Electricity Market Module

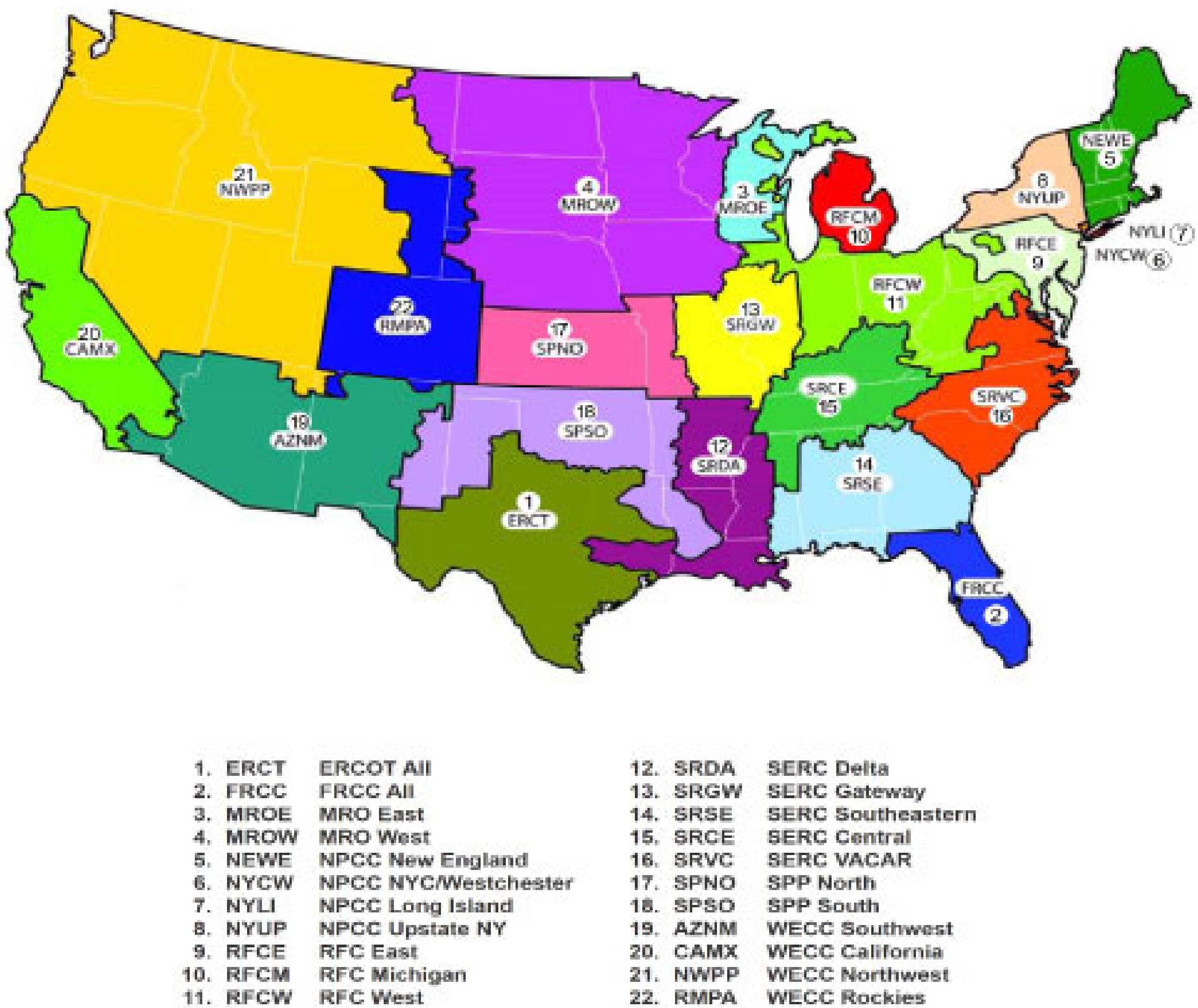
The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules—electricity capacity planning, electricity fuel dispatching, electricity load and demand, and electricity finance and pricing. It includes nonutility capacity 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 2011*, DOE/EIA-M068(2011).

