Assumptions to the Annual Energy Outlook 2025: Electricity Market Module

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Electricity Market Module

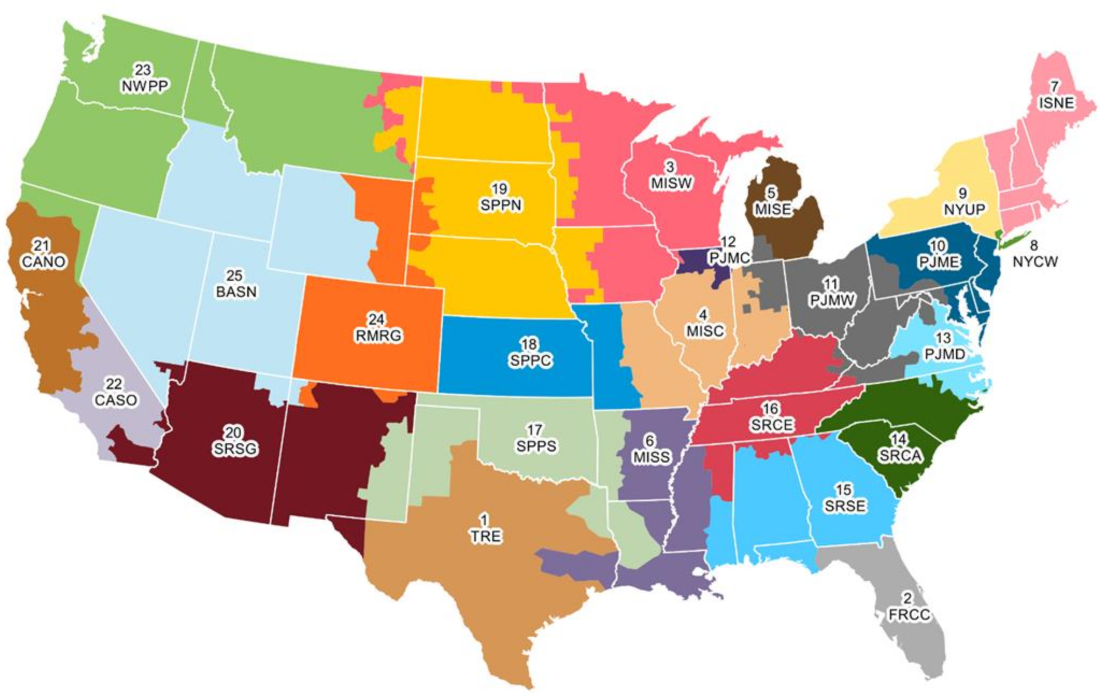
The Electricity Market Module (EMM) in the National Energy Modeling System (NEMS) is made up of four primary submodules: electricity load and demand, electricity capacity planning, electricity fuel dispatching, and electricity finance and pricing, as well as the ReStore Submodule, which interfaces with both the renewable and electricity modules The EMM also includes nonutility capacity and generation as well as electricity transmission and trade. Our publication, *The Electricity Market Module of the National Energy Modeling System: Model Documentation 2025, DOE/EIA-M068* (*2025*), describes the EMM further.

Based on fuel prices and electricity demands that other NEMS modules provide, the EMM determines the most economical way to supply electricity within environmental and operational constraints. Each EMM submodule includes assumptions about the operations of the electric power sector and the costs of various options. This document describes the model parameters and assumptions used in the EMM and discusses legislation and regulations that we incorporate in the EMM.

EMM regions

We use 25 electricity supply regions to represent U.S. power markets. The regions follow North American Electric Reliability Corporation (NERC) assessment region boundaries and independent system operator (ISO) and regional transmission organization (RTO) region boundaries (as of early 2019). Subregions are based on regional pricing zones (Figure 1 and Table 1).

Figure 1. Electricity Market Module regions



Data source: U.S. Energy Information Administration

Table 1. National Energy Modeling System's Electricity Market Module regions

Number	Abbreviation	NERC/ISO[a] subregion name	Geographic name[b]
1	TRE	Texas Reliability Entity	Texas
2	FRCC	Florida Reliability Coordinating Council	Florida
3	MISW	Midcontinent ISO/West	Upper Mississippi Valley
4	MISC	Midcontinent ISO/Central	Middle Mississippi Valley
5	MISE	Midcontinent ISO/East	Michigan
6	MISS	Midcontinent ISO/South	Mississippi Delta
7	ISNE	Northeast Power Coordinating Council/ New England	New England
8	NYCW	Northeast Power Coordinating Council/ New York City & Long Island	Metropolitan New York
9	NYUP	Northeast Power Coordinating Council/Upstate New York	Upstate New York
10	PJME	PJM/East	Mid-Atlantic
11	PJMW	PJM/West	Ohio Valley
12	PJMC	PJM/Commonwealth Edison	Metropolitan Chicago
13	PJMD	PJM/Dominion	Virginia
14	SRCA	SERC Reliability Corporation/East	Carolinas
15	SRSE	SERC Reliability Corporation/Southeast	Southeast
16	SRCE	SERC Reliability Corporation/Central	Tennessee Valley
17	SPPS	Southwest Power Pool/South	Southern Great Plains
18	SPPC	Southwest Power Pool/Central	Central Great Plains
19	SPPN	Southwest Power Pool/North	Northern Great Plains
20	SRSG	Western Electricity Coordinating Council/Southwest	Southwest
21	CANO	Western Electricity Coordinating Council/California North	Northern California
22	CASO	Western Electricity Coordinating Council/California South	Southern California
23	NWPP	Western Electricity Coordinating Council/Northwest Power Pool	Northwest
24	RMRG	Western Electricity Coordinating Council/Rockies	Rockies
25	BASN	Western Electricity Coordinating Council/Basin	Great Basin

Data source: U.S. Energy Information Administration

[a] NERC=North American Electric Reliability Corporation; ISO=independent system operator.

[b] Names are intended to describe approximate locations. Exact regional boundaries do not necessarily correspond to state borders or to other regional naming conventions.

Model parameters and assumptions

Generating capacity types

The EMM considers many capacity types for electricity generation (Table 2).

Table 2. Generating capacity types represented in the Electricity Market Module

Capacity type
Existing coal steam plants[a]
Ultra-supercritical coal (USC)[b]
USC with 30% carbon capture and sequestration (CCS)
USC with 95% CCS
Oil or natural gas steam—oil or natural gas steam turbine
Combined-cycle (CC)—single-shaft (1x1x1)[c] configuration
Combined-cycle—multi-shaft (2x2x1)[d] configuration
Combined-cycle with CCS—single-shaft configuration with 95% CCS
Combustion turbine (CT)—aeroderivative
CT—industrial frame
Fuel cell—solid oxide
Hydrogen turbine[e]
Conventional nuclear
Advanced nuclear—advanced light water reactor
Advanced nuclear–small modular reactor
Generic distributed generation—base load
Generic distributed generation—peak load
Conventional hydropower—hydraulic turbine
Pumped storage—hydraulic turbine reversible
Battery storage—four-hour lithium-ion battery
Geothermal
Municipal solid waste (MSW)—landfill gas-fired internal combustion engine
Biomass—fluidized bed
Solar thermal[f]
Solar photovoltaic (PV) with single-axis tracking
Solar PV with battery storage[g]
Wind
Wind offshore

Data source: U.S. Energy Information Administration

[a] The Electricity Market Module represents 32 types of existing coal steam plants based on the different possible configurations of nitrogen oxide, particulate, and sulfur dioxide emission control devices as well as options for controlling mercury and carbon (Table 9).

[b] AEO2025 assumes new coal plants without CCS cannot be built because of emission standards for new plants. These technologies exist in the modeling framework, but they are assumed to be unavailable to be built in the projections.

[c] Single-shaft (1x1x1) configuration with one H-class combustion turbine, one heat recovery steam generator, and one steam turbine generator.

[d] Multi-shaft (2x2x1) configuration with two H-class combustion turbines, two heat recovery steam generators, and one steam turbine generator.

[e] Hydrogen turbine modeled after an industrial frame CT, as modified to burn 100% hydrogen.

[f] Existing solar thermal plants are represented in the module but are not assumed as a new technology option.

[g] Includes 150 megawatts (MW) of PV and 50 MW of four-hour battery storage coupled through a direct current bus and connected to the grid through a 150-MW inverter.

New electric-generating plant characteristics

The inputs to the Electricity Capacity Planning Submodule are the cost and performance characteristics of new generating technologies (Table 3). In addition to these characteristics, we use fuel prices from the NEMS fuel supply modules and expectations for future fuel prices to compare options when new capacity is needed. We assume heat rates for new fossil-fueled technologies remain constant throughout the projection period.

We base initial cost inputs for new technologies on cost estimates developed by a 2024 report prepared by Sargent & Lundy, adjusted for learning cost adjustments for any capacity added since 2023 (Table 3).[1] This report uses a consistent estimation methodology across all technologies to develop cost and performance characteristics for technologies that we consider in the EMM. We do not use the costs that the consultant developed for geothermal and hydro plants; instead we use previously developed site-specific costs. We also do not update costs for distributed generation plants in the electric power sector for this report, and input assumptions remain the same as in previous *Annual Energy Outlook* (AEO) reports.

Except as noted below, the overnight costs represent the estimated cost of building a plant before adjusting for regional cost factors (Table 3). Overnight costs exclude interest expenses during plant construction and development. The base overnight costs include project contingencies to account for undefined project scope, pricing uncertainty, and owners' cost components. Technologies with limited commercial experience may include a technological optimism factor to account for the tendency during technology research and development to underestimate the full engineering and development costs for new technologies. A cost-adjustment factor, based on the producer price index for metals and metal products, allows the overnight capital costs in the future to drop if this index decreases or to rise if it increases. The base year for this commodity cost index is consistent with the base year of the cost estimates, so the initial cost estimate for AEO2025 also reflects changes in the commodity index between 2023 and 2024.

All technologies demonstrate some degree of variability in cost, based on project size, location, and access to key infrastructure (such as grid interconnections, fuel supply, and transportation). For onshore wind and solar PV, in particular, the cost favorability of the lowest-cost regions compounds the underlying variability in regional cost and creates a significant differential between the unadjusted costs, the average regional costs, and the capacity-weighted average national costs as observed from recent market experience. To reflect this difference, we report the weighted-average cost for both onshore wind and solar PV based on the regional cost factors assumed for these technologies in AEO2025 and the actual regional distribution of wind and solar builds that occurred in 2023 (Table 3).

