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Electricity Market Module

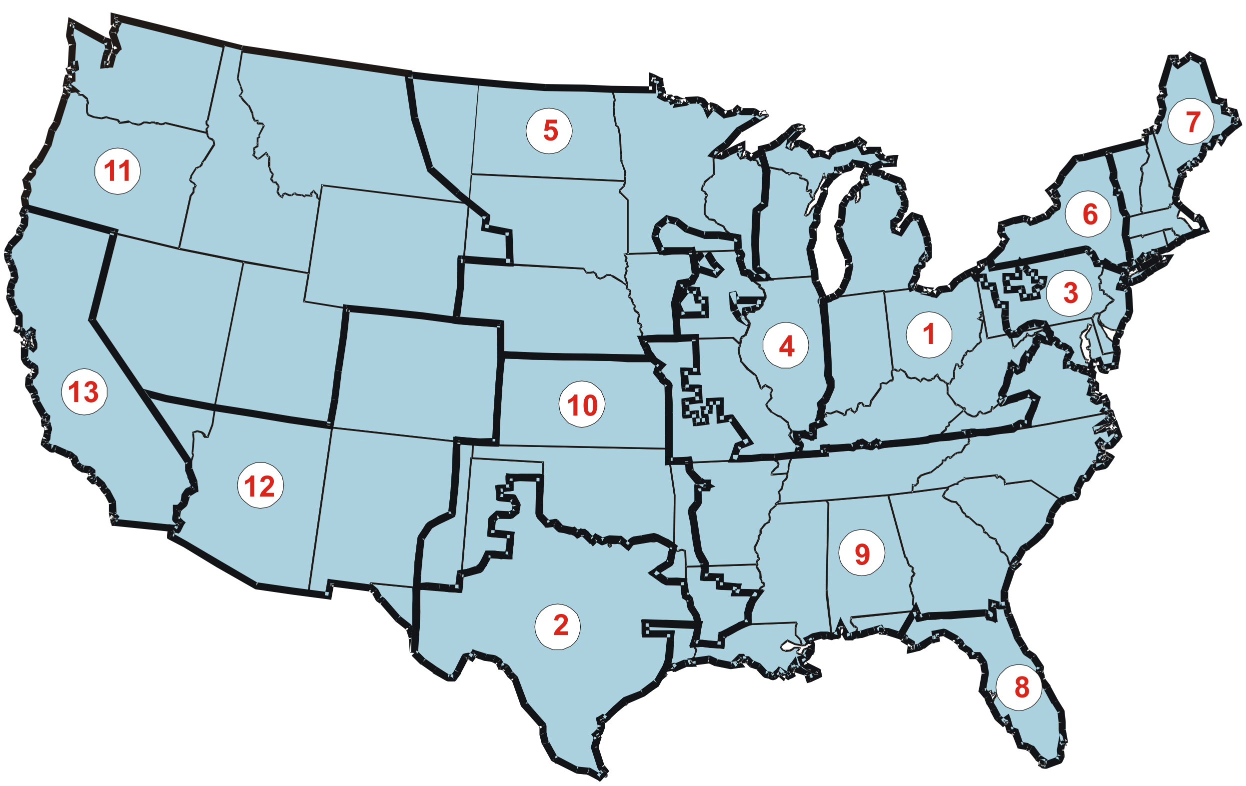
The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules—electricity capacity planning, electricity fuel dispatching, load and demand electricity, and electricity finance and pricing. It includes nonutility capacity 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 2008*, DOE/EIA-M068(2008).

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 (region definitions as of 2004).

Figure 6. Electricity Market Model Supply Regions



1 East Central Area Reliability Coordination Agreement (ECAR)
2 Electric Reliability Council of Texas (ERCOT)
3 Mid-Atlantic Area Council (MAAC)
4 Mid-America Interconnected Network (MAIN)
5 Mid-Continent Area Power Pool (MAPP)
6. New York (NY)
7. New England (NE)
8 Florida Reliability Coordinating Council (FL)
9 Southeastern Electric Reliability Council (SERC)
10 Southwest Power Pool (SPP)
11 Northwest Power Pool (NWP)
12. Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA)
13 California (CA)

Model Parameters and Assumptions

Generating Capacity Types

The capacity types represented in the EMM are shown in Table 37.

