Chapter 8. Electricity Market Module

The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules: electricity load and demand, electricity capacity planning, electricity fuel dispatching, and electricity finance and pricing. It includes nonutility capacity and generation, and electricity transmission and trade. A detailed description of the EMM is provided in the forthcoming EIA publication, Electricity Market Module of the National Energy Modeling System 2016, DOE/EIA-M068(2016).

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. There are assumptions about the operations of the electricity sector and the costs of various options in each of the EMM Submodules. This section describes the model parameters and assumptions used in the EMM. It includes a discussion of legislation and regulations that are incorporated in the EMM, as well as information about the climate change action plan.

EMM regions

The supply regions used in the EMM were developed for the *Annual Energy Outlook 2011*, and correspond to the North American Electric Reliability Corporation (NERC) regions in place at that time, divided into subregions, as shown in Figure 8.1.

Figure 8.1. Electricity Market Model Supply Regions

Model parameters and assumptions

Generating capacity types

The capacity types represented in the EMM are shown in Table 8.1.

Table 8.1. 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 Sequestration
Oil/Gas Steam - Oil/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 carbon sequestration
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 - Baseload
Generic Distributed Generation - Peak
Conventional Hydropower - Hydraulic Turbine
Pumped Storage - Hydraulic Turbine Reversible
Geothermal
Municipal Solid Waste
Biomass - Fluidized Bed
Solar Thermal - Central Tower
Solar Photovoltaic – Single Axis Tracking
Wind
Wind Offshore

[1] The EMM represents 32 different types of existing coal steam plants, based on the different possible configuration of NOx, particulate and SO2 emission control devices, as well as future options for controlling mercury and carbon. (See Table 8.10.).

[2] The AEO2016 assumes new coal plants without CCS cannot be built, due to emission standards for new plants. These technologies exist in the modeling framework, but are not assumed available to be built in the projections.

Source: U.S. Energy Information Administration.

New generating plant characteristics

The cost and performance characteristics of new generating technologies are inputs to the electricity capacity planning submodule (Table 8.2). These characteristics are used in combination with fuel prices from the NEMS fuel supply modules and foresight on fuel prices 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 commissioned an external consultant to update current cost estimates for certain utility-scale electric generating plants [81]. This report used a consistent methodology, similar to the one used to develop the estimates for previous AEOs, but accounted for more recent data and experience, and also included alternative designs not previously considered. Updated costs were used for coal with carbon capture and sequestration (CCS), the combined cycle (without CCS) technologies, the combustion turbine technologies, advanced nuclear, onshore wind and solar photovoltaic (PV). Costs for other technologies are consistent with AEO2015 assumptions. A cost adjustment factor, based on the producer price index for metals and metal products, allows the overnight costs to fall in the future if this index drops, or rise further if it increases.

The overnight costs shown in Table 8.2, except as noted below, represent the estimated cost of building a plant before adjusting for regional cost factors. Overnight costs exclude interest 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 in particular, the cost favorability of the lowest-cost regions compound the underlying variability in regional cost and create a significant differential between the unadjusted costs and the capacity-weighted average national costs as observed from recent market experience. To correct for this, Table 8.2 shows a weighted average cost for wind based on the regional cost factors assumed for wind in the AEO2016 and the actual regional distribution of wind builds that occurred in 2014.

Table 8.3 presents a full listing of the overnight costs for each technology and electricity region (Figure 6), if the resource or technology is 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 impact the available capacity of a combustion turbine, and EIA’s modeling addresses this 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. As sites near existing transmission, with access to a road network, or otherwise located on lower-development-cost lands are utilized, additional costs may be incurred to access sites with less favorable characteristics. EIA represents this through a multiplier applied to the wind plant capital costs that increases as the best sites in a given region are developed.

Table 8.2. Cost and performance characteristics of new central station electricity generating technologies

Technology	First Available Year[1]	Size (MW)	Lead time (years)	Base Overnight Cost in 2015 (2015 $/kW)	Contingency Factors: Project Contin-gency Factor[2]	Contingency Factors: Techno-logical Optimism Factor[3]	Total Overnight Cost in 2015[4,10] (2015 $/kW)	Variable O&M[5] (2015 $/MWh)	Fixed O&M (2015 $/ kW/yr.)	Heatrate[6] in 2015 (Btu/ kWh)	nth-of-a-kind Heatrate (Btu/ kWh)
Coal with 30% carbon sequestration (CCS)	2019	650	4	4,649	1.07	1.03	5,098	6.95	68.49	9,750	9,221
Conv Gas/Oil Comb Cycle	2018	702	3	911	1.05	1.00	956	3.42	10.76	6,600	6,350
Adv Gas/Oil Comb Cycle (CC)	2018	429	3	1,000	1.08	1.00	1,080	1.96	9.78	6,300	6,200
Adv CC with CCS	2018	340	3	1,898	1.08	1.04	2,132	6.97	32.69	7,525	7,493
Conv Comb Turbine[7]	2017	100	2	1,026	1.05	1.00	1,077	3.42	17.12	9,960	9,600
Adv Comb Turbine	2017	237	2	632	1.05	1.00	664	10.47	6.65	9,800	8,550
Fuel Cells	2018	10	3	6,217	1.05	1.10	7,181	44.21	0.00	9,500	6,960
Adv Nuclear	2022	2,234	6	5,288	1.10	1.05	6,108	2.25	98.11	10,449	10,449
Distributed Generation-Base	2018	2	3	1,448	1.05	1.00	1,520	7.98	17.94	9,004	8,900
Distributed Generation - Peak	2017	1	2	1,739	1.05	1.00	1,826	7.98	17.94	10,002	9,880
Biomass	2019	50	4	3,498	1.07	1.01	3,765	5.41	108.63	13,500	13,500
Geothermal[8,9]	2019	50	4	2,559	1.05	1.00	2,687	0.00	116.12	9,541	9,541
MSW Landfill Gas	2018	50	3	7,954	1.07	1.00	8,511	9.00	403.97	14,360	18,000
Conventional Hydropower[9]	2019	500	4	2,191	1.10	1.00	2,411	2.62	14.70	9,541	9,541
Wind[10]	2018	100	3	1,536	1.07	1.00	1,644	0.00	45.98	9,541	9,541
Wind Offshore	2019	400	4	4,605	1.10	1.25	6,331	0.00	76.10	9,541	9,541
Solar Thermal[8]	2018	100	3	3,895	1.07	1.00	4,168	0.00	69.17	9,541	9,541
Photovoltaic[8,11]	2017	150	2	2,362	1.05	1.00	2,480	0.00	21.33	9,541	9,541

[1]Represents the first year that a new unit could become operational.

[2]A contingency allowance is defined by the American Association of Cost Engineers as the "specific provision for unforeseeable elements of costs within a defined project scope; particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur."

[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 including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2015.

[5]O&M = Operations and maintenance.

[6]For hydro, wind, solar and geothermal technologies, the heat rate shown represents the average heat rate for conventional thermal generation as of 2014. This is used for purposes of calculating primary energy consumption displaced for these resources, and does not imply an estimate of their actual energy conversion efficiency.

[7] Combustion turbine units can be built by the model prior to 2017 if necessary to meet a given region's reserve margin.

[8]Capital costs are shown before investment tax credits are applied.

[9]Because geothermal and hydro 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's total overnight cost of $1644/kW represents the average input value across all 22 electricity market regions, as weighted by the wind capacity installed during 2014 in each region to account for the substantial regional variation in wind costs (as shown in Table 8.3). The input value used for AEO 2016 was $1837/kW, and represents the cost of building a 100 MW wind 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 AC power available to the grid for the installed capacity.

Sources: For the AEO2016 cycle, EIA updated cost estimates for certain electric generating technologies, based on a draft report provided by external consultants. This report will be provided on the EIA website when finalized. Costs were updated for coal with CCS, the combined cycle (without CCS) technologies, the combustion turbine technologies, advanced nuclear, onshore wind and solar PV. Costs for other technologies are consistent with AEO2015 assumptions.

Table 8.3. Total overnight capital costs of new electricity generating technologies by region

2015 $/kW

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	4,760	5,001	4,841	4,887	5,119	N/A	N/A	4,802	5,478	4,951	5,134
Conv Gas/Oil Comb Cycle	875	904	913	933	1,062	1,541	1,541	1,080	1,131	955	979
Adv Gas/Oil Comb Cycle (CC)	1,035	1,056	1,026	1,068	1,200	1,644	1,644	1,219	1,267	1,071	1,116
Adv CC with CCS	1,991	2,065	2,073	2,051	2,184	3,111	3,111	2,195	2,333	2,089	2,147
Conv Comb Turbine	1,035	1,075	1,024	1,066	1,119	1,517	1,517	1,104	1,185	1,067	1,092
Adv Comb Turbine	645	666	640	666	720	1,028	1,028	714	774	666	686
Fuel Cells	6,728	6,893	7,217	7,000	7,245	8,703	8,703	7,145	7,374	7,173	7,159
Adv Nuclear	5,857	5,943	6,150	6,020	6,364	N/A	N/A	6,462	6,529	6,102	6,224
Distributed Generation - Base	1,353	1,392	1,491	1,486	1,737	2,482	2,482	1,759	1,819	1,543	1,559
Distributed Generation - Peak	1,754	1,822	1,735	1,806	1,896	2,571	2,571	1,871	2,008	1,809	1,851
Biomass	3,471	3,569	3,837	3,644	3,878	4,620	4,620	3,893	4,010	3,746	3,803
Geothermal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
MSW – Landfill Gas	7,830	8,077	8,579	8,241	8,587	10,724	10,724	8,502	8,792	8,485	8,460
Conventional Hydropower	N/A	N/A	N/A	3,047	3,292	N/A	N/A	2,604	N/A	N/A	2,597
Wind	1,617	N/A	2,204	1,819	2,465	N/A	2,241	2,241	2,241	2,204	2,204
Wind Offshore	5,780	8,357	6,369	6,400	6,496	8,110	8,110	6,274	6,496	6,300	6,369
Solar Thermal	3,551	3,776	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Photovoltaic[1]	2,135	2,269	2,376	2,437	2,559	N/A	3,469	2,433	2,574	2,453	2,443

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	4,798	5,206	4,816	4,744	4,627	5,027	4,886	5,653	5,782	5,247	5,739
Conv Gas/Oil Comb Cycle	873	991	898	877	851	947	913	1,043	1,204	994	1,119
Adv Gas/Oil Comb Cycle (CC)	1,033	1,129	1,060	1,053	1,013	1,095	1,072	1,280	1,378	1,175	1,320
Adv CC with CCS	2,007	2,207	2,021	1,977	1,935	2,122	2,059	2,413	2,490	2,206	2,395
Conv Comb Turbine	1,048	1,113	1,077	1,030	1,019	1,089	1,067	1,244	1,237	1,128	1,295
Adv Comb Turbine	654	696	683	643	640	680	668	788	799	710	954
Fuel Cells	6,793	7,303	6,764	6,807	6,692	7,030	6,908	7,080	7,504	7,102	6,879
Adv Nuclear	5,894	6,199	5,876	5,906	5,839	6,034	5,961	6,065	N/A	6,126	6,108
Distributed Generation - Base	1,359	1,570	1,386	1,377	1,327	1,480	1,427	1,520	1,889	1,534	1,600
Distributed Generation - Peak	1,777	1,886	1,826	1,745	1,727	1,845	1,808	2,108	2,097	1,912	2,195
Biomass	3,502	3,829	3,483	3,517	3,438	3,663	3,599	3,765	4,051	3,773	3,524
Geothermal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3,982	2,742	2,687	N/A
MSW - Landfill Gas	7,941	8,672	7,872	7,941	7,753	8,298	8,102	8,358	8,979	8,358	8,060
Conventional Hydropower	3,138	2,217	3,138	1,330	1,940	N/A	2,637	N/A	2,432	2,411	2,801
Wind	2,388	2,204	2,388	2,388	2,388	1,516	1,378	1,980	1,984	1,980	1,516
Wind Offshore	6,331	N/A	5,818	N/A	5,717	N/A	N/A	N/A	6,604	6,433	N/A
Solar Thermal	N/A	N/A	N/A	N/A	N/A	N/A	3,822	4,093	4,660	4,118	3,839
Photovoltaic[1]	2,210	2,500	2,170	2,192	2,081	2,383	2,284	2,403	2,765	2,443	2,326

Table shows overnight capital costs for projects initiated in 2015. 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.

N/A: plant type cannot be built in the region due to lack of resources, sites or specific state legislation.

[1]PV represents a ground-mounted utility-scale system. Roof-top or other distributed PV can be built in NYCW, but the ability to site larger, ground-mounted plants may be limited in the densely populated region.

Region map: Figure 6.

Technological optimism and learning

Overnight costs for each technology are calculated as a function of regional construction parameters, project contingency, and 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 8.4). Where technologies use similar components, these components learn at the same rate as these units are built. For example, it is assumed that the underlying turbine generator for a combustion turbine, combined cycle, and integrated coal-gasification combined cycle unit is basically the same. Therefore construction of any of these technologies would contribute to learning reductions for the turbine component.

The learning function, OC, has the nonlinear form:

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

where C is the cumulative capacity for the technology component.

Table 8.4. 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%
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: Please see the text for a description of the methodology for learning in the Electricity Market Module.

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

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 (LR) is an exogenous parameter input for each component (Table 8.4). The progress ratio and LR are related by:

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

The parameter “b” is calculated from the second equality above (b =-(ln(1-LR)/ln(2))). The parameter “a” is computed from initial conditions, i.e.,

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

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 a significant amount of 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 represents cost reductions due to 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 8.5). For technologies that do not share components, this weighted average learning rate is calculated exogenously, and input as a single component.

These technologies may still have a mix of revolutionary components and more mature components, but it is not necessary to include this detail in the model unless capacity from multiple technologies would contribute to the component learning. In the case of the solar PV technology, it is assumed that the module component accounts for 30% of the cost, and that the balance of system components accounts for the remaining 70%. Because the amount of end-use PV capacity (existing and projected) is significant relative to total solar PV capacity, and because 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 8.6 shows the capacity credit toward component learning for the various technologies. It was assumed that for all combined-cycle technologies, the turbine unit contributed two-thirds of the capacity, and the steam unit one-third. Therefore, building one gigawatt of gas combined cycle would contribute 0.67 gigawatts (GW) toward turbine learning, and 0.33 GW toward steam 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 - CC” component, all combined cycle capacity would be counted 100%, both conventional and advanced.

Table 8.5. Component cost weights for new technologies

Technology	Pulverized Coal	Combus-tion Turbine-conven-tional	Combustion Turbine - advanced	HRSG	Gasifier	Carbon Capture/ Sequestion	Balance of Plant -IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuel Prep Biomass
Coal with carbon sequestration	75%	0%	0%	0%	0%	25%	0%	0%	0%	0%
Conv Gas/Oil Comb	0%	30%	0%	40%	0%	0%	0%	0%	30%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	0%	30%	40%	0%	0%	0%	0%	30%	0%
Adv CC with carbon sequestration	0%	0%	20%	25%	0%	40%	0%	0%	15%	0%
Conv Comb Turbine	0%	50%	0%	0%	0%	0%	0%	50%	0%	0%
Adv Comb Turbine	0%	0%	50%	0%	0%	0%	0%	50%	0%	0%
Biomass	50%	0%	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 there is overlap with other technologies.

HRSG = Heat Recovery Steam Generator.

Source: Market-Based Advanced Coal Power Systems, May 1999, DOE/FE-0400.

Table 8.6. Component capacity weights for new technologies

Technology	Pulverized Coal	Combustion Turbine-conven-tional	Combus-tion Turbine-advanced	HRSG	Gasifier	Carbon Capture/ Seques-tration	Balance of Plant-IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuel Prep Biomass
Coal with Carbon sequestration	100%	0%	0%	0%	0%	100%	0%	0%	0%	0%
Conv Gas/Oil Comb Cycle	0%	67%	0%	33%	0%	0%	0%	0%	100%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	0%	67%	33%	0%	0%	0%	0%	100%	0%
Adv CC with carbon sequestration	0%	0%	67%	33%	0%	100%	0%	0%	100%	0%
Conv Comb Turbine	0%	100%	0%	0%	0%	0%	0%	100%	0%	0%
Adv Comb Turbine	0%	0%	100%	0%	0%	0%	0%	100%	0%	0%
Biomass	50%	0%	0%	0%	0%	0%	0%	0%	0%	100%

HRSG = Heat Recovery Steam Generator.

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) as well as 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 8.2 for costs and performance assumptions. It is assumed that these plants reduce the costs of transmission upgrades that would otherwise be needed.

Demand storage

The EMM includes the option to build a new demand storage technology to simulate load shifting, through programs such as smart meters. This is modeled as a new technology build, but with operating characteristics similar to pumped storage. The technology is able to decrease the load in peak slices, but must generate to replace that demand in other time slices. There is an input factor that identifies the amount of 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. This plant type is limited to operating only in the peak load slices, and it is assumed that this capacity is limited to 3.5% of peak demand on average in 2040, with limits varying from 2.2% to 6.8% of peak across the regions.

Coal-to-gas conversion

Since the AEO2015, the EMM includes the representation of conversion of existing coal plants to burn natural gas. In recent years, a number of companies have announced plans to 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 [82]. AEO2016 includes explicit representation of conversions of 8.8 GW by changing the plant type and fuel source for specific units, based on announced plans. Additionally, the EMM was revised to include the option to convert additional coal plants to gas-fired steam plants if economic.

The modeling structure for coal-to-gas conversions was based on EPA's modeling for the Base Case v5.13 [83]. For this modeling, coal-to-gas conversion refers to the modification of an existing boiler to allow it to fire natural gas. It does not refer to the addition of a gas turbine, the replacement of a coal boiler with a new natural gas combined cycle plant, or to the gasification of coal for use in a combustion turbine. There are two components of cost for the retrofit option – 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 involves installation of new gas burners as well as modifications to the boiler and possibly environmental equipment. EPA's estimates were developed by engineering staff and discussions with industry engineers, and were designed to be applicable across the existing coal fleet. In the EMM, costs were estimated for eligible coal plants identified by EPA, which excluded units under 25 MW as well as units with fluidized bed combustion or stoker boilers. There is no capacity penalty for conversion to gas, but there is a 5% heat rate penalty to reflect reduced efficiency due to lower stack temperature and the corresponding higher moisture loss when gas is combusted instead of coal. Fixed O&M costs are assumed to be reduced by 33% for the converted plant due to reduced needs for operators, maintenance materials, and maintenance staff. Variable O&M costs are reduced by 25% due to reduced waste disposal and other costs. The incremental capital cost is described by the following functions:

For pulverized-coal-fired boilers:

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

For cyclone boilers:

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

Where CAP is the capacity of the unit in megawatts and the calculated cost is in 2011 dollars per kW.

EIA used EPA's assumptions regarding natural gas pipeline requirements, which were based on a detailed assessment for every coal boiler in the United States, to determine gas volumes needed, distance to the closest pipeline, and size of the lateral pipeline required to get unit-specific costs. The resulting cost per kW of boiler capacity varies widely, from $4/kW to $3,584/kW, with an average cost of $193/kW (in 2015 dollars).

Representation of 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 is made up of nine time slices. First, the load data is split into three seasons: winter (December through March), summer (June through September), and fall/spring. Within each season the load data is 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.

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 Operators (ISOs)/Regional Transmission Operators (RTOs). The reserve margin values from the AEO2016 Reference case are set based on these regional Reference Margins reported to NERC, and range from 14% to 17% [84].

Operating reserves

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 there is another disruption to supply. 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 is particularly important as more intermittent generators are added to the grid, because technologies like 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 slice. The amount of spinning reserves required is computed as a percentage of the load height of the slice plus a percentage of the distance between the load of the slice and the seasonal peak. An additional requirement is calculated that is a percentage of the intermittent capacity available in that time period to reflect the greater uncertainty associated with the availability of intermittent resources. All technologies except for 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 both. Minimum levels of generation are required if a plant is contributing to spinning reserves, and vary by plant type, with plant types typically associated with baseload operation having higher minimums than those that can operate more flexibly to meet intermediate or peak demand.

Fossil fuel-fired and nuclear steam plant retirement

Fossil-fired steam plant retirements and nuclear retirements are calculated endogenously within the model. Generating units are assumed to retire when it is no longer economical to continue running them. 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 new replacement capacity. The going-forward costs include fuel, operations and maintenance costs, and annual capital additions, which are unit-specific and based on historical data. The average capital additions for existing plants are $8 per kilowatt (kW) for oil and gas steam plants, $17 per kW for coal plants, and $23 per kW for nuclear plants (in 2015 dollars). These costs are added to the estimated costs at existing plants regardless of their age. Beyond 30 years of age an additional $7 per kW capital charge for fossil plants and $34 per kW 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 mitigate the effects of aging.

EIA assumes all retirements reported as planned during the next ten years on the Form EIA-860 will occur. Additionally, the AEO2016 nuclear projection assumes a decrease of 3.0 GW by 2020 to reflect existing nuclear units that appear at risk of early closure due to a combination of high operating costs and low electricity prices.

Biomass co-firing

Coal-fired power plants are assumed to co-fire with biomass fuel if it is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. This expenditure is assumed to be $526 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 AEO2016 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 (NRC). Uprates can vary from small (less than 2%) increases in capacity, which require very little capital investment or plant modification, to extended uprates of 15-20%, requiring significant modifications. Recently, several companies have canceled previously planned extended uprates due to lower demand projections and low electricity prices [85]. AEO2016 assumes that only those uprates reported to EIA as planned modifications on the Form EIA-860 will take place in the Reference case, representing 0.1 GW of additional capacity.

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 the trading of capacity and energy to help another region satisfy its reserve margin requirement, while 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 Federal Energy Regulatory Commission (FERC) Form 1, "Electric Utility Annual Report" as well as 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 as well. 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 slice. 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 via supply curves using cost data from the Department of Energy report, “Northern Lights: The Economic and Practical Potential of Imported Power from Canada” (DOE/PE-0079). International economy trade 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 utilizes 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; that is, 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. The price of electricity in the regulated regions consists of the average cost of generation, transmission, and distribution for each customer class.

In the competitive regions, the energy component of price is based on marginal cost, which is defined as the cost of the last (or most expensive) unit dispatched. The competitive generation price includes the marginal energy cost (fuel and variable operations and maintenance costs), taxes, and a capacity payment. The capacity payment is calculated as a combination of levelized costs for combustion turbines and the marginal value of capacity calculated within the EMM. 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. 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 contribution to overall peak demand.

The price of electricity in the regions with a competitive generation market consists of 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 percent of electricity load in the region subject to deregulation. In competitively supplied regions, a transition period is assumed to occur (usually over a 10-year period) from the effective date of restructuring, with a gradual shift to marginal cost pricing.

The Reference case assumes a transition to full competitive pricing in the three New York regions and in the ReliabilityFirst Corporation/East region, and a 95% transition to competitive pricing in New England (Vermont being the only fully-regulated state in that region). Eight regions fully regulate their electricity supply, including the Florida Reliability Coordinating Council, 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, since 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 region. All other regions reflect a mix of both competitive and regulated prices.

There have been ongoing changes to pricing structures for ratepayers in competitive states since the inception of retail competition. The AEO has incorporated these changes as they have been incorporated into utility tariffs. These have included transition period rate reductions and freezes instituted by various states, and surcharges in California relating to the 2000-2001 energy crisis in the state. Since price freezes have ended, many costs related to the transition to competition are now explicitly added to the distribution portion and sometimes the transmission portion of the customer bill, regardless of whether or not the customer bought generation service from a competitive or regulated supplier. There have also been unexpected costs relating to unforeseen events that have been included in the calculation of electricity prices. For instance, as a result of volatile fuel markets, state regulators have sometimes had a hard time 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 bill (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 bill include the Federally Mandated Congestion Charges (FMCC), a bill pass-through associated with the Federal Energy Regulatory Commission 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, operations and maintenance costs, which impact the cost of both competitive and regulated electricity supply. Since most of these costs, such as transition costs, are temporary in nature, they are gradually phased out throughout the projection.

Electricity distribution prices are adjusted for two aspects related to the Clean Power Plan (CPP), a state level program to reduce CO2 emissions, described in more detail in the Legislation and Regulations section below. The CPP is expected to induce incremental energy efficiency (EE) due to programs implemented by the end-use sectors but affecting consumers costs. The residential and commercial modules pass the costs associated with the incremental EE programs to the EMM, where they are added to the distribution component of electricity price. Additionally, as the CPP is implemented in the AEO2016 Reference case, a CO2 emissions cap is in place which results in CO2 allowances being allocated. If allowances are allocated to load-serving entities, as assumed in the Reference case, the costs of purchasing the allowances (by generators) is reflected in the generation price, but distribution prices are reduced to reflect the revenues that the load-serving entities receive from the sale of the allowances and rebate back to consumers.

Fuel price expectations

Capacity planning decisions in the EMM are based on a life-cycle cost analysis over a 30-year period. This 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 prior run. The expectations for the world oil price and natural gas wellhead price are set using the resulting prices from a prior 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 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 prior run throughout the projection horizon, 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 which determines the delivered price to generators in mills per kilowatthour. To produce reactor-grade uranium, the uranium (U308) 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 U235, typically 3-5% 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

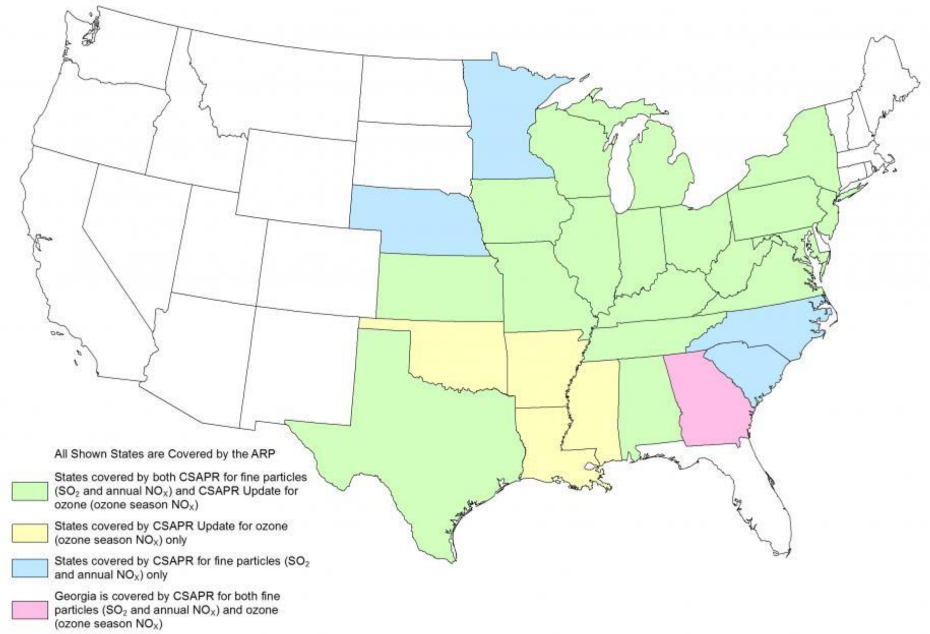
Clean Air Act Amendments of 1990 (CAAA1990) and Cross State Air Pollution Rule (CSAPR)

The AEO2016 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. EPA realigns the CSAPR schedule to comply with the Court's ruling, with Phase 1 beginning in December 2014 and more stringent Phase II targets taking effect in January 2016. Although CSAPR remains in place, the courts remanded CSAPR back to EPA in June 2015 for additional refinement affecting the Phase II implementation of NOx emission limits. The AEO2016 assumes the original targets are still in place.

Under CSAPR, 27 states must restrict emissions of sulfur dioxide and/or nitrogen oxide, which are precursors to the formation of fine particulate matter (PM2.5) and ozone. CSAPR establishes four distinct cap-and-trade system groups composed of different member states (Figure 8.2). CSAPR permits allowance trading between states within a group (approximated in NEMS by trade between coal demand regions) but not between groups.

As specified in CAAA1990, EPA developed a two-phase nitrogen oxide (NOx) program, with the first set of standards for existing coal plants applied in 1996 while the second set was implemented in 2000. Dry bottom wall-fired and tangential-fired boilers, the most common boiler types, are referred to as Group 1 Boilers, and were required to make significant reductions beginning in 1996 and further reductions in 2000. Relative to their uncontrolled emission rates, which range roughly between 0.6 and 1.0 pounds per million Btu, they are required to make reductions between 25% and 50% to meet the Phase I limits and further reductions to meet the Phase II limits. EPA did not impose limits on existing oil and 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 NOx limits are incorporated in EMM.

Figure 8.2. Cross State Air Pollution Rule



Source: U.S. Environmental Protection Agency, https://www.epa.gov/airmarkets

Table 8.7 shows the average capital costs for environmental control equipment utilized by NEMS for existing coal plants as retrofit options in order to remove sulfur dioxide (SO2), nitrogen oxides (NOX), mercury and/or hydrogen chloride (HCl). In the EMM, plant-specific costs are calculated based on the size of the unit and other operating characteristics. The table reflects the capacity-weighted averages of all plants falling into each size category. FGD units are assumed to remove 95% of the SO2, while SCR units are assumed to remove 90% of the NOX. The EMM also includes an option to install a dry sorbent injection (DSI) system, which is assumed to remove 70% of the SO2. However, the DSI option is only available under the mercury and air toxics rule discussed in the next section, as its primary benefit is for reducing hydrogen chloride (HCl).

Clean Power Plan with New Source Performance Standards for power generation

Under the Clean Air Act (CAA) Sections 111(b) and 111(d), EPA developed rules to constrain carbon emissions from power plants in October 2015. Section 111(b) sets carbon pollution standards for new, modified, and reconstructed power plants [86]. Section 111(d) sets performance standards for existing fossil fuel-fired plants and implemented through the Clean Power Plan (CPP) [87]. Final rules to support the performance standards and model trading rules were in effect by October 2015. However, on February 9, 2016, the U.S. Supreme Court issued a stay in enforcement of the existing plant rule, pending hearings of legal challenges by states and affected industries [88]. Given the high degree of uncertainty surrounding the actual state of "current law" in the case, the AEO2016 Reference case includes the CPP, and an alternative No CPP case, assuming that the CPP is not enforced, also is included.

To model the provisions of the performance standards for new plants, the AEO2016 assumes that the only coal technology allowed to be built in the future includes 30% carbon capture to ensure the ability to meet the standard of 1,400 lb CO_2 per MWh. New coal plants without carbon capture and storage technology cannot be built. The new natural gas combined-cycle plants modeled in previous AEOs were already below 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.

The CPP sets interim and final CO_2 emission performance rates for two subcategories of fossil fuel-fired EGUs: existing fossil steam units (interim/final rate, 1,534/1,305 lb CO_2/MWh net) and existing stationary CTs (interim/final rate, 832/731 lb CO_2/MWh net). The interim target must be met in 2022 and the final target in 2030, and EPA provides a phased-in approach over three steps during the implementation period.

States have significant flexibility in implementation of the CPP rule. EPA developed both rate-based and mass-based state-specific standards that are an equivalent quantitative expression of the source specific rates, and the states may choose between the two program types. In so doing, each state must determine whether to apply its emissions reduction requirements to affected EGUs, or to meet the equivalent state-wide CPP rate-based goal or mass-based goal. After choosing the rate-based or mass-based compliance option, states must then choose between: (1) an Emission Standards Plan Type, in which the state places all requirements directly on its affected EGUs, with all requirements federally enforceable; and (2) a State Measures Plan Type, which can include a mix of measures that may apply to affected EGUs and/or other entities, and may lead to CO_2 reductions from affected EGUs, but are not federally enforceable. States may use a wide variety of measures to comply with the rate-based standards, including options not assumed by EPA in the calculation of the standard. For example, new nuclear generation, new end-use renewable generation, and incremental demand reductions due to energy efficiency can be used as zero-emitting compliance options to offset emissions from affected generators.

The EMM was revised to represent both average rate-based or mass-based goals, with the option controlled by user input. Because the EMM is not a state-level model, EIA represents the CPP using EMM regions as compliance regions, implicitly assuming some level of state cooperation. EPA's state- level targets are mapped to EMM region using a generation-based weighting. Additional levels of cooperation across EMM regions can also be modeled. For the AEO2016 Reference case, EIA assumed that all regions opted to meet a mass-based target and that trading was only done within EMM regions. EPA developed two different mass-based targets, one covering only existing sources and another including new sources. EIA assumed the target including new sources was implemented, as this satisfies EPA's requirement to show that leakage of emissions to new sources will not occur as a result of implementation of the CPP. Other methods to limit leakage have not yet been well specified.

Under a mass-based program, an assumption must be made regarding the distribution of the initial allowances, which could be allocated to generators or load-serving entities, or sold through auction. The EMM was revised to represent any of these assumptions, with the impact flowing through to retail prices. The AEO2016 Reference case assumes allowances are allocated to load-serving entities, which provide the revenue back to consumers through lower distribution prices.

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 hydrogen chloride (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 are scheduled to take effect in 2015, but allow for a one-year waiver to comply, and require that all qualifying units achieve the maximum achievable control technology (MACT) for each of the three covered pollutants. For AEO2016, EIA assumes that all coal-fired generating units with a capacity greater than 25 megawatts will comply with the rule beginning in 2016, due to the large number of plants requesting the one-year extension. All power plants are required to reduce their mercury emissions to 90% below their uncontrolled emissions levels.

Because the EMM does not explicitly model HCl or PM2.5, specific control technologies are assumed to be used to achieve compliance. In order to meet the HCl requirement, units must have either flue gas desulfurization (FGD) scrubbers or dry sorbent injection (DSI) systems in order to continue operating. A full fabric filter (FF) is also required to meet the PM2.5 limits and to improve the effectiveness of the DSI technology. 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 cobenefit. The EMM considers all combinations of controls and may choose to add NOx or SO2 controls purely to lower mercury if it is economic 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 $6 (2015 dollars) per kilowatt of capacity [89]. 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 8.7. The amount of activated carbon required to meet a given percentage removal target is given by the following equations [90].

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

Table 8.7. Coal plant retrofit costs

2015 dollars per kW

Coal Plant Size (MW)	FGD Capital Costs	DSI Capital Costs	FF Capital Costs	SCR Capital Costs
<100	929	155	266	402
100 - 299	650	80	197	266
300 - 499	514	48	166	217
500 - 699	457	35	152	203
>=700	410	30	139	185

Source: Documentation for EPA Base Case v4.10 using the Integrated Planning Model, August 2010, EPA Contract EP-W-08-018, Appendices to Chapter 5.

Power plant mercury emissions assumptions

The EMM represents 35 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, sulfur dioxide (SO2) control devices, nitrogen oxide (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 that was in the fuel is removed by various parts of the plant. Table 8.8 provides the assumed EMFs for existing coal plant configurations without mercury-specific controls.

Table 8.8. 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: SO2 Controls - Wet = Wet Scrubber and Dry = Dry Scrubber, Particulate Controls, BH - fabric filter/baghouse. CSE = cold side electrostatic precipitator, HSE = hot side electrostatic precipitator, NOx Controls, 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: EPA, EMFs. www.epa.gov/clearskies/technical.html . 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.

Planned SO2 Scrubber and NOx control equipment additions

EIA assumes that all planned retrofits, as reported on the Form EIA-860, will occur as currently scheduled. For AEO2016, this includes 14.5 GW of planned SO2 scrubbers (Table 8.9) and 0.3 GW of planned selective catalytic reduction (SCR) added after 2014.

Carbon capture and sequestration retrofits

The EMM includes the option of retrofitting existing coal plants for carbon capture and sequestration (CCS). The modeling structure for CCS retrofits within the EMM was developed by the National Energy Technology Laboratory[91] 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 around 30% and 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 $1,679 per kilowatt, and ranging from $1,222 to $2,386 per kilowatt. It was assumed that only plants greater than 500 megawatts and with heat rates below 12,000 Btu per kilowatthour would be considered for CCS retrofits.

Table 8.9. Planned SO2 scrubber additions by EMM region

Regions	gigawatts
Texas Reliability Entity	0.0
Florida Reliability Coordinating Council	0.0
Midwest Reliability Council - East	1.2
Midwest Reliability Council - West	1.4
Northeast Power Coordinating Council/New England	0.0
Northeast Power Coordinating Council/NYC-Westchester	0.0
Northeast Power Coordinating Council/Long Island	0.0
Northeast Power Coordinating Council/Upstate	0.0
ReliabilityFirst Corporation/East	0.0
ReliabilityFirst Corporation/Michigan	1.7
ReliabilityFirst Corporation/West	4.8
SERC Reliability Corporation/Delta	0.0
SERC Reliability Corporation/Gateway	1.2
SERC Reliability Corporation/Southeastern	1.0
SERC Reliability Corporation/Central	0.0
SERC Reliability Corporation/Virginia-Carolina	0.0
Southwest Power Pool/North	1.3
Southwest Power Pool/South	1.6
Western Electricity Coordinating Council/Southwest	0.0
Western Electricity Coordinating Council/California	0.0
Western Electricity Coordinating Council/Northwest Power Pool Area	0.0
Western Electricity Coordinating Council/Rockies	0.5
Total	14.5

Source: U.S. Energy Information Administration, Form EIA-860, “Annual Electric Generator Report.”

Heat rate improvement retrofits

Since the AEO2015, the EMM includes the capability to evaluate the potential for making 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, and therefore reducing 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 as it considers the tradeoff between the investment expenditures and the savings in fuel and/or environmental compliance costs. The amount of potential increase in efficiency can vary depending on the type of equipment installed at a unit, as well as the beginning configuration of the plant. The EMM represents 32 configurations of existing coal-fired plants based on different combinations of particulate, sulfur dioxide (SO2), nitrogen oxide (NOx), mercury, and carbon emission controls (Table 8.10). 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 [92]. 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. Leidos employed statistical modeling techniques to create the predictive models.

For the EMM plant types, the coal-fired generating units were categorized according to 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 the application of 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 purposes of the quartile analysis and for each of these combinations Leidos created a minimum and 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 8.11)

Table 8.10. 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 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

Table 8.11. 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-yr)
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.

Source: U.S. Energy Information Administration/Leidos Corporation.

State air emissions regulation

AEO2016 continues to model the Northeast Regional Greenhouse Gas Initiative (RGGI), which applies to fossil-fuel powered plants over 25 megawatts in the northeastern United States. The state of 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. Because the baseline and projected emissions were calculated before the economic recession that began in 2008, the actual emissions in the first years of the program have been less than the cap, leading to excess allowances and allowance prices at the floor price. As a result, in February 2013 program officials announced a tightening of the cap starting in 2014. Beginning with AEO2014, the EMM applies these revised targets, which reflect a cap that is 45% of the original target for 2014.

The California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006, authorized the California Air Resources Board (CARB) to set California's GHG reduction goals for 2020 and establish a comprehensive, multi-year program to reduce GHG emissions in California. As one of the major initiatives for AB 32, CARB designed a cap-and-trade program that started on January 1, 2012, with the enforceable compliance obligations beginning in 2013 for the electric power sector and industrial facilities. Fuel providers must comply starting in 2015. The AB 32 cap-and-trade provisions are incorporated in NEMS through an emission constraint in the EMM that also accounts for the emissions determined by the other sectors. Within the power sector, emissions from plants owned by California utilities but located out of 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 Bill, providing some compliance flexibility and cost containment.

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% investment tax credit for geothermal and solar facilities, and introduced a production tax credit for eligible renewable technologies (subsequently extended and expanded). EPACT2005 provides a 20% investment tax credit for Integrated Coal-Gasification Combined Cycle capacity and a 15% investment tax credit 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 production tax credit (PTC) of 1.8 cents (nominal) per kWh for new nuclear capacity beginning operation by 2020. This PTC is specified for the first 8 years of operation, and is limited to $125 million annually and 6 GW of new capacity. However, this credit may be shared to additional units if more than 6 GW are under construction by January 1, 2014. EPACT2005 extended the PTC for qualifying renewable facilities by 2 years, or through December 31, 2007. It also repealed the Public Utility Holding Company Act (PUHCA).

Renewable electricity tax credits

The investment and energy production tax credits initiated in EPACT92 and amended in EPACT2005 have been further amended through a series of Acts, which have been 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 phaseout [93]. The AEO2016 reflects the most recent changes implemented through the 2016 Consolidated Appropriation Act passed in December 2015. Solar projects under construction before the end of 2019 receive an investment tax credit of 30%, and the credit is phased down over two years, and then is reduced to 10% for plants under construction after 2021.

The production tax credit (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 AEO2016, wind, poultry litter, geothermal, and closed-loop biomass resources receive a tax credit of 2.3 cents/kWh; all other renewable resources receive a 1.1 cent/kWh (that is, one-half the value of the credit for other resources) tax credit. EIA assumes that biomass facilities obtaining the PTC will use open-loop fuels, as 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 wind projects 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; and 40% of the current PTC if construction begins in 2019.

The investment and production tax credits are exclusive of one another, and thus may not both be claimed for the same geothermal facility (which is eligible to receive either).

American Recovery and Reinvestment Act (ARRA)

Smart grid expenditures

ARRA provides $4.5 billion for smart grid demonstration projects. While 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, facilitate greater use of renewables, and provide information to utilities and their customers that will lead to greater investment in energy efficiency and reduced peak load demands. The funds provided will not fund a widespread implementation of smart grid technologies, but could stimulate more rapid investment 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, it was assumed that line losses would fall slightly, peak loads would fall as customers shifted their usage patterns, and customers would be more responsive to pricing signals. Historically, line losses, expressed as the percentage of electricity lost, have been falling for many years as utilities make investments to replace aging or failing equipment.

Smart grid technologies also have the potential to reduce peak demand through the increased deployment of demand response programs. It is assumed that the Federal expenditures on smart grid technologies will stimulate efforts that reduce peak demand from what they otherwise would be, with the amount of total peak load reduction growing from 2.2% initially to 3.5% by 2040, although the shifts vary by region. Load is shifted to offpeak hours, so net energy consumed remains largely constant.

FERC Orders 888 and 889

The Federal Energy Regulatory Commission (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 due to 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 are able to satisfy load requirements anywhere within the region. Similarly, it is assumed that transactions between regions will occur if the cost differentials between them make such transactions economical.

Notes and sources

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