5/kg in years in which the second phase or third phase of the NSPS is active, and $1/kg in all other years.
[c] NGCC unit additions that install CCS are no longer subject to the GHG mitigation measures outlined above.
[d] Limitations were assigned to the portion of modeled plants that comprised units greater than 300 MW, where an NGCC unit is defined by a combustion turbine and the capacity-weighted share of steam capacity at the facility.

The GHG mitigation measures described in this memo are illustrative since states are afforded flexibility to implement the proposed rules, and thus the impacts could be different to the extent states make different choices than those assumed in the illustrative analysis. Additionally, the way that EGUs choose to comply with the GHG mitigation measures may differ from the methods projected in the modeling for this memo.

The updated modeling summarized in this document continues to be based on the applicability criteria for affected units that the EPA included in the proposed rulemaking. As noted in the proposed rulemaking, the EPA is also considering certain variations in those applicability requirements, including, for existing natural gas combined cycle (NGCC) units and natural gas combustion turbines (NGCT), variations in the proposed threshold of 300 MW. In addition, while the proposed rulemaking applied that threshold on a unit-level basis, and all of the modeling performed to date does the same, comments from stakeholders to date have led the EPA to also consider applying the threshold on a plant-level basis. EPA is considering the appropriate MW threshold for such a plant-level approach and whether such an approach should also include a unit-level MW threshold.

Updates to IPM to Support Integrated Proposal Modeling

The IPM analysis that was included as part of the evaluation of the scenarios presented in the RIA for this rulemaking allowed for co-firing of hydrogen at new combustion turbines and did not offer the option to co-fire hydrogen at existing combustion turbines. In order to capture the requirements on existing turbines, the model was updated to allow for co-firing hydrogen at affected existing combustion turbines, *i.e.*, units greater than 300 MW, starting in the 2030 run year. Additionally, to better capture emission rate requirements as a function of annual capacity factor, model plants were allowed to switch to lower utilization levels in subsequent years and no longer co-fire hydrogen even if they selected hydrogen co-firing in earlier run years. The ability to co-fire hydrogen at affected existing turbines is also included in the updated baseline scenario presented here.

Methodology for Evaluating the Illustrative Integrated Proposal Modeling Scenario

In order to assess the impacts of the integrated proposal modeling this memo presents the change in the total production costs[4] and emissions projected by IPM under the updated baseline and integrated proposal scenario. The model projections capture the costs associated with installation and use of GHG mitigation measures at affected sources as well as the resulting effects on dispatch. Additionally, EPA estimates monitoring, reporting and recordkeeping (MR&R) costs for affected EGUs for the timeframe of 2024 to 2042, and these costs are added to the estimated change in the total system production cost projected by IPM.

While use of CCS at new and existing sources and co-firing natural gas at existing coal-fired facilities are captured endogenously within IPM v6.21, hydrogen co-firing at new gas-fired EGUs is, at present, represented exogenously as a fuel that is available to affected facilities at a delivered cost of $1/kg, becoming $0.5/kg when phase 2 and phase 3 are active.

Estimated Impacts of the Integrated Proposal

Emissions Reduction Assessment

The EGU CO_2 emissions reductions are presented in this document from 2028 through 2042 and are based on IPM projections. Table 3 presents the estimated reduction in power sector CO_2 emissions resulting from compliance with the evaluated illustrative scenario.

Table 3 EGU Annual CO_2 Emissions and Emissions Changes (million metric tons) for the Baseline and the Illustrative Integrated Proposal Scenario from 2028 through 2040 [5]

Year	Total Annual CO_2 Emissions (million metric tons)		Change from Updated Baseline run
	Updated Baseline run	Integrated Proposal	Integrated Proposal
2028	1,222	1,209	-13
2030	972	879	-93
2035	608	558	-51

[4] The change in production costs is reflective of the costs borne by the power sector to meet the requirements of the rule. after netting out the tax incentives in the Inflation Reduction Act. However, the production cost changes do not equal social costs because they do not include a complete accounting of transfers (e.g., taxes paid by the power sector), the tax incentives provided by the Inflation Reduction Act, and effects in other sectors of the economy. For details, please see Section 5 of the RIA.

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

2040	481	446	-36
Cumulative 2028-42	10,194	9,419	-775

Within the compliance modeling, sources within each subcategory are subject to GHG mitigation measures beginning in 2030. Since IPM has perfect foresight, investment decisions prior to the start of the program are influenced by how those assets would fare under the policy assumed. Hence, we see small reductions in 2028 prior to the imposition of the policy in 2030. Emission reductions peak in 2030, reflective of the start of the requirements on existing coal-fired EGUs. The second phase of the NSPS is assumed to begin in the 2035 run year, while the third phase of the NSPS is assumed to begin in the 2040 run year. The impact of the Inflation Reduction Act (IRA) is to increase the cost-competitiveness of low-emitting technologies, with the result that emissions are projected to fall significantly over the forecast period under the updated baseline. Hence, reductions from the rules are highest in 2030 relative to the updated baseline and also decline over time. For details on the EGU emissions controls assumed in the illustrative scenario, please see Table 1 and Table 2.

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.