Table 4 lists the overnight capital costs for each technology and EMM region for the resources or technologies that are available to be built in each region (Figure 1). The regional costs reflect the impact of locality adjustments, including one to address ambient air conditions for technologies that include a combustion turbine and one to adjust for additional costs associated with accessing remote wind resources. Temperature, humidity, and air pressure can affect the available capacity of a combustion turbine, and our modeling addresses this possibility through an additional cost multiplier by region. Unlike most other generation technologies where fuel can be transported to the plant, wind generators are located in areas with the best wind resources. Sites that are located near existing transmission with access to a road network or are otherwise located on lower development-cost lands are generally built up first, after which additional costs may be incurred to access sites with less favorable characteristics. We represent this trend through a multiplier applied to the wind plant capital costs that increases as the best sites in a given region are developed.

Table 3. Cost and performance characteristics of new central station electricity generating technologies

Technology	First available year[a]	Size (MW)	Lead time (years)	Base overnight cost[b] (2024$/ kW)	Techno-logical optimism factor[c]	Total overnight cost[d,e] (2024$/kW)	Variable O&M[f] (2024$/ MWh)	Fixed O&M (2024$/ kWy)	Heat rate[g] (Btu/kWh)
USC with 30% carbon capture and sequestration (CCS)	2029	650	5	$5,085	1.03	$5,212	$8.43	$48.34	9,751
USC with 95% CCS	2029	650	5	$6,989	1.05	$7,339	$13.94	$88.04	12,293
Combined-cycle—single-shaft	2027	627	3	$875	1.00	$875	$3.39	$15.75	6,226
Combined-cycle—multi-shaft	2027	1,227	3	$824	1.00	$824	$3.46	$12.31	6,226
Combined-cycle with 95% CCS	2028	543	4	$2,245	1.10	$2,469	$5.13	$25.17	7,239
Combustion turbine—aeroderivative[h]	2026	211	2	$1,522	1.00	$1,522	$5.79	$9.70	9,447
Combustion turbine—industrial frame	2026	419	2	$791	1.00	$791	$4.05	$6.97	9,142
Fuel cells	2027	10	3	$7,447	1.06	$7,896	$0.70	$36.67	6,469
Hydrogen turbine	2026	237	2	$823	1.00	$823	$5.36	$8.34	8,295
Nuclear—light water reactor	2030	2,156	6	$7,449	1.05	$7,821	$2.54	$158.61	10,452
Nuclear—small modular reactor	2030	480	6	$8,467	1.10	$9,314	$3.23	$123.88	10,452
Distributed generation—base	2027	2	3	$1,743	1.00	$1,743	$10.25	$23.06	8,900
Distributed generation—peak	2026	1	2	$2,093	1.00	$2,093	$10.25	$23.06	9,880
Battery storage[i]	2025	150	1	$1,580	1.00	$1,580	$0.00	$40.62	NA
Biomass	2029	50	5	$4,571	1.00	$4,571	$5.75	$149.74	13,300
Biomass with 95% CCS	2029	50	5	$11,991	1.08	$12,890	$9.80	$265.21	19,965
Geothermal[i, j]	2028	50	4	$3,097	1.00	$3,097	$0.00	$162.94	3,412
Conventional hydropower[i,j]	2028	100	4	$3,090	1.00	$3,090	$1.66	$49.79	3,412
Wind[e]	2027	200	3	$1,626	1.00	$1,626	$0.00	$33.55	3,412
Wind offshore[i]	2028	900	4	$3,506	1.00	$3,506	$0.00	$156.37	3,412
Solar photovoltaic (PV) with tracking[e,k]	2026	150	2	$1,379	1.00	$1,379	$0.00	$22.91	3,412
Solar PV with storage [k]	2026	150	2	$1,990	1.00	$1,990	$0.00	$39.84	3,412

Data source: Sargent & Lundy, *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, January 2024; Hydroelectric: Oak Ridge National Lab, *An Assessment of Energy Potential at Non-Powered Dams in the United States*, 2012, and Idaho National Engineering and Environmental Laboratory, *Estimation of Economic Parameters of U.S. Hydropower Resources*, 2003; Geothermal: National Renewable Energy Laboratory, Updated U.S. Geothermal Supply Curve, 2010

Note: MW=megawatt; kW=kilowatt; MWh=megawatthour; kWy=kilowattyear; kWh=kilowatthour; Btu=British thermal unit

[a] The first year that a new unit could become operational.

[b] Base cost includes project contingency costs.

[c] We apply the technological optimism factor to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[d] Overnight capital cost includes contingency factors and excludes regional multipliers (except as noted for wind and solar PV) and learning effects. Interest charges are also excluded. The capital costs represent current costs for plants that would come online in 2025.

[e] Total overnight cost for wind and solar PV technologies in the table are the average total cost across all 25 electricity market regions, as weighted by the respective capacity of that type installed during 2023 in each region to account for the substantial regional variation in wind and solar costs (Table 4). The input value used for onshore wind in AEO2025 is $1,403/kW, and for solar PV with tracking, it is $1,379/kW, which represents the cost of building a plant excluding regional factors. Region-specific factors contributing to the substantial regional variation in cost include differences in typical project size across regions, accessibility of resources, and variation in labor and other construction costs throughout the country.

[f] O&M=operations and maintenance

[g] The nuclear average heat rate is the weighted average tested heat rate for nuclear units as reported on the Form EIA-860, *Annual Electric Generator Report*. No heat rate is reported for battery storage because it is not a primary conversion technology; conversion losses are accounted for when the electricity is first generated, and electricity-to-storage losses of 15% are accounted for through the additional demand for electricity required to meet load. For hydropower, wind, solar, and geothermal technologies, the heat content of electricity (3,412 Btu/kWh) is used to calculate primary energy consumption from the generation of these resources.
[h] Combustion turbine aeroderivative units can be built by the module before 2026, if necessary, to meet a region's reserve margin.
[i] Capital costs are shown before investment tax credits are applied.
[j] Because geothermal and hydropower cost and performance characteristics are specific for each site, the table entries show the cost of the least expensive plant that could be built in the Northwest region for hydro and the Great Basin region for geothermal, where most of the proposed sites are located.
[k] Costs and capacities are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

Table 4. Total overnight capital costs of new electricity generating technologies by region

2024 dollars per kilowatt

Technology	1 TRE	2 FRCC	3 MISW	4 MISC	5 MISE	6 MISS	7 ISNE	8 NYCW	9 NYUP	10 PJME	11 PJMW	12 PJMC	13 PJMD
USC with 30% CCS	$4,886	$5,015	$5,415	$5,561	$5,605	$5,081	$5,980	NA	$5,860	$6,018	$5,211	$6,490	$5,602
USC with 95% CCS	$6,625	$6,919	$7,770	$7,876	$7,802	$7,235	$8,376	NA	$7,923	$8,424	$7,301	$9,936	$7,479
CC—single-shaft	$789	$811	$904	$892	$906	$835	$962	$1,219	$927	$963	$850	$1,067	$884
CC—multi-shaft	$743	$764	$851	$844	$854	$789	$910	$1,154	$874	$909	$801	$1,008	$834
CC with 95% CCS	$2,190	$2,266	$2,574	$2,535	$2,579	$2,340	$2,758	$4,962	$2,643	$2,775	$2,395	$3,136	$2,501
CT—aeroderivative	$1,377	$1,402	$1,582	$1,553	$1,579	$1,455	$1,669	$1,971	$1,615	$1,643	$1,488	$1,786	$1,534
CT—industrial frame	$706	$723	$828	$812	$827	$752	$879	$1,083	$847	$869	$773	$962	$799
Fuel cells	$7,577	$7,695	$8,046	$8,393	$8,234	$7,909	$8,541	$10,056	$8,195	$8,468	$7,801	$9,133	$8,042
Hydrogen turbine	$734	$752	$862	$845	$861	$783	$915	$1,128	$882	$905	$804	$1,002	$832
Nuclear—light water reactor	$7,452	$7,632	$7,906	$8,500	$8,071	$8,172	$8,684	NA	$8,124	$8,431	$7,764	$9,278	$7,926
Nuclear—small modular reactor	$8,874	$9,065	$9,530	$9,791	$9,604	$9,401	$10,057	NA	$9,654	$9,987	$9,271	$10,960	$9,393
Distributed generation—base	$1,572	$1,616	$1,801	$1,778	$1,804	$1,663	$1,916	$2,428	$1,846	$1,919	$1,693	$2,125	$1,761
Distributed generation—peak	$1,894	$1,929	$2,176	$2,137	$2,173	$2,002	$2,296	$2,711	$2,222	$2,260	$2,048	$2,457	$2,111
Battery storage	$1,558	$1,571	$1,578	$1,651	$1,594	$1,631	$1,655	$1,764	$1,610	$1,625	$1,572	$1,689	$1,598
Biomass	$4,241	$4,356	$4,716	$4,873	$4,883	$4,420	$5,426	$7,365	$5,443	$5,539	$4,657	$5,627	$5,308
Biomass with 95% CCS	$11,664	$12,124	$13,517	$13,651	$13,551	$12,561	$14,319	$19,600	$13,766	$14,680	$12,738	$16,644	$13,206
Geothermal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Conventional hydropower	$4,508	$5,507	$2,191	$1,456	$2,965	$4,387	$2,030	NA	$4,154	$4,314	$3,760	NA	$3,817
Wind	$1,460	NA	$1,582	$1,636	$1,592	$1,416	$2,061	NA	$2,285	$2,340	$1,526	$1,860	$2,845
Wind offshore	$3,331	$3,832	$3,679	NA	$3,607	NA	$3,847	$4,616	$3,678	$3,798	$3,453	$4,174	$3,567
Solar PV with tracking	$1,326	$1,347	$1,409	$1,412	$1,411	$1,368	$1,448	$1,693	$1,418	$1,457	$1,374	$1,563	$1,386
Solar PV with storage	$1,925	$1,953	$2,019	$2,049	$2,029	$1,996	$2,090	$2,386	$2,038	$2,089	$1,982	$2,220	$2,001