Table 37. 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 - Integrated Gasification Combined-Cycle
Solar Thermal - Central Receiver
Solar Photovoltaic - Single Axis Flat Plate
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, Office of Integrated Analysis and Forecasting.

New Generating Plant Characteristics

The cost and performance characteristics of new generating technologies are inputs to the electricity capacity planning submodule (Table 38). 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.

The overnight costs shown in Table 38 are the cost estimates to build a plant in a typical region of the country. Differences in plant costs due to regional distinctions are calculated by applying regional multipliers that represent variations in the cost of labor. 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 38. Cost and Performance Characteristics of New Central Station Electricity Generating Technologies

Technology	Online Year[1]	Size (mW)	Leadtime (Years)	Base Overnight Cost in 2007 ($2006/kW)	Contingency Factors: Project Contingency Factor[2]	Contingency Factors: Technological Optimism Factor[3]	Total Overnight Cost in 2007[4] (2006 $/kW)	Variable O&M[5] ($2006 mills/kWh)	Fixed O&M[5] ($2006/kW)	Heatrate[6] in 2007 (Btu/kWhr)	Heatrate nth-of-a-kind (Btu/kWr)
Scrubbed Coal New[7]	2011	600	4	1,434	1.07	1.00	1,534	4.46	26.79	9,200	8,740
Integrated Coal-Gasification Combined Cycle (IGCC)[7]	2011	550	4	1,657	1.07	1.00	1,773	2.84	37.62	8,765	7,450
IGCC with Carbon Sequestration	2011	380	4	2,302	1.07	1.03	2,537	4.32	44.27	10,781	8,307
Conv Gas/Oil Comb Cycle	2010	250	3	683	1.05	1.00	717	2.01	12.14	7,196	6,800
Adv Gas/Oil Comb Cycle (CC)	2010	400	3	654	1.08	1.00	706	1.95	11.38	6,752	6,333
ADV CC with Carbon Sequestration	2010	400	3	1,254	1.08	1.04	1,409	2.86	19.36	8,613	7,493
Conv Combustion Turbine[8]	2009	160	2	476	1.05	1.00	500	3.47	11.78	10,833	10,450
Adv Combustion Turbine	2009	230	2	450	1.05	1.00	473	3.08	10.24	9,289	8,550
Fuel Cells	2010	10	3	4,653	1.05	1.10	5,374	46.62	5.50	7,930	6,960
Advanced Nuclear	2016	1350	6	2,143	1.10	1.05	2,475	0.48	66.05	10,400	10,400
Distributed Generation -Base	2009	5	2	972	1.05	1.00	1,021	6.93	15.59	9,200	8,900
Distributed Generation -Peak	2010	2	3	1,168	1.05	1.00	1,227	6.93	15.59	10,257	9,880
Biomass	2011	80	4	2,490	1.07	1.05	2,809	6.53	62.70	8,911	8,911
MSW - Landfill Gas	2010	30	3	1,773	1.07	1.00	1,897	0.01	111.15	13,648	13,648
Geothermal[7,9]	2011	50	4	1,057	1.05	1.00	1,110	0.00	160.18	35,376	33,729
Conventional Hydropower[9]	2011	500	4	1,410	1.10	1.00	1,551	3.41	13.59	10,022	10,022
Wind	2010	50	3	1,340	1.07	1.00	1,434	0.00	29.48	10,022	10,022
Wind Offshore	2011	100	4	2,547	1.10	1.03	2,872	0.00	87.05	10,022	10,022
Solar Thermal[7]	2010	100	3	3,499	1.07	1.00	3,744	0.00	55.24	10,022	10,022
Photovoltaic[7]	2009	5	2	5,380	1.05	1.00	5,649	0.00	11.37	10,022	10,022

[1]Online year represents the first year that a new unit could be completed, given an order date of 2007.

[2]A contingency allowance is defined by the American Association of Cost Engineers as the "specific provision for unforeseeable elements if 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 2007.

[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 2006. 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 2009 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.

