Electricity Market Module

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The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules—electricity capacity planning, electricity fuel dispatching, electricity load and demand, 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 EIA publication, Electricity Market Module of the National Energy Modeling System 2012, DOE/EIA-M068(2012).

Based on fuel prices and electricity demands provided by the other modules of the 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 EMM. It includes a discussion of legislation and regulations that are incorporated in EMM as well as information about the climate change action plan. The various electricity and technology cases are also described.

EMM regions

The supply regions used in EMM are based on the North American Electric Reliability Corporation regions and subregions shown in Figure 6.

Figure 6. 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]
High Sulfur Pulverized Coal with Wet Flue Gas Desulfurization
Advanced Coal - Integrated Coal Gasification Combined Cycle
Advanced Coal with 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 - Fixed Tilt
Wind
Wind Offshore

[1]The EMM represents 32 different types of existing coal steam plants, based on the different possible configuration of NO_x, particulate and SO_2 emission control devices, as well as future options for controlling mercury.
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 fossil-fueled technologies are assumed to decline linearly through 2025.

For the *AEO2011*, EIA commissioned an external consultant to develop current cost estimates for utility-scale electric generating plants [1]. This report continues to be the basis for the cost assumptions for *AEO2012*. 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 represent the estimated cost of building a plant in a typical region of the country. Differences in plant costs due to regional distinctions are calculated by applying regional multipliers. Regional multipliers by technology were also updated for *AEO2012* based on regional cost estimates developed by the consultant. The regional variations account for multiple factors, such as differences in terrain, weather, population, and labor wages. The base overnight cost is multiplied by a project contingency factor and a technological optimism factor (described later in this chapter), resulting in the total construction cost for the first-of-a-kind unit used for the capacity choice decision.

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

Technology	Online Year[1]	Size (mW)	Lead time (years)	Base Overnight Cost in 2010 (2010 $/kW)	Contingency Factors: Project Contingency Factor[2]	Contingency Factors: Technological Optimism Factor[3]	Total Overnight Cost in 2010[4] (2010 $/kW)	Variable O&M[5] (2010 $/mWh)	Fixed O&M (2010$/kW)	Heatrate[6] in 2011 (Btu/KWh)	nth-of-a-kind Heatrate (Btu/KWh)
Scrubbed Coal New[7]	2015	1300	4	2,658	1.07	1.00	2,844	4.25	29.67	8,800	8,740
Integrated Coal-Gasification Comb Cycle (IGCC)[7]	2015	1200	4	3,010	1.07	1.00	3,220	6.87	48.90	8,700	7,450
IGCC with carbon sequestration	2017	520	4	4,852	1.07	1.03	5,348	8.04	69.30	10,700	8,307
Conv Gas/Oil Comb Cycle	2014	540	3	931	1.05	1.00	977	3.43	14.39	7,050	6,800
Adv Gas/Oil Comb Cycle (CC)	2014	400	3	929	1.08	1.00	1,003	3.11	14.62	6,430	6,333
Adv CC with carbon sequestration	2017	340	3	1,834	1.08	1.04	2,060	6.45	30.25	7,525	7,493
Conv Comb Turbine[8]	2013	85	2	927	1.05	1.00	974	14.70	6.98	10,745	10,450
Adv Comb Turbine	2013	210	2	634	1.05	1.00	666	9.87	6.70	9,750	8,550
Fuel Cells	2014	10	3	5,918	1.05	1.10	6,836	0.00	350.00	9,500	6,960
Adv Nuclear	2017	2236	6	4,619	1.10	1.05	5,335	2.04	88.75	10,460	10,460
Distributed Generation - Base	2014	2	3	1,366	1.05	1.00	1,434	7.46	16.78	9,050	8,900
Distributed Generation - Peak	2013	1	2	1,640	1.05	1.00	1,722	7.46	16.78	10,056	9,880
Biomass	2015	50	4	3,519	1.07	1.02	3,859	5.00	100.55	13,500	13,500
Geothermal[7,9]	2011	50	4	2,393	1.05	1.00	2,513	9.64	108.62	9,760	9,760
MSW - Landfill Gas	2011	50	3	7,694	1.07	1.00	8,233	8.33	378.76	13,648	13,648
Conventional Hydropower[9]	2015	500	4	2,134	1.10	1.00	2,347	2.55	14.27	9,760	9,760
Wind	2011	100	3	2,278	1.07	1.00	2,437	0.00	28.07	9,760	9,760
Wind Offshore	2015	400	4	4,345	1.10	1.25	5,974	0.00	53.33	9,760	9,760
Solar Thermal[7]	2014	100	3	4,384	1.07	1.00	4,691	0.00	64.00	9,760	9,760
Photovoltaic[7,10]	2013	150	2	4,528	1.05	1.00	4,755	0.00	16.70	9,760	9,760