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Technology	14 SRCA	15 SRSE	16 SRCE	17 SPPS	18 SPPC	19 SPPN	20 SRSG	21 CANO	22 CASO	23 NWPP	24 RMRG	25 BASN	Average
USC with 30% CCS	$5,039	$5,060	$5,175	$5,249	$5,346	$5,113	$5,334	NA	NA	$5,606	$5,277	$5,476	$5,427
USC with 95% CCS	$7,129	$7,167	$7,363	$6,952	$7,558	$7,270	$7,574	NA	NA	$8,108	$7,239	$7,834	$7,630
CC—single-shaft	$815	$822	$846	$808	$857	$815	$766	$1,031	$1,008	$905	$705	$808	$888
CC—multi-shaft	$770	$775	$800	$761	$807	$767	$723	$978	$955	$855	$663	$764	$838
CC with 95% CCS	$2,278	$2,306	$2,380	$2,261	$2,425	$2,295	$2,166	$3,017	$2,935	$2,588	$1,984	$2,294	$2,583
CT—aeroderivative	$1,433	$1,434	$1,482	$1,415	$1,488	$1,439	$1,315	$1,713	$1,682	$1,571	$1,247	$1,399	$1,531
CT— industrial frame	$740	$742	$768	$730	$775	$747	$685	$919	$899	$826	$647	$731	$803
Fuel cells	$7,906	$7,801	$7,983	$7,896	$8,061	$7,807	$7,916	$9,070	$8,965	$8,290	$7,764	$8,270	$8,233
Hydrogen turbine	$770	$772	$800	$760	$807	$777	$712	$956	$935	$860	$673	$761	$836
Nuclear—light water reactor	$8,148	$7,859	$8,177	$7,574	$7,939	$7,665	$8,084	NA	NA	$8,499	$7,661	$8,426	$8,090
Nuclear—small modular reactor	$9,349	$9,255	$9,456	$9,058	$9,451	$9,227	$9,501	NA	NA	$9,884	$9,202	$9,747	$9,533
Distributed generation—base	$1,623	$1,637	$1,686	$1,610	$1,707	$1,624	$1,527	$2,055	$2,008	$1,803	$1,404	$1,609	$1,769
Distributed generation—peak	$1,972	$1,973	$2,038	$1,947	$2,047	$1,980	$1,809	$2,356	$2,314	$2,162	$1,715	$1,924	$2,106
Battery storage	$1,631	$1,591	$1,625	$1,562	$1,589	$1,561	$1,599	$1,710	$1,714	$1,642	$1,561	$1,642	$1,621
Biomass	$4,396	$4,407	$4,500	$4,557	$4,688	$4,505	$4,825	$6,181	$6,041	$4,989	$4,780	$4,779	$5,020
Biomass with 95% CCS	$12,353	$12,453	$12,774	$12,212	$13,223	$12,765	$13,056	$16,218	$15,852	$14,042	$12,661	$13,504	$13,725
Geothermal	NA	NA	NA	NA	NA	NA	$3,156	$3,131	$2,534	$3,063	NA	$3,097	$2,996
Conventional hydropower	$2,125	$4,609	$2,382	$4,560	$1,922	$1,806	$3,663	$3,875	$3,731	$3,090	$3,689	$4,032	$3,416
Wind	$1,754	$1,738	$1,775	$1,359	$1,561	$1,519	$1,557	$3,241	NA	$2,042	$1,377	$1,623	$1,825
Wind offshore	$3,547	NA	NA	NA	NA	NA	NA	$4,176	$4,147	$3,873	NA	NA	$3,822
Solar PV with tracking	$1,361	$1,364	$1,378	$1,350	$1,391	$1,370	$1,390	$1,541	$1,517	$1,435	$1,368	$1,413	$1,420
Solar PV with storage	$1,988	$1,978	$2,005	$1,952	$2,005	$1,973	$2,011	$2,211	$2,181	$2,071	$1,972	$2,047	$2,047

Data source: U.S. Energy Information Administration, Office of Long-Term Energy Modeling

Notes: Costs include contingency factors, regional cost multipliers, and ambient condition multipliers. Interest charges are excluded. The costs are shown before investment tax credits are applied.

NA=not available; plant type cannot be built in the region because of a lack of resources, sites, or specific state legislation.

USC=ultra-supercritical; CCS=carbon capture and sequestration; CC=combined cycle; CT=combustion turbine; PV=photovoltaic

Electricity Market Module region map

New construction financing

The Electricity Capacity Planning Submodule of the EMM assumes that new power plants are built in a competitive environment and that different generating technologies generally have the same financing options available. We describe a few exceptions in this section. The EMM assumes projects are financed by both debt and equity, and it uses the after-tax weighted average capital cost as the discount rate when calculating the discounted cash flow analysis for building and operating new plants.

In the EMM, the corporate tax rate is set at 21%, and all new construction is immediately expensed through a one-year depreciation schedule. The EMM phases out this temporary change to depreciation schedules by 2027, based on the Tax Cuts and Jobs Act of 2017. This phase out affects both retail price calculations and costs of financing new generation, transmission, and distribution builds.

In the EMM, the assumed debt fraction for new builds is 60%, with a corresponding 40% equity fraction. The EMM bases the cost of debt on the Industrial Baa bond rate, passed to the EMM as an annual projection from the Macroeconomic Module. The cost of debt in AEO2025 averages 5.4% for capacity builds from 2024 through 2050. The cost of equity is calculated using the Capital Asset Pricing Model (CAPM), which assumes the return is equal to a risk-free rate plus a risk premium that is specific to the industry (described in more detail in the EMM documentation). The average cost of equity in AEO2025 is 10.5%, and the resulting discount rate with a 60/40 debt/equity split is 6.7% from 2024 through 2050.

The AEO2025 Reference case includes a three-percentage-point adder to the cost of capital (both equity and debt) when evaluating investments in new coal-fired power plants without full carbon capture and sequestration (CCS) and in new natural gas-fired combined-cycle (NGCC) plants. We also apply the adder to pollution control retrofits to reflect financial risks associated with major investments in long-lived power plants with a relatively higher rate of CO_2 emissions. Coal technology that captures 30% of CO_2 emissions is still considered a high emitter relative to other new sources and may continue to face potential financial risk if carbon emission rules are further expanded. The only coal technology that does not receive the three-percentage-point increase in cost of capital is the technology designed to capture 95% of CO_2 emissions. AEO2025 extends the adder to NGCC plants as more state and federal incentives are put in place to encourage low- or zero-carbon emitting technologies, making building new natural gas-fired plants subject to increased risk of changing policies that could shorten their effective cost recovery period. The adder is not applied to simple-cycle combustion turbine plants because those plant types are most often built for reserve capacity and do not contribute as much to emissions.

Technological optimism and learning

We calculate overnight costs for each technology as a function of regional construction parameters, project contingencies, technological optimism, and learning factors.

The technological optimism factor represents the demonstrated tendency to underestimate actual costs for a first-of-a-kind, unproven technology. As experience is gained, the technological optimism factor is gradually reduced to 1.0.

NEMS determines the learning function at a component level. It breaks each new technology into major components: revolutionary, evolutionary, or mature. We assume each component has different learning rates, based on the experience with the design component (Table 5). If technologies use similar components, these components learn at the same rate that these units are built. For example, we assume the underlying turbine generators are basically the same for a combustion turbine, combined-cycle, and integrated coal-gasification combined-cycle unit. Therefore, construction of any of these technologies would contribute to learning cost reductions for the turbine component.

Table 5. Learning parameters for new generating technology components

Technology component	Period 1 learning rate (LR1)	Period 2 learning rate (LR2)	Period 3 learning rate (LR3)	Period 1 doublings	Period 2 doublings	Annual minimum learning
Pulverized coal	—	10%	1%	—	5	0.38%
Hydrogen	20%	10%	1%	3	5	0.77%
Combustion turbine—natural gas	—	10%	1%	—	5	0.38%
Heat recovery steam generator (HRSG)	—	—	1%	—	—	0.19%
Gasifier	—	10%	1%	—	5	0.38%
Carbon capture and sequestration	20%	10%	1%	3	5	0.77%
Balance of plant—turbine	—	—	1%	—	—	0.19%
Balance of plant—combined cycle	—	—	1%	—	—	0.19%
Fuel cell	20%	10%	1%	3	5	0.77%
Advanced nuclear	5%	3%	1%	3	5	0.77%
Biomass	—	10%	1%	—	5	0.38%
Distributed generation—base	—	5%	1%	—	5	0.38%
Distributed generation—peak	—	5%	1%	—	5	0.38%
Geothermal	—	8%	1%	—	5	0.38%
Hydropower	—	—	1%	—	—	0.77%
Battery storage	20%	10%	1%	1	5	0.19%
Wind	—	—	1%	—	—	0.77%
Wind offshore	20%	10%	1%	3	5	0.77%
Solar photovoltaic (PV)—module	20%	10%	1%	1	5	0.38%
Balance of plant—solar PV	—	10%	1%	—	5	0.38%

Data source: U.S. Energy Information Administration, Office of Long-Term Energy Modeling

Note: The text describes the methodology for learning in the Electricity Market Module. If a column does not contain a value, the learning period has already passed for that technology.

The learning function, OC, has the following nonlinear form:

$$OC(C) = a*C^{-b},$$

where C is the cumulative capacity for the technology component.

The progress ratio (pr) is defined by speed of learning (that is, how much costs decline for every doubling of capacity). The reduction in capital cost for every doubling of cumulative capacity (learning rate, or LR) is an exogenous parameter input for each component (Table 5). The progress ratio and learning rate are related by the following:

$$pr = 2^{-b} = (1 - LR).$$

The parameter *b* is calculated from the second equality above (that is, $b = -(\ln(1\text{-}LR)/\ln(2))$). The parameter *a* is computed from the following initial conditions:

$$a = OC(C_0)/C_0^{-b},$$

where

C_0 = the initial cumulative capacity.

Once the LR and the cumulative capacity (C_0) are known for each interval, we can compute the parameters (*a* and *b*). We developed three learning steps to reflect different stages of learning as a new design is introduced into the market. New designs with significant untested technology will have high rates of learning initially, and more conventional designs will not have as much learning potential. If the calculated factor is less than the annual minimum learning assumption, then we apply the minimum learning to reflect developments due to ongoing research and development.

Once we calculate the learning rates by component, we calculate a weighted-average learning factor for each technology. We base the weights on the share of the initial cost estimate that is attributable to each component (Table 6). For technologies that do not share components, we calculate this weighted-average learning rate exogenously and input it as a single component. These technologies may still have a mix of revolutionary components and more mature components, but we do not need to include this detail in the module unless capacity from multiple technologies would contribute to component learning.

Table 6. Component cost weights for new technologies

Technology	Pulverized coal	Hydrogen	Combustion turbine	HRSG	Carbon capture and sequestration	Balance of plant—turbine	Balance of plant—combined cycle
USC with 30% CCS	90%	0%	0%	0%	10%	0%	0%
USC with 95% CCS	80%	0%	0%	0%	20%	0%	0%
Combined-cycle—single-shaft	0%	0%	25%	10%	0%	0%	65%
Combined-cycle—multi-shaft	0%	0%	25%	10%	0%	0%	65%
Combined-cycle with 95% CCS	0%	0%	15%	5%	40%	0%	40%
Combustion turbine—aeroderivative	0%	0%	50%	0%	0%	50%	0%
Combustion turbine—industrial frame	0%	0%	50%	0%	0%	50%	0%
Hydrogen turbine	0%	5%	48%	0%	0%	48%	0%

Data source: U.S. Energy Information Administration, Office of Long-Term Energy Modeling
Note: HRSG=heat recovery steam generator; CCS=carbon capture and sequestration

In the case of solar PV technology, we assume the module component accounts for 38% of the cost, and we assume the balance of system components account for the remaining 62%. Because the amount of end-use PV capacity (existing and projected) is significant relative to total solar PV capacity and the technology of the module component is common across the end-use and electric power sectors, calculating the learning factor for the PV module component also takes into account capacity built in the residential and commercial sectors. The PV with battery storage cost is split between the battery component (26%), the PV module (29%), and the PV balance of system (45%). For the offshore wind technology, we assume that offshore-specific components make up 50% of the cost, and the remaining 50% overlaps with the onshore wind technology.