Sources: The values shown in this table are developed by the Energy Information Administration, Office of Integrated Analysis and Forecasting, from analysis of reports and discussions with various sources from industry, government, and the Department of Energy Fuel Offices and National Laboratories. They are not based on any specific technology model, but rather, are meant to represent the cost and performance of typical plants under normal operating conditions for each plant type. Key sources reviewed are listed in the ‘Notes and Sources’ section at the end of the chapter.

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 39). 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 39. Learning Parameters for New Generating Technology Components

Technology Component	Period 1 Learning Rate	Period 2 Learning Rate	Period 3 Learning Rate	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	10%	5%	1%	3	5	10%
Advanced Nuclear	5%	3%	1%	3	5	10%
Fuel prep - Biomass IGCC	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 Integrated Analysis and Forecasting.

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 (f) is an exogenous parameter input for each component (Table 39). Consequently, the progress ratio and *f* are related by:

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

The parameter "b" is calculated by (b =-(ln(1-*f*)/ln(2)). The parameter "a" can be found from initial conditions. That is,

$$a = OC(C0)/C0^{-b}$$

where C0 is the cumulative initial capacity. Thus, once the rates of learning (f) and the cumulative capacity (C0) are known for each interval, the corresponding parameters (a and b) of the nonlinear function are known. Three learning steps were developed, to reflect different stages of learning as a new design is introduced to 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. All design components receive 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 rate by component is 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 40). 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 40. Component Cost Weights for New Technologies

Technology	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 IGCC
Integrated Coal_Gasification Comb Cycle (IGCC)	0%	15%	20%	41%	0%	24%	0%	0%	0%
IGCC with carbon sequestration	0%	10%	15%	30%	30%	15%	0%	0%	0%
Conv Gas/Oil Comb Cycle	30%	0%	40%	0%	0%	0%	0%	30%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	30%	40%	0%	0%	0%	0%	30%	0%
Adv CC with carbon sequestration	0%	20%	25%	0%	40%	0%	0%	15%	0%
Conv Comb Turbine	50%	0%	0%	0%	0%	0%	50%	0%	0%
Adv Comb Turbine	0%	50%	0%	0%	0%	0%	50%	0%	0%
Biomass	0%	12%	16%	33%	0%	20%	0%	0%	19%

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 41 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. All non-capacity components, such as the balance of plant category, contribute 100 percent toward the component learning.

International Learning. In *AEO2008*, capital costs for all new electricity generating technologies (fossil, nuclear, and renewable) decrease in response to foreign and domestic experience. Foreign units of new

Table 41. Component Capacity Weights for New Technologies

Technology	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 IGCC
Integrated Coal_Gasification Comb Cycle (IGCC)	0%	67%	33%	100%	0%	100%	0%	0%	0%
IGCC with carbon sequestration	0%	67%	33%	100%	100%	100%	0%	0%	0%
Conv Gas/Oil Comb Cycle	67%	0%	33%	0%	0%	0%	0%	100%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	67%	33%	0%	0%	0%	0%	100%	0%
Adv CC with carbon sequestration	0%	67%	33%	0%	100%	0%	0%	100%	0%
Conv Comb Turbine	100%	0%	0%	0%	0%	0%	100%	0%	0%
Adv Comb Turbine	0%	100%	0%	0%	0%	0%	100%	0%	0%
Biomass	0%	67%	33%	100%	0%	100%	0%	0%	100%

HRSG = Heat Recovery Steam Generator.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

technologies are assumed to contribute to reductions in capital costs for units that are installed in the United States to the extent that (1) the technology characteristics are similar to those used in U.S. markets, (2) the design and construction firms and key personnel compete in the U.S. market, (3) the owning and operating firm competes actively in the U.S. market, and (4) there exists relatively complete information about the status of the associated facility. If the new foreign units do not satisfy one or more of these requirements, they are given a reduced weight or not included in the domestic learning effects calculation.

AEO2008 includes 5,000 megawatts of advanced coal gasification combined-cycle capacity, 5,244 megawatts of advanced combined-cycle natural gas capacity, 11 megawatts of biomass capacity and 47 megawatts each of traditional wind and offshore wind capacity to be built outside the United States from 2000 through 2003. The learning function also includes 7,200 megawatts of advanced nuclear capacity, representing two completed units and four additional units under construction in Asia.