[1]Online year represents the first year that a new unit could be completed, given an order date of 2011. For wind, geothermal and landfill gas, the online year was moved earlier to acknowledge the significant market activity already occuring in anticipation of the expiration of the Production Tax Credit.
[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 2011.
[5]O&M = Operations and maintenance.
[6]For hydro, geothermal, wind, and solar technologies, the heatrate shown represents the average heatrate for conventional thermal generation as of 2010. 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]Capital costs are shown before investment tax credits are applied.
[8]Combustion turbine units can be built by the model prior to 2013 if necessary to meet a given region's reserve margin.
[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]Costs and capacities are expressed in terms of net AC power available to the grid for the installed capacity.
Sources: For the *AEO2012* cycle, EIA continues to use the previously developed cost estimates for utility-scale electric generating plants, prepared by external consultants for *AEO2011*. This report can be found at www.eia.gov/oiaf/beck_plantcosts/index.html. Site-specific costs for geothermal were provided by the National Energy Renewable Laboratory, "Updated U.S. Geothermal Supply Curve," February 2010.

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 4 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 8.3). 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 has the nonlinear form:

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

where C is the cumulative capacity for the technology component.

Table 8.3. 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 2025
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	20%	10%	1%	3	5	20%
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%	-	-	1%
Wind Offshore	20%	10%	1%	3	5	20%
Solar Thermal	20%	10%	1%	3	5	10%
Solar PV - Module	20%	10%	1%	1	5	10%
Balance of Plant - Solar PV	20%	10%	1%	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 (e.g., 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 8.3). 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.

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

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 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 8.4). 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 50 percent of the cost, and that the balance of system components accounts for the remaining 50 percent. 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 8.5 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 toward turbine learning, and 0.33 gigawatts toward steam learning. Components that do not contribute to the capacity of the plant, such as the balance of plant category, receive 100 percent 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 percent, both conventional and advanced.

Table 8.4. Component cost weights for new technologies

Technology	Pulverized Coal	Combus-tion 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
Integrated Coal-Gasification Comb Cycle (IGCC)	0%	0%	15%	20%	41%	0%	24%	0%	0%	0%
IGCC with carbon sequestration	0%	0%	10%	15%	30%	30%	15%	0%	0%	0%
Conv Gas/Oil Comb Cycle	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 percent 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 8.5. Component capacity weights for new technologies

Technology	Pulverized Coal	Combus-tion 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
Integrated Coal-Gasification Comb Cycle (IGCC)	0%	0%	67%	33%	100%	0%	100%	0%	0%	0%
IGCC with carbon sequestration	0%	0%	67%	33%	100%	100%	100%	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 electricity model 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 for *AEO2012*, it is assumed that this capacity is limited to 3 percent of peak demand on average, with limits varying from 2 percent to 6 percent of peak across the regions.

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 9 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 percent of the load, and then two off-peak segments representing the next 49 percent and 50 percent, respectively. The seasons were defined to account for seasonal variation in supply availability.

Reserve margins—the percentage of capacity required in excess of peak demand needed for unforeseeable outages—are determined within the model through an iterative approach comparing the marginal cost of capacity and the cost of unserved energy. The target reserve margin is adjusted each model cycle until the two costs converge. The resulting reserve margins from the *AEO2012* Reference case range from 8 to 21 percent.

Fossil fuel-fired and nuclear steam plant retirement

Fossil-fired steam plant retirements and nuclear retirements are calculated endogenously within the model. Plants 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 plants. A plant is assumed to retire if the expected revenues from it 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 plant-specific and based on historical data. The average capital additions for existing plants are $8 per kilowatt (kW) for oil and gas steam plants, $16 per kW for coal plants and $22 per kW for nuclear plants (in 2010 dollars). These costs are added to the estimated costs at existing plants regardless of their age. Beyond 30 years of age an additional $6 per kW capital charge for fossil plants, and $32 per kW charge for nuclear plants is included in the retirement decision to reflect further investment to address impacts of aging. Age-related cost increases are due to capital expenditures for major repairs or retrofits, decreases in plant performance, and/or increased 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 *AEO2012* nuclear projection assumes an additional 5.5 gigawatts of nuclear plant retirements by 2035 based on the uncertainty related to resolving issues associated with long-term operations and aging management.