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 Council 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: 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]. 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 represented 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 *AEO2011* based on regional costs 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 (2009 $/kW)	Contingency Factors: Project Contingency Factor[2]	Contingency Factors: Techno logical Optimism Factor[3]	Total Overnight Cost in 2010[4] (2009 $/kW)	Variable O&M[5] (2009 $/MWh)	Fixed O&M (2009$/kW)	Heatrate[6] in 2010 (Btu/kWhr)	nth-of-a-kind Heatrate (Btu/kWhr)
Scrubbed Coal New[7]	2014	1300	4	2,625	1.07	1.00	2,809	4.20	29.31	8,800	8,740
Integrated Coal-Gasification Comb Cycle (IGCC)7	2014	1200	4	2,974	1.07	1.00	3,182	6.79	58.52	8,700	7,450
IGCC with carbon sequestration	2016	520	4	4,797	1.07	1.03	5,287	8.83	68.47	10,700	8,307
Conv Gas/Oil Comb Cycle	2013	540	3	921	1.05	1.00	967	3.37	14.22	7,050	6,800
Adv Gas/Oil Comb Cycle (CC)	2013	400	3	917	1.08	1.00	991	3.07	14.44	6,430	6,333
Adv CC with carbon sequestration	2016	340	3	1,813	1.08	1.04	2,036	6.37	29.89	7,525	7,493
Conv Comb Turbine[8]	2012	85	2	916	1.05	1.00	961	8.15	9.75	10,745	10,450
Adv Comb Turbine	2012	210	2	626	1.05	1.00	658	6.90	14.52	9,750	8,550
Fuel Cells	2013	10	3	5,846	1.05	1.10	6,752	0.00	345.80	9,500	6,960
Adv Nuclear	2016	2236	6	4,567	1.10	1.05	5,275	2.00	87.69	10,453	10,453
Distributed Generation - Base	2013	2	3	1,349	1.05	1.00	1,416	7.37	16.58	9,050	8,900
Distributed Generation - Peak	2012	1	2	1,620	1.05	1.00	1,701	7.37	16.58	10,069	9,880
Biomass	2014	50	4	3,395	1.07	1.02	3,724	6.94	99.30	13,500	13,500
Geothermal[7,9]	2011	50	4	2,364	1.05	1.00	2,482	9.52	107.27	30,000	30,000
MSW - Landfill Gas	2011	50	3	7,698	1.07	1.00	8,237	8.23	369.28	13,648	13,648
Conventional Hydropower[9]	2014	500	4	2,019	1.10	1.00	2,221	2.42	13.55	9,854	9,854
Wind	2011	100	3	2,251	1.07	1.00	2,409	0.00	27.73	9,854	9,854
Wind Offshore	2014	400	4	4,404	1.10	1.25	6,056	0.00	86.98	9,854	9,854
Solar Thermal[7]	2013	100	3	4,333	1.07	1.00	4,636	0.00	63.23	9,854	9,854
Photovoltaic[7,10]	2012	150	2	4,474	1.05	1.00	4,697	0.00	25.73	9,854	9,854

[1]Online year represents the first year that a new unit could be completed, given an order date of 2010. 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 2010.
[5]O&M = Operations and maintenance.
[6]For hydro, wind, and solar technologies, the heatrate shown represents the average heatrate for conventional thermal generation as of 2009. 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 2012 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 *AEO2011* cycle, EIA commissioned an external consultant to develop current cost estimates for utility-scale electric generating plants. This report can be found at http://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	20%
Solar PV	15%	8%	1%	3	5	20%

[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: 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.

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	Combustion Turbine-conventional	Combustion Turbine-advanced	HRSG	Gasifier	Carbon Capture/ Sequestration	Balance of Plant-IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuelprep 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% 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	Fuelprep 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 use 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 AEO2011, it is assumed that this capacity is limited to 3 percent of peak demand in each region.