Table 4 EGU Annual Emissions and Emissions Changes for NO_X, SO_2, and Ozone NO_X for the Illustrative Integrated Proposal Scenario for 2028 to 2040

Year	Total Annual NO_x Emissions (Thousand Tons)		Change from Updated Baseline run
	Updated Baseline run	Integrated Proposal	Integrated Proposal
2028	457	447	-10
2030	368	301	-67
2035	214	197	-17
2040	162	152	-10
Year	**Total Ozone Season NO_x Emissions (Thousand Tons)**		**Change from Updated Baseline run**
	Updated Baseline run	**Integrated Proposal**	**Integrated Proposal**
2028	195	190	-5
2030	163	140	-23
2035	104	99	-5
2040	80	77	-3
Year	**Total Annual SO_2 Emissions (Thousand Tons)**		**Change from Updated Baseline run**
	Updated Baseline run	**Integrated Proposal**	**Integrated Proposal**
2028	394	379	-15
2030	282	172	-110
2035	130	89	-41
2040	89	58	-31

[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 proposal scenario are presented below in Table 5.[6] Since the proposed 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 5 National Power Sector Compliance Cost Estimates (billions of 2019 dollars) for the Illustrative Integrated Proposal Scenario

	Integrated Proposal
2024 to 2042 (Net Present Value)	11.2

[6] 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 2042 (Annualized)	0.84
2028 (Annual)	-0.22
2030 (Annual)	4.04
2035 (Annual)	0.03
2040 (Annual)	0.48

"2024 to 2042 (Annualized)" reflects total estimated annual compliance costs levelized over the period 2024 through 2042 and discounted using a 3.76% real discount rate.[7] This does not include compliance costs beyond 2042. "2024 to 2042 (Net Present Value)" reflects total estimated annual compliance costs over the period 2024 through 2042 and discounted using a 3.76% real discount rate. This does not include compliance costs beyond 2042. "2028 (Annual)" through "2040 (Annual)" costs reflect annual estimates in each of those run years.[8]

There are several notable aspects of the results presented in Table 5. The estimated annual compliance costs for the integrated proposal are negative (*i.e.*, a cost reduction) in 2028, although this illustrative scenario reduces CO_2 emissions as shown in Table 3Table 4 EGU Annual Emissions and Emissions Changes for NO_X, SO_2, and Ozone NO_X for the Illustrative Integrated Proposal Scenario for 2028 to 2040 Table 4 EGU Annual Emissions and Emissions Changes for NO_X, SO_2, and Ozone NO_X for the Illustrative Integrated Proposal Scenario for 2028 to 2040 . While seemingly counterintuitive, estimating negative compliance costs in a single year is possible given the assumption of perfect foresight. IPM's objective function is to minimize the discounted present value (PV) of a stream of annual total cost of generation over a multi-decadal time period.[9] Under the updated baseline, the proposed Good Neighbor Plan (GNP) rule[10] results in installation of SCR controls in the 2028 run year on some coal-fired EGUs that currently lack them. Under the integrated proposal scenario modeled, a subset of these facilities retires rather than retrofits, since they would face additional requirements under the GHG regulations modeled. This in turn results in lower capital costs in the first run year and is balanced by higher costs in later years. Costs peak in 2030, reflecting the

[7] 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 19-year period (2024 to 2042) using the 3.76 percent rate as well.

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

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

[10] Consistent with the modeling in support of the RIA for this rulemaking, EPA modeled the proposed GNP as this was the latest information available at the time of the analysis. EPA has since finalized the GNP and has taken administrative action with respect to aspects of that rule on an interim basis in response to certain litigation developments. EPA intends to consider whether and to what extent updates to the GNP assumptions are warranted based on these developments in modeling for the final rule.

date of imposition of requirements in the proposed Emission Guidelines for coal-fired steam generating units.

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 2042 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.[11] For this analysis we first calculated the PV of the cost streams from 2024 through 2042[12] 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).[13] After calculating the PV of the cost streams, the same 3.76 percent discount rate and 2024 to 2042 time period are used to calculate the levelized annual (*i.e.*, annualized) cost estimates shown in Table 5Table 5 National Power Sector Compliance Cost Estimates (billions of 2019 dollars) for the Illustrative Integrated Proposal Table 5 National Power Sector Compliance Cost Estimates (billions of 2019 dollars) for the Illustrative Integrated Proposal .[14]

Impacts on Fuel Use, Prices and Generation Mix

The proposed NSPS and the proposed Emissions Guidelines are expected to result in significant GHG emissions reductions. The rules are also expected to have some impact on the economics of the power sector. Consideration of these potential impacts is an important

[11] 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.

[12] 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.

[13] 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."

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

component of assessing the relative impact of the illustrative integrated proposal scenario. 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 and 2040 IPM model run years.

Table 6 and Table 7Table 7 2028, 2030, 2035 and 2040 Projected U.S. Power Sector Natural Gas Use for the Updated Baseline and the Table 7 2028, 2030, 2035 and 2040 Projected U.S. Power Sector Natural Gas Use for the Updated Baseline and the present the percentage changes in national coal and natural gas usage by EGUs in the 2028, 2030, 2035, and 2040 run years. These fuel use estimates reflect some power companies choosing to shift to natural gas-fired and renewable generating sources and away from coal-fired sources in 2030 rather than implement available cost-reasonable controls in response to the imposition of GHG mitigation measures under the proposed Emissions Guidelines. Under the illustrative integrated proposal in the 2035 and 2040 run year, natural gas consumption increases are less than in the 2030 run year, reflective of the imposition of the second and third phases of the NSPS.