Table 7 shows the capacity credit toward component learning for the various technologies. For all combined-cycle technologies, we assume the turbine unit contributes two-thirds of the capacity, and the heat recovery steam generator (HRSG) contributes the remaining one-third. Therefore, building one gigawatt (GW) of natural gas or oil combined-cycle capacity would contribute 0.67 GW toward turbine learning and 0.33 GW toward HRSG learning. Components that do not contribute to the capacity of the plant, such as the balance of plant category, receive 100% capacity credit for any capacity built with that component. For example, when calculating capacity for the balance of plant component for the combined-cycle technology, we would count all combined-cycle capacity as 100%, both single-shaft and multi-shaft.

Table 7. Component capacity weights for new technologies

Technology	Pulverized coal	Hydrogen	Combustion turbine	HRSG	Carbon capture and sequestration	Balance of plant—turbine	Balance of plant—combined cycle
USC with 30% CCS	100%	0%	0%	0%	100%	0%	0%
USC with 90% CCS	100%	0%	0%	0%	100%	0%	0%
Combined-cycle—single-shaft	0%	0%	67%	33%	0%	0%	100%
Combined-cycle—multi-shaft	0%	0%	67%	33%	0%	0%	100%
Combined-cycle with 90% CCS	0%	0%	67%	33%	100%	0%	100%
Combustion turbine—aeroderivative	0%	0%	100%	0%	0%	100%	0%
Combustion turbine—industrial frame	0%	0%	100%	0%	0%	100%	0%
Hydrogen turbine	0%	100%	100%	0%	0%	100%	0%

Data source: U.S. Energy Information Administration, Office of Long-Term Energy Modeling
Note: HRSG=heat recovery steam generator; CCS=carbon capture and sequestration

International learning

The learning algorithm incorporates international capacity for onshore wind, offshore wind, battery storage, and solar PV technologies because of significant overlap in the market for major plant components. Existing international capacity that is consistent with technology characteristics used in U.S. markets counts toward the base capacity amount. Assumed future additions are added to EMM projections of new U.S. capacity additions, which contributes to future doubling of capacity and associated learning cost reduction. The international projections for new capacity come from the *International Energy Outlook 2023* projections for countries outside of the United States. We apply a weighting factor to reduce the international capacity projections to reflect components of the project cost that may not apply to U.S. markets, such as country-specific labor or installation costs.

Distributed generation

We model distributed generation in the end-use sectors (as described in the relevant AEO2025 assumptions documents) and in the EMM. This section describes how distributed generation is represented in the EMM only. We model two generic distributed technologies. The first technology represents peaking capacity (capacity that has relatively high operating costs and is operated when demand is at its highest). The second generic technology for distributed generation represents base-load capacity (capacity that is operated on a continuous basis under a variety of demand levels). Costs and performance characteristics are listed in Table 3. We assume these plants reduce the cost of transmission upgrades that would otherwise be needed.

Demand storage

Although not modeled in AEO2025, the EMM includes a demand storage technology that could simulate load shifting through programs such as smart meters. The demand storage technology would be modeled as a new technology capacity addition but with operating characteristics similar to pumped storage. The technology can decrease the load during peak periods, but it must generate replacement electricity at other times. The EMM uses an input factor to identify the replacement generation needed, where a factor of less than 1.0 can represent peak shaving rather than purely shifting the load to other times. The EMM no longer projects builds of this technology type because we added a more detailed modeling of battery storage (as described in the Intermittent and storage modeling section). This storage technology also reduces and shifts peak demand use.

Coal-to-gas conversion

The EMM includes existing coal plants that were converted to burn natural gas, based on the current configuration and primary fuel use of the plants, as reported to EIA. In recent years, a number of companies have retrofitted their coal plants to operate as single-cycle, natural gas steam plants to reduce emissions from the plant or to take advantage of low natural gas prices. The EMM also includes the option to convert additional coal plants to natural gas-fired steam plants, if economical. For AEO2025, the EMM also reflects both existing capacity and retrofit options that represent coal plants that are now co-firing with significant levels of coal and natural gas. These plants are listed as fossil steam plants in the AEO2025 reports but may use both coal and natural gas fuels.

We base the modeling structure for coal-to-natural gas conversions on the U.S. Environmental Protection Agency's (EPA) modeling for the 2023 Reference case.[2] For this modeling, coal-to-natural gas conversion means an existing boiler is modified to burn natural gas. Coal-to-natural gas conversion, in this instance, is not the same as adding a natural gas turbine, replacing a coal boiler with a new natural gas combined-cycle plant, or gasifying coal for a combustion turbine. The cost for retrofitting has two components: boiler modification costs and the cost to extend natural gas lateral pipeline spurs from the boiler to a natural gas main pipeline. The same retrofit costs are assumed for either conversion to 100% natural gas or conversion to co-fire with coal and natural gas.

Allowing natural gas firing in a coal boiler typically means installing new natural gas burners, modifying the boiler, and potentially modifying the environmental equipment. EPA's engineers developed the cost estimates based on discussions with industry engineers. These estimates were designed to apply across the existing coal fleet. In the EMM, costs are estimated for eligible coal plants that EPA identified, which excludes units of less than 25 megawatts (MW) and units with fluidized-bed combustion or stoker boilers. The EMM does not include any capacity penalty for converting to natural gas, but it assumes a 5% heat rate penalty to reflect reduced efficiency as a result of lower stack temperature and the corresponding higher moisture loss when natural gas is combusted instead of coal. The EMM assumes that converted plants have 33% lower fixed operations and maintenance (O&M) costs because these plants need fewer operators, maintenance materials, and maintenance staff. Variable O&M costs are 25% lower because of lower waste disposal and other costs. The incremental capital cost (in 2022 dollars per kilowatt [kW]) is described by these functions:

For pulverized-coal-fired boilers:

$$\text{Cost per kW} = 484.75 * (75 / CAP)^{0.35}$$

For cyclone boilers:

$$\text{Cost per kW} = 346.25 * (75 / CAP)^{0.35}$$

where

CAP = the capacity of the unit in megawatts.

To get unit-specific costs, we use EPA's assumptions for natural gas pipeline requirements, which are based on a detailed assessment of every coal boiler in the United States, to determine natural gas volumes needed, distance to the closest pipeline, and size of the lateral pipeline required. The resulting cost per kilowatt of boiler capacity varies widely; an average cost is $214/kW (in 2024 dollars).

Representing electricity demand

The annual electricity demand projections from the NEMS demand modules are converted into load-duration curves for each of the EMM regions by using historical hourly load data. We updated the system load shapes by EMM region for AEO2025 using data from 2018 to 2022 reported on the Form EIA-930[3] and normalized for weather by developing a regression model using temperature, wind speed, relative humidity, and parameters related to the time of day, using 30 years of weather data. The projected load shapes in the module can change over time by applying end-use specific shapes to incremental demand growth relative to an initial base year. End-use load shapes for the residential and commercial end uses were updated using the National Renewable Energy Lab (NREL) RESTOCK[4] and COMSTOCK[5] databases, and the building types and end-use equipment were aligned with the categories modeled by the NEMS building modules. The transportation demand module represents multiple types of electric vehicles (EVs) and determines where the charging for light-duty vehicles will occur (residential or commercial sites). We used several sources to develop load shapes for the different modes of EV charging, but primarily NREL.[6] When modeling sector demand and prices in the EMM, the EV charging demands are allocated to the site where the charging occurs, either residential or commercial, rather than as a transportation sector demand.

For both types of load shapes described above, the inputs are developed to reflect a 24-hour profile for each of three typical day-types—weekday, weekend, and a single peak day per month—and each month of the year. These profiles are then aggregated into the load-duration curve for the EMM, which has nine time periods. First, we split the load data into three seasons: winter (December through March), summer (June through September), and the shoulder seasons (October through November and April through May). Within each season, the load data are sorted from high to low, and three load segments are created: a peak segment representing the top 1% of the load and then two off-peak segments representing the next 49% and 50%, respectively. We define these seasons to account for seasonal variation in supply availability.

Our Residential Demand Module and Commercial Demand Module provide end-use consumption to the EMM, including demand from the grid and from onsite generation. The majority of the onsite generation is supplied by behind-the-meter PV generation (in other words, rooftop PV generation), and the end-use modules only provide an annual amount. The EMM dispatches both electric power sector and end-use PV capacity using detailed solar resource profiles to more accurately reflect when the generation occurs. For non-PV onsite generation, the EMM assumes the onsite end-use generation has a uniform capacity factor throughout the year. In the residential and commercial reporting, the end-use consumption reflects the total electricity consumed by end use, whether provided from generation onsite or purchased from the grid. However, the reported electricity sales by sector only reflect the demand from the grid, and the onsite generation is reported as direct use.

Intermittent and storage modeling

The EMM includes the ReStore Submodule to provide the detail needed to represent renewable availability at a greater level than the nine time periods described in the previous section. We developed this submodule to adequately model the value of four-hour battery storage technology, which can be used to balance renewable generation in periods of high intermittent output but low demand. The ReStore Submodule solves a set of linear programming sub-problems within the EMM to provide the capacity planning and dispatch submodules with information on the value of battery storage and the level of variable renewable energy curtailments. The sub-problems solve a set of 576 representative hours for the year, and the results are aggregated back to the nine time periods the EMM uses. The ReStore Submodule’s additional time granularity better represents hydroelectric dispatch, determines wind and solar generation and any required curtailments, and determines the optimal use of any battery storage capacity. Because it includes hourly level dispatch, the ReStore Submodule represents the costs or constraints to ramping conventional technologies up and down to respond to fluctuations in intermittent generation. It also provides the planning module with information on the value of storage to determine future builds.

Capacity and operating reserves

Reserve margins (the percentage of capacity above peak demand that is needed to adequately maintain reliability during unforeseeable outages) are established for each region by its governing body: public utility commission, NERC region, ISO, or RTO. Because of uncertainty and differences in how these entities measure peak demand and account for capacity accreditation for renewable and battery technologies relative to how they are measured in our modules, we do not use reported reserve margins directly. We calculated the implied reserve margin for 2024 from the model output to reflect the achieved levels and assumed those would be maintained, ranging from 1% to 19%. We used the reference reserve margins reported to NERC as a maximum value if our calculated values were higher.[7] The reserves required are based on the assumed percentage multiplied by peak demand. We calculate the total capacity required as the average of the net peak load hours (net of variable renewable generation) plus reserves. Dispatchable technologies contribute to the reserve margin constraint fully, but intermittent and storage technologies have a capacity credit that we calculate based on their availability during the net peak load hours.

