Electricity Market Module

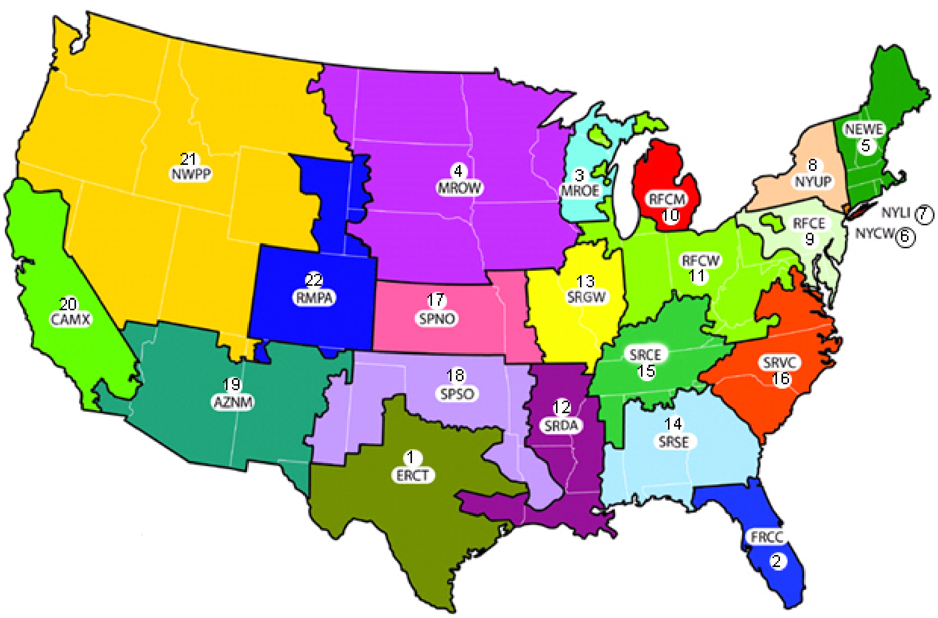
The Electricity Market Module (EMM) in the U.S. Energy Information Administration's (EIA) National Energy Modeling System (NEMS) is composed of four submodules: electricity load and demand, electricity capacity planning, electricity fuel dispatching, and electricity finance and pricing. The EMM also includes nonutility capacity and generation as well as electricity transmission and trade. A detailed description of the EMM is provided in the EIA publication, *The Electricity Market Module of the National Energy Modeling System: Model Documentation 2018, DOE/EIA-M068* (*2018*).

Based on fuel prices and electricity demands provided by the other modules of NEMS, 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 electricity sector and the costs of various options. This section describes the model parameters and assumptions used in the EMM and discusses legislation and regulations that are incorporated in the EMM.

EMM regions

The supply regions used in the EMM were developed for EIA's *Annual Energy Outlook 2011* (AEO2011). They correspond to the North American Electric Reliability Corporation (NERC) regions in place at that time, divided into subregions, as shown in Figure 1.

Figure 1. Electricity Market Module Regions



1 - ERCT	ERCOT All	12 - SRDA	SERC Delta
2 - FRCC	FRCC All	13 - SRGW	SERC Gateway
3 - MROE	MRO East	14 - SRSE	SERC Southeastern
4 - MROW	MRO West	15 - SRCE	SERC Central
5 - NEWE	NPCC New England	16 - SRVC	SERC VACAR
6 - NYCW	NPCC NYC/Westchester	17 - SPNO	SPP North
7 - NYLI	NPCC Long Island	18 - SPSO	SPP South
8 - NYUP	NPCC Upstate NY	19 - AZNM	WECC Southwest
9 - RFCE	RFC East	20 - CAMX	WECC California
10 - RFCM	RFC Michigan	21 - NWPP	WECC Northwest Power Pool
11 - RFCW	RFC West	22 - RMPA	WECC Rockies

Source: U.S. Energy Information Administration

Model parameters and assumptions

Generating capacity types

Capacity types represented in the EMM are shown in Table 1.

Table 1. Generating capacity types represented in the Electricity Market Module

Capacity type
Existing coal steam plants[1]
Ultra-supercritical coal (USC)[2]
Advanced coal—integrated coal gasification combined-cycle (IGCC)[2]
USC with 30% carbon capture and sequestration (CCS)
USC with 90% CCS
Oil/natural gas steam—oil/natural gas steam turbine
Combined cycle—conventional gas/oil combined-cycle combustion turbine
Advanced combined cycle—advanced gas/oil combined-cycle combustion turbine
Advanced combined cycle with CCS
Internal combustion engine
Combustion turbine—conventional combustion turbine
Advanced combustion turbine—steam injected gas turbine
Molten carbonate fuel cell
Conventional nuclear
Advanced nuclear—advanced light water reactor
Generic distributed generation—base load
Generic distributed generation—peak load
Conventional hydropower—hydraulic turbine
Pumped storage—hydraulic turbine reversible
Battery storage—four-hour battery
Geothermal
Municipal solid waste
Biomass—fluidized bed
Solar thermal—central tower
Solar photovoltaic (PV)—single-axis tracking
Solar PV—fixed-tilt
Wind
Wind offshore

[1] The EMM represents 32 types of existing coal steam plants, based on the different possible configurations of nitrogen oxide (NOx), particulate and sulfur dioxide (SO2) emission control devices, and options for controlling mercury and carbon (see Table 9).
[2] AEO2019 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 not assumed to be available to be built in the projections.
Source: U.S. Energy Information Administration

New generating plant characteristics

Inputs to the electricity capacity planning submodule are the cost and performance characteristics of new generating technologies (Table 2). In addition to these characteristics, fuel prices from the NEMS fuel supply modules and foresight on fuel prices are used to compare options when new capacity is needed. Heat rates for new fossil-fueled technologies are assumed to decline linearly through 2025.

For AEO2016, EIA hired a consultant to update current cost estimates for certain utility-scale electric generating plants [1]. This report used a consistent methodology, similar to the one used to develop the estimates for previous AEOs, but it accounted for more recent data and experience and also included alternative designs not previously considered. Updated costs were used for

- Coal plants with 30% carbon capture and sequestration (CCS)
- Combined-cycle (without CCS) technologies
- Combustion-turbine technologies
- Advanced nuclear
- Onshore wind
- Solar photovoltaic (PV)

After AEO2016 was completed, the consultant provided an addendum to the report [2] that included costs for several additional technologies. Subsequent AEOs incorporated *coal with 90% CCS technology* from this report. AEO2019 includes the internal combustion engine as a new technology option, based on the specifications in the 2016 consultant's report. Input costs for other technologies, other than advanced combined cycle, remain consistent with AEO2016 assumptions. Initial costs shown in Table 2 also reflect adjustments for learning cost reductions based on capacity built since the cost estimates were prepared. A cost-adjustment factor, based on the producer price index for metals and metal products, allows the overnight costs in the future to fall if this index drops or to rise if it increases.

Input costs for the advanced combined-cycle technology were reviewed and updated for AEO2019 based primarily on a study by the Brattle Group and Sargent and Lundy for the PJM Interconnection's cost for new entry analysis [3]. This study found that the costs for new combined-cycle plants have dropped significantly in recent years as a result of economies of scale for the larger combustion turbines that are used for the combined-cycle plant configuration. Costs of recent builds reported to EIA were also reviewed to develop an updated initial cost estimate that is about 29% lower than that used for AEO2018.

Except as noted below, the overnight costs shown in Table 2 represent the estimated cost of building a plant before adjusting for regional cost factors. Overnight costs exclude interest expenses during plant construction and development. 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.

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 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 and the capacity-weighted average national costs as observed from recent market experience. To correct for this difference, Table 2 shows a weighted-average cost for both wind and solar PV based on the regional cost factors assumed for these technologies in AEO2019 and the actual regional distribution of wind and solar builds that occurred in 2017.