Distributed Generation

Distributed generation is modeled in the end-use sectors as well as in the EMM, which is described in the appropriate chapters. 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 38 for costs and performance assumptions. It is assumed that these plants reduce the costs of transmission upgrades that would otherwise be needed.

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 33 percent and 66 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 interative 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 *AEO2008* reference case range from 10 to 14 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. If the expected revenues from these plants are not sufficient to cover the annual going forward costs, the plant is assumed to retire 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 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 $20 per kW for nuclear plants (in 2006 dollars). These costs are added to existing plants regardless of their age. Beyond 30 years of age an additional $6 per kW capital charge for fossil plants, and $30 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 allowed 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 $115 to $265 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.

New Nuclear Plant Orders

A new nuclear technology competes with other fossil-fired and renewable technologies as new generating capacity is needed to meet increasing demand, or replace retiring capacity, throughout the projection period. The cost assumptions for new nuclear units are based on an analysis of recent cost estimates for nuclear designs available in the United States and worldwide. The capital cost assumptions in the reference case represent the expense of building a new single unit nuclear plant of approximately 1,000 megawatts at a new "Greenfield" site. Since no new nuclear plants have been built in the US in many years, there is a great deal of uncertainty about the true costs of a new unit. The estimate used for *AEO2008* is an average of the construction costs incurred in completed advanced reactor builds in Asia, adjusting for expected learning from other units still under construction.

Nuclear Uprates

The AEO2008 nuclear power projection also 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 modifications, 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. *AEO2008* assumes that all of those uprates approved, pending or expected by the NRC will be implemented, for a capacity increase of 2.7 gigawatts between 2007 and 2030. Table 42 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 42. Nuclear Upratres by EMM Region
(gigawatts)

Region	
East Central Area Reliability Coordination Agreement	0.1
Electric Reliability Council of Texas	0.4
Mid-Atlantic Area Council	0.1
Mid-America Interconnected Network	0.1
Mid-Continent Area Power Pool	0.0
New York	0.1
New England	0.0
Florida Reliability Coordinating Council	0.0
Southeastern Electric Reliability Council	1.8
Southwest Power Pool	0.0
Northwest Power Pool	0.0
Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada	0.1
California	0.1
Total	2.7

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, based on Nuclear Regulatory Commission survey, http://www.nrc.gov/reactors/operating/licensing/power-uprates.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 National Electric Reliability Council 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 2004*. They are locked in for the term of the contract. Contracts that are scheduled to expire by 2013 are assumed not to be renewed. Because there is no information available about expiration dates for contracts that go beyond 2013, they are assumed to be phased out by 2022. In addition, in certain regions where data show an established commitment to build plants to serve another region, new plants are permitted to be built to serve the other region's needs. This option is available to compete with other resource options.

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 allowed 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. Existing and planned transactions are obtained from the North American Electric Reliability Council's *Electricity Supply and Demand Database 2004*. 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

The reference case assumes a transition to full competitive pricing in New York, Mid-Atlantic Area Council, and Texas, and a 95 percent transition to competitive pricing in New England (Vermont being the only fully-regulated State in that region). California returned to almost fully regulated pricing in 2002, after beginning a transition to competition in 1998. In addition electricity prices in the East Central Area Reliability Council, the Mid-American Interconnected Network, the Southeastern Electric Reliability Council, the Southwest Power Pool, the Northwest Power Pool, and the Rocky Mountain Power Area/Arizona are a mix of both competitive and regulated prices. Since some States in each of these regions have not taken action to deregulate their pricing of electricity, prices in those States are assumed to continue to be based on traditional cost-of-service pricing. The price for mixed regions is a load-weighted average of the competitive price and the regulated price, with the weight based on the percent of electricity load in the region that has taken action to deregulate. The reference case assumes that State-mandated price freezes or reductions during a specified transition period will occur based on the terms of the legislation. In general, the transition period is assumed to occur over a ten-year period from the effective date of restructuring, with a gradual shift to marginal cost pricing. In regions where none of the states in the region have introduced competition—Florida Reliability Coordinating Council and Mid-Continent Area Power Pool—electricity prices are assumed to remain regulated and the cost-of-service calculation is used to determine electricity prices.