In addition to the planning reserve margin requirement, system operators typically require a specific level of operating reserves (in other words, generators available within a short amount of time to meet demand in case a generator goes down or another supply disruption occurs). These reserves can be provided by plants that are operating at less than full capacity (spinning reserves) or by capacity not operating but can be brought online quickly (non-spinning reserves). This assumption is particularly important as more intermittent generators are added to the grid because technologies such as wind and solar have unpredictable availability. The capacity and dispatch submodules of the EMM include explicit constraints requiring spinning reserves in each load time period. We compute the amount of spinning reserves required as a percentage of the load height for the time period plus a percentage of the distance between the load for the time period and the seasonal peak. An additional calculated requirement is a percentage of the intermittent capacity available in that period to reflect the greater uncertainty associated with the availability of intermittent resources. All technologies (except intermittent plant types and distributed generation) can be used to meet spinning reserves. We developed different operating modes for each technology type to allow the module to choose between operating a plant to maximize generation or contributing to spinning reserves or a combination of the two. Minimum generation levels are required if a plant is contributing to spinning reserves, and these minimums vary by plant type. Plant types typically associated with baseload operation have higher minimums than those that can operate more flexibly to meet intermediate or peak demand. We assume that battery storage capacity can provide spinning reserves when there is remaining charge not projected to be discharged in a given hour by the ReStore Submodule and when there is remaining discharge capacity.

Variable heat rates for coal-fired power plants

Low natural gas prices and rising shares of intermittent generation have shifted coal plant operations from baseload to greater levels of cycling. The efficiency of coal plants can vary based on their output, and a plant's efficiency can decrease when it runs in a cycling mode or provides operating reserves. The EMM models variable heat rates for coal plants based on the operating mode the EMM chooses to better reflect actual fuel consumption and costs.

We constructed the relationship between operating levels and efficiencies from data available for 2013 through 2015 in the EPA's continuous emission monitoring system (CEMS) and other EMM plant data. We used a statistical analysis to estimate piecewise linear equations that reflect the efficiency as a function of the generating unit's output. We estimated the equations by coal plant type, taking into account the configuration of existing environmental controls, and by geographic coal demand region, based on plant-level data. We developed equations for up to 10 coal plant configurations across the 16 coal regions used in the EMM. The form of the piecewise linear equations for each plant type and region combination can vary, and they have between 3 and 11 steps.

Within the EMM, these equations calculate heat-rate adjustment factors to normalize the average heat rate in the input plant database (which is based on historical data and is associated with a historical output level) and to adjust the heat rate under different operating modes. The EMM allows six different modes within each season for coal plants. These modes are based on combinations of maximizing generation, maximizing spinning reserves, or load following, and they can be invoked for the full season (all three time periods) or for about half the season (only peak and intermediate time periods). Each of these modes is associated with different output levels, and we calculate the heat-rate adjustment factor based on the capacity factor implied by the operating mode.

Endogenous plant retirement modeling

Fossil fuel-fired steam plant retirements and nuclear and wind retirements are determined endogenously within the module. We assume generating units retire when continuing to run them is no longer economical. Each year, the module determines whether the market price of electricity is high enough to support the continued operation of existing plant generators. We project that a generating unit will retire if the expected revenues from the generator are not enough to cover the annual going-forward costs and if building replacement capacity will not lower the overall cost of producing electricity. Going-forward costs include fuel, O&M costs, and annual capital expenditures (CAPEX), which are unit-specific and based on historical data. The average annual capital additions for existing plants are $13/kW for oil and natural gas steam plants and $59/kW for nuclear plants (in 2024 dollars). We add these costs to the estimated costs at existing plants regardless of their ages. Beyond 50 years old, the retirement decision includes an additional $22/kW capital charge for nuclear plants to reflect additional costs associated with the impacts of aging. Age-related cost increases are attributed to capital expenditures for major repairs or retrofits, subsequent license renewals and regulatory compliance costs, and increases in maintenance costs to reduce the effects of aging. For wind plants, an additional aging cost of $4/kW is added beyond 30 years, rising to $9/kW beyond 40 years. These annual cost adders reflect cost recovery of major capital expenditures to replace major component parts to continue operating.

In 2018, we commissioned Sargent and Lundy (S&L) to analyze historical fossil fuel O&M costs and CAPEX and to recommend updates to the EMM.[8] The study focused particularly on whether age is a cost factor over time. S&L found that for most technologies, age is not a significant variable that influences annual costs, and in particular, capital expenditures seem to be incurred steadily over time rather than as a step increase at a certain age. Therefore, we do not model step increases in O&M costs for fossil fuel technologies. For coal plants, the report developed a regression equation for capital expenditures for coal plants based on age and whether the plant had installed a flue gas desulfurization (FGD) unit. We incorporated the following equation in NEMS to assign capital expenditures for coal plants over time:

CAPEX (2017 dollars per kilowattyear) = 16.53 + (0.126 × age in years) + (5.68 × FGD)

where

FGD = 1 if a plant has an FGD; zero otherwise.

For the remaining fossil fuel technologies, the module assumes no aging function. Instead, both O&M and CAPEX remain constant over time. We updated the O&M and CAPEX inputs for existing fossil fuel plants using the data set analyzed by S&L, and S&L's report describes them in more detail. We assigned costs for the EMM based on plant type and size category (three to four tiers per type), and we split plants within a size category into three cost groups to provide additional granularity for the module. We assigned plants that were not in the data sample (primarily those not reporting to the Federal Energy Regulatory Commission [FERC]) an input cost based on their size and the cost group that was most common in their regions.

The report found that most CAPEX spending for combined-cycle and combustion-turbine plants is associated with vendor-specified major maintenance events, generally based on factors such as the number of starts or total operating hours. S&L recommended that CAPEX for these plants be recovered as a variable cost, so we assume no separate CAPEX costs for combined-cycle or combustion-turbine plants, and we incorporate the CAPEX data into the variable O&M input cost.

We assume that all retirements reported as planned on the Form EIA-860, *Annual Electric Generator Report*, will occur in addition to some others that have been announced but are not yet reported to us. This assumption includes 2.2 GW of nuclear capacity retirements and 50.4 GW of coal capacity retirements after 2024.

For AEO2025, we updated existing nuclear unit operating costs based on an evaluation of aggregated plant data reported for the most recent five-year period available (2019−2023). We developed average plant costs for several categories:

- Design type (pressurized water reactor or boiling water reactor)
- Single- or multi-unit plant
- Regulated or deregulated ownership
- Region

We assigned individual plant costs by averaging the category averages based on each plant's characteristics. In general, we found that operating costs were lower for deregulated plants versus regulated plants and multi-unit plants had lower costs than single-unit plants. Cost variations based on design type or region were much smaller.

Biomass co-firing

We assume coal-fired power plants co-fire with biomass fuel if doing so is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. We assume this expenditure is $676/kW of biomass capacity. A coal-fired unit modified to allow co-firing can generate up to 15% of the total output using biomass fuel, assuming sufficient residue supplies are available.

Nuclear uprates

The AEO2025 nuclear power projection does not reflect any capacity increases at existing units. Nuclear plant operators can increase the rated capacity at plants through power uprates, which are license amendments that the U.S. Nuclear Regulatory Commission (NRC) must approve. Uprates can vary from small (for example, less than 2%) increases in capacity, which require very little capital investment, to extended uprates of 15% to 20%, which require significant plant modifications. No uprates were reported as planned modifications on the Form EIA-860, and the NRC reports no further uprate applications are under review or expected.[9]

Interregional electricity trade

The EMM represents both firm and economy electricity transactions among utilities in different regions. In general, firm electricity transactions involve trading capacity and energy to help another region satisfy its reserve margin requirement, and economy electricity transactions involve energy transactions motivated by the marginal generation costs of different regions. The existing capacity limits constrain the flow of power from region to region. We primarily derive the interregional capacity limits from transmission capacity inputs to the National Renewable Energy Laboratory's ReEDS (Regional Energy Deployment System) model. Additional sources include the Western Electricity Coordinating Council's (WECC) seasonal reliability assessments and the New York Independent System Operator's *Reliability Needs Assessments*. International capacity limits are derived from the Northeast Power Coordinating Council's (NPCC) and WECC's seasonal assessments, the Electricity Reliability Council of Texas's *DC Tie Operations Documents*, and Canadian Provincial Electricity websites. Known firm power contracts are compiled from FERC Form 1, *Annual Report of Major Electricity Utility*, and we also consult utility Integrated Resource Plan documents, individual ISO reports, and Canadian Provincial Electricity websites. The EMM includes an option to add interregional transmission capacity. In some cases, building generating capacity in a neighboring region may be more economical, but expanding the transmission grid may incur additional costs. Explicitly expanding the interregional transmission capacity may also make the transmission line available for additional economy trade.

We determine economy transactions in the dispatching submodule by comparing the marginal generating costs of adjacent regions in each time period. If one region has less expensive generating resources available in a given time period (adjusting for transmission losses and transmission capacity limits) than another region, we assume the regions exchange power.

International electricity trade

The EMM represents two components of international firm power trade: existing and planned transactions as well as unplanned transactions. We compile data on existing and planned transactions from FERC Form 1 and provincial reliability assessments. The EMM endogenously determines international electricity trade on an economic basis based on surplus energy that we expect to be available from Canada by region in each time period. We determine Canada's surplus energy using a mini-dispatching submodule that uses Canadian provincial plant data, load curves, demand forecasts, and fuel prices to determine the excess electricity supply by year, load slice, supply step, step cost, and Canadian province. The projected data on Canada come from the *International Energy Outlook 2023*.

Electricity pricing

We project electricity pricing for the 25 electricity market regions for fully competitive, partially competitive, and fully regulated supply regions. The price of electricity to the consumer includes generation, transmission, and distribution prices and applicable taxes.

In AEO2025, transmission and distribution remain regulated, so the price of transmission and distribution is based on the average cost to build, operate, and maintain these systems using a cost-of-service regulation model. We project continued capital investment in the transmission and distribution system as a function of changes in peak demand, based on historical trends. We add additional transmission capital investment with each new generating build to account for the costs to connect to the grid. We developed regression equations to project transmission and distribution operating and maintenance costs as a function of peak demand and overall customer sales. The total electricity price in the regulated regions consists of the average cost of generation, transmission, and distribution for each customer class.

In competitive regions, the generation price includes the marginal energy cost, taxes, and a capacity payment. The marginal energy cost is the cost of the last (or most expensive) unit dispatched, reflecting fuel and variable costs only. We calculate the capacity payment as a weighted average of the levelized costs for combustion turbines and the marginal value of capacity calculated within the EMM, which reflects the cost of maintaining the assumed reserve margin. We calculate the capacity payment for all competitive regions, and these payments should be viewed as a proxy for additional capital recovery that must be procured from customers rather than as representing a specific market. The capacity payment also includes the costs associated with meeting the spinning reserves requirement. The EMM calculates the total cost for both reserve margin and spinning reserve requirements in a given region and allocates them to the sectors, based on their contributions to overall peak demand.