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 $274 per kW of biomass capacity. A coal-fired unit modified to allow co-firing can generate up to 15 percent of the total output using biomass fuel, assuming sufficient residue supplies are available.

Nuclear uprates

The *AEO2012* 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 percent) increases in capacity, which require very little capital investment or plant modification, to extended uprates of 15-20 percent, requiring significant modifications. Historically, most uprates were small, and the *AEO* projections accounted for them only after they were implemented and reported, but recent surveys by the NRC and EIA have indicated that more extended power uprates are expected in the near future. *AEO2012* assumes that all of those uprates reported to EIA as planned modifications on the Form EIA-860 will take place, representing 0.8 gigawatts of additional capacity. EIA also assumes an additional 6.5 gigawatts of nuclear power uprates will be completed over the projection period, based on interactions with industry stakeholders and the NRC. Table 8.6 provides a summary of projected uprate capacity additions by region.

Table 8.6. Nuclear uprates by EMM region
gigawatts

Texas Reliability Entity	0.25
Florida Reliability Coordinating Council	0.67
Midwest Reliability Council - East	0.00
Midwest Reliability Council - West	0.49
Northeast Power Coordinating Council/New England	0.25
Northeast Power Coordinating Council/NYC-Westchester	0.00
Northeast Power Coordinating Council/Long Island	0.00
Northeast Power Coordinating Council/Upstate	0.50
ReliabilityFirst Corporation/East	0.82
ReliabilityFirst Corporation/Michigan	0.25
ReliabilityFirst Corporation/West	0.97
SERC Reliability Corporation/Delta	0.25
SERC Reliability Corporation/Gateway	0.00
SERC Reliability Corporation/Southeastern	0.25
SERC Reliability Corporation/Central	0.75
SERC Reliability Corporation/Virginia-Carolina	1.10
Southwest Power Pool/North	0.00
Southwest Power Pool/South	0.00
Western Electricity Coordinating Council/Southwest	0.25
Western Electricity Coordinating Council/California	0.50
Western Electricity Coordinating Council/Northwest Power Pool Area	0.00
Western Electricity Coordinating Council/Rockies	0.00
Total	7.31

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis, based on Nuclear Regulatory Commission survey www.nrc.gov/reactors/operating/licensing/power-updates.html.

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 North American Electric Reliability Corporation and Western Electricity Coordinating Council Summer and Winter Assessment of Reliability of Bulk Electricity Supply in North America. Known firm power contracts are obtained from NERC's Electricity Supply and Demand Database 2007 and information provided in the 2011 Summer and Winter Assessments. They are locked in for the term of the contract. Contracts that are scheduled to expire by 2016 are assumed not to be renewed. Because there is no information available about expiration dates for contracts that go beyond 2016, they are assumed to be phased out by 2025. The EMM includes an option to add interregional transmission capacity. In some cases it may be more economic 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 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 obtained from the North American Electric Reliability Corporation's Electricity Supply and Demand Database 2007. 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 is determined using Canadian electricity supply and demand projections from the MAPLE-C model developed for Natural Resources Canada.