The price of electricity to the consumer is comprised of 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.

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 *AEO2008*. 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 *AEO2008* projection assumes a further decline of 18 percent by 2025 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 *AEO2008* 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 *AEO2008*, 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.

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 we have had to add in extra spending on transmission. Our 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. We 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 20-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.

Legislation and Regulations

Clean Air Act Amendments of 1990 (CAAA90) and Clean Air Interstate Rule (CAIR)

It is assumed that electricity producers comply with the CAIR, which mandates limits on sulfur dioxide (SO_2) and /or nitrogen oxide (NO_x) in 28 eastern states and the District of Columbia. The annual limits for SO_2 emissions are 3.6 million tons beginning in 2010 and 2.5 million tons starting in 2015. The corresponding limits of NO_x emissions are 1.5 million tons in 2009 and 1.3 million tons in 2015.

Prior to the implementation of these targets, generators are still required to comply with the SO_2 and NO_x limits specified by the CAAA90. The western states not covered by the CAIR are assumed to comply with the CAAA90 throughout the projection period. By 2010, the CAAA90 assigns an annual limit of 1.7 million tons for SO_2 in these areas. Utilities are assumed to satisfy the limits on sulfur emissions by retrofitting units with flue gas desulfurization (FGD) equipment, transferring or purchasing sulfur emission allowances, operating high-sulfur coal units at a lower capacity utilization rate, or switching to low-sulfur fuels. It is assumed that the market for trading emission allowances is allowed to operate without regulation and that the States do not further regulate the selection of coal too be used.

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 their 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.

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 43). 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 43. Summer Season NO_x 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 (SO_2) and selective catalytic reduction (SCR) equipment to remove nitrogen oxides (NO_x) are given below for 300, 500, and 700-megawatt coal plants. FGD units are assumed to remove 95 percent of the SO_2, while SCR units are assumed to remove 90 percent of the NO_x. The costs per megawatt of capacity decline with plant size and are shown in Table 44.

Table 44. Coal Plant Retrofit Costs
(2006 Dollars)

Coal Plant Size (MW)	FGD Capital Costs ($/KW)	SCR Capital Costs ($/KW)
300	301	124
500	230	108
700	190	98

Note: The model was run for each individual plant assuming a 1.3 retrofit factor for FGDs and 1.6 factor for SCRs.

Source: CUECOST3.xls model (as updated 2/9/2000) developed for the Environmental Protection Agency by Raytheon Engineers and Constructors, Inc. EPA Contract number 68-D7-0001.

Clean Air Mercury Rule (CAMR)[1]

The CAMR establishes a cap-and-trade program with a two-phase implementation. The regulation specifies a limit of 38 tons beginning in 2010 and 15 tons starting in 2018. To reduce mercury, power companies can change their fuels, redispatch their units, change the configuration of their units or add mercury specific controls. To represent this, 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 $5 (2006 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 $64 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 Electricity Market Module (EMM) of the National Energy Modeling System (NEMS) 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 45 provides the assumed EMFs for existing coal plant configurations without mercury specific controls.

Table 45. 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 Scrubber 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, 46.9 gigawatts of capacity are assumed to add these controls (Table 46). 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 46. Planned SO_2 Scrubber Additions Represented by Region

Region	Capacity (Gigawatts)
East Central Area Reliability Coordination Agreement	20.1
Electric Reliability Council of Texas	0.0
Mid-Atlantic Area Council	4.1
Mid-America Interconnected Network	1.7
Mid-Continent Area Power Pool	1.1
New York	0.0
New England	0.0
Florida Reliability Coordinating Council	0.0
Southeastern Electric Reliability Council	19.2
Southwest Power Pool	0.0
Northwest Power Pool	0.0
Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada	0.7
California	0.0
Total	46.9

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, based on public announcements and reports to Form EIA-767, "Annual Steam-Electric Plant Operation and Design Data".