To put these reductions into context, under the updated baseline, power sector coal consumption is projected to decrease from 252 million tons in 2028 to 176 million tons in 2030 (15 percent annually between 2028-2030), and to 80 million tons in 2035 (11 percent annually between 2030-2035). Under the integrated proposal modeling, coal consumption is projected to decrease from 245 million tons in 2028 to 103 million tons in 2028 (29 percent annually between 2028-2030), and 61 million tons in 2035 (8 percent annually between 2030-2035). Between 2015 and 2020, coal consumption in the electric power sector fell between 8 and 19 percent annually.[15]

Table 8 presents the projected hydrogen power sector consumption under the updated baseline and the illustrative integrated proposal scenario.

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

Table 6 2028, 2030, 2035 and 2040 Projected U.S. Power Sector Coal Use for the Updated Baseline and the Illustrative Integrated Proposal Scenario

Million Tons				Percent Change from Updated Baseline
	Year	Updated Baseline	Integrated Proposal	Integrated Proposal
Appalachia	2028	48	46	-4%
Interior		51	49	-4%
Waste Coal		4	4	0%
West		148	145	-2%
Total		252	245	-3%
Appalachia	2030	28	18	-35%
Interior		37	31	-16%
Waste Coal		4	3	-32%
West		107	51	-52%
Total		176	103	-41%
Appalachia	2035	11	10	-8%
Interior		20	21	9%
Waste Coal		2	0	-82%
West		48	29	-38%
Total		80	61	-24%
Appalachia	2040	6	6	-1%
Interior		16	19	25%
Waste Coal		2	0	-100%
West		39	25	-35%
Total		62	50	-19%

Table 7 2028, 2030, 2035 and 2040 Projected U.S. Power Sector Natural Gas Use for the Updated Baseline and the Illustrative Integrated Proposal Scenario

Year	Trillion Cubic Feet		Percent Change from Updated Baseline
	Updated Baseline	Integrated Proposal	Integrated Proposal
2028	12.5	12.6	0%
2030	12.6	13.6	8%
2035	9.9	9.6	-3%
2040	8.1	7.7	-5%

Table 8 2028, 2030, 2035 and 2040 Projected U.S. Power Sector Hydrogen Use for the Updated Baseline and the Illustrative Integrated Proposal Scenario

Year	Million Metric Tons	
	Updated Baseline	**Integrated Proposal**
2028	0.0	0.0
2030	0.0	0.0
2035	0.1	4.4
2040	0.0	2.8

Table 9 and Table 10 present the projected coal and natural gas prices in 2028, 2030, 2035 and 2040, as well as the percent change from the updated baseline projected due to the illustrative scenario. In 2030, gas prices are higher, which is reflective of higher gas consumption as a result of the imposition of the proposed Emission Guidelines for coal-fired steam generating units. In 2035 and 2040, the second and third phases of the NSPS are assumed to be active, resulting in less gas consumption and lower prices.

Table 9 2028, 2030, 2035 and 2040 Projected Minemouth and Power Sector Delivered Coal Price (2019 dollars) for the Updated Baseline and the Illustrative Integrated Proposal Scenario

	Year	$/MMBtu		Percent Change from Updated Baseline
		Updated Baseline	**Integrated Proposal**	**Integrated Proposal**
Minemouth	2028	1.16	1.15	0%
Delivered		1.59	1.58	-1%
Minemouth	2030	1.17	1.27	9%
Delivered		1.47	1.46	-1%
Minemouth	2035	1.34	1.41	5%
Delivered		1.38	1.39	1%
Minemouth	2040	1.42	1.50	5%
Delivered		1.42	1.42	0%

Table 10 2028, 2030, 2035 and 2040 Projected Henry Hub and Power Sector Delivered Natural Gas Price (2019 dollars) for the Updated Baseline and the Illustrative Integrated Proposal Scenario

	Year	$/MMBtu		Percent Change from Updated Baseline
		Updated Baseline	Integrated Proposal	Integrated Proposal
Henry Hub	2028	3.0	3.0	0%
Delivered Natural Gas		3.0	3.0	0%
Henry Hub	2030	2.4	2.6	10%
Delivered Natural Gas		2.5	2.8	9%
Henry Hub	2035	1.9	1.8	-5%
Delivered Natural Gas		2.1	2.0	-5%
Henry Hub	2040	2.0	2.0	-4%
Delivered Natural Gas		2.2	2.1	-4%

Table 11 presents the projected percentage changes in the amount of electricity generation in 2028, 2030, 2035 and 2040 by fuel type. Consistent with the fuel use projections and emissions trends above, EPA projects an overall shift from coal to gas and renewables under the updated baseline, and these trends persist under the modeled illustrative integrated proposal scenario. The projected impacts are highest in 2030, reflecting the imposition of the proposed Emissions Guidelines, and are smaller thereafter. The 45Q tax credit for CCS 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.

Table 11 2028, 2030, 2035 and 2040 Projected U.S. Generation by Fuel Type for the Updated Baseline and the Illustrative Integrated Proposal Scenario