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 Council 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 AEO2011 Reference case range from 8 to 20 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 $21 per kW for nuclear plants (in 2009 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.

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 ranges from about $123 to $282 per kilowatt of biomass capacity, depending on the type and size of the boiler. 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. Larger units are required to pay additional transportation costs as the level of co-firing increases, due to the concentrated use of the regional supply.

Nuclear uprates

The *AEO2011* 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. *AEO2011* assumes that all of those uprates approved, pending or expected by the NRC will be implemented, for a capacity increase of 3.8 gigawatts between 2010 and 2035. Table 8.6 provides a summary of projected uprate capacity additions by region. In cases where the NRC did not specifically identify the unit expected to uprate, EIA assumed the units with the lowest operating costs would be the next likely candidates for power increases.

Table 8.6 Nuclear uprates by EMM region
gigawatts

Texas Reliability Entity	0.0
Florida Reliability Coordinating Council	0.0
Midwest Relibility Council - East	0.0
Midwest Reliability Council - West	0.2
Northeast Power Coordinating Council/New England	0.1
Northeast Power Coordinating Council/NYC-Westchester	0.0
Northeast Power Cooordinating Council/Long Island	0.0
Northeast Power Coordinating Council/Upstate	0.2
Reliability*First* Corporation/East	0.4
Reliability*First* Corporation/Michigan	0.0
Reliability*First* Corporation/West	0.7
SERC Reliability Corporation/Delta	0.3
SERC Reliability Corporation/Gateway	0.1
SERC Reliability Corporation/Southeastern	0.3
SERC Reliability Corporation/Central	0.6
SERC Reliability Corporation/Virginia-Carolina	0.7
Southwest Power Pool/North	0.0
Southwest Power Pool/South	0.0
Western Electricity Coordinating Council/Southwest	0.0
Western Electricity Coordinating Council/California	0.1
Western Electricity Coordinating Council/Northwest Power Pool Area	0.2
Western Electricity Coordinating Council/Rockies	0.0
Total	3.8

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis, based on Nuclear Regulatory Commission survey http://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 Electric 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. 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. For *AEO2011*, the option to add interregional transmission capacity was added to the EMM. 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 the *AEO2011* 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. 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 marginal cost includes fuel, operation and maintenance, taxes, and a reliability price adjustment, which represents the value of capacity in periods of high demand. The price of electricity in the regions with a competitive generation market consists of the marginal 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 Reliability*First* Corporation/ East region, and a 97 percent transition to competitive pricing in New England (Vermont being the only fully-regulated State in that region). Seven 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/North (SPNO), and the Western Electricity Coordinating Council / Rockies (RMPA). ERCOT, 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.

In recent years, the move towards competition in the electricity business has led utilities to make efforts to reduce costs to improve their market position. These cost reduction efforts are reflected in utility operating data reported to the Federal Energy Regulatory Commission (FERC) and these trends have been incorporated in the *AEO2011*. Both General and Administrative (G&A) expenses and Operations and Maintenance (O&M) expenses have shown declines in recent years. The O&M declines show variation based on the plant type. A regression analysis of recent data was done to determine the trend, and the resulting function was used to project declines throughout the projection. The analysis of G&A costs used data from 1992 through 2001, which had a 15 percent overall decline in G&A costs, and a 1.8 percent average annual decline rate. The *AEO2011* projection assumes a further decline of 18 percent by 2023 based on the results of the regression analysis. The O&M cost data was available from 1990 through 2001, and showed average annual declines of 2.1 percent for all steam units, 1.8 percent for combined cycle and 1.5 percent for nuclear. The AEO2010 assumes further declines in O&M expenses for these plant types, for a total decline through 2025 of 17 percent for combined cycle, 15 percent for steam and 8 percent for nuclear.

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 *AEO2011*, 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 Reliability First Corporation/ East and West regions, and the WECC/ California region.