The total electricity price in regions with a competitive generation market is the competitive cost of generation summed with the average costs of transmission and distribution. The price for mixed regions includes the load-weighted average of the competitive price and the regulated price, based on the percentage of electricity load in the region that is subject to deregulation.

The AEO2025 Reference case assumes full competitive pricing in the two New York regions and in the mid-Atlantic and Metropolitan Chicago regions, and it assumes 95% competitive pricing in New England (Vermont being the only fully regulated state in that region). Eleven regions fully regulate their electricity supply:

- Florida
- Carolinas
- Southeast
- Tennessee Valley
- Southern Great Plains
- Central Great Plains
- Northern Great Plains
- Upper Mississippi Valley
- Mississippi Delta
- Southwest
- Rockies

All other regions reflect a mix of both competitive and regulated prices.

Regulated price components allocate costs to the end-use sectors based on a variety of allocation methods. For example, fuel and variable costs are shared based on the sector's share of total demand, while capital and other fixed costs use allocation methods related to the sector's contribution to peak demand. Adding to peak demand typically requires more investment in new capacity, so more of the costs will go to the sectors contributing to peak demand. As described earlier, EV charging is now allocated to residential and commercial sectors, and the EV charging demand patterns are often based on overnight charging that does not coincide with typical peak demand periods. Therefore, increases in EV charging demand may affect sector prices differently and will depend on where the charging occurs as well as the charging profile assumed.

Fuel price expectations

We base capacity planning decisions in the EMM on a life-cycle cost analysis during a 30-year period, which requires foresight assumptions for fuel prices. We derive expected coal, natural gas, and oil prices using rational expectations, or perfect foresight. In this approach, we define expectations for future years by the realized solution values for these years in a previous model run. The expectations for the world crude oil price and natural gas wellhead price are set using the resulting prices from a previous model run. We calculate the markups to the delivered fuel prices based on the markups from the previous year within a NEMS run. We determine coal prices using the same coal supply curves developed in the NEMS Coal Market Module. The supply curves produce prices at different stages of coal production as a function of labor productivity, mine costs, and utilization. The EMM develops expectations for each supply curve based on the actual demand changes from the previous run throughout the projection period, resulting in updated mining utilization and different supply curves.

The perfect foresight approach generates an internally consistent scenario from which we can form expectations consistent with the projections realized in the model. The NEMS model involves iterative run cycles until the expected values and realized values for variables converge between cycles.

Nuclear fuel prices

We develop projected nuclear fuel prices offline and input them into the EMM because NEMS does not have an internal fuel supply module for uranium processing and nuclear fuel fabrication. We updated the nuclear fuel price projections for AEO2023 based on a logarithmic trend of reported nuclear plant fuel costs over the past 15 years.

Legislation and regulations

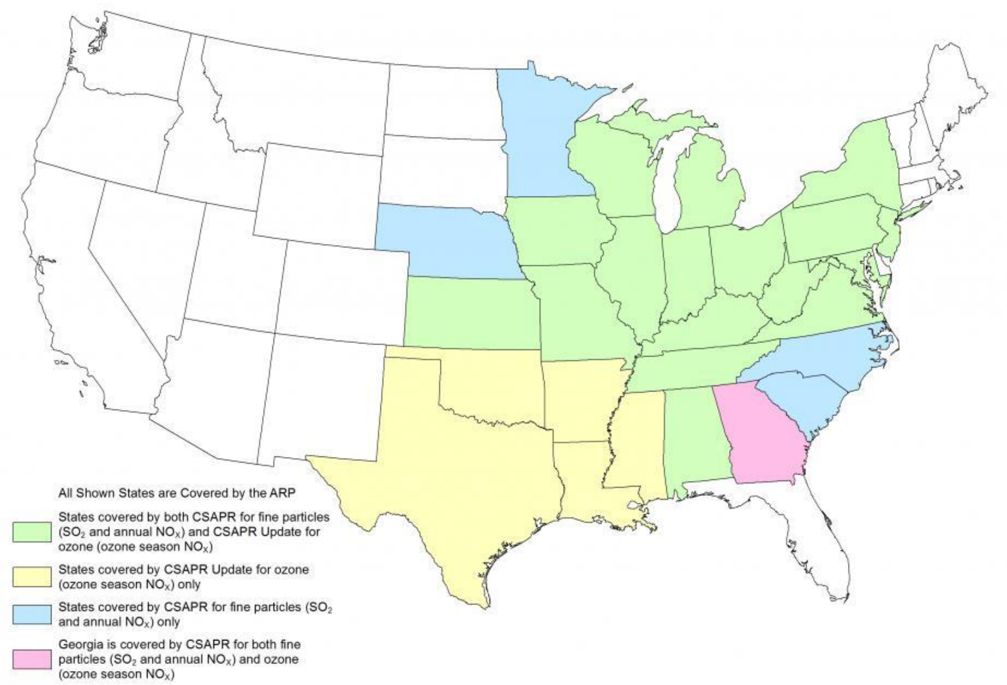
AEO2025 represents, to the extent possible within the NEMS model framework, current laws and regulations applicable to the electric power sector. Because of the time lags involved in model development and publication, laws and regulations in-force as of December 1, 2024, are included in the Reference case and other applicable cases of the AEO2025. Changes to laws and regulations resulting from executive action, judicial review, or the legislative subsequent to December 1, 2024, are not included in AEO2025 and will be included as possible in future AEO publications.

Cross-State Air Pollution Rule and Clean Air Act Amendments of 1990

AEO2025 continues to include the Cross-State Air Pollution Rule (CSAPR), which addresses the interstate transport of air emissions from power plants. Under CSAPR, 27 states must restrict emissions of sulfur dioxide (SO_2) and nitrogen oxide (NO_x), which are precursors to fine particulate matter (PM2.5) and ozone forming. CSAPR establishes four allowance-trading programs for SO_2 and NO_x composed of different member states, based on each state's contribution to downwind nonattainment of the National Ambient Air Quality Standards (Figure 2). In addition, CSAPR splits the allowance-trading program into two regions for SO_2, Group 1 and Group 2, and trading is permitted only between states within a group (estimated in NEMS by trade between coal demand regions) but not between groups. On March 15, 2021, EPA finalized an update to the CSAPR to require additional emissions reductions of NO_x from power plants in 12 states and to revise the budgets for their emissions from 2022 to 2024.

The AEO2025 does not reflect changes that would have been introduced through EPA's 2023 Good Neighbor Plan to further revise NO_x standards because the U.S. Supreme Court issued a stay on implementation. The requirements under CSAPR remain in place.

Figure 2. Cross-State Air Pollution Rule



Data source: U.S. Environmental Protection Agency, Clean Air Markets

In addition to interstate transport, the Clean Air Act Amendments of 1990 (CAAA1990) requires existing major stationary sources of NO_x located in nonattainment areas to install and operate NO_x controls that meet Reasonably Available Control Technology (RACT) standards. To implement this requirement, EPA developed a two-phase NO_x program that took effect for existing coal plants in 1996 and 2000. The EMM assumes all operating plants have made the necessary retrofits to comply with these standards and calculates plant emissions based on the reported environmental controls on each plant. All new fossil fuel units must meet current standards. These limits are 0.11 pounds per million British thermal units (MMBtu) for conventional coal, 0.02 pounds/MMBtu for advanced coal, 0.02 pounds/MMBtu for combined cycle, and 0.08 pounds/MMBtu for combustion turbines. The EMM incorporates these RACT NO_x limits.

Table 8 shows the average capital costs for environmental control equipment in NEMS for existing coal plants as retrofit options to remove SO_2, NO_x, mercury (Hg), and hydrogen chloride (HCl). In the EMM, we calculate plant-specific costs based on the size of the unit and other operating characteristics, and these numbers reflect the capacity-weighted averages of all plants in each size category. We assume FGD units remove 95% of the SO_2 and selective catalytic reduction (SCR) units remove 90% of the NO_x.

Table 8. Coal plant retrofit costs

2024 dollars per kilowatt

Coal plant size (megawatts)	FGD capital costs	FF capital costs	SCR capital costs
<100	$1,175	$333	$476
100–299	$822	$252	$350
300–499	$650	$214	$306
500–699	$593	$199	$291
>=700	$529	$182	$271

Data source: U.S. Energy Information Administration, Office of Long-Term Energy Modeling
Notes: FGD=flue gas desulfurization unit; FF=fabric filter; SCR=selective catalytic reduction unit

In April 2024, EPA finalized its Section 111 of the Clean Air Act (CAA) regulating CO_2 emissions from existing coal, oil, and natural gas-fired steam generating units and new natural gas-fired combustion turbines.[10] The ruling requires existing steam turbines at coal-fired power plants to either convert to a natural gas-fired steam unit or cofire with at least 40% natural gas by 2030 if the units are intended to operate until January 1, 2039, or they must be retrofitted with a carbon capture and sequestration (CCS) system with a 90% capture rate by 2032 if they are intended to operate beyond January 1, 2039; otherwise they must retire. AEO2025 represents these requirements for existing coal plants, allowing the model to make economic decisions regarding conversion fully to natural gas-fired operation, conversion to cofire with natural gas, or retrofit with a CCS system by the appropriate deadlines.

EPA also revised carbon pollution standards for new, modified, and reconstructed power plants under CAA Section 111(b). The emission rate for newly constructed coal steam units maintains the 2015 standard of 1,400 pounds of CO_2 per megawatthour, which requires at least partial sequestration. The EMM allows new coal technologies (ultra-supercritical technology) with either 30% or 95% removal rates to be built if economical. The 2024 rule also created different categories for compliance by new natural gas-fired technologies. Plants that intend to run as base load (greater than 40% capacity factor) must operate with 90% CO_2 capture by 2032, while plants operating at intermediate or low load levels have standards consistent with current efficient designs and use of low-emitting fuel. The AEO2025 represents this restriction in operation on any new natural gas-fired combined-cycle plants that are built without CCS. The EMM does not explicitly represent modified or reconstructed power plants, which are also covered by the rule.

Heat rate improvement retrofits

The EMM can evaluate heat rate improvements at existing coal-fired generators. A generator with a lower heat rate can generate the same amount of electricity while consuming less fuel, which reduces corresponding emissions of SO_2, NO_x, Hg, and CO_2. Improving heat rates at power plants can lower fuel costs and help them comply with environmental regulations. Heat rate improvement is a planning activity because it considers the tradeoff between the investment expenditures and the savings in fuel and environmental compliance costs. The amount of potential increase in efficiency can vary depending on the type of equipment installed at a unit and the beginning configuration of the plant. The EMM represents 32 configurations of existing coal-fired plants based on different combinations of particulate, SO_2, NO_x, Hg, and CO_2 emissions controls (Table 9). These categories form the basis for evaluating the potential for heat rate improvements.