	Year	Generation (TWh)		Percent Change from Updated Baseline
		Updated Baseline	Integrated Proposal	Integrated Proposal
Coal	2028	484	468	-3%
Coal with CCS		0	0	-
Coal with Gas co-firing		0	0	-
Natural Gas		1,773	1,788	1%
Hydrogen Co-firing		0	0	-
Natural Gas with CCS		0	0	-
Nuclear		765	765	0%
Hydro		294	295	0%
Non-Hydro RE		964	967	0%
Oil/Gas Steam		30	29	-3%
Other		30	30	0%
Grand Total		4,341	4,342	0%
Coal	2030	243	78	-68%
Coal with CCS		66	84	28%
Coal with Gas co-firing		0	5	-
Natural Gas		1,722	1,854	8%
Hydrogen Co-firing		0	0	-
Natural Gas with CCS		50	30	-39%
Nuclear		734	734	0%
Hydro		303	303	0%
Non-Hydro RE		1,269	1,278	1%
Oil/Gas Steam		33	47	43%
Other		29	29	0%
Grand Total		4,447	4,442	0%
Coal	2035	44	0	-100%
Coal with CCS		75	84	12%
Coal with Gas co-firing		0	1	-
Natural Gas		1,326	1,105	-17%
Hydrogen Co-firing		0	283	-
Natural Gas with CCS		77	42	-45%
Nuclear		660	661	0%
Hydro		329	325	-1%
Non-Hydro RE		2,179	2,171	0%
Oil/Gas Steam		16	19	18%

Other		29	29	0%
Grand Total		4,737	4,722	0%
Coal	2040	24	0	-99%
Coal with CCS		55	61	12%
Coal with Gas co-firing		0	0	-
Natural Gas		1,086	1,063	-2%
Hydrogen Co-firing		0	42	-
Natural Gas with CCS		77	38	-51%
Nuclear		616	618	0%
Hydro		346	345	0%
Non-Hydro RE		2,826	2,849	1%
Oil/Gas Steam		3	3	-1%
Other		28	28	1%
Grand Total		5,061	5,048	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 12 presents the projected percentage changes in the amount of generating capacity in 2028, 2030, 2035 and 2040 by primary fuel type. In 2030, the proposed Emissions Guidelines are assumed to be in effect. Under the integrated proposal modeling, 44 GW of coal-fired EGUs have committed retirements by 2035 and operate at an annual capacity factor of 20 percent or less in 2030, and as such are subject to the near-term existing coal-fired steam generating units subcategory. By 2040, 1 GW of coal-fired EGU capacity has committed to retirement and is subject to the 40 percent natural gas co-firing requirement. 12 GW of coal-fired EGUs that plan to operate past 2040 are subject to the long-term existing coal-fired steam generating unit subcategory and, as such, install CCS (reflecting 3 GW incremental to the updated baseline). Finally, 21 GW of coal-fired EGUs undertake coal to gas conversion (9 GW incremental to the updated baseline).

Under the updated baseline, total coal retirements between 2023 and 2035 are projected to be 104 GW (or 15 GW annually). Under the proposed rules, total coal retirements between 2023 and 2035 are projected to be 126 GW (or 18 GW annually). This is in comparison to an average historical retirement rate of 11 GW per year from 2015 – 2020.[16]

[16] See EIA's Today in Energy: https://www.eia.gov/todayinenergy/detail.php?id=50838.

By 2030 the proposal is projected to result in an additional 1 GW of coal retirements, by 2035 an incremental 22 GW of coal retirements and by 2040 an incremental 18 GW of coal retirements relative to the updated baseline. These compliance decisions reflect EGU operators making least-cost decisions on how to achieve efficient compliance with the rules while maintaining sufficient generating capacity to ensure grid reliability.[17]

An incremental 9 GW of renewable capacity is projected by 2040 (consisting primarily of solar capacity builds) in the integrated proposal scenario. Under the integrated proposal scenario, 27 GW of economic NGCC additions occur by 2035 (3 GW incremental to the updated baseline), and 40 GW of economic NGCT additions occur by 2035 (20 GW incremental to the updated baseline). These builds partially reflect early action, *i.e.*, builds that would otherwise have occurred later in the forecast period under the updated baseline. Of these units, 20 GW of NGCCs and 4 GW of NGCT additions are projected to co-fire hydrogen in 2035. In 2040, 1 GW of NGCC and 4 GW of NGCT additions are projected to continue to co-fire hydrogen.

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

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

Table 12 2028, 2030, 2035 and 2040 Projected U.S. Capacity by Fuel Type for the Updated Baseline and the Illustrative Integrated Proposal Scenario

	Year	Capacity (GW)		Percent Change from Updated Baseline
		Updated Baseline	Integrated Proposal	Integrated Proposal
Coal	2028	100	99	-1%
Coal with CCS		0	0	-
Coal with Gas co-firing		0	0	-
Natural Gas		463	468	1%
Hydrogen Co-firing		0	0	-
Natural Gas with CCS		0	0	-
Nuclear		96	96	0%
Hydro		102	102	0%
Non-Hydro RE		315	316	0%
Oil/Gas Steam		63	63	0%
Other		7	7	0%
Grand Total		1,146	1,151	0%
Coal	2030	60	44	-25%
Coal with CCS		9	12	29%
Coal with Gas co-firing		0	1	-
Natural Gas		454	462	2%
Hydrogen Co-firing		0	0	-
Natural Gas with CCS		7	4	-39%
Nuclear		92	92	0%
Hydro		104	104	0%
Non-Hydro RE		403	405	0%
Oil/Gas Steam		60	70	15%
Other		7	7	0%
Grand Total		1,196	1,200	0%
Coal	2035	33	0	-99%
Coal with CCS		11	12	13%
Coal with Gas co-firing		0	1	-
Natural Gas		460	446	-3%
Hydrogen Co-firing		0	42	-
Natural Gas with CCS		10	6	-45%
Nuclear		84	84	0%
Hydro		108	108	0%
Non-Hydro RE		667	664	0%
Oil/Gas Steam		59	68	14%
Other		7	7	0%