Electricity pricing

Electricity pricing is forecast for 22 electricity market regions in *AEO2012* 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. In competitive regions, an algorithm in place allows customers to compete for better rates among rate classes as long as the overall average cost is met. 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 generation 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 cost (fuel and variable operations and maintenance), taxes, and a reliability price adjustment, which represents what customers are willing to pay for added capacity to avoid outages in periods of high 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 is a load-weighted average of the competitive price and the regulated price, based on the percent of electricity load in the region that has taken action to deregulate. In competitively supplied regions, a transition period is assumed to occur (usually over a ten-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 97-percent transition to competitive pricing in New England (Vermont being the only fully-regulated State in that region). Six regions fully regulate their electricity supply, including the Florida Reliability Coordinating Council, three of the SERC Reliability Corporation subregions - Southeastern (SRSE), Central (SRCE) and Virginia-Carolina (SRVC) - Southwest Power Pool Regional Entity/North (SPNO), and the Western Electricity Coordinating Council / Rockies (RMPA). The Texas Reliability Entity, which in the past was considered fully competitive by 2010, now reaches only 88-percent 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 7 percent competitive supply sold currently in the Western Electricity Coordinating Council (WECC)/ California region. All other regions are 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 there. Since price freezes for most customers have ended or will end in the next year or two, a large survey of utility tariffs found that many costs related to the transition to competition were 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 are some unexpected costs relating to unforeseen events. For instance, as a result of volatile fuel markets, State regulators have had a hard time enticing retail suppliers to offer competitive supply to residential and smaller commercial and industrial customers. They have often resorted to procuring the energy themselves through auction or competitive bids or have allowed distribution utilities to procure the energy on the open market for their customers for a fee. For *AEO2012*, 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 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 forecast. Regions found to have these added costs include the Northeast Power Coordinating Council/ New England and New York regions, the ReliabilityFirst Corporation/ East and West regions, and the WECC/ California region.

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 (U_3O_8) 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 U-235, typically 3-5 percent 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 one mill per kilowatthour charge that is assessed on nuclear generation to go to the DOE's Nuclear Waste Fund is also included in the final nuclear price. The analysis uses forecasts from Energy Resources International for the underlying uranium prices.

Legislation and regulations

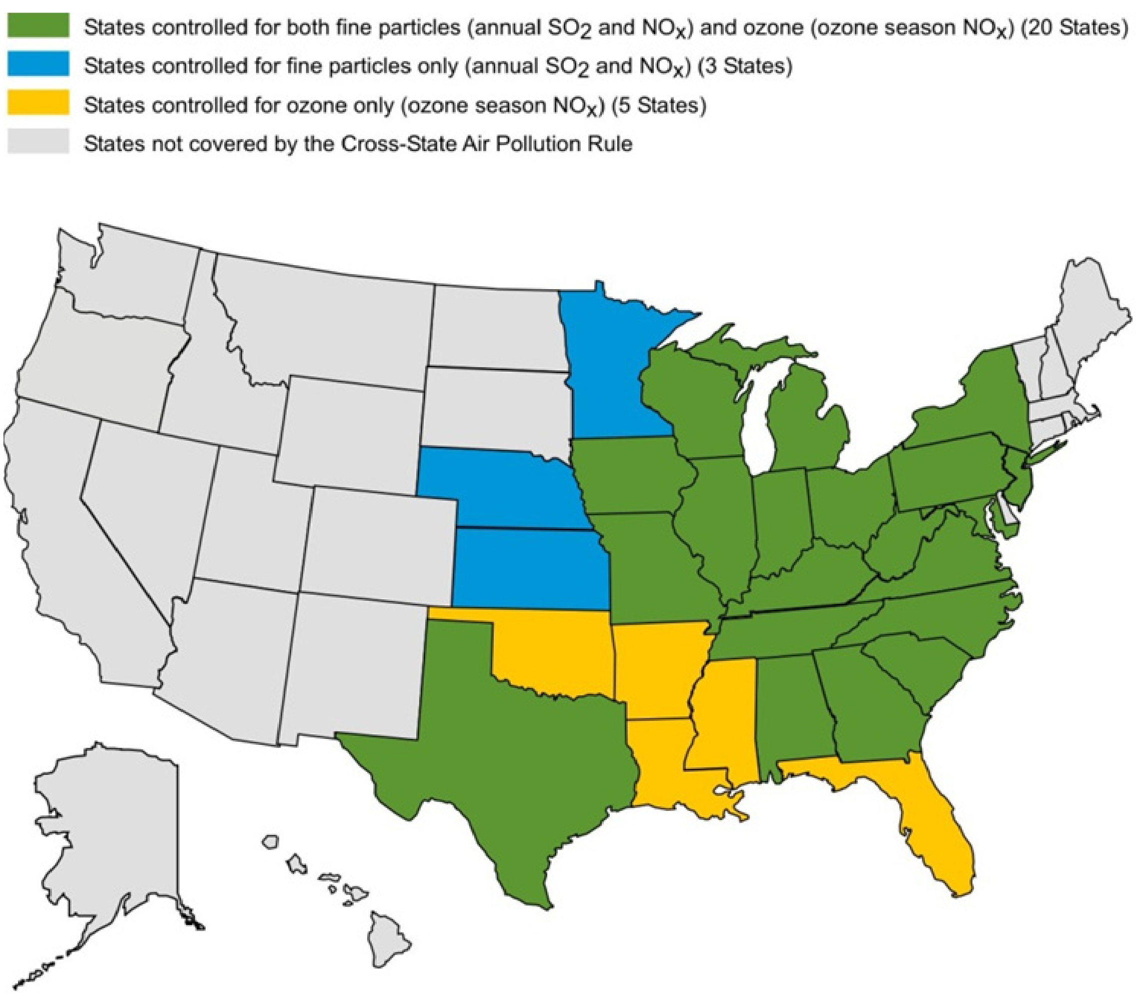
Clean Air Act Amendments of 1990 (CAAA90) and Cross-State Air Pollution Rule (CSAPR)