We contracted with Leidos, Inc., to develop a methodology to evaluate the potential for heat rate improvement at existing coal-fired generating plants.[11] Leidos performed a statistical analysis of the heat rate characteristics of coal-fired generating units that we modeled in the EMM. Specifically, Leidos developed a predictive model for coal-fired electric generating unit heat rates as a function of various unit characteristics, and Leidos employed statistical modeling techniques to create the predictive models.

For the EMM plant types, Leidos categorized the coal-fired generating units into four equal groups, or quartiles, based on observed versus predicted heat rates. Units in the first quartile (Q1), which operated more efficiently than predicted, were generally associated with the least potential for heat rate improvement. Units in the fourth quartile (Q4), representing the least efficient units relative to predicted values, were generally associated with the highest potential for heat rate improvement. Leidos developed a matrix of heat rate improvement options and associated costs, based on a literature review and engineering judgment.

Little or no coal-fired capacity exists for the EMM plant types with mercury and carbon-control configurations; therefore, Leidos did not develop estimates for those plant types. These plant types were ultimately assigned the characteristics of the plant types with the same combinations of particulate, SO_2, and NO_x controls. Plant types with relatively few observations were combined with other plant types that had similar improvement profiles. As a result, Leidos developed nine unique plant type combinations for the quartile analysis, and for each of these combinations, Leidos created a maximum potential for heat rate improvement along with the associated costs to achieve those improved efficiencies.

Leidos used the minimum and maximum characteristics as a basis for developing estimates of midrange cost and heat rate improvement potential. The EMM used the midrange estimates as its default values (Table 10).

Table 9. Existing pulverized-coal plant types in the National Energy Modeling System's Electricity Market Module

Plant type	Particulate controls	SO_2 controls	NO_x controls	Mercury controls	Carbon controls
B1	BH	None	Any	None	None
B2	BH	None	Any	None	CCS
B3	BH	Wet	None	None	None
B4	BH	Wet	None	None	CCS
B5	BH	Wet	SCR	None	None
B6	BH	Wet	SCR	None	CCS
B7	BH	Dry	Any	None	None
B8	BH	Dry	Any	None	CCS
C1	CSE	None	Any	None	None
C2	CSE	None	Any	FF	None
C3	CSE	None	Any	FF	CCS
C4	CSE	Wet	None	None	None
C5	CSE	Wet	None	FF	None
C6	CSE	Wet	None	FF	CCS
C7	CSE	Wet	SCR	None	None
C8	CSE	Wet	SCR	FF	None
C9	CSE	Wet	SCR	FF	CCS
CX	CSE	Dry	Any	None	None
CY	CSE	Dry	Any	FF	None
CZ	CSE	Dry	SCR	FF	CCS
H1	HSE/Oth	None	Any	None	None
H2	HSE/Oth	None	Any	FF	None
H3	HSE/Oth	None	Any	FF	CCS
H4	HSE/Oth	Wet	None	None	None
H5	HSE/Oth	Wet	None	FF	None
H6	HSE/Oth	Wet	None	FF	CCS
H7	HSE/Oth	Wet	SCR	None	None
H8	HSE/Oth	Wet	SCR	FF	None
H9	HSE/Oth	Wet	SCR	FF	CCS
HA	HSE/Oth	Dry	Any	None	None
HB	HSE/Oth	Dry	Any	FF	None
HC	HSE/Oth	Dry	Any	FF	CCS

Data source: U.S. Energy Information Administration
Note: *Particulate controls*: BH=baghouse; CSE=cold-side electrostatic precipitator; HSE/Oth=hot-side electrostatic precipitator, other, or none. SO_2=sulfur dioxide; NO_x=nitrogen oxide. *SO_2 controls*: wet=wet scrubber; dry=dry scrubber. *NO_x controls*: SCR=selective catalytic reduction. *Mercury controls*: FF=fabric filter. *Carbon controls*: CCS=carbon capture and sequestration.

Table 10. Heat rate improvement (HRI) potential and cost (capital as well as fixed operations and maintenance) by plant type and quartile as used for input into the National Energy Modeling System

Plant type and quartile combination	Count of total units	Percentage HRI potential	Capital cost (million 2014 dollars per megawatt)	Average fixed operations and maintenance cost (2014 dollars per megawatt per year)
B1-Q1	32	(s)	$0.01	$200
B1-Q2	15	1%	$0.10	$2,000
B1-Q3	18	4%	$0.20	$4,000
B1-Q4	20	6%	$0.90	$20,000
B3-Q1	13	(s)	$0.01	$300
B3-Q2	24	1%	$0.05	$1,000
B3-Q3	16	6%	$0.20	$3,000
B3-Q4	15	9%	$0.60	$10,000
B5C7-Q1	16	(s)	(s)	$80
B5C7-Q2	42	1%	$0.03	$700
B5C7H7-Q3	84	7%	$0.10	$2,000
B5C7H7-Q4	59	10%	$0.20	$4,000
B7-Q1	27	(s)	(s)	$70
B7-Q2	25	1%	$0.04	$800
B7-Q3Q4	30	7%	$0.30	$5,000
C1H1-Q1	148	(s)	$0.01	$200
C1H1-Q2	117	1%	$0.10	$2,000
C1H1-Q3	72	4%	$0.40	$8,000
C1H1-Q4	110	7%	$1.00	$30,000
C4-Q1	15	(s)	(s)	$80
C4-Q2	27	1%	$0.04	$900
C4-Q3	32	6%	$0.20	$2,000
C4-Q4	39	10%	$0.30	$5,000
CX-Q1Q2Q3Q4	15	7%	$0.20	$4,000
H4-Q1Q2Q3	13	3%	$0.20	$3,000
IG-Q1	3	(s)	(s)	$60
Total set	**1,027**	**4%**	**$0.30**	**$6,000**

Data source: U.S. Energy Information Administration, based on data from Leidos, Inc.
Note: Leidos selected the plant type and quartile groupings so that each grouping contained at least 10 generating units, except for the integrated gasification combined-cycle (IG) type, which has essentially no heat rate improvement potential.
(s)=less than 0.05% for HRI potential or less than 0.005 million dollars per megawatt for capital cost.

Mercury regulation

The Mercury and Air Toxics Standards (MATS) were finalized in December 2011 to fulfill EPA's requirement to regulate mercury emissions from power plants. MATS also regulates other hazardous air pollutants (HAPS) such as hydrochloric acid (HCl) and fine particulate matter (PM2.5). MATS applies to coal- and oil-fired power plants with a nameplate capacity greater than 25 MW, and it required that all qualifying units achieve the maximum achievable control technology (MACT) for each of the three covered pollutants by 2016. We assume that all coal-fired generating units affected by the rule meet HCl and PM2.5 standards, which the EMM does not explicitly model.

All power plants must reduce their mercury emissions to 90% less than their uncontrolled emissions levels. When plants alter their configuration by adding equipment, such as an SCR to remove NO_x or an SO_2 scrubber, mercury removal is often a resulting co-benefit. The EMM considers all control combinations and can choose to add NO_x or SO_2 controls purely to lower mercury if it is economical to do so. Plants can also add activated carbon-injection systems specifically designed to remove mercury. Activated carbon can be injected in front of existing particulate-control devices, or a supplemental fabric filter can be added with activated carbon injection capability.

We assume the equipment to inject activated carbon in front of an existing particulate control device costs about \$8 (2024 dollars) per kilowatt of capacity.[12] We also calculate the costs of a supplemental fabric filter with activated carbon injection (often referred as a COPAC unit) by unit (Table 8). The amount of activated carbon required to meet a given percentage removal target is given by the following equations.[13]

For a unit with a cold-side electrostatic precipitator (CSE) that uses subbituminous coal and simple activated carbon injection, the following equation is used:

ACI = activated carbon injection rate in pounds per million actual cubic feet of flue gas

- Hg Removal (%) = 65 - (65.286 / (ACI + 1.026))

For a unit with a CSE that uses bituminous coal and simple activated carbon injection, we use:

- Hg Removal (%) = 100 - (469.379 / (ACI + 7.169))

For a unit with a CSE and a supplemental fabric filter with activated carbon injection, we use:

- Hg Removal (%) = 100 - (28.049 / (ACI + 0.428))

For a unit with a hot-side electrostatic precipitator (HSE) or other particulate control and a supplemental fabric filter with activated carbon injection, we use:

- Hg Removal (%) = 100 - (43.068 / (ACI + 0.421))

Power plant mercury emissions assumptions

The EMM represents 36 coal plant configurations and assigns a mercury emissions modification factor (EMF) to each configuration. Each configuration has different combinations of boiler types, particulate control devices, SO_2 control devices, NO_x control devices, and mercury control devices. An EMF is the amount of mercury in the fuel that remains after passing through all the plant's systems. For example, an EMF of 0.60 means that 40% of the mercury in the fuel is removed by various parts of the plant. Table 11 provides the assumed EMFs for existing coal plant configurations without mercury-specific controls.

Table 11. Mercury emission modification factors

SO_2 control	Configuration particulate control	NO_x control	EIA EMFs Bit coal	EIA EMFs Sub coal	EIA EMFs Lignite coal	EPA EMFs Bit coal	EPA EMFs Sub coal	EPA EMFs Lignite coal
None	BH	—	0.11	0.27	0.27	0.11	0.26	1.00
Wet	BH	None	0.05	0.27	0.27	0.03	0.27	1.00
Wet	BH	SCR	0.10	0.27	0.27	0.10	0.15	0.56
Dry	BH	—	0.05	0.75	0.75	0.50	0.75	1.00
None	CSE	—	0.64	0.97	0.97	0.64	0.97	1.00
Wet	CSE	None	0.34	0.73	0.73	0.34	0.84	0.56
Wet	CSE	SCR	0.10	0.73	0.73	0.10	0.34	0.56
Dry	CSE	—	0.64	0.65	0.65	0.64	0.65	1.00
None	HSE/Oth	—	0.90	0.94	0.94	0.90	0.94	1.00
Wet	HSE/Oth	None	0.58	0.80	0.80	0.58	0.80	1.00
Wet	HSE/Oth	SCR	0.42	0.76	0.76	0.10	0.75	1.00
Dry	HSE/Oth	—	0.60	0.85	0.85	0.60	0.85	1.00

Data source: U.S. Environmental Protection Agency emission modification factors (EPA EMFs). EIA EMFs not from EPA: Lignite EMFs, *Mercury Control Technologies for Coal-Fired Power Plants*, presented by the Office of Fossil Energy on July 8, 2003. Bituminous coal mercury removal for a Wet/HSE/Oth/SCR configured plant, Table EMF1, *Analysis of Mercury Control Cost and Performanc*e, Office of Fossil Energy & National Energy Technology, U.S. Department of Energy, January 2003, Washington, DC

Note: Under *SO_2 control*: SO_2=sulfur dioxide; wet=wet scrubber; dry=dry scrubber. Under *particulate control*: BH=fabric filter or baghouse; CSE=cold-side electrostatic precipitator; HSE/Oth=hot-side electrostatic precipitator, other, or none. Under *NO_x control*: NO_x=nitrogen oxide; SCR=selective catalytic reduction.