Grand Total		1,439	1,438	0%
Coal	2040	28	0	-99%
Coal with CCS		8	9	12%
Coal with Gas co-firing		0	0	-
Natural Gas		503	515	2%
Hydrogen Co-firing		0	12	-
Natural Gas with CCS		10	6	-45%
Nuclear		79	79	0%
Hydro		110	110	0%
Non-Hydro RE		868	877	1%
Oil/Gas Steam		59	67	14%
Other		7	7	0%
Grand Total		1,672	1,683	1%

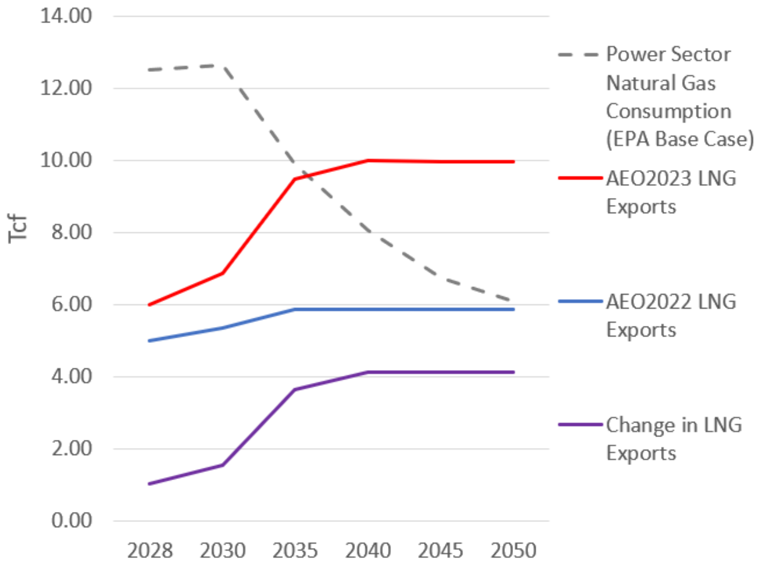
Note: In this table, “Non-Hydro RE” includes biomass, geothermal, landfill gas, solar, and wind

Contextualizing the Change in LNG Exports in AEO 2023

As part of their regular release schedule, EIA published the AEO 2023[18] in March of 2023. This forecast included several key updates that captured the impacts of various measures of the Inflation Reduction Act (IRA) as well as ongoing market conditions. One important update was the projection of increased LNG exports relative to earlier versions of the AEO. As shown in Figure 1 below, LNG exports in AEO 2023 are projected to increase by about 4 Tcf annually by 2040 relative to AEO 2022, an increase that is equal to roughly half the total power sector gas consumption projected under the EPA Post IRA Summer 2022 Baseline.

[18] Available at: https://www.eia.gov/outlooks/aeo/

Figure 1 Projected Power Sector Natural Gas Consumption under EPA IPM Baseline and AEO 2022/23 LNG Exports



Sources: EIA AEO 2022, EIA AEO 2023, EPA

When EPA conducted its analysis of the proposals, the Agency did not have the benefit of these updated results. As part of ongoing baseline updates, EPA intends to reflect the additional LNG export capacity projected in the AEO 2023 in future analyses. In this analysis, EPA presents an illustrative baseline and integrated proposal run that include a characterization of higher LNG export capacity consistent with the AEO 2023.

Updates to IPM to Support Modeling Higher Levels of LNG Exports

In order to capture the increase in LNG export capacity projected in the AEO 2023, EPA modified the natural gas outlook used in the IPM runs described earlier (*i.e.*, the Updated Baseline and the Illustrative Integrated Proposal Scenario) by increasing natural gas demand to account for the difference between projected LNG exports in the AEO 2022 and AEO 2023.[19] The analysis described in this section is preliminary, in that the approach does not include use of the Gas Market Model to account for subnational pricing impacts of increased LNG exports. Additionally, the projected power sector CO_2 emissions fall below the threshold established in the IRA for expiration of clean energy tax credits (25% below 2022 levels) in run year 2045;

[19] The updated gas supply curves used in this analysis are available in the docket for this rulemaking.

however, this illustrative analysis does not reflect that phaseout. Nevertheless, EPA believes that these preliminary runs provide important information on the potential impacts of this baseline change and therefore has included these results as part of this memo.

Estimated Impacts of the Integrated Proposal with Increased LNG Export

Emissions Reduction Assessment

As described earlier, the EGU CO_2 emissions reductions are presented in this document from 2028 through 2042 and are based on IPM projections. Table 13 presents the estimated reduction in power sector CO_2 emissions resulting from compliance with the evaluated illustrative scenario.

Table 13 EGU Annual CO_2 Emissions and Emissions Changes (million metric tons) for the Updated Baseline with LNG Update and the Illustrative Integrated Proposal Scenario with LNG Update from 2028 through 2040 [20]

Year	Total Annual CO_2 Emissions (Million Metric Tonnes)		Change from Updated Baseline run with LNG Update
	Updated Baseline run with LNG Update	Integrated Proposal with LNG Update	Integrated Proposal with LNG Update
2028	1,223	1,195	-27
2030	988	844	-145
2035	613	505	-108
2040	372	340	-32
Cumulative 2028-42	9,724	8,455	-1,270

As under the illustrative integrated proposal scenario, we see small reductions in 2028 prior to the imposition of the policy in 2030 under the runs that include the LNG update. Emission reductions peak in 2030, reflective of the start of the requirements on existing coal-fired EGUs. The second phase of the NSPS is assumed to begin in the 2035 run year, while the third phase of the NSPS is assumed to begin in the 2040 run year. The higher natural gas prices that result from the LNG export update amplifies the impact of the IRA in deploying incremental low-emitting generation technologies, with the result that emissions are projected to fall significantly over the forecast period under the updated baseline. Hence, reductions from the

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

rules are highest in 2030 relative to the updated baseline with LNG update and decline over time. For details on the GHG mitigation measures assumed in the illustrative scenario, please see Table 1 and Table 2.