The Cross-State Air Pollution Rule (CSAPR) was released by EPA in July 2011 and was created to regulate SO_2 and NO_x emissions from coal, oil, and natural gas steam power plants. CSAPR is intended to help States meet their National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter. CSAPR implementation has been delayed because of a stay issued by the U.S. Court of Appeals for the D.C. Circuit. However, it is included in *AEO2012* despite the stay, because the Court of Appeals had not made a final ruling at the time *AEO2012* was completed.

CSAPR puts limits on annual emissions of SO2 and NOx, as well as seasonal NOx limits to address ground-level ozone. Twenty-three States are subject to the annual limits, and 25 States are subject to the seasonal limits. CSAPR consists of four individual cap and trade programs, covering two different SO2 groups, the Annual NOx group and the Seasonal NOx group (Figure 7). Each program was scheduled to begin in January 2012 with an initial annual cap, and for the Group 1 SO2 program, the cap is reduced further in 2014.

As specified in the CAAA90, EPA has developed a two-phase nitrogen oxide (NO_x) 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, referred to as Group 1 Boilers, 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 percent to meet the Phase I limits and further reductions to meet the Phase II limits. The EPA did not impose limits on existing oil and gas plants, but some states have additional NO_x regulations. All new fossil units are required to meet 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 NO_x limits are incorporated in EMM.

Figure 7. States covered by CSAPR limits on sulfur dioxide and nitrogen oxide emissions



Source: U.S. Energy Information Administration.

Sample costs of adding flue gas desulfurization equipment (FGD) to remove sulfur dioxide (SO_2) and selective catalytic reduction (SCR) equipment to remove nitrogen oxides (NOx) are given below for 100, 300, 500, and 700-megawatt coal plants. In the EMM, plant-specific costs are calculated based on the size of the unit and other operating characteristics. FGD units are assumed to remove 95 percent of the SO_2, while SCR units are assumed to remove 90 percent of the NOx. For *AEO2012*, the EMM also includes an option to install a dry sorbent injection (DSI) system, which is assumed to remove 70 percent of the SO_2. 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). The costs per megawatt of capacity decline with plant size and are shown in Table 8.7.

Table 8.7. Coal plant retrofit costs
2010 dollars

Coal Plant Size (MW)	FGD Capital Costs ($/kw)	SCR Capital Costs ($/kw)	DSI Capital Costs ($/kw)
100	642	222	125
300	497	187	57
500	432	174	40
700	360	155	31

Documentation for EPA Base Case v4.10 using the Integrated Planning Model, August 2010, EPA Contract EP-W-08-018.

Mercury regulation

The Mercury and Air Toxics Standards (MATS) rule was finalized in December 2011 to fulfill EPA's requirement to regulate mercury emissions from power plants. MATS also regulates other hazardous air pollutants (HAPS) such as hydrogen chloride (HCl) and fine particulate matter (PM2.5). The rule 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 and require that all qualifying units achieve the maximum achievable control technology (MACT) for each of the three covered pollutants. For *AEO2012*, EIA assumes that all coal-fired generating units with a capacity greater than 25 megawatts will comply with the rule beginning in 2015. All power plants are required to reduce their mercury emissions to 90 percent 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 is also required to meet the PM2.5 limits and to improve the effectiveness of the DSI technology. For mercury reductions, the EMM allows plants to alter their configuration by adding equipment, such as an SCR to remove NO_x or an SO_2 scrubber. They 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 (2010 dollars) per kilowatt of capacity, while the cost of a supplemental fabric filter with activated carbon injection (often referred as a COPAC unit) is approximately $150 (2010 dollars) per kilowatt of capacity [2]. The amount of activated carbon required to meet a given percentage removal target is given by the following equations [3].