Companies are also announcing plans to retrofit units with controls to reduce NOx emissions to comply with emission limits in certain states. In the reference case planned post-combustion control equipment amounts to 35.5 gigawatts of selective catalytic reduction (SCR) and another 1.6 gigawatts of selective non-catalytic reduction (SNCR) equipment.

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. In the *AEO2008* Reference case it is projected that 8 gigawatts of new nuclear capacity will be built by 2020, each receiving a credit worth 1.35 cents per kilowatthour. 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).

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 it economic to do so.

Electricity Alternative Cases

Low and High Cost Fossil Cases

The *high cost fossil case* assumes that the costs of advanced fossil generating technologies (integrated coal- gasification combined-cycle, advanced natural gas combined-cycle and turbines) will remain at current costs during the projection period, that is, no learning reductions are applied to the cost. Operating efficiencies for advanced technologies are assumed to be constant at 2008 levels. Capital costs of conventional generating technologies are the same as those assumed in the reference case (Table 47).

In the *low cost fossil case*, capital costs, heat rates and operating costs for the advanced coal and gas technologies are assumed to be ten percent lower than Reference case levels in 2030. Since learning occurs in the Reference case, costs and performance in the high case are reduced from initial levels by more than ten percent. Heat rates for advanced fossil technologies, in the high fossil case, fall to 16 to 31 percent below initial levels, while capital costs are reduced by 19 percent to 25 percent between 2008 and 2030.

The *low and high cost fossil cases* are fully-integrated 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 ten percent reduction in the capital and operating cost for the advanced nuclear technology in 2030, 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 18 percent reduction in capital costs between 2008 and 2030. The *low nuclear cost case* therefore assumes a 26 percent reduction between 2008 and 2030. The *high* nuclear cost case assumes that capital costs for the advanced nuclear technology do not decline from 2008 levels (Table 48). Cost and performance characteristics for all other technologies are as assumed in the reference case.

Table 47. Cost and Performance Characteristics for Fossil-Fueled Generating Technologies: Three Cases

	Total Overnight Cost in 2007 Reference (2006 $/kW)	Total Overnight Cost[1] Reference (2006 $/kW)	High Cost Fossil (2006 $/kW)	Low Cost Fossil (2006 $/kW)	Heatrate in 2007 (Reference) Btu/kWhr	Heat Rate Reference BTU/kWhr	High Cost Fossil Btu/kWhr	Low cost Fossil Btu/kWhr
Pulverized Coal	1534				9200			
2015		1504	1504	1504		9069	9069	9069
2020		1477	1472	1483		8904	8904	8904
2025		1453	1450	1462		8740	8740	8740
2030		1432	1429	1440		8740	8740	8740
Advanced Coal	1773				8765			
2015		1719	1774	1658		8389	8765	8176
2020		1681	1774	1574		7920	8765	7441
2025		1635	1774	1493		7450	8765	6705
2030		1566	1774	1409		7450	8765	6705
Advanced Coal with Sequestration	2537				10781			
2015		2423	2537	2343		10074	10781	9837
2020		2342	2537	2205		9191	10781	8656
2025		2254	2537	2067		8307	10781	7476
2030		2142	2537	1927		8307	10781	7476
Conventional Combined Cycle	717				7196			
2015		703	703	703		7064	7064	7064
2020		693	693	693		6932	6932	6932
2025		683	683	683		6800	6800	6800
2030		673	673	673		6800	6800	6800
Advanced Gas	706				6752			
2015		688	707	662		6612	6752	6401
2020		675	707	633		6473	6752	6051
2025		657	707	602		6333	6752	5700
2030		634	707	571		6333	6752	5700
Advanced Gas with Sequestration	1409				8613			
2015		1343	1271	1336		8240	8613	7990
2020		1296	1271	1255		7866	8613	7367
2025		1241	1271	1175		7493	8613	6744
2030		1181	1450	1094		7493	8613	6744
Conventional CombustionTurbine	500				10833			
2015		490	490	490		10675	10675	10675
2020		483	483	483		10563	10563	10563
2025		476	476	476		10450	10450	10450
2030		469	469	469		10450	10450	10450
Advanced CombustionTurbine	473				9289			
2015		459	473	440		9012	9289	8691
2020		449	473	416		8781	9289	8193
2025		433	473	395		8550	9289	7695
2030		412	473	371		8550	9289	7695

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

Source: AEO2008 National Energy Modeling System runs: AEO2008.D030208F, HCFOSS08.D030308A, LCFOSS08.D030308A.