— =not applicable; Bit=bituminous coal; Sub=subbituminous coal. The NO_x control system is not assumed to enhance mercury removal unless a wet scrubber is present, so we left it blank (—) in such configurations.

Tax credit for carbon oxide sequestration

The Section 45Q sequestration tax credit was modified as part of the Inflation Reduction Act of 2022 (IRA).[14] The AEO2025 represents the sequestration tax credit and the captured carbon market in the Carbon Capture, Allocation, Transportation and Sequestration submodule. The 45Q credits are available to both power and industrial sources that capture and permanently sequester CO_2 in geologic storage or use CO_2 in enhanced oil recovery (EOR). Credits are available to plants that start construction or begin a retrofit after December 31, 2022, and before January 1, 2033. The tax credits are applied for the first 12 years of operation. The credit values vary depending on whether the CO_2 is used for EOR or is permanently sequestered. The IRA increased the credit values starting in 2023, relative to the previous versions of the credit, if qualified facilities meet the prevailing wage and apprenticeship requirements for the additional bonus credit (as assumed in the AEO2025 Reference case).

Carbon capture and sequestration retrofits

The EMM includes the option of retrofitting existing coal and natural gas-fired combined cycle plants with CCS. The modeling structure for CCS retrofits within the EMM was developed by the National Energy Technology Laboratory (NETL)[15] and uses a generic model of retrofit costs as a function of basic plant characteristics (such as heat rate). EIA updated retrofit costs for both types of plants using the public power generation CO_2 capture retrofit database models provided by NETL,[16] using plant-specific characteristics from EIA's power plant surveys. We assume the CCS retrofits remove 90% of the carbon input. Adding CCS equipment results in a capacity derate and a reduced efficiency of about 30% at the existing coal plant. The costs depend on the size and efficiency of the plant; capital costs average $2,377/kW for coal retrofits and $1,437/kW for natural gas retrofits. For coal plants, this analysis assumes that only plants greater than 500 MW and with heat rates lower than 12,000 Btu per kilowatthour (kWh) would be considered for CCS retrofits.

State air emissions regulations

AEO2025 continues to model the Northeast Regional Greenhouse Gas Initiative (RGGI), which applies to fossil fuel-powered plants larger than 25 MW in northeastern and certain mid-Atlantic states. After withdrawing in 2011, New Jersey adopted rules to rejoin the program in 2019.[17] In July 2020, Virginia passed legislation to join the program and was included beginning in 2021,[18] resulting in 11 states in the accord. The rule caps CO_2 emissions from covered electricity-generating facilities and requires that they account for each ton of CO_2 emitted with an allowance purchased at auction. EMM incorporates all subsequent updates to the original rule, which include amended caps, a specific cap through 2030, modifications to the Cost Containment Reserves (available if defined allowance-price triggers are exceeded), and an Emissions Containment Reserve (to be used if prices fall lower than established trigger prices). The cap reflects adjustments to the budget allocation as additional states join.

The California Senate Bill 32 (SB32), passed in October 2016, revises and extends the greenhouse gas (GHG) emission reductions that were previously in place to comply with Assembly Bill 32 (AB32), the Global Warming Solutions Act of 2006. AB32 implements a cap-and-trade program in which the electric power sector as well as industrial facilities and fuel providers must have met emission targets by 2020. SB32 requires the California Air Resources Board (CARB) to enact regulations to ensure the maximum technologically feasible and cost-effective GHG emission reductions occur, and it set a new state emission target of 40% lower than 1990 emission levels by 2030.

A companion law, Assembly Bill 197 (AB197), directs the CARB to consider social costs for any new programs to reduce emissions and makes direct emission reductions from stationary, mobile, and other sources a priority. The California Assembly Bill 398 (AB398), passed in July 2017, clarifies how the new targets will be achieved.

AEO2025 continues to assume that a cap-and-trade program remains in place, and it sets annual targets through 2030 that remain constant afterward. The emissions constraint is in the EMM but accounts for the emissions determined by other sectors. Within the electric power sector, emissions from plants owned by California utilities but located outside of the state, as well as emissions from electricity imports into California, count toward the emission cap. Estimates of these emissions are included in the EMM constraint. We calculate and add an allowance price to fuel prices for the affected sectors. We model a limited number of allowances for banking and borrowing as well as an allowance reserve and offsets, as specified in the bills. These provisions provide some compliance flexibility and cost containment. Changes in other modules to address SB32 and AB197, such as assumed policy changes that affect vehicle travel and increases in energy efficiency, are described in the Transportation Demand Module assumptions, Commercial Demand Module assumptions, Residential Demand Module assumptions, and the Summary of Legislation and Regulations on the *Assumptions to the Annual Energy Outlook 2025* web page.

State and federal revenue support for existing nuclear power plants

Three states have legislation to support prices for existing nuclear units that could be at risk of early closure because of declining profitability. The New York Clean Energy Standard,[19] established in 2016, created zero emission credits (ZEC) that apply to certain nuclear units. The Illinois Future Energy Jobs Act,[20] passed in 2017, also created a ZEC program covering a 10-year term. The Clinton and Quad Cities nuclear plants were selected to receive payments under the original ZEC program. In September 2021, the Illinois Climate and Equitable Jobs Act[21] was passed and includes carbon mitigation credits available to additional nuclear power plants, which led to the reversal of plans to shut down the Byron and Dresden plants. In 2018, the New Jersey Senate passed bill S. 2313,[22] which established a ZEC program that is funded by a $0.004/kWh annual charge that equals about $300 million per year. Three nuclear reactors are eligible to receive payments from the fund during the year of its implementation plus the three following years, and they may be considered for additional three-year renewal periods thereafter.

Although each program has different methods for calculating payments and eligibility, this legislation is modeled more generally in EMM by explicitly requiring nuclear units located in Illinois, upstate New York, and New Jersey to continue to operate through the specific program's period (the module cannot choose to endogenously retire the plant). We determine the cost of each program by comparing the affected plants' costs with the corresponding revenues based on the modeled marginal energy prices to evaluate plant profitability. If plant costs exceed revenues, the module applies a subsidy payment. The plant recovers the subsidy payment cost through retail prices as an adder to the electric distribution price component to represent ZEC purchases by load-serving entities.

In addition, a federal nuclear credit program was passed as part of the Infrastructure Investment and Jobs Act in August 2021.[23] The program aims to support nuclear power plants that are struggling to remain economically viable in competitive electricity markets and are at risk of shut down. The Secretary of Energy will determine specific unit eligibility and credit level under a $6 billion budget. The EMM models this program by expanding the state ZEC logic to all competitive states that are not already receiving state payments, but for these additional states, the costs are not passed through to electricity prices.

In Ohio, House Bill 128[24] repealed provisions of an earlier 2019 bill that provided financial support to nuclear plants. The bill maintained financial support for the coal-fired power plants owned and operated by the Ohio Valley Electric Corporation, which includes the 1,300-MW Clifty Creek Generating Station on the Ohio River in Jefferson County, Indiana, and the 1,086-MW Kyger Creek Generating Station on the Ohio River in Gallia County, Ohio. These plants are designated as must-run plants in the EMM until 2030 and are not candidates for economic retirement before then.

The Inflation Reduction Act of 2022 (IRA) introduces a zero-emission nuclear power production tax credit (PTC) for existing plants that were in service before the act was enacted. The credit value starts at 0.3 cents/kWh (2022 dollars), but this base value is reduced if a plant's average revenues exceed 2.5 cents/kWh (where revenues include any payments from programs listed previously). The tax credit can then be increased by a factor of five if facilities meet certain labor requirements. In the EMM, we calculate the value of this credit endogenously based on the modeled plant revenues received, and we assume all existing plants meet the labor requirements. The tax credit is available for electricity generated in 2024 through 2032.

Federal tax credits for new construction

The Energy Policy Act of 1992 (EPACT1992) originally implemented a permanent 10% investment tax credit (ITC) for geothermal and solar facilities and introduced a PTC for eligible renewable technologies (subsequently extended and expanded). The Energy Policy Act of 2005 (EPACT2005) provides a 20% ITC for integrated coal-gasification, combined-cycle capacity and a 15% ITC for other advanced coal technologies. These credits are limited to 3 GW in both cases. These credits have been fully allocated, and we do not assume they are available for new, unplanned capacity construction. EPACT2005 also contains a PTC of 1.8 cents/kWh (nominal) for new nuclear capacity beginning operation by 2020. This PTC applies to the first eight years of operation and is limited to $125 million annually and to 6 GW of new capacity. The Bipartisan Budget Act of 2018 revised the PTC eligibility to include plants online after 2020 and retained the 6 GW limit.

The ITCs and energy PTCs initiated in EPACT1992 and amended in EPACT2005 have been further amended through a series of acts that we have implemented in NEMS over time. The IRA also created ITCs and PTCs available to all clean electricity technologies, defined as those with a zero GHG emission rate. New advanced nuclear and small modular reactor facilities placed in service after December 31, 2024, are eligible to take either credit, both of which are adjusted for bonuses if certain conditions are met regarding employee wages, domestic content (which requires certain construction materials to be produced in the United States), and development in key communities. AEO2025 assumes that new nuclear facilities will opt to take the clean electricity PTC. This PTC starts with a base value of 0.3 cents/kWh in 1992 dollars that is adjusted for inflation each year based on IRS guidelines. For new nuclear plants, we assume that the wage and apprenticeship requirements are met to increase the base level by a factor of five and that the plants receive a 10% bonus for meeting the domestic content requirement.

New battery storage technologies are eligible for the clean electricity ITC, and AEO2025 assumes that the wage and apprenticeship requirements are met, resulting in a 30% ITC level. Federal tax credit assumptions for renewable technologies are discussed in detail in the Renewable Fuels Module (RFM) assumptions. The IRA tax credits are available to all eligible technologies until 2032, after which they phase out if an emissions reduction of 75% below 2022 levels from electric generation is reached. Plants that are under construction in the year the threshold is met will still receive 100% of the tax credit, but the value will fall to 75% in the next year and 50% in the following year. Plants under construction four or more years after the threshold is met will not receive tax credits. The EMM implements the phaseout schedule based on when the threshold is met and the applicable construction lead times of each technology. The determination of the phaseout is endogenous. The threshold is not met in the AEO2025 Reference case but is met in different years across several side cases.

Notes and Sources

[1] *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, Sargent & Lundy, January 2024.
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