For a unit with a 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 HSE/Other, and a supplemental fabric filter with activated carbon injection:

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

ACI = activated carbon injected in pounds per million actual cubic feet.

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 (SO_2) control devices, nitrogen oxide (NO_x) 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 percent 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		
SO_2 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: SO_2 Controls - Wet = Wet Scrubber and Dry = Dry Scrubber, Particulate Controls, BH - fabric filter/baghouse. CSE = cold side electrostatic precipitator, HSE = hot side electrostatic precipitator, NO_x Controls, SCR = selective catalytic reduction,
— = not applicable, Bit = bituminous coal, Sub = subbituminous coal. The NO_x control system is not assumed to enhance mercury removal unless a wet scrubber is present, so 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 Laboratory, U.S. Department of Energy, January 2003, Washington, DC.

Planned SO_2 Scrubber and NO_x control equipment additions

EIA assumes that all planned retrofits, as reported on the Form EIA-860, will occur as currently scheduled. For *AEO2012*, this includes 10.8 gigawatts of planned SO_2 scrubbers (Table 8.9) and 4.5 gigawatts of planned selective catalytic reduction (SCR).

Carbon capture and sequestration retrofits

Although a Federal greenhouse gas program is not assumed in the *AEO2012* Reference case, the EMM includes the option of retrofitting existing coal plants for carbon capture and sequestration (CCS). This option is important when considering alternate scenarios that do constrain carbon emissions. The modeling structure for CCS retrofits within the EMM was developed by the National Energy Technology Laboratory[4] and uses a generic model of retrofit costs as a function of basic plant characteristics (such as heatrate). The costs have been adjusted to be consistent with costs of new CCS technologies. The CCS retrofits are assumed to remove 90 percent of the carbon input. The addition of the CCS equipment results in a capacity derate of around 30 percent and reduced efficiency of 43 percent at the existing coal plant. The costs depend on the size and efficiency of the plant, with the capital costs ranging from $1,110 to $1,620 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.

State Air Emissions Regulation

AEO2012 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 CO_2 emissions from covered electricity generating facilities and requires that they account for each ton of CO_2 emitted with an allowance purchased at auction. 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.

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. Although the cap-and-trade program applies to multiple economic sectors, for *AEO2012* it is only assumed to be implemented in the electric power sector. The electric power sector represented 25 percent of the State's GHG emissions in 2008, and therefore the EMM modeled the power sector cap at 25 percent of the limits specified in the bill for all sectors.

Table 8.9. Planned SO_2 scrubber additions by EMM region
gigawatts

Texas Reliability Entity	0.0
Florida Reliability Coordinating Council	0.0
Midwest Reliability Council - East	0.0
Midwest Reliability Council - West	0.0
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	1.0
ReliabilityFirst Corporation/East	1.2
ReliabilityFirst Corporation/Michigan	0.0
ReliabilityFirst Corporation/West	4.4
SERC Reliability Corporation/Delta	0.0
SERC Reliability Corporation/Gateway	0.0
SERC Reliability Corporation/Southeastern	4.1
SERC Reliability Corporation/Central	0.2
SERC Reliability Corporation/Virginia-Carolina	0.0
Southwest Power Pool/North	0.0
Southwest Power Pool/South	0.0
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	0.0
Total	10.8

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

Energy Policy Acts of 1992 (EPACT92) and 2005 (EPACT05)

The provisions of the EPACT92 include revised licensing procedures for nuclear plants and the creation of exempt wholesale generators (EWGs). The EPACT05 provides a 20-percent investment tax credit for Integrated Coal-Gasification Combined Cycle capacity and a 15-percent investment tax credit for other advanced coal technologies. These credits are limited to 3 gigawatts in both cases. It also contains a production tax credit (PTC) of 1.8 cents (nominal) per kilowatthour for new nuclear capacity beginning operation by 2020. This PTC is specified for the first 8 years of operation, is limited to $125 million (per gigawatt) annually, and is limited to 6 gigawatts of new capacity. However, this credit may be shared to additional units if more than 6 gigawatts are under construction by January 1, 2014. EPACT05 extended the PTC for qualifying renewable facilities by 2 years, or December 31, 2007. It also repealed the Public Utility Holding Company Act (PUHCA).