Transmission costs for the AEO are traditionally projected based on regressions of historical spending per non-coincident peak time electricity use to ensure that the model builds enough transmission infrastructure to accommodate growth in peak electricity demand. However, since spending decreased throughout the 1990s EIA has had to add in extra spending on transmission. Additions were based on several large studies, such as the Department of Energy's National Transmission Grid Study, which set out to document how much spending would be needed to keep the national grid operating efficiently. Transmission spending has in fact been increasing very recently. EIA will be monitoring transmission spending closely over the next several years and updates will be made as new information becomes available.

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 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 Clean Air Interstate Rule (CAIR)

The Clean Air Interstate Rule is a cap-and-trade program promulgated by the EPA in 2005 to reduce SO2 and NOx emissions in order to help States meet their National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter, and to further emissions reductions already achieved through earlier programs. On July 11, 2008 the U.S. District Court of Appeals overturned CAIR. However, on December 23, 2008, the Court of Appeals issued a new ruling that allowed CAIR to remain in effect while EPA determines the appropriate modifications to address the original objections. Therefore, CAIR is modeled explicitly in the *AEO2011*.

As specified in the CAAA90, EPA has 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, 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 NOx 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 NOx limits are incorporated in EMM.

In addition, the EPA has issued rules to limit the emissions of NOx, specifically calling for capping emissions during the summer season in 22 Eastern and Midwestern states. After an initial challenge, these rules have been upheld, and emissions limits have been finalized for 19 states and the District of Columbia (Table 8.7). Within EMM, electric generators in these 19 states must comply with the limit either by reducing their own emissions or purchasing allowances from others who have more than they need.

Table 8.7. Summer Season NOx Emissions Budgets for 2004 and Beyond
thousand tons per season

State	Emissions Cap
Alabama	29.02
Connecticut	2.65
Delaware	5.25
District of Columbia	0.21
Illinois	32.37
Indiana	47.73
Kentucky	36.50
Maryland	14.66
Massachusetts	15.15
Michigan	32.23
New Jersey	10.25
New York	31.04
North Carolina	31.82
Ohio	48.99
Pennsylvania	47.47
Rhode Island	1.00
South Carolina	16.77
Tennessee	25.81
Virginia	17.19
West Virginia	26.86

Source: U.S. Environmental Protection Agency, Federal Register, Vol. 65, number 42 (March 2, 2002) pages 11222-11231.

The costs of adding flue gas desulfurization equipment (FGD) to remove sulfur dioxide (SO2) and selective catalytic reduction (SCR) equipment to remove nitrogen oxides (NOx) are given below for 300, 500, and 700-megawatt coal plants. FGD units are assumed to remove 95 percent of the SO2, while SCR units are assumed to remove 90 percent of the NOx. The costs per megawatt of capacity decline with plant size and are shown in Table 8.8.

Table 8.8. Coal plant retrofit costs
2009 dollars

Coal Plant Size (MW)	FGD Capital Costs ($/KW)	SCR Capital Costs ($/KW)
300	556	179
500	464	161
700	428	159

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

Mercury regulation

The Clean Air Mercury Rule set up a national cap-and-trade program with emission limits set to begin in 2011. This rule was vacated in February, 2008 and therefore is not included in the *AEO2011*. However, many States had already begun adopting more stringent regulations calling for the application of the best available control technology on all electricity generating units of a certain capacity. After the court's decision, more States imposed their own regulations. Because State laws differ, a rough estimate was created that generalized the various State programs into a format that could be used in NEMS. The EMM allows plants to alter their configuration by adding equipment, such as an SCR to remove NOx or an SO2 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 (2009 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 $77 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 8.9 provides the assumed EMFs for existing coal plant configurations without mercury specific controls.