Table 3 lists the overnight capital costs for each technology and EMM region (Figure 1) for the resources or technologies that are available to be built in the given region. The regional costs reflect the impact of locational 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 EIA's 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 must be 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. EIA represents 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 2. Cost and performance characteristics of new central station electricity generating technologies

Technology	First available year[1]	Size (MW)	Lead time (years)	Base overnight cost (2018 $/kW)	Project contingency factor[2]	Techno-logical optimism factor[3]	Total overnight cost[4,10] (2018 $/kW)	Variable O&M[5] (2018 $/MWh)	Fixed O&M (2018$/ kW/yr)	Heat rate[6] (Btu/ kWh)	Final heat rate (Btu/kWh)
Coal with 30% carbon sequestration (CCS)	2022	650	4	4,713	1.07	1.03	5,169	7.31	72.12	9,750	9,221
Coal with 90% CCS	2022	650	4	5,212	1.07	1.03	5,716	9.89	83.75	11,650	9,257
Conv gas/oil combined cycle (CC)	2021	702	3	952	1.05	1.00	999	3.61	11.33	6,600	6,350
Adv gas/oil CC	2021	1,100	3	736	1.08	1.00	794	2.06	10.30	6,300	6,200
Adv CC with CCS	2021	340	3	1,963	1.08	1.04	2,205	7.34	34.43	7,525	7,493
Internal combustion engine	2020	85	2	1,306	1.05	1.00	1,371	6.03	7.11	8,500	8,160
Conv combustion turbine[7]	2020	100	2	1,072	1.05	1.00	1,126	3.61	18.03	9,840	9,600
Adv combustion turbine	2020	237	2	658	1.05	1.00	691	11.02	7.01	9,800	8,550
Fuel cells	2021	10	3	6,250	1.05	1.10	7,197	46.56	0.00	9,500	6,960
Adv nuclear	2022	2,234	6	5,224	1.10	1.05	6,034	2.37	103.31	10,461	10,461
Distributed generation—base	2021	2	3	1,501	1.05	1.00	1,576	8.40	18.90	8,958	8,900
Distributed generation—peak	2020	1	2	1,804	1.05	1.00	1,894	8.40	18.90	9,948	9,880
Battery storage	2019	30	1	1,857	1.05	1.00	1,950	7.26	36.32	NA	NA
Biomass	2022	50	4	3,642	1.07	1.00	3,900	5.70	114.39	13,500	13,500
Geothermal[8,9]	2022	50	4	2,654	1.05	1.00	2,787	0.00	122.28	NA	NA
MSW—landfill gas	2021	50	3	8,313	1.07	1.00	8,895	9.47	425.38	18,000	18,000
Conventional hydropower[9]	2022	500	4	2,680	1.10	1.00	2,948	1.36	40.85	NA	NA
Wind[10]	2021	100	3	1,518	1.07	1.00	1,624	0.00	48.42	NA	NA
Wind offshore[8]	2022	400	4	4,758	1.10	1.25	6,542	0.00	80.14	NA	NA
Solar thermal[8]	2021	100	3	4,011	1.07	1.00	4,291	0.00	72.84	NA	NA
Solar PV— tracking[8,10,11]	2020	150	2	1,876	1.05	1.00	1,969	0.00	22.46	NA	NA
Solar PV—fixed tilt[8,10,11]	2020	150	2	1,698	1.05	1.00	1,783	0.00	22.46	NA	NA

[1] Represents the first year that a new unit could become operational.
[2] AACE International (the Association for the Advancement of Cost Engineering) has defined contingency as "…an amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs."
[3] The technological optimism factor is applied 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.
[4] 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 2019.
[5] O&M = operations and maintenance.
[6] 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; electricity-to-storage losses are accounted for through the additional demand for electricity required to meet load. For hydropower, wind, solar, and geothermal technologies, no heat rate is reported because the power is generated without fuel combustion and no set British thermal unit (Btu) conversion factors exist. The model calculates the average heat rate for fossil generation in each year for reporting primary energy consumption displaced for these resources.
[7] Conventional combustion turbine units can be built by the model before 2020, if necessary, to meet a region's reserve margin.
[8] Capital costs are shown before investment tax credits are applied.
[9] Because geothermal and hydropower cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.
[10] Wind and both solar PV technologies' total overnight costs shown in the table show the average input value across all 22 electricity market regions, as weighted by the respective capacity of that type installed during 2017 in each region, to account for the substantial regional variation in wind and solar costs (as shown in Table 3). The input value used for wind in AEO2019 was $1,920 per kilowatt (kW), for solar PV with tracking it was $2,160/kW, and for solar PV fixed tilt it was $2,024, representing 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.
[11] Costs and capacities are expressed in terms of net alternating current (AC) power available to the grid for the installed capacity.
MW = megawatt, kW = kilowatt, MWh = megawatthour, kWh = kilowatthour

Sources: Input costs other than Advanced Combined Cycle are consistent with those used in AEO2018, and they are primarily based on a report provided by external consultants. The base costs above reflect calculated learning cost reductions based on recent builds that occurred since the cost report was provided. The cost differential between the two PV technologies was based on Lawrence Berkeley National Lab's *Utility-Scale Solar Report*. Hydropower site costs for non-powered dams were updated for AEO2018 using data from Oak Ridge National Lab. Costs for advanced CC were updated for AEO2019 based on a PJM Interconnection *Cost of New Entry* report and EIA analysis of reported costs.

Table 3. Total overnight capital costs of new electricity generating technologies by region

$2018 per kilowatt

Technology	1 (ERCT)	2 (FRCC)	3 (MROE)	4 (MROW)	5 (NEWE)	6 (NYCW)	7 (NYLI)	8 (NYUP)	9 (RFCE)	10 (RFCM)	11 (RFCW)
Coal with 30% CCS	4,631	4,838	5,112	4,969	5,417	N/A	N/A	5,045	5,649	5,138	5,220
Coal with 90% CCS	5,121	5,350	5,636	5,493	5,959	N/A	N/A	5,579	6,207	5,681	5,756
Conv gas/oil CC	914	945	954	975	1,110	1,611	1,611	1,128	1,182	998	1,023
Adv gas/oil CC	761	777	754	785	882	1,209	1,209	896	932	788	821
Adv CC with CCS	2,058	2,135	2,144	2,121	2,258	3,217	3,217	2,270	2,412	2,161	2,220
Internal combustion engine	1,233	1,267	1,343	1,346	1,468	1,969	1,969	1,429	1,510	1,383	1,382
Conv combustion turbine	1,082	1,123	1,070	1,114	1,169	1,586	1,586	1,154	1,239	1,116	1,142
Adv combustion turbine	671	694	666	694	749	1,071	1,071	744	806	693	714
Fuel cells	6,744	6,909	7,233	7,016	7,262	8,723	8,723	7,161	7,392	7,190	7,176
Adv nuclear	5,787	5,871	6,077	5,947	6,288	N/A	N/A	6,384	6,451	6,028	6,149
Distributed generation—base	1,403	1,444	1,547	1,542	1,802	2,574	2,574	1,824	1,887	1,600	1,617
Distributed generation—peak	1,819	1,889	1,800	1,873	1,967	2,667	2,667	1,941	2,083	1,876	1,920
Battery storage	1,910	1,926	1,948	1,944	1,978	2,286	2,286	1,943	1,996	1,949	1,953
Biomass	3,595	3,697	3,974	3,774	4,017	4,785	4,785	4,032	4,153	3,880	3,939
Geothermal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
MSW—landfill gas	8,183	8,441	8,966	8,613	8,975	11,207	11,207	8,886	9,188	8,868	8,841
Conventional hydropower	NA	5,255	NA	1,723	1,937	NA	NA	3,963	4,116	NA	3,588
Wind	1,455	NA	2,413	1,483	2,554	NA	2,773	2,286	2,169	2,518	1,849
Wind offshore	5,973	6,542	6,581	6,613	6,712	8,380	8,380	6,483	6,712	6,509	6,581
Solar thermal	3,656	3,888	NA	NA	NA	NA	NA	NA	NA	NA	NA
Solar PV—tracking	2,173	1,759	2,069	1,876	2,419	3,212	2,058	1,946	2,283	2,986	1,977
Solar PV—fixed tilt	2,037	1,649	1,939	1,758	2,267	3,010	1,928	1,824	2,139	2,798	1,853