Energy Improvement and Extension Act 2008 (EIEA2008)

EIEA2008 extended the investment tax credit of 30 percent through 2016 for solar and fuel cell facilities.

American Recovery and Reinvestment Act (ARRA)

Updated tax credits for Renewables

ARRA extended the expiration date for the PTC to January 1, 2013, for wind and January 1, 2014, for all other eligible renewable resources. In addition, ARRA allows companies to choose an investment tax credit (ITC) of 30 percent in lieu of the PTC and allows for a grant in lieu of this credit to be funded by the U.S. Treasury. For some technologies, such as wind, the full PTC would appear to be more valuable than the 30 percent ITC; however, the difference can be small. Qualitative factors, such as the lack of partners with sufficient tax liability, may cause companies to favor the ITC grant option. *AEO2012* generally assumes that renewable electricity projects will claim the more favorable tax credit or grant option available to them.

Loan guarantees for renewables

ARRA provided $6 billion to pay the cost of guarantees for loans authorized by the Energy Policy Act of 2005. While most renewable projects which start construction prior to September 30, 2011 are potentially eligible for these loan guarantees, the application and approval of guarantees for specific projects is a highly discretionary process, and has thus far been limited. While *AEO2012* includes projects that have received loan guarantees under this authority, it does not assume automatic award of the loans to potentially eligible technologies.

Support for CCS

ARRA provided $3.4 billion for additional research and development on fossil energy technologies. A portion of this funding is expected to be used to fund projects under the Clean Coal Power Initiative program, focusing on projects that capture and sequester greenhouse gases. To reflect the impact of this provision, *AEO2012* Reference case assumes that an additional 1 gigawatt of coal capacity with CCS will be stimulated by 2017.

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 generator to 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 the 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. In *AEO2012*, it is assumed that the Federal expenditures on smart grid technologies will stimulate efforts that reduce peak demand in 2035 by 3 percent from what they otherwise would be. Load is shifted to offpeak hours, so net energy consumed remains largely constant.

FERC Orders 888 and 889

FERC has 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. Consequently, utilities are expected to functionally or physically unbundle 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.

Electricity alternative cases

Integrated Technology cases

The Integrated High Technology Cost case combines assumptions from the end-use High Technology cases with assumptions on lower costs of new power plants, including renewables, nuclear and fossil. Assumptions for the other sectors appear in the respective chapters. This case assumes that the capital and operating costs for new fossil and nuclear plants will start 20 percent lower than in the Reference case, and will be 40 percent lower than Reference case levels in 2035.

The Integrated 2011 technology case combines assumptions from the end-use 2011 Technology cases and higher costs for new power plants. In the EMM it is assumed that the base costs of all nuclear and fossil generating technologies will remain at current costs during the projection period, with no reductions due to learning. The annual commodity cost adjustment factor is still applied as in the Reference case.

Table 8.10 shows the costs assumed for new fossil technologies across the Integrated Technology cases, while Table 8.11 shows the costs for new nuclear plants in the same cases.

Table 8.10. Cost and performance characteristics for fossil-fueled generating technologies: three cases

		Total Overnight Cost[1]		
	Total Overnight Cost in 2012 (Reference) (2010$/kW)	Reference (2010$/kW)	Low Integrated Technology (2010$/kW)	High Integrated Technology (2010$/kW)
Pulverized Coal	2844			
2015		2985	3005	2311
2020		2784	2830	2034
2025		2597	2666	1784
2030		2354	2449	1515
2035		2115	2229	1269
Advanced Coal	3220			
2015		3366	3403	2604
2020		3100	3204	2265
2025		2865	3019	1968
2030		2565	2773	1651
2035		2281	2524	1368
Advanced Coal with Sequestration	5348			
2015		5564	5650	4306
2020		5094	5321	3721
2025		4673	5013	3209
2030		4155	4605	2674
2035		3662	4191	2197
Conventional Combined Cycle	977			
2015		1026	1033	794
2020		956	972	698
2025		892	916	614
2030		809	841	520
2035		727	766	436
Advanced Gas	1003			
2015		1050	1060	813
2020		963	998	703
2025		890	940	611
2030		795	864	511
2035		706	786	424
Advanced Gas with Sequestration	2060			
2015		2141	2177	1657
2020		1949	2050	1423
2025		1782	1931	1224
2030		1576	1774	1014
2035		1383	1614	829
Conventional Combustion Turbine	974			
2015		1022	1029	790
2020		953	969	696
2025		889	913	610
2030		806	838	518
2035		724	763	434
Advanced Combustion Turbine	666			
2015		695	704	538
2020		631	663	461
2025		579	624	398
2030		512	573	329
2035		451	522	270

[1]Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects online in the given year.