Table 8.9. Mercury emission modification factors

Configuration			EIA EMFs			EPA EMFs		
SO_2 Control	Particulate Control	NO_x 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	0.05	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. http://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 ccrubber and NO_x control equipment additions

In recent years, in response to state emission reduction programs and compliance agreements with the Environmental Protection Agency, some companies have announced plans to add scrubbers to their plants to reduce sulfur dioxide and particulate emissions. Where firm commitments appear to have been made these plans have been represented in NEMS. Based on EIA analysis of announced plans, 31.4 gigawatts of capacity are assumed to add these controls (Table 8.10). The greatest number of retrofits is expected to occur in the Midwestern States, where there is a large base of coal capacity impacted by the SO_2 limit in CAIR, as well as in the Southeastern Electric Reliability Council because of the Clean Smokestacks bill passed by the North Carolina General Assembly.

Table 8.10 Planned SO_2 scrubber additions by EMM region

gigawatts

Texas Reliability Entity	0.0
Florida Reliability Coordinating Council	1.4
Midwest Relibility Council - East	0.0
Midwest Reliability Council - West	1.1
Northeast Power Coordinating Council/New England	0.0
Northeast Power Coordinating Council/NYC-Westchester	0.0
Northeast Power Cooordinating Council/Long Island	0.0
Northeast Power Coordinating Council/Upstate	0.2
Reliability*First* Corporation/East	4.0
Reliability*First* Corporation/Michigan	0.8
Reliability*First* Corporation/West	6.2
SERC Reliability Corporation/Delta	0.0
SERC Reliability Corporation/Gateway	3.7
SERC Reliability Corporation/Southeastern	8.5
SERC Reliability Corporation/Central	2.5
SERC Reliability Corporation/Virginia-Carolina	2.9
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	31.4

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis, based on public announcements and reports to Form EIA-860, "Annual Electric Generator Report".

Companies are also announcing plans to retrofit units with controls to reduce NO_x emissions to comply with emission limits in certain states. In the Reference case planned post-combustion control equipment amounts to 17.9 gigawatts of selective catalytic reduction (SCR).

Carbon capture and sequestration retrofits

Although a federal greenhouse gas program is not assumed in the *AEO2011* 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). For *AEO2011*, the costs were adjusted upwards 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 ranging from $1,100 to $1,600 per kilowatt. It was assumed that only plants greater than 500 megawatts and with heatrates below 12,000 BTU per kilowatthour would be considered for CCS retrofits.

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 PTC to qualifying wind facilities entering service by December 31, 2009. Eligibility of other facilities such as geothermal, hydroelectric, and biomass facilities, was extended through December 31, 2010.

American Recovery and Reinvestment Act (ARRA)

Updated tax credits for Renewables

ARRA further 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. The *AEO2011* 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 the *AEO2011* 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, the *AEO2011* 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 the AEO2011, 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

Fossil Technology Cost cases

The High Fossil Technology Cost case assumes that the base costs of all 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 8.11)   Capital costs of non-fossil generating technologies are the same as those assumed in the Reference case.

In the Low Fossil Technology Cost case, capital costs, and operating costs for the fossil technologies are assumed to start 20% lower than the Reference case levels and to be 40 percent lower than Reference case levels in 2035. Since learning occurs in the Reference case, costs and performance in the low case are reduced from initial levels by more than 40 percent, across the fossil technologies. Capital costs are reduced by 43 percent to 58 percent between 2011 and 2035.

The Low and High Fossil Technology Cost cases are fully-integrated NEMS runs, allowing feedback from the end-use demand and fuel supply modules.

Nuclear Cost cases

For nuclear power plants, two nuclear cost cases analyze the sensitivity of the projections to lower and higher costs for new plants. The cost assumptions for the Low nuclear cost case reflect a 20 percent decline in initial costs and a 40 percent reduction in the capital and operating cost for the advanced nuclear technology in 2035, relative to the Reference case. Since the Reference case assumes some learning occurs regardless of new orders and construction, the Reference case already projects a 35 percent reduction in capital costs between 2011 and 2035. The Low Nuclear Cost case assumes a 51 percent reduction between 2011 and 2035. The High Nuclear Cost case assumes that base capital costs for the advanced nuclear technology do not decline from 2011 levels (Table 8.12). The capital costs are still tied to key commodity price indices, but no cost improvement from “learning-by-doing” effects is assumed.