Technology	12 (SRDA)	13 (SRGW)	14 (SRSE)	15 (SRCE)	16 (SRVC)	17 (SPNO)	18 (SPSO)	19 (AZNM)	20 (CAMX)	21 (NWPP)	22 (RMPA)
Coal with 30% CCS	4,714	5,251	4,672	4,724	4,559	4,972	4,833	5,019	5,753	5,086	4,952
Coal with 90% CCS	5,219	5,802	5,167	5,224	5,036	5,493	5,344	5,544	6,327	5,613	5,459
Conv gas/oil CC	912	1,035	939	916	889	990	954	1,090	1,258	1,039	1,169
Adv gas/oil CC	759	830	780	774	745	805	788	941	1,014	864	971
Adv CC with CCS	2,075	2,282	2,090	2,045	2,001	2,194	2,129	2,495	2,575	2,281	2,477
Internal combustion engine	1,271	1,406	1,259	1,255	1,212	1,338	1,293	1,330	1,534	1,360	1,328
Conv combustion turbine	1,096	1,163	1,126	1,076	1,065	1,138	1,115	1,300	1,293	1,179	1,353
Adv combustion turbine	681	724	711	669	666	708	696	820	832	739	993
Fuel cells	6,809	7,320	6,780	6,823	6,708	7,046	6,924	7,097	7,521	7,118	6,895
Adv nuclear	5,823	6,125	5,805	5,835	5,769	5,962	5,889	5,992	N/A	6,052	6,034
Distributed generation—base	1,409	1,628	1,438	1,428	1,376	1,535	1,480	1,576	1,960	1,591	1,660
Distributed generation—peak	1,843	1,957	1,894	1,810	1,791	1,914	1,875	2,186	2,175	1,983	2,276
Battery storage	1,923	1,969	1,918	1,920	1,911	1,940	1,929	1,941	2,025	1,957	1,931
Biomass	3,627	3,966	3,607	3,642	3,560	3,794	3,728	3,900	4,196	3,907	3,650
Geothermal	NA	NA	NA	NA	NA	NA	NA	4,130	2,844	2,787	NA
MSW—landfill gas	8,299	9,064	8,228	8,299	8,103	8,672	8,468	8,735	9,384	8,735	8,423
Conventional hydropower	NA	NA	4,398	1,389	2,027	1,833	NA	3,495	3,560	2,948	3,520
Wind	2,256	1,653	2,256	2,256	2,082	1,413	1,450	2,654	2,243	1,687	1,539
Wind offshore	6,542	N/A	6,012	N/A	5,907	N/A	N/A	N/A	6,823	6,647	NA
Solar thermal	NA	NA	NA	NA	NA	NA	3,935	4,214	4,798	4,240	3,952
Solar PV—tracking	1,877	1,637	1,648	1,392	1,724	1,442	1,864	2,218	2,332	1,461	1,915
Solar PV—fixed tilt	1,759	1,534	1,545	1,305	1,616	1,351	1,747	2,078	2,185	1,369	1,795

Notes: Costs include contingency factors and regional cost and ambient conditions 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.
CCS = carbon capture and sequestration, CC = combined cycle, PV = photovoltaic, MSW = municipal solid waste

Electricity Market Module region map.

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis

New construction financing

The capacity planning module of the EMM assumes that new power plants are built in a competitive environment and that different generating technologies generally have the same financing assumptions, with a few exceptions described below. Projects are assumed to be financed by both debt and equity, and the after-tax weighted average cost of capital is used as the discount rate when calculating the discounted cash flow analysis for building and operating new plants.

AEO2019 considers the impacts of the Tax Cuts and Jobs Act of 2017. In the EMM, these factors are reflected by reducing the corporate tax rate to 21% and immediately expensing all new construction through a one-year depreciation schedule. The change to depreciation schedules is phased out by 2027. This phase-out affects both retail price calculations and costs of financing new generation, transmission, and distribution builds.

In the AEO2019, the assumed debt fraction for new builds is 60%, with a corresponding 40% equity fraction. Because plants that receive a tax credit—either production tax credit (PTC) or investment tax credit (ITC)—typically require a tax equity partner to take advantage of the credits, they will have a larger share of equity. Therefore, the EMM assumes that the debt fraction is lowered to 50% for technologies receiving a tax credit, but this fraction reverts to 60% as the tax credits are phased out. If tax credits were extended, the difference in the debt fraction would remain (as in the No PTC/ITC Sunset case run for an AEO2018 *Issues in Focus* article).

The cost of debt is based on the Industrial Baa bond rate, passed to the EMM as an annual projection from the Macroeconomic Module. The cost of debt in AEO2019 averages 5.8% for capacity builds from 2020 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 specific to the industry (described in more detail in the EMM documentation). The average cost of equity in AEO2019 is 10.8% and the resulting discount rate with a 60/40 debt/equity split is 7.0% from 2020 through 2050.

In the AEO2019 Reference case, there is a three-percentage-point adder to the cost of capital (both equity and debt) when evaluating investments in new coal-fired power plants and new coal-to-liquids (CTL) plants without full CCS. AEO2019 also assumes pollution control retrofits to reflect financial risks associated with major investments in long-lived power plants with a relatively higher rate of carbon dioxide (CO2) emissions. Although only coal-fired technologies with CCS are assumed available for new builds, the technology that captures 30% of CO2 emissions is still considered a high emitter relative to other new sources and may continue to face potential financial risk if carbon emission controls are further strengthened. Only the technology designed to capture 90% of CO2 emissions does not receive the three-percentage-point increase in cost of capital.

Technological optimism and learning

Overnight costs for each technology are calculated as a function of regional construction parameters, project contingency, and the 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, after building four units, the technological optimism factor is gradually reduced to 1.0.

The learning function in NEMS is determined at a component level. Each new technology is broken into its major components, and each component is identified as revolutionary, evolutionary, or mature. Different learning rates are assumed for each component, based on the level of experience with the design component (Table 4). Where technologies use similar components, these components learn at the same rate as these units are built. For example, the underlying turbine generator for a combustion turbine, combined-cycle, and integrated coal-gasification combined-cycle unit is assumed to be basically the same. Therefore, construction of any of these technologies would contribute to learning reductions for the turbine component.

Table 4. 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	Minimum total learning by 2035
Pulverized coal	—	—	1%	—	—	5%
Combustion turbine—conventional	—	—	1%	—	—	5%
Combustion turbine—advanced	—	10%	1%	—	5	10%
HRSG[1]	—	—	1%	—	—	5%
Gasifier	—	10%	1%	—	5	10%
Carbon capture/sequestration	20%	10%	1%	3	5	20%
Balance of plant—IGCC	—	—	1%	—	—	5%
Balance of plant—turbine	—	—	1%	—	—	5%
Balance of plant—combined cycle	—	—	1%	—	—	5%
Fuel cell	20%	10%	1%	3	5	20%
Advanced nuclear	5%	3%	1%	3	5	10%
Fuel prep—biomass	—	10%	1%	—	5	10%
Distributed generation—base	—	5%	1%	—	5	10%
Distributed generation—peak	—	5%	1%	—	5	10%
Geothermal	—	8%	1%	—	5	10%
Municipal solid waste	—	—	1%	—	—	5%
Hydropower	—	—	1%	—	—	5%
Battery storage	20%	10%	1%	1	5	20%
Wind	—	—	1%	—	—	5%
Wind offshore	20%	10%	1%	3	5	20%
Solar thermal	20%	10%	1%	3	5	10%
Solar PV—module	—	10%	1%	—	5	10%
Balance of plant—solar PV	—	14%	1%	—	5	10%

[1]HRSG = heat recovery steam generator

Note: See the text for a description of the methodology for learning in the Electricity Market Module. Where no value is shown for a column, that learning period has already passed for the technology.

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis

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 (i.e., how much costs decline for every doubling of capacity). The reduction in capital cost for every doubling of cumulative capacity (learning rate—LR) is an exogenous parameter input for each component (Table 4). The progress ratio and LR are related by the following:

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

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

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

where C_0 is the initial cumulative capacity. Once the rates of learning (LR) and the cumulative capacity (C_0) are known for each interval, the parameters (*a* and *b*) can be computed. Three learning steps were developed to reflect different stages of learning as a new design is introduced into the market. New designs with significant untested technology will see high rates of learning initially, while more conventional designs will not have as much learning potential. Costs of all design components are adjusted to reflect a minimal amount of learning, even if new capacity additions are not projected. This methodology represents cost reductions as a result of future international development or increased research and development.

Once the learning rates by component are calculated, a weighted-average learning factor is calculated for each technology. The weights are based on the share of the initial cost estimate that is attributable to each component (Table 5). For technologies that do not share components, this weighted-average learning rate is calculated exogenously and input as a single component.

