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Assumptions for the Annual Energy Outlook 2003

With Projections to 2025

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Energy Information Administration

Contents

Introduction

This report presents the major assumptions of the National Energy Modeling System (NEMS) used to generate the projections in the *Annual Energy Outlook 2003*[1] (*AEO2003*), including general features of the model structure, assumptions concerning energy markets, and the key input data and parameters that are most significant in formulating the model results. Detailed documentation of the modeling system is available in a series of documentation reports.[2] A synopsis of NEMS, the model components, and the interrelationships of the modules is presented in *The National Energy Modeling System: An Overview.*[3]

The National Energy Modeling System

The projections in the *AEO2003* were produced with the National Energy Modeling System. NEMS is developed and maintained by the Office of Integrated Analysis and Forecasting of the Energy Information Administration (EIA) to provide projections of domestic energy-economy markets in the midterm time period and perform policy analyses requested by decisionmakers and analysts in the U.S. Congress, the Department of Energy's Office of Policy and International Affairs, other DOE offices, and other government agencies.

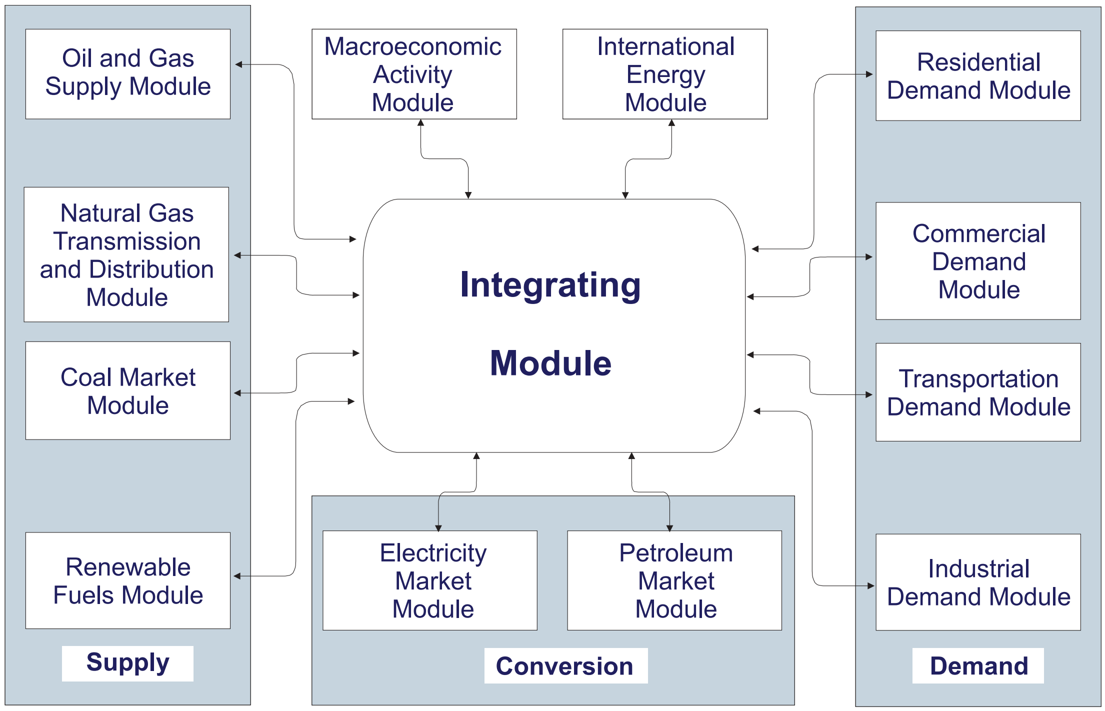
The time horizon of NEMS is approximately 20 years, the midterm period in which the structure of the economy and the nature of energy markets are sufficiently understood that it is possible to represent considerable structural and regional detail. Because of the diverse nature of energy supply, demand, and conversion in the United States, NEMS supports regional modeling and analysis in order to represent the regional differences in energy markets, to provide policy impacts at the regional level, and to portray transportation flows. The level of regional detail for the end-use demand modules is the nine Census divisions. Other regional structures include production and consumption regions specific to oil, gas, and coal supply and distribution, the North American Electric Reliability Council regions and subregions for electricity, and aggregations of the Petroleum Administration for Defense Districts (PADD) for refineries. Only national results are presented in the *AEO2003,* with the regional and other detailed results available on the EIA Home Page. (http://www.eia.doe.gov/oiaf/aeo/index.html)

For each fuel and consuming sector, NEMS balances the energy supply and demand, accounting for the economic competition between the various energy fuels and sources. NEMS is organized and implemented as a modular system (Figure 1). The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. The primary flows of information among each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