Electricity Plant Capital Cost cases

The costs to build new power plants have risen dramatically in the past few years, driven primarily by significant increases in the costs of construction related materials, such as cement, iron, steel and copper. For the *AEO2011* Reference case, initial overnight costs for all technologies were updated to be consistent with costs estimates for 2010. A cost adjustment factor based on the projected producer price index for metals and metal products is also applied throughout the forecast, allowing the overnight costs to fall in the future if this index drops or rise further if the index increases. Although there is significant correlation between commodity prices and power plant costs, there may be other factors that influence future costs that raise the uncertainties surrounding the future costs of building new power plants. For the *AEO2011*, two additional cost cases were run which focus on the uncertainties of future plant construction costs. These cases use exogenous assumptions for the annual adjustment factors, rather than linking to the metals price index. The cases are discussed in the Issues in Focus article, "Cost Uncertanties for new Electric Power Plants." (*AEO* pages 40-42)

- In the Frozen Plant Capital Costs case, base overnight costs for all new electric generating technologies are assumed to be frozen at 2015 levels. Cost decreases due to learning can still occur. In this case, costs do decline slightly over the projection, but by 2035 are roughly 25 percent above Reference case costs for the same year.
- In the Decreasing Plant Capital Costs case, base overnight costs for all new electric generating technologies are assumed to fall more rapidly than in the Reference case. The base overnight costs are assumed to be 20 percent below the Reference case, through a reduction in the annual cost index. Costs are also assumed to decline more rapidly, so that by 2035 the cost factor is assumed to be 40 percentage points below the Reference case value.

Electricity Environmental Regulation cases

Over the next few years electricity generators will have to begin steps to comply with a large number of new environmental regulations that are currently in various stages of promulgation. The *AEO2011* Reference case does not include regulations that are still under development. However, the issues in Focus article, "Power Sector Environmental Regulations on the Horizon" (*AEO* pages 45-53) discusses the status of the different rules and examines potential impacts through a number of scenarios.

- In the Transport Mercury MACT 20 case, it is assumed that the Air Transport Rule limits on SO_2 and NO_X and a 90 percent mercury MACT are enacted. A 20 year recovery period for environmental control projects is assumed.
- In the Transport Mercury MACT 5 case, the same rules as in the first case are assumed, but a five year recovery period is used on the investments in environmental control projects.
- The Retrofit Required 20 case is designed to represent a scenario where stringent requirements are placed on air emission from coal plants. It assumes that utility boilers fall under the MACT rule, which requires all plants to install FGD scrubbers by 2020 in order to comply with acid gas reduction requirements. It also requires that all plants install SCRs in order to meet future NO_x and ozone requirements. If the investment in an FGD and SCR is not economic, then the plant is retired. Investments in retrofits are assumed recovered over a 20 year life.
- The Retrofit Required 5 case assumes the same stringent requirements as above, but uses a five year economic life for retrofits.
- The Low Gas Price Retrofit Required 20 case is identical to the Retrofit Required 20 case, but also adds an assumption of increased domestic shale gas availability and utilization rate, as in the Oil and Gas High Shale EUR case. Increased access to natural gas lowers the natural gas prices paid by the electric power sector.
- The Low Gas Price Retrofit Required 5 case assumes the same environmental requirements and lower gas prices as above, but uses a five year economic life for retrofits.