Table 5. Component cost weights for new technologies

Technology	Pulverized coal	Combustion turbine—conventional	Combustion turbine—advanced	HRSG	Gasifier	Carbon capture/ sequestration	Balance of plant-turbine	Balance of plant-combined cycle	Fuel prep biomass
Coal with CCS	75%	0%	0%	0%	0%	25%	0%	0%	0%
Conv gas/oil CC	0%	30%	0%	40%	0%	0%	0%	30%	0%
Adv gas/oil CC	0%	0%	30%	40%	0%	0%	0%	30%	0%
Adv CC with CCS	0%	0%	20%	25%	0%	40%	0%	15%	0%
Internal combustion engine	0%	50%	0%	0%	0%	0%	50%	0%	0%
Conv combustion turbine	0%	50%	0%	0%	0%	0%	50%	0%	0%
Adv combustion turbine	0%	0%	50%	0%	0%	0%	50%	0%	0%
Biomass	50%	0%	0%	0%	0%	0%	0%	0%	50%

Note: All unlisted technologies have a 100% weight with the corresponding component. Components are not broken out for all technologies unless they overlap with other technologies.
HRSG = heat recovery steam generator, CCS = carbon capture and sequestration, CC = combined cycle
Source: Market-Based Advanced Coal Power Systems, May 1999, DOE/FE-0400

These technologies may still have a mix of revolutionary components and more mature components, but this detail is not necessary to include in the model unless capacity from multiple technologies would contribute to the component learning. In the case of the solar PV technology, the module component is assumed to account for 30% of the cost, and the balance of system components is assumed to account for the remaining 70%. 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, the calculation of the learning factor for the PV module component also takes into account capacity built in the residential and commercial sectors.

Table 6 shows the capacity credit toward component learning for the various technologies. For all combined-cycle technologies, the turbine unit was assumed to contribute two-thirds of the capacity, while the heat recovery steam generator (HRSG) contributed the remaining one-third. Therefore, building one gigawatt (GW) of natural gas/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—combined cycle* component, all combined-cycle capacity would be counted as 100%, both conventional and advanced.

Table 6. Component capacity weights for new technologies

Technology	Pulverized coal	Combustion turbine-conventional	Combustion turbine—advanced	HRSG	Gasifier	Carbon capture/ sequestrati on	Balance of plant-turbine	Balance of plant-combined cycle	Fuel prep biomass
Coal with CCS	100%	0%	0%	0%	0%	100%	0%	0%	0%
Conv gas/oil CC	0%	67%	0%	33%	0%	0%	0%	100%	0%
Adv gas/oil CC	0%	0%	67%	33%	0%	0%	0%	100%	0%
Adv CC with CCS	0%	0%	67%	33%	0%	100%	0%	100%	0%
Internal combustion engine	0%	100%	0%	0%	0%	0%	100%	0%	0%
Conv combustion turbine	0%	100%	0%	0%	0%	0%	100%	0%	0%
Adv combustion turbine	0%	0%	100%	0%	0%	0%	100%	0%	0%
Biomass	50%	0%	0%	0%	0%	0%	0%	0%	100%

HRSG = heat recovery steam generator, CCS = carbon capture and sequestration, CC = combined cycle
Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis

Distributed generation

Distributed generation is modeled in the end-use sectors (as described in the appropriate chapters) and in the EMM. This section describes the representation of distributed generation in the EMM only. Two generic distributed technologies are modeled. The first technology represents peaking capacity (capacity that has relatively high operating costs and is operated when demand levels are at their 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). See Table 2 for costs and performance characteristics. These plants are assumed to reduce the costs of transmission upgrades that would otherwise be needed.

Demand storage

Although not currently modeled in AEO2019, 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 in peak slices, but it must generate electricity to replace that demand in other time slices. An input factor is used to identify the replacement generation needed, where a factor of less than 1.0 can be used to represent peak shaving rather than purely shifting the load to other time periods. The AEO2019 cases no longer project builds of this technology type because a more detailed modeling of battery storage has been added and is described in the demand section below. This storage technology is also a method of reducing and shifting peak demand use.

Coal-to-gas conversion

Since AEO2015, the EMM includes existing coal plants that were converted to burn natural gas. In recent years, a number of companies have retrofit their coal plants to operate as single-cycle steam plants to reduce emissions from the plant or to take advantage of low natural gas prices [4]. The EMM reflects the current configuration and primary fuel use of the plants as reported to EIA. The EMM includes the option to convert additional coal plants to natural gas-fired steam plants, if economical.

The modeling structure for coal-to-gas conversions is based on the Environmental Protection Agency's (EPA) modeling for the Base Case v.5.13 [5]. For this modeling, coal-to-gas conversion is when an existing boiler is modified to burn natural gas. Coal-to-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 to gasifying coal for a combustion turbine. The cost for the retrofit option is composed of two components—boiler modification costs and the cost of extending natural gas lateral pipeline spurs from the boiler to a natural gas main pipeline.

Allowing natural gas firing in a coal boiler typically means installing new natural gas burners, modifying the boiler, and potentially modifying the environmental equipment. The EPA's engineering staff developed the estimates based on discussions with industry engineers. These estimates were designed to apply across the existing coal fleet. In the EMM, costs were estimated for eligible coal plants the EPA identified, which excluded 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 conversion to natural gas, but a 5% heat rate penalty is assumed 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. Fixed operations and maintenance (O&M) costs are assumed to be reduced by 33% for the converted plant because these plants need fewer operators, maintenance materials, and maintenance staff. Variable O&M costs are reduced by 25% because of lower waste disposal and other costs. The incremental capital cost is described by these functions:

For pulverized-coal-fired boilers

$$\text{Cost per kW} = 267 * (75 / \text{CAP})^{0.35}$$

For cyclone boilers

$$\text{Cost per kW} = 374 * (75 / \text{CAP})^{0.35}$$

Where CAP is the capacity of the unit in MW and the calculated cost is in 2011 dollars per kilowatt (kW).

To get unit-specific costs, EIA used EPA's assumptions regarding natural gas pipeline requirements, which were based on a detailed assessments 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 kW of boiler capacity varies widely, with an average cost of $203/kW (in 2018 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 (based on North American Electric Reliability Corporation regions and subregions) using historical hourly load data. The load-duration curve in the EMM has nine time periods. First, the load data are split into three seasons: winter (December through March), summer (June through September), and fall/spring (October/November and April/May, respectively). 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. The seasons were defined to account for seasonal variation in supply availability.

Although the annual demands from the end-use modules are typically provided net of any onsite generation, an enhancement developed for AEO2017 remains in place to account for behind-the-meter PV generation (i.e., rooftop PV generation) more explicitly in the EMM. Because the end-use models only provide an annual demand, they cannot accurately reflect when the PV generation occurs. Instead, the generation from these systems was modeled by estimating reductions in load for several specific end-use applications. The EMM now receives the total end-use demands without removing rooftop PV generation and then dispatches both power sector and end-use PV capacity using detailed solar resource profiles. Although the total generation requirement from the power sector capacity is the same as before, this enhancement more accurately reflects the demand and resource availability by time period.

Intermittent/Storage modeling

For AEO2019, a new submodel, the ReStore model, within the EMM was introduced to provide the granularity needed to represent renewable availability at a greater level of detail than the nine time periods described in the previous section. The new submodel was also introduced to adequately model the value of the four-hour battery storage technology, which can be used to balance renewable generation in periods of high intermittent output but low demand. The ReStore submodel solves a set of linear programming sub-problems within the EMM to provide the capacity planning and dispatch models information regarding 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 results are aggregated back to the nine time periods the EMM uses. The ReStore model incorporates an improved representation of 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 model represents the costs or constraints to ramping conventional technologies up and down to respond to fluctuations in intermittent generation. It also provides the planning model information on the value of storage to determine future builds. Additional details on the ReStore model is available in the *Renewables* chapter.

Capacity and operating reserves

Reserve margins (the percentage of capacity in excess of peak demand required to adequately maintain reliability during unforeseeable outages) are established for each region by its governing body—public utility commission, NERC region, or Independent System Operator (ISO)/Regional Transmission

Organization (RTO). The reserve margin values from the AEO2019 Reference case are based on these regional Reference Margins reported to NERC, ranging from 14% to 17% [6].

In addition to the planning reserve margin requirement, system operators typically require a specific level of operating reserves—generators available within a short period of time to meet demand in case a generator goes down or another supply disruption occurs. These reserves can be provided through plants that are already operating but not at full capacity (spinning reserves) as well as through capacity not currently operating but that 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 uncertain availability that can be difficult to predict. Since AEO2014, the capacity and dispatch submodules of the EMM have been updated to include explicit constraints requiring spinning reserves in each load time period. The amount of spinning reserves required is computed as a percentage of the load height of the time period plus a percentage of the distance between the load of 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 storage, intermittents, and distributed generation can be used to meet spinning reserves. Different operating modes are developed for each technology type to allow the model to choose between operating a plant to maximize generation versus contributing to spinning reserves, or a combination of the two. Minimum levels of generation 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.