Table 48. Cost Characteristics for Advanced Nuclear Technology: Two Cases

Advanced Nuclear Technology	Overnight Cost in 2006 (Reference) (2006$/kW)	Total Overnight Cost[1] Reference Case (2006$/kW)	High Nuclear Cost (2006$/KW)	Low Nuclear Cost (2006$/kW)
	2475			
2015		2378	2474	2270
2020		2262	2474	2123
2025		2098	2474	1976
2030		2033	2474	1829

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

Source: AEO2008 National Energy Modeling System runs: AEO2008.D030208F, HCNUC08.D030308A, LCNUC08.D030308A.

Low and High Energy Project Cost Cases

The *AEO2008* Issues in Focus article, "Impacts of Uncertainties in Energy Project Costs", examines two scenarios that vary cost assumptions in the power sector as well as the oil and gas and petroleum submodules. This section will discuss the assumptions used in the EMM for these two cases. Additional assumptions for these integrated cases can be found in the relevant oil and natural gas chapters of this document.

The reference case assumes that investment costs are based on the latest cost data, including any commodity price increases over the past few years, and that they will remain at these levels throughout the forecast. The base costs for all technologies in the reference case were increased by 15 percent relative to *AEO2007* to reflect recent cost increases.

The *high energy project cost case* assumes that the factor costs continue to rise, leading to increasing investment costs in the energy industry. In the power sector, it is assumed that the base costs of new generating construction increase by 2.5 percent per year from 2007 through 2030, a rate based on the construction cost growth of the past five years. Although changes in learning rates can also impact the cost projections, in general, costs for most technologies in 2030 are about 75 percent higher in the *high energy project cost case* than in the reference case.

The *low energy project cost case* assumes that the underlying factor cost markets gradually see cost declines back to the levels of the early 2000's, before the spikes. In the power sector, it is assumed that the base costs of new generating construction decline by 15 percent over the next ten years.

Limited Electricity Generation Supply and Limited Natural Gas Supply Cases

The *AEO2008* Issues in Focus article, "Limited Electricity Generation Supply and Limited Natural Gas Supply Cases", examines cases where severe pressure is put on the natural gas industry. Three cases were developed to analyze the uncertainties surrounding the availability of non-natural gas-fired power plants and the potential for new natural gas supplies. This section describes the assumptions used in the case restricting electricity technologies. The assumptions for the second case can be found in the natural gas chapter of this document. A combined case was also run for the article, and uses the assumptions from both the electricity and natural gas models.

The *limited electricity generation supply case* focuses on the potential challenges in the power sector facing non-natural gas-fired technologies. This case assumes that no new coal plants will be built unless they include carbon sequestration, due to uncertainty surrounding future environmental requirements. This case also assumes that new builds of nuclear, wind and biomass will be restricted to reference case levels. New non-natural gas-fired capacity, including sequestration and other renewables, is assumed to cost 25 percent more than in the reference case. Output from existing nuclear capacity is also assumed to decline after plants reach 40 years of age due to uncertainties surrounding the ability of older plants to maintain high capacity factors.

Notes and Sources

[1] On February 8, 2008, the U.S Court of Appeals found CAMR to be unlawful and voided it, ruling that the EPA had not proven that mercury was a pollutant eligible for regulation under a less stringent portion of the Clean Air Act; however, EIA did not have time to revise *AEO2008* before publication to remove the impact of CAMR.

[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.

Sources referenced in Table 38.

Fossil technology cost and performance characteristics were developed utilizing reviews performed by A2H Energy Services and Booz Allen Hamilton (BAH) in May 2004. A2H and BAH reviewed the parameters utilized in the Annual Energy Outlook 2004 (AEO2004) and provided recommended changes where needed. The averages of the AE2004 values and the recommended values were used.

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