In addition to annual CO_2 reductions, there are also reductions in other air emissions associated with EGUs burning fossil fuels that result from compliance strategies to reduce annual 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 14.

Table 14 EGU Annual Emissions and Emissions Changes for NO_X, SO_2, and Ozone NO_X for the Updated Baseline with LNG Update and Illustrative Integrated Proposal with LNG Update Scenario for 2028 to 2040

Year	Total Annual NO_x Emissions (Thousand Tons)		Change from Updated Baseline run with LNG Update
	Updated Baseline run with LNG Update	Integrated Proposal with LNG Update	Integrated Proposal with LNG Update
2028	457	447	-10
2030	378	308	-70
2035	231	197	-33
2040	154	140	-13
Year	Total Ozone Season NO_x Emissions (Thousand Tons)		Change from Updated Baseline run with LNG Update
	Updated Baseline run with LNG Update	Integrated Proposal with LNG Update	Integrated Proposal with LNG Update
2028	194	190	-4
2030	168	143	-25
2035	112	95	-17
2040	77	71	-5
Year	Total Annual SO_2 Emissions (Thousand Tons)		Change from Updated Baseline run with LNG Update
	Updated Baseline run with LNG Update	Integrated Proposal with LNG Update	Integrated Proposal
2028	422	388	-34
2030	328	194	-133
2035	191	109	-82
2040	104	64	-39

[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 scenario are presented in Table 15.[21] Since the rules are estimated to result in additional recordkeeping, monitoring or reporting requirements, the costs associated with compliance, monitoring, recordkeeping, and reporting requirements are included within the estimates in this table.

Table 15 National Power Sector Compliance Cost Estimates (billions of 2019 dollars) for the Illustrative Integrated Proposal Scenario with LNG Update

	Integrated Proposal with LNG Update
2024 to 2042 (Net Present Value)	6.2
2024 to 2042 (Annualized)	0.46
2028 (Annual)	-0.58
2030 (Annual)	3.30
2035 (Annual)	-0.95
2040 (Annual)	0.73

"2024 to 2042 (Annualized)" reflects total estimated annual compliance costs levelized over the period 2024 through 2042 and discounted using a 3.76 real discount rate.[22] This does not include compliance costs beyond 2042. "2024 to 2042 (Net Present Value)" reflects total estimated annual compliance costs over the period 2024 through 2042 and discounted using a 3.76 real discount rate. This does not include compliance costs beyond 2042. "2028 (Annual)" through "2040 (Annual)" costs reflect annual estimates in each of those run years.[23]

There are several notable aspects of the results presented in Table 15. The estimated annual compliance costs for the integrated proposal are negative (*i.e.*, a cost reduction) in 2028, for similar reasons as under the cases presented earlier. Costs are also negative in 2035, reflecting the improved competitiveness of hydrogen priced at $0.5/kg under tighter domestic natural gas market conditions relative to the Post-IRA Summer 2022 Reference Case.

In addition to evaluating annual compliance cost impacts, EPA also calculated the net present value and annualized compliance costs over the 2024-42 period using the same approach as outlined earlier in this document.

[21] 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.

[22] 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 19-year period (2024 to 2042) using the 3.76 percent rate as well.

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

Impacts on Fuel Use, Prices and Generation Mix

Table 16 and Table 17 Table 7 2028, 2030, 2035 and 2040 Projected U.S. Power Sector Natural Gas Use for the Updated Baseline and the Table 7 2028, 2030, 2035 and 2040 Projected U.S. Power Sector Natural Gas Use for the Updated Baseline and the present the percentage changes in national coal and natural gas usage by EGUs in the 2028, 2030, 2035, and 2040 run years. These fuel use estimates reflect some power companies choosing to shift to natural gas and renewables from coal in 2030. Tighter natural gas markets result in greater uptake of hydrogen co-firing, particularly in the 2035 run year. This, in turn, reduces demand for natural gas and drives prices lower. By 2040, consumption levels are consistent with the updated baseline with LNG update.

Table 18 presents the projected hydrogen power sector consumption under the updated baseline with LNG update and the illustrative integrated proposal scenario with LNG update.

Table 16 2028, 2030, 2035 and 2040 Projected U.S. Power Sector Coal Use for the Updated Baseline with LNG Update and the Illustrative Integrated Proposal Scenario with LNG Update

Million Tons				Percent Change from Updated Baseline with LNG Update
	Year	**Updated Baseline with LNG Update**	**Integrated Proposal with LNG Update**	**Integrated Proposal with LNG Update**
Appalachia	2028	54	53	-2%
Interior		52	50	-3%
Waste Coal		4	4	0%
West		154	146	-5%
Total		265	254	-4%
Appalachia	2030	37	30	-18%
Interior		38	32	-16%
Waste Coal		4	3	-25%
West		118	58	-50%
Total		198	124	-37%
Appalachia	2035	22	24	5%
Interior		24	22	-7%
Waste Coal		4	1	-80%
West		62	39	-37%
Total		112	85	-24%
Appalachia	2040	10	9	-4%
Interior		18	22	19%
Waste Coal		4	0	-100%
West		41	28	-31%
Total		73	59	-19%