Variable heat rates for coal-fired power plants

Low natural gas prices and rising shares of intermittent generation have led to a shift in coal plant operations from baseload to greater cycling. The efficiency of coal plants can vary based on their output levels, with reduced efficiency when plants run in a cycling mode or to provide operating reserves. The AEO2017 code introduced variable heat rates for coal plants based on the operating mode chosen by the EMM to better reflect actual fuel consumption and costs.

A relationship between operating levels and efficiencies was constructed from data available for 2013 through 2015 in the EPA continuous emission monitoring system (CEMS) and other EMM plant data. A statistical analysis was used to estimate piecewise linear equations that reflect the efficiency as a function of the generating unit's output. The equations were estimated by coal plant type, taking into account the configuration of existing environmental controls, and by the geographic coal demand region for the plant, based on plant-level data. Equations were developed 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 has between 3 and 11 steps.

Within the EMM, these equations are used to 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 currently allows six different modes within each season for coal plants. Theses 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 approximately half the season (only peak and intermediate time periods). Each of these modes is associated with different output levels, and the heat rate adjustment factor is calculated based on the capacity factor implied by the operating mode.

Fossil fuel-fired and nuclear steam plant retirement

Fossil-fired steam plant retirements and nuclear retirements are determined endogenously within the model. Generating units are assumed to retire when continuing to run them is no longer economical. Each year, the model determines whether the market price of electricity is sufficient to support the continued operation of existing plant generators. A generating unit is assumed to retire if the expected revenues from the generator are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building replacement capacity. The 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 $10 per kW for oil and natural gas steam plants and $26 per kW for nuclear plants (in 2018 dollars). These costs are added to the estimated costs at existing plants regardless of their ages. Beyond 30 years old, an additional $36 per kW capital charge for nuclear plants is included in the retirement decision to reflect further investment to address the impacts of aging. Age-related cost increases are attributed to capital expenditures for major repairs or retrofits, decreases in plant performance, and/or increases in maintenance costs to reduce the effects of aging.

For the AEO2019 modeling cycle, Sargent and Lundy (S&L) was commissioned to analyze historical fossil O&M costs and CAPEX and to recommend updates to the EMM [7].The study focused particularly on whether age is a factor in the level of costs over time. They found that for most technologies, age is not a significant variable influencing annual costs, and in particular, capital expenditures seem to be incurred steadily over time rather than in the form of a particular step increase at a certain age. Therefore, the aging cost adder used in previous AEOs at age 30 has been removed for fossil 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. The equation below has been incorporated in NEMS to assign capital expenditures for coal plants over time:

$$CAPEX = 16.53 + (0.126 \times age) + (5.68 \times FGD)$$

Where FGD = 1 if a plant has an FGD; zero otherwise (2017 $/kW)

For the remaining fossil technologies, no aging function is assumed. Instead, both O&M and CAPEX remain constant over time. The O&M and CAPEX inputs for existing fossil plants were updated using the data set analyzed by S&L and are described in more detail in their report. Costs were assigned for the EMM based on plant type and size category (3–4 tiers per type), and plants within a size category were split into three cost groups to provide additional granularity for the model. Plants that were not in the data sample, primarily those not reporting to the Federal Energy Regulatory Commission (FERC), were assigned an input cost based on their sizes and the cost group that was most prevalent for their regional locations.

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 EIA assumes no separate CAPEX costs for CC or CT plants and incorporates the CAPEX data into the variable O&M input cost.

EIA assumes that all retirements reported as planned during the next 10 years on the Form EIA-860, *Annual Electric Generator Report*, will occur in addition to some others that have been announced but not yet reported to EIA. This assumption includes 11.1 GW of nuclear capacity retirements and 35.0 GW of coal capacity retirements after 2018.

For AEO2018, EIA updated the nuclear unit operating costs using inputs from an Idaho National Laboratory (INL) Report [8], which was based on a review of public and proprietary cost data for three plant types:

- Small single-unit nuclear plants (less than 900 MW)
- Large single-unit nuclear plants (greater than or equal to 900 MW)
- Multiple-unit nuclear plants

EIA compared the INL data with the average unit cost data previously used in the EMM for these plant types and found that for multiple-unit plants, the EIA data were close to the reported INL costs. However, for the single-unit plants, the costs were substantially lower than the INL estimates, particularly for small single-unit nuclear plants. The input nuclear O&M cost assumptions were updated to be consistent with the INL costs.

Biomass co-firing

Coal-fired power plants are assumed to co-fire with biomass fuel if doing so is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. This expenditure is assumed to be $554 per 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 AEO2019 nuclear power projection assumes capacity increases at existing units. Nuclear plant operators can increase the rated capacity at plants through power uprates, which are license amendments that must be approved by the U.S. Nuclear Regulatory Commission. Uprates can vary from small (less than 2%) increases in capacity—which require very little capital investment—or extended uprates of 15% to 20%, which requires significant plant modifications. AEO2019 assumes that uprates reported to EIA as planned modifications on the Form EIA-860 will take place in the Reference case, representing 0.5 GW of additional capacity in 2019. EIA also analyzed the remaining uprate potential by reactor, based on the reactor design and previously implemented uprates, and developed regional estimates for projected uprates. A total of 2.5 GW of increased nuclear capacity through uprates is assumed to occur in 2029 through 2050.

Interregional electricity trade

Both firm and economy electricity transactions among utilities in different regions are represented within the EMM. In general, firm power transactions involve trading capacity and energy to help another region satisfy its reserve margin requirement, and economy transactions involve energy transactions motivated by the marginal generation costs of different regions. The flow of power from region to region is constrained by the existing and planned capacity limits as reported in the NERC and Western Electricity Coordinating Council Summer and Winter Assessment of Reliability of Bulk Electricity Supply in North America, as well as information obtained from the Open Access Same-Time Information System (OASIS). Known firm power contracts are compiled from the FERC Form 1, *Annual Report of Major Electricity Utility*, and information provided in the latest available Summer and Winter Assessments and individual ISO reports. The EMM includes an option to add interregional transmission capacity. In some cases, it may be more economical to build generating capacity in a neighboring region, but additional costs to expand the transmission grid will be incurred. Explicitly expanding the interregional transmission capacity may also make the transmission line available for additional economy trade.

Economy transactions are determined 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, the regions are assumed to exchange power.

International electricity trade

Two components of international firm power trade are represented in the EMM—existing and planned transactions and unplanned transactions. Data on existing and planned transactions are compiled from the FERC Form 1 and provincial reliability assessments. Unplanned firm power trade is represented by competing Canadian supply with U.S. domestic supply options. Canadian supply is represented in supply curves using cost data from the U.S. Department of Energy report, *Northern Lights: The Economic and Practical Potential of Imported Power from Canada (DOE/PE-0079)*. International electricity trade on an economic basis is determined endogenously based on surplus energy expected to be available from Canada by region in each time slice. Canadian surplus energy was determined using a mini-dispatch model 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.

Electricity pricing

Electricity pricing is projected for 22 electricity market regions for fully competitive, partially competitive, and fully regulated supply regions. The price of electricity to the consumer comprises the price of generation, transmission, and distribution, including applicable taxes.

Transmission and distribution are considered to remain regulated in the AEO. This assumption means that 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. Continued capital investment in the transmission and distribution system is projected as a function of changes in peak demand, based on historical trends. Additional transmission capital investment is added with each new generating build to account for the costs to connect to the grid. Regression equations have been developed to project transmission and distribution operating and maintenance costs as a function of peak demand and overall customer sales. The total price of electricity 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 defined as the cost of the last (or most expensive) unit dispatched, reflecting fuel and variable costs only. The capacity payment is calculated 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. The capacity payment is calculated for all competitive regions and should be viewed as a proxy for additional capital recovery that must be procured from customers rather than the representation of a specific market. The capacity payment also includes the costs associated with meeting the spinning reserves requirement discussed earlier in this report. The total cost for both reserve margin and spinning reserve requirements in a given region is calculated within the EMM and allocated to the sectors based on their contributions to overall peak demand.

The total price of electricity 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 reflects a load-weighted average of the competitive price and the regulated price, based on the percentage of electricity load in the region subject to deregulation.

The AEO2019 Reference case assumes full competitive pricing in the three New York regions and in the ReliabilityFirst Corporation/East region and 95% competitive pricing in New England (Vermont being the only fully-regulated state in that region). Eight regions fully regulate their electricity supply: the Florida Reliability Coordinating Council (FRCC), four of the SERC Reliability Corporation subregions–Delta (SRDA), Southeastern (SRSE), Central (SRCE) and Virginia-Carolina (SRVC)– the Southwest Power Pool Regional Entities (SPNO and SPSO), and the Western Electricity Coordinating Council/Rockies (RMPA). The Texas Reliability Entity, which in the past was considered fully competitive by 2010, is now only 88% competitive because many cooperatives have declined to become competitive or allow competitive energy to be sold to their customers. California returned to almost fully regulated pricing in 2002 after beginning a transition to competition in 1998, with only 10% competitive supply sold currently in the Western Electricity Coordinating Council (WECC)/California (CAMX) region. All other regions reflect a mix of both competitive and regulated prices.

Pricing structures for ratepayers in competitive states have experienced ongoing changes since the inception of retail competition. AEO has incorporated these changes as they have been incorporated into utility tariffs. For example, as a result of volatile fuel markets, state regulators have sometimes had difficulty enticing retail suppliers to offer competitive supply to residential and smaller commercial and industrial customers. Subsequent state legislation has led to generation service supplied by regulator or utility-run auction or competitive bid for the market energy price plus an administration fee.

Typical charges that all customers must pay on the distribution portion of their bills (depending on where they reside) include transition charges (including persistent stranded costs), public benefits charges (usually for efficiency and renewable energy programs), administrative costs of energy procurement, and nuclear decommissioning costs. Costs added to the transmission portion of the bills include the Federally Mandated Congestion Charges (FMCC), a bill pass-through associated with the FERC passage of Standard Market Design (SMD) to enhance reliability of the transmission grid and control congestion. Additional costs not included in historical data sets have been added in adjustment factors to the transmission and distribution capital and O&M costs, which affect the cost of both competitive and regulated electricity supply. Because most of these costs, such as transition costs, are temporary in nature, they are gradually phased out during the projection period.

Fuel price expectations

Capacity planning decisions in the EMM are based on a life-cycle cost analysis during a 30-year period, which requires foresight assumptions for fuel prices. Expected prices for coal, natural gas, and oil are derived using rational expectations, or perfect foresight. In this approach, expectations for future years are defined 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. The markups to the delivered fuel prices are calculated based on the markups from the previous year within a NEMS run. Coal prices are determined using the same coal supply curves developed in the NEMS Coal Market Module. The supply curves produce prices at different levels of coal production, as a function of labor productivity, and costs and utilization of mines. Expectations for each supply curve are developed in the EMM 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 for which the formation of expectations is consistent with the projections realized in the model. The NEMS model involves iterative cycling of runs until the expected values and realized values for variables converge between cycles.

Nuclear fuel prices

Nuclear fuel prices are calculated through an offline analysis that determines the delivered price to generators in dollars per megawatthour (MWh). To produce reactor-grade uranium, the uranium (U3O8) must first be mined and then sent through a conversion process to prepare for enrichment. The enrichment process takes the fuel to a given purity of uranium-235, typically 3% to 5% for commercial reactors in the United States. Finally, the fabrication process prepares the enriched uranium for use in a specific type of reactor core. The price of each of the processes is determined, and the prices are summed to get the final price of the delivered fuel. The analysis uses forecasts from Energy Resources International for the underlying uranium prices.

Legislation and regulations

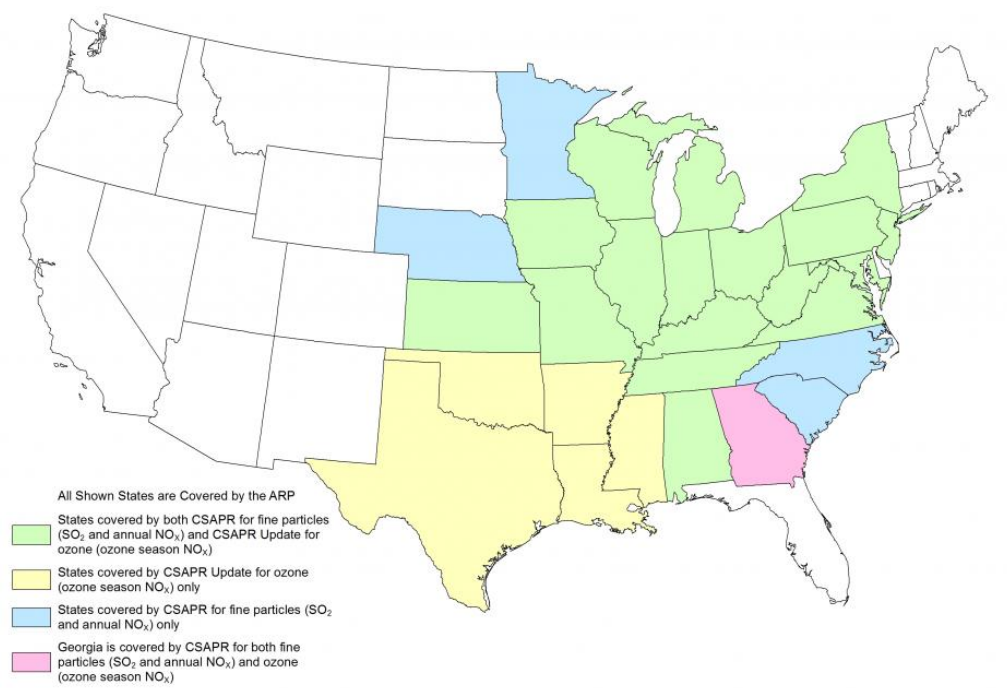
Cross-State Air Pollution Rule and Clean Air Act Amendments of 1990

AEO2019 includes the implementation of the Cross-State Air Pollution Rule (CSAPR), which addresses the interstate transport of air emissions from power plants. After a series of court rulings over the years, the Supreme Court in October 2014 lifted its stay and upheld CSAPR as a replacement for the Clean Air Interstate Rule. On September 7, 2016, EPA finalized an update to the CSAPR ozone season program, reflected in EIA’s assumed emission budgets and target dates.

Under CSAPR, 27 states must restrict emissions of sulfur dioxide (SO2) and nitrogen oxide (NOx), which are precursors to the formation of fine particulate matter (PM2.5) and ozone. CSAPR establishes four distinct allowance trading programs for SO2 and NOx composed of different member states based on the contribution of each state to downwind non-attainment of National Ambient Air Quality Standards (Figure 2). In addition, CSAPR splits the allowance trading program into two regions for SO2, Group 1 and Group 2, with trading permitted only between states within a group (approximated in NEMS by trade between coal demand regions) but not between groups.

In addition to interstate transport, the Clean Air Act Amendments of 1990 (CAAA1990) introduced the requirement for existing major stationary sources of NOx located in nonattainment areas to install and operate NOx controls that meet Reasonably Available Control Technology (RACT) standards. To implement this requirement, EPA developed a two-phase NOx program. The first set of RACT standards for existing coal plants was put in place in 1996, and the second set was implemented in 2000. Dry bottom wall-fired and tangential-fired boilers, the most common boiler types, referred to as Group 1 Boilers, were required to make significant reductions beginning in 1996 and again in 2000. Relative to their uncontrolled emission rates, which range from about 0.6 to 1.0 pounds per million British thermal units (Btu), these boilers are required to reduce NOx emissions by 25% to 50% to meet the Phase I limits. Further reductions are required to meet the Phase II limits. EPA did not impose limits on existing oil and natural gas plants, but some states have instituted additional NOx regulations. All new fossil units are required to meet current standards. In pounds per million Btu, these limits are 0.11 for conventional coal, 0.02 for advanced coal, 0.02 for combined cycle, and 0.08 for combustion turbines. These RACT NOx limits are incorporated in EMM.

Figure 2. Cross-State Air Pollution Rule



Source: U.S. Environmental Protection Agency, Clean Air Markets

Table 7 shows the average capital costs for environmental control equipment used in NEMS for existing coal plants as retrofit options to remove SO2, NOx, mercury (Hg), and hydrogen chloride (HCl). In the EMM, plant-specific costs are calculated based on the size of the unit and other operating characteristics, and these numbers reflect the capacity-weighted averages of all plants falling into each size category. Flue gas desulfurization (FGD) units are assumed to remove 95% of the SO2 and selective catalytic reduction (SCR) units are assumed to remove 90% of the NOx.

Table 7. Coal plant retrofit costs

2018 dollars per kW

Coal plant size (MW)	FGD capital costs	FF capital costs	SCR capital costs
<100	1,000	284	463
100–299	674	204	293
300–499	545	175	243
500–699	480	159	218
>=700	435	147	202

Notes: kW = kilowatt, MW = megawatt, FGD = flue gas desulfurization unit, FF = fabric filter, SCR = selective catalytic reduction unit.

Clean Power Plan with New Source Performance Standards for power generation

The Clean Power Plan (CPP) is not included in any AEO2019 cases. Following an Executive Order on Energy Independence, signed March 28, 2017, EPA issued a Notice of Proposed Rulemaking (NOPR) to repeal the CPP on October 12, 2017, based on the finding that it is inconsistent with the CAA [9, 10]. In August 2018, EPA proposed the Affordable Clean Energy (ACE) rule as the replacement to the CPP, which defines the "best system of emission reduction" (BSER) for existing power plants as on-site, heat-rate efficiency improvements [11]. The ACE rule is still under review and has not been finalized, and it is not assumed to be in place in the AEO2019 Reference or side cases.

EPA also finalized carbon pollution standards for new, modified, and reconstructed power plants under CAA Section 111(b) in October 2015 [12]. On December 6, 2018, EPA proposed a revision to the 2015 standards, which were based on the determination that partial carbon capture and storage was the BSER for new plants. The new proposal increases the proposed emission rate for newly constructed steam units from 1,400 lb CO_2/MWh to 1,900–2,000 lb/MWh, depending on plant size, based on the determination that the BSER for new plants is the most efficient demonstrated steam cycle in combination with best operating practices [13]. This proposal is currently in the review phase, therefore the original 2015 standards continue to be assumed in the AEO2019 Reference case and all side cases by assuming that new coal technologies must have at least 30% carbon capture. New coal plants without CCS technology cannot be built. The new natural gas combined-cycle plants modeled in previous AEOs were already lower than the 1,000 lb CO_2/MWh standard, and no change was necessary to the natural gas technology assumptions to reflect the final rule. The NEMS electricity model does not explicitly represent modified or reconstructed power plants, which are also covered by the rule.

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 regulate other hazardous air pollutants (HAPS) such as HCl and fine particulate matter (PM2.5). MATS applies to coal- and oil-fired power plants with a nameplate capacity greater than 25 megawatts. The standards took effect in 2015, but they allowed for a one-year waiver to comply and required that all qualifying units achieve the maximum achievable control technology (MACT) for each of the three covered pollutants. For AEO2019, EIA assumes that all coal-fired generating units affected by the rule are in compliance in terms of meeting HCl and PM2.5, which the EMM does not explicitly model.

All power plants are required to reduce their mercury emissions to 90% below their uncontrolled emissions levels. When plants alter their configuration by adding equipment such as an SCR to remove NOx or an SO2 scrubber, removal of mercury is often a resulting co-benefit. The EMM considers all combinations of controls and may choose to add NOx or SO2 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.

The equipment to inject activated carbon in front of an existing particulate control device is assumed to cost approximately $7 (2018 dollars) per kW of capacity [14]. The costs of a supplemental fabric filter with activated carbon injection (often referred as a COPAC unit) are calculated by unit, with average costs shown in Table 7. The amount of activated carbon required to meet a given percentage removal target is given by the following equations [15]:

For a unit with a cold-side electrostatic precipitator (CSE), using subbituminous coal and simple activated carbon injection

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

For a unit with a CSE, using bituminous coal and simple activated carbon injection

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

For a unit with a CSE and a supplemental fabric filter with activated carbon injection

- 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

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

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

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 represents different combinations of boiler types, particulate control devices, SO2 control devices, NOx control devices, and mercury control devices. An EMF represents the amount of mercury that was 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 8 provides the assumed EMFs for existing coal plant configurations without mercury-specific controls.

EIA assumes that all planned retrofits, as reported on the Form EIA-860, will occur as currently scheduled. For AEO2019, retrofits include 1.0 GW of planned SO2 scrubbers.

Table 8. Mercury emission modification factors

	Configuration		EIA EMFs			EPA EMFs		
SO2 control	particulate control	NOX control	Bit coal	Sub coal	Lignite coal	Bit coal	Sub coal	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

Notes: Under SO2 control—Wet = wet scrubber and Dry = dry scrubber; Under Particulate control—BH = fabric filter/baghouse, CSE = cold-side electrostatic precipitator, HSE/Oth = hot-side electrostatic precipitator/other/none; Under NOx control: SCR = selective catalytic reduction.
— = not applicable, Bit = bituminous coal, Sub = subbituminous coal. The NOx control system is not assumed to enhance mercury removal unless a wet scrubber is present, so it is left blank in such configurations.
Sources: 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 Performance, Office of Fossil Energy & National Energy Technology, U.S. Department of Energy, January 2003, Washington, DC

Carbon capture and sequestration retrofits

The EMM includes the option of retrofitting existing coal plants for CCS. The modeling structure for CCS retrofits within the EMM was developed by the National Energy Technology Laboratory [16] and uses a generic model of retrofit costs as a function of basic plant characteristics (such as heat rate). The costs have been adjusted to be consistent with costs of new CCS technologies. The CCS retrofits are assumed to remove 90% of the carbon input. The addition of the CCS equipment results in a capacity derate of about 30% and a reduced efficiency of 43% at the existing coal plant. The costs depend on the size and efficiency of the plant, with the capital costs averaging $1,762 per kW and ranging from $1,284 per kW to $2,474 per kW. 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.

Beginning in AEO2018, the EMM includes the option to retrofit existing natural gas-fired combined-cycle plants with CCS technology, also based on the modeling structure developed by NETL.

Heat rate improvement retrofits

Since AEO2015, the EMM has included the capability to evaluate heat rate improvements at existing coal-fired generators. A generator with a lower heat rate can generate the same quantity of electricity while consuming less fuel, which redues corresponding emissions of SO2, NOx, mercury, and CO2. Improving heat rates at power plants can lower fuel costs and help achieve compliance 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, SO2, NOx, mercury, and carbon emission controls (Table 9). These categories form the basis for evaluating the potential for heat rate improvements.

EIA entered into a contract with Leidos, Inc. to develop a methodology to evaluate the potential for heat-rate improvement at existing coal-fired generating plants [17]. Leidos performed a statistical analysis of the heat-rate characteristics of coal-fired generating units modeled by EIA 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, the coal-fired generating units were categorized into four equal groups, or quartiles, based on observed versus predicted heat rates. Units in the first quartile (Q1), which perform better 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, estimates were not developed for those plant types. These plant types were ultimately assigned the characteristics of the plants with the same combinations of particulate, SO2, and NOx controls. Plant types with relatively few observations were combined with other plant types having similar improvement profiles. As a result, nine unique plant type combinations were developed 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 mid-range cost and heat-rate improvement potential. The mid-range estimates were used as the default values in the EMM (Table 10).

Table 9. Existing pulverized-coal plant types in the NEMS Electricity Market Module

Plant type	Particulate controls	SO2 controls	NOx 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

Notes: Particulate controls—BH = baghouse, CSE = cold-side electrostatic precipitator,
HSE/Oth = hot-side electrostatic precipitator/other/none;
SO2 = sulfur dioxide, NOx = nitrogen oxide.
SO2 controls—Wet = wet scrubber, Dry = dry scrubber;
NOx controls—SCR = selective catalytic reduction;
Mercury controls—FF = fabric filter;
Carbon controls—CCS = carbon capture and storage
Source: U.S. Energy Information Administration

Table 10. Heat rate improvement (HRI) potential and cost (capital, fixed O&M) by plant type and quartile as used for input to NEMS

Plant type and quartile combination	Count of total units	Percentage HRI potential	Capital cost (million 2014 $/MW)	Average fixed O&M cost (2014 $/MW/y)
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**

(s) = less than 0.05% for HRI potential or less than 0.005 million $/MW for capital cost.
Note: Leidos selected the plant type and quartile groupings so that each grouping contained at least 10 generating units, with the exception of the integrated gasification combined-cycle (IG) type, which has essentially no heat rate improvement potential.
MW = megawatt
Source: U.S. Energy Information Administration/Leidos Corporation

State air emissions regulation

AEO2019 continues to model the Northeast Regional Greenhouse Gas Initiative (RGGI), which applies to fossil-fuel powered plants larger than 25 MW in the northeastern United States. New Jersey withdrew from the program at the end of 2011, leaving nine states in the accord. The rule caps CO2 emissions from covered electricity generating facilities and requires that they account for each ton of CO2 emitted with an allowance purchased at auction. The original cap was revised downward in 2014 and the new cap has been reflected since AEO2014. The participating states conducted a program review leading to an Updated Model Rule in December 2017 [18]. Since AEO2018, EMM incorporates the updates to the original rule, including specifying a cap through 2030, modifications to the Cost Containment Reserves (available if defined allowance-price triggers are exceeded), and creation of an Emissions Containment Reserve (to be used if prices fall lower than established trigger prices).

The California Senate Bill 32 (SB32), passed in October 2016, revised and extended the greenhouse gas (GHG) emission reductions that were previously in place through the Assembly Bill 32 (AB32), the Global Warming Solutions Act of 2006. Assembly Bill 32 implemented a cap-and-trade program with emission targets required by 2020 from the electric power sector as well as from industrial facilities and fuel providers. SB32 requires the California Air Resources Board (CARB) to enact regulations ensuring the maximum technologically feasible and cost-effective GHG emission reductions, and it sets 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 when determining implementation of any programs to reduce emissions and to prioritize reducing direct emission reductions from stationary, mobile, and other sources. The California Assembly Bill 398 (AB398), passed in July 2017, provided more clarification on how the new targets will be achieved. AEO2019 continues to assume that a cap-and-trade program remains in place, with the new target specified in 2030 and remaining constant afterward. The emissions constraint is in the EMM but accounts for the emissions determined by other sectors. Within the 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, and estimates of these emissions are included in the EMM constraint. An allowance price is calculated and added to fuel prices for the affected sectors. Limited banking and borrowing of allowances as well as an allowance reserve and offsets have been modeled, as specified in the bills, providing 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 appropriate chapters of this report.

State revenue support for existing nuclear power plants

Three states have passed legislation in recent years to provide price support 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, creates zero emission credits (ZEC) that apply to certain nuclear units. The New York load-serving entities are responsible for purchasing ZECs equal to their share of the statewide load, providing an additional revenue source to the nuclear units holding the ZECs. The program is set to cover a 12-year term, and the annual value of the ZEC is determined by the state, taking into account the state-determined value of clean energy, which will be reevaluated over time.

The Illinois Future Energy Jobs Bill [20], passed in 2017, also creates a ZEC program covering a 10-year term. Nuclear power plants serving at least 100,000 customers in Illinois are eligible for ZECs. The Illinois Power Agency must procure ZECs in each year of the program to cover 16% of 2014 utility sales. The value of the ZEC is capped at a state-determined value of clean energy and will increase over time, subject to an annual cap of $250 million.

In 2018, the New Jersey Senate passed bill S. 2313 [21], which established a ZEC program that is funded by a $0.004 per kilowatt-hour annual charge to create a fund of about $300 million per year. Three nuclear reactors are eligible to receive payments from the fund during the year of implementation plus the three following years and may be considered for additional three-year renewal periods thereafter.

This legislation is modeled in AEO2019 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 model cannot choose to endogenously retire the plant). The cost of each program is determined 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, a subsidy payment is applied. The cost of the subsidy payment is recovered through retail prices as an adder to the electric distribution price component to represent the purchase of ZECs by load-serving entities.

Energy Policy Acts of 1992 (EPACT1992) and 2005 (EPACT2005)

The provisions of EPACT1992 include revised licensing procedures for nuclear plants and the creation of exempt wholesale generators (EWGs). EPACT1992 also implemented a permanent 10% ITC for geothermal and solar facilities and introduced a PTC for eligible renewable technologies (subsequently extended and expanded). 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 are not assumed to be available for new, unplanned capacity built within the EMM. EPACT2005 also contains a PTC of 1.8 cents (nominal) per kWh for new nuclear capacity beginning operation by 2020. This PTC is specified for the first eight years of operation and is limited to $125 million annually and to 6 GW of new capacity. However, this credit may be shared to additional units if more than 6 GW were under construction by January 1, 2014. EPACT2005 extended the PTC for qualifying renewable facilities by two years, or through December 31, 2007, and also repealed the Public Utility Holding Company Act (PUHCA).

The investment and energy PTCs initiated in EPACT1992 and amended in EPACT2005 have been further amended through a series of acts that were incorporated in previous AEOs. A history of these tax credits is described in AEO2016 Legislation and Regulations LR3—Impact of a Renewable Energy Tax Credit extension and phase-out [22]. AEO2019 continues to reflect the most recent changes implemented through the 2016 Consolidated Appropriation Act passed in December 2015. Based on guidance from the Internal Revenue Service allowing for a four-year period between construction start and online date, the 30% ITC is assumed for all solar plants online by 2023. The ITC drops to 10% for plants coming online after 2023.

The PTC is a per-kWh tax credit available for qualified wind, geothermal, closed-loop and open-loop biomass, landfill gas, municipal solid waste, hydroelectric, and marine and hydrokinetic facilities. The value of the credit, originally 1.5 cents/kWh, is adjusted for inflation annually and is available for 10 years after the facility has been placed in service. For AEO2019, wind, poultry litter, geothermal, and closed-loop biomass resources receive a tax credit of 2.4 cents/kWh; all other renewable resources receive a 1.2 cent/kWh tax credit (that is, one-half the value of the credit for other resources). EIA assumes that biomass facilities obtaining the PTC will use open-loop fuels because closed-loop fuels are assumed to be unavailable and/or too expensive for widespread use during the period that the tax credit is available. The PTC has been recently extended by the 2016 Consolidated Appropriation Act passed in December 2015 for projects under construction through 2016. The PTC is scheduled to phase down in value for wind projects as follows:

- 80% of the current PTC if construction begins in 2017
- 60% of the current PTC if construction begins in 2018
- 40% of the current PTC if construction begins in 2019

Plants that begin construction in 2020 or later do not receive a PTC. Based on documentation released by the Internal Revenue Service, EIA assumes that wind plants will be able to claim the credit for up to four years after beginning construction.

The ITCs and PTCs are exclusive of one another and both cannot be claimed for the same facility. EIA assumes that the PTC is chosen for new geothermal plants when it is available (through December 2016) and that the 10% ITC is chosen for plants developed after 2016. Both onshore and offshore wind projects are eligible to claim the ITC in lieu of the PTC. Although onshore wind projects are expected to choose the PTC, EIA assumes offshore wind farms will claim the ITC because of the high capital costs for offshore wind.

American Recovery and Reinvestment Act (ARRA)

Smart grid expenditures

The ARRA provides $4.5 billion for smart grid demonstration projects. Although somewhat difficult to define, smart grid technologies generally include a wide array of measurement, communications, and control equipment employed throughout the transmission and distribution system that will enable real-time monitoring of the production, flow, and use of power from the generator to the consumer. Among other things, these smart grid technologies are expected to enable more efficient use of the transmission and distribution grid, lower line losses, and greater use of renewables. Smart grid technologies also provide information to utilities and their customers that may contribute to greater investment in energy efficiency and reduced peak load demands. The funds provided will not support a widespread implementation of smart grid technologies, but the investments could stimulate more rapid development than would otherwise occur.

Several changes were made throughout NEMS to represent the impacts of the smart grid funding provided in ARRA. In the electricity module, line losses are assumed to fall slightly, peak loads are assumed to fall as customers shift their usage patterns, and customers are assumed to be more responsive to pricing signals. Historically, line losses, expressed as the percentage of electricity lost, have been falling for many years as utilities have made investments to replace aging or failing equipment.

FERC Orders 888 and 889

FERC issued two related rules (Orders 888 and 889) designed to bring low-cost power to consumers through competition, ensure continued reliability in the industry, and provide for open and equitable transmission services by owners of these facilities.

Specifically, Order 888 requires open access to the transmission grid currently owned and operated by utilities. The transmission owners must file nondiscriminatory tariffs that offer other suppliers the same services that the owners provide for themselves. Order 888 also allows these utilities to recover stranded costs (investments in generating assets that are unrecoverable as a result of consumers selecting another supplier). Order 889 requires utilities to implement standards of conduct and an Open Access Same-Time Information System (OASIS) through which utilities and non-utilities can receive information regarding the transmission system. As a result, utilities have functionally or physically unbundled their marketing functions from their transmission functions.

These orders are represented in EMM by assuming that all generators in a given region can satisfy load requirements anywhere within the region. Similarly, the EMM assumed that transactions between regions will occur if the cost differentials between them make those transactions economical.

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