Table 8.11. Cost characteristics for fossil-fueled generating technologies: three cases

	Total Overnight Cost in 2011 (Reference) (2009$/kW)	Total Overnight Cost[1] Reference (2009$/kW)	High Fossil Cost (2009$/kW)	Low Fossil Cost (2009$/kW)
Pulverized Coal	2809			
2015		2871	2894	2202
2020		2756	2838	1998
2025		2563	2697	1751
2030		2343	2499	1503
2035		2126	2304	1275
Advanced Coal	3182			
2015		3226	3278	2472
2020		3066	3215	2222
2025		2817	3055	1925
2030		2534	2833	1626
2035		2265	2610	1358
Advanced Coal with Sequestration	5287			
2015		5306	5446	4068
2020		4770	5339	3457
2025		4315	5075	2948
2030		3822	4705	2452
2035		3356	4336	2014
Conventional Combined Cycle	967			
2015		988	995	757
2020		949	976	688
2025		882	928	602
2030		806	860	517
2035		732	793	439
Advanced Gas	991			
2015		1007	1020	771
2020		962	1000	696
2025		887	951	605
2030		798	881	512
2035		714	812	428
Advanced Gas with Sequestration	2036			
2015		2040	2097	1563
2020		1804	2057	1307
2025		1626	1954	1111
2030		1430	1812	918
2035		1247	1669	748
Conventional Combustion Turbine	961			
2015		983	990	754
2020		943	970	684
2025		877	922	599
2030		802	855	515
2035		728	789	437
Advanced Combustion Turbine	658			
2015		666	677	510
2020		634	665	459
2025		581	631	396
2030	658			
2035		458	539	275

[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. *AEO2011* National Energy Modeling System runs: REF2011.D020911A, HCFOSS11.D020911A, LCFOSS11.D020911A

Table 8.12 Cost characteristics for advanced nuclear technology: three cases

Advanced Nuclear Technology	Overnight Cost in 2011 (Reference) (2009$/kW)	Total Overnight Cost[1] Reference (2009$/kW)	High Nuclear Cost (2009$/kW)	Low Nuclear Cost (2009$/kW)
	5275			
2015		5311	5433	4113
2020		4853	5327	3556
2025		4316	5064	2985
2030		3868	4694	2514
2035		3435	4325	2061

[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. AEO2011 National Energy Modeling System runs: REF2011.D020911A, HCNUC11.D020911A, LCNUC11.D020911A.

Table 8.13 Cost characteristics for new electric generating technologies: three cases
2009$/kw

		Reference		Frozen Cost Case		Decreasing Cost Case	
	Initial Cost 2011	2020	2035	2020	2035	2020	2035
Scrubbed Coal New	2809	2756	2126	2820	2675	1995	1269
Integrated Coal-Gasification Comb Cycle (IGCC)	3182	3066	2265	3136	2852	2218	1354
IGCC with carbon sequestration	5287	4770	3356	4880	4225	3451	2006
Conv Gas/Oil Comb Cycle	967	949	732	971	921	686	437
Adv Gas/Oil Comb Cycle (CC)	991	962	714	984	900	696	428
Adv CC with carbon sequestration	2036	1804	1247	1845	1572	1305	746
Conv Comb Turbine	961	943	728	965	916	683	434
Adv Comb Turbine	658	634	458	648	578	458	275
Fuel Cells	6752	6011	3777	6150	4752	4350	2255
Adv Nuclear	5275	4853	3435	4965	4322	3512	2050
Distributed Generation - Base	1416	1347	958	1378	1214	975	584
Distributed Generation - Peak	1701	1555	1124	1602	1426	1008	585
Biomass	3724	3597	2696	3681	3392	2603	1609
Geothermal	2482	2364	2546	2419	3285	1704	1486
MSW - Landfill Gas	8237	8082	6233	8269	7843	5849	3721
Conventional Hydropower	2221	2257	987	2309	1356	1191	1547
Wind	2409	2412	1941	2468	2443	1743	1158
Wind Offshore	6056	5440	3927	5567	4941	3935	2343
Solar Thermal	4636	3408	2008	3486	2527	2466	1199
Photovoltaic	4697	4056	2496	4150	3140	2935	1293

Source: U.S. Energy Information Administration. *AEO2011* National Energy Modeling System runs: AEO2011.D020911A, FRZCST11.D020911A, DECCST11.D020911A.

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.