Table 17 2028, 2030, 2035 and 2040 Projected U.S. Power Sector Natural Gas Use for the Updated Baseline with LNG Update and the Illustrative Integrated Proposal Scenario with LNG Update

Year	Trillion Cubic Feet		Percent Change from Updated Baseline with LNG Update
	Updated Baseline with LNG Update	**Integrated Proposal with LNG Update**	**Integrated Proposal with LNG Update**
2028	12.1	12.0	-1%
2030	12.0	12.9	8%
2035	8.8	8.4	-5%
2040	5.6	5.6	0%

Table 18 2028, 2030, 2035 and 2040 Projected U.S. Power Sector Hydrogen Use for the Updated Baseline with LNG Update and the Illustrative Integrated Proposal Scenario with LNG Update

Year	Million Metric Tons	
	Baseline with LNG Update	Integrated Proposal with LNG Update
2028	0.0	0.0
2030	0.0	0.0
2035	0.1	5.7
2040	0.1	2.9

Table 19 and Table 20 present the projected coal and natural gas prices in 2028, 2030, 2035 and 2040, as well as the percent change from the updated baseline with LNG update projected due to the illustrative scenario. In 2030, natural gas prices are higher due to increased natural gas consumption as a result of the imposition of the proposed Emission Guidelines for coal-fired steam generating units. In 2035 and 2040, the second and third phases of the NSPS are assumed to be active, resulting in less gas consumption and lower prices.

Table 19 2028, 2030, 2035 and 2040 Projected Minemouth and Power Sector Delivered Coal Price (2019 dollars) for the Updated Baseline with LNG Update and the Illustrative Integrated Proposal Scenario with LNG Update

	Year	$/MMBtu		Percent Change from Updated Baseline with LNG Update
		Updated Baseline with LNG Update	Integrated Proposal with LNG Update	Integrated Proposal with LNG Update
Minemouth	2028	1.16	1.17	0%
Delivered		1.61	1.60	-1%
Minemouth	2030	1.17	1.26	8%
Delivered		1.51	1.53	1%
Minemouth	2035	1.32	1.39	5%
Delivered		1.47	1.53	4%
Minemouth	2040	1.41	1.48	5%
Delivered		1.48	1.51	2%

Table 20 2028, 2030, 2035 and 2040 Projected Henry Hub and Power Sector Delivered Natural Gas Price (2019 dollars) for the Updated Baseline with LNG Update and the Illustrative Integrated Proposal Scenario with LNG Update

	Year	$/MMBtu		Percent Change from Updated Baseline with LNG Update
		Updated Baseline with LNG Update	Integrated Proposal with LNG Update	Integrated Proposal with LNG Update
Henry Hub	2028	3.1	3.1	0%
Delivered Natural Gas		3.1	3.1	0%
Henry Hub	2030	2.6	2.8	9%
Delivered Natural Gas		2.7	2.9	8%
Henry Hub	2035	2.4	2.3	-5%
Delivered Natural Gas		2.7	2.5	-6%
Henry Hub	2040	2.5	2.4	-3%
Delivered Natural Gas		2.7	2.6	-3%

Table 21 presents the projected percentage changes in the amount of electricity generation in 2028, 2030, 2035 and 2040 by fuel type. Consistent with the fuel use projections and emissions trends above, EPA projects an overall shift from coal to gas and renewables under the updated baseline with LNG update, and these trends persist under the illustrative scenario analyzed. The projected impacts are highest in 2030, reflecting the imposition of the proposed Emissions Guidelines, and are smaller thereafter.

Table 21 2028, 2030, 2035 and 2040 Projected U.S. Generation by Fuel Type for the Updated Baseline with LNG Update and the Illustrative Integrated Proposal Scenario with LNG Update

	Year	Generation (TWh)		Percent Change from Updated Baseline with LNG Update
		Updated Baseline with LNG Update	Integrated Proposal with LNG Update	Integrated Proposal with LNG Update
Coal	2028	512	491	-4%
Coal with CCS		0	0	-
Coal with Gas co-firing		0	0	-
Natural Gas		1,708	1,696	-1%
Hydrogen Co-firing		0	0	-
Natural Gas with CCS		0	0	-
Nuclear		765	765	0%
Hydro		293	294	0%
Non-Hydro RE		1,002	1,036	3%
Oil/Gas Steam		29	29	-1%
Other		30	30	0%
Grand Total		4,339	4,341	0%
Coal	2030	289	72	-75%
Coal with CCS		65	119	82%
Coal with Gas co-firing		0	5	-
Natural Gas		1,656	1,769	7%
Hydrogen Co-firing		0	0	-
Natural Gas with CCS		34	27	-22%
Nuclear		734	734	0%
Hydro		302	306	1%
Non-Hydro RE		1,307	1,340	2%
Oil/Gas Steam		27	38	42%
Other		29	29	0%
Grand Total		4,445	4,440	0%
Coal	2035	97	0	-100%
Coal with CCS		84	119	41%
Coal with Gas co-firing		0	2	-
Natural Gas		1,226	958	-22%
Hydrogen Co-firing		0	309	-
Natural Gas with CCS		41	33	-18%
Nuclear		660	659	0%
Hydro		327	330	1%
Non-Hydro RE		2,258	2,277	1%

Oil/Gas Steam		5	6	38%
Other		29	29	-1%
Grand Total		4,728	4,724	0%
Coal	2040	36	0	-99%
Coal with CCS		64	75	18%
Coal with Gas co-firing		0	0	-
Natural Gas		777	783	1%
Hydrogen Co-firing		0	45	-
Natural Gas with CCS		41	29	-29%
Nuclear		603	605	0%
Hydro		348	347	0%
Non-Hydro RE		3,181	3,153	-1%
Oil/Gas Steam		1	1	-12%
Other		28	28	0%
Grand Total		5,079	5,066	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 22 presents the projected percentage changes in the amount of generating capacity in 2028, 2030, 2035 and 2040 by primary fuel type. In 2030, the proposed Emissions Guidelines are assumed to be in effect. Under the integrated proposal modeling with LNG update, 40 GW of coal-fired EGUs have committed retirements by 2035 and operate at an annual capacity factor of 20 percent or less in 2030, and as such are subject to the near-term existing coal-fired steam generating units subcategory. One GW of coal-fired EGUs has committed to retirement by 2040 and is subject to the 40 percent natural gas co-firing requirement. 17 GW of coal-fired EGUs that plan to operate past 2040 are subject to the long-term existing coal-fired steam generating unit subcategory and, as such, install CCS (reflecting 5 GW incremental to the updated baseline with LNG update). Finally, 19 GW of coal-fired EGUs undertake coal to gas conversion (8 GW incremental to the updated baseline with LNG update).

Under the updated baseline with LNG update, total coal retirements between 2023 and 2035 are projected to be 97 GW. Under the proposed rules, total coal retirements between 2023 and 2035 are projected to be 120 GW.

By 2030 the proposal modeling projects an additional 1 GW of coal retirements, by 2035 an incremental 23 GW of coal retirements and by 2040 an incremental 17 GW of coal retirements relative to the updated baseline with LNG update. These compliance decisions reflect

EGU operators making least-cost decisions on how to achieve compliance with the guidelines while maintaining sufficient generating capacity to ensure grid reliability.[24]

An incremental 7 GW of renewable capacity additions is projected by 2035 (consisting primarily of solar capacity builds) in the integrated proposal scenario with LNG update. Under the integrated proposal scenario with LNG update, 20 GW of economic NGCC additions occur by 2035 (3 GW incremental to the updated baseline with LNG update), and 39 GW of economic NGCT additions occur by 2035 (21 GW incremental to the updated baseline with LNG update). These builds partially reflect early action, i.e., builds that would otherwise have occurred later in the forecast period under the updated baseline with LNG update. Of these units, 17 GW of NGCCs and 6 GW of NGCT additions co-fire hydrogen in 2035. In 2040, 1 GW of NGCC and 6 GW of NGCT additions are projected to continue to co-fire hydrogen. Of the existing NGCC units greater than 300 MW, 25 GW are projected to co-fire hydrogen in 2035 and 5 GW are projected to co-fire hydrogen in 2040.

Under the updated baseline with LNG update, the reduction in generation from natural gas- and coal-fired facilities is greater than the reduction in their capacities over time. Hence, thermal resources are, on average, operated less frequently over time due to the increase in renewable generation. These trends are also present under the illustrative integrated proposal with LNG update scenario.

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

Table 22 2028, 2030, 2035 and 2040 Projected U.S. Capacity by Fuel Type for the Updated Baseline with LNG Update and the Illustrative Integrated Proposal Scenario with LNG Update

	Year	Capacity (GW)		Percent Change from Updated Baseline with LNG Update
		Updated Baseline with LNG Update	Integrated Proposal with LNG Update	Integrated Proposal with LNG Update
Coal	2028	102	100	-2%
Coal with CCS		0	0	-
Coal with Gas co-firing		0	0	-
Natural Gas		457	462	1%
Hydrogen Co-firing		0	0	-
Natural Gas with CCS		0	0	-
Nuclear		96	96	0%
Hydro		102	102	0%
Non-Hydro RE		325	333	2%
Oil/Gas Steam		61	61	0%
Other		7	7	0%
Grand Total		1,149	1,161	1%
Coal	2030	63	41	-35%
Coal with CCS		9	17	83%
Coal with Gas co-firing		0	1	-
Natural Gas		450	456	1%
Hydrogen Co-firing		0	0	-
Natural Gas with CCS		5	4	-22%
Nuclear		92	92	0%
Hydro		104	104	0%
Non-Hydro RE		414	422	2%
Oil/Gas Steam		58	67	16%
Other		7	7	0%
Grand Total		1,203	1,211	1%
Coal	2035	39	0	-99%
Coal with CCS		12	17	42%
Coal with Gas co-firing		0	1	-
Natural Gas		455	434	-5%
Hydrogen Co-firing		0	48	-
Natural Gas with CCS		5	4	-18%
Nuclear		84	84	0%
Hydro		108	108	0%

Non-Hydro RE		691	698	1%
Oil/Gas Steam		57	66	14%
Other		7	7	0%
Grand Total		1,458	1,467	1%
Coal	2040	29	0	-99%
Coal with CCS		9	11	18%
Coal with Gas co-firing		0	0	-
Natural Gas		493	505	3%
Hydrogen Co-firing		0	12	-
Natural Gas with CCS		5	4	-18%
Nuclear		79	79	0%
Hydro		110	110	0%
Non-Hydro RE		981	974	-1%
Oil/Gas Steam		57	65	14%
Other		7	7	0%
Grand Total		1,771	1,768	0%

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