Source: U.S. Energy Information Administration. *AEO2012* National Energy Modeling System runs: REF2012.D020112C, LTRKITEN.D031312A, HTRKITEN.D032812A

Table 8.11. Cost characteristics for advanced nuclear technology: three cases

		Total Overnight Cost[1]		
	Overnight Cost in 2012 (Reference) (2010$/kW)	Reference (2010$/kW)	Low Integrated Technology (2010$/kW)	High Integrated Technology (2010$/kW)
Advanced Nuclear	5335			
2015		5466	5638	4231
2020		4733	5309	3456
2025		4302	5002	2954
2030		3850	4594	2477
2035		3414	4181	2049

[1]Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects online in the given year.
Source: U.S. Energy Information Administration. *AEO2012* National Energy Modeling System runs: REF2012.D020112C, LTRKITEN.D031312A, HTRKITEN.D032812A.

Electricity Environmental Regulation cases

Over the next few years electricity generators will have to begin steps to comply with a number of new environmental-Regulations, primarily through adding environmental controls at existing coal power plants. The additional cases examine the impacts of shorter economic recovery periods for the environmental controls, both with natural gas prices similar to the *AEO2012* reference case and with lower natural gas prices.

- The Reference 5 case assumes that the economic recovery period for investments in new environmental controls is reduced from 20 years to 5 years.
- The Low Gas Price 5 case uses more optimistic assumptions about future volumes of shale gas production, leading to lower natural gas prices, combined with the five-year recovery period for new environmental controls. The domestic shale gas resource assumption comes from the Low Tight Oil and Shale Gas Resource case.

Nuclear Alternative cases

For *AEO2012*, two alternate cases were run for nuclear power plants to address uncertainties about the operating lives of existing reactors, the potential for new nuclear capacity, and capacity uprates at existing plants. These scenarios are discussed in the Issues in Focus article, "Nuclear Power in *AEO2012*" in the full *AEO2012* report.

- The Low Nuclear case assumes that all existing nuclear plants are retired after 60 years of operation. In the Reference case, existing plants are assumed to run as long as they continue to be economic, implicitly assuming that a second 20-year license renewal will be obtained for most plants reaching 60 years before 2035. This case was run to analyze the impact of additional nuclear retirements, which could occur if the oldest plants do not receive a second license extension. In this case, 31 gigawatts of nuclear capacity are assumed to be retired by 2035. his case assumes that no new nuclear capacity will be added throughout the projection, excluding the capacity already planned and under construction. The case also assumes that only those capacity uprates reported to EIA will be completed. The Reference case assumes additional uprates based on Nuclear Regulatory Commission (NRC) surveys and industry reports.
- The High Nuclear case assumes that all existing nuclear units will receive a second license renewal and operate beyond 60 years (excluding one announced retirement). In the Reference case, beyond the announced retirement of Oyster Creek, an additional 5.5 gigawatts of nuclear capacity is assumed to be retired through 2035, reflecting uncertainty surrounding future aging impacts and/or costs. This case was run to provide a more optimistic outlook where all licenses are renewed and all plants are assumed to find it economic to continue operating beyond 60 years. The High Nuclear case also assumes additional planned nuclear capacity is completed based on combined license (COL) applications with the NRC. The Reference case assumes 6.8 gigawatts of planned capacity are added, while the High Nuclear case includes 13.5 gigawatts of planned capacity additions.

Notes and sources

[1] Updated Capital Cost Estimates for Electricity Generation Plants, EIA, November 2010.

[2] These costs were developed using the National Energy Technology Laboratory Mercury Control Performance and Cost Model, 1998.

[3] U.S. Department of Energy, Analysis of Mercury Control Cost and Performance, Office of Fossil Energy & National Energy Technology Laboratory, January 2003.

[4] Retrofitting Coal-Fired Power Plants for Carbon Dioxide Capture and Sequestration - Exploratory Testing of NEMS for Integrated Assessments, DOE/NETL-2008/1309, P.A. Geisbrecht, January 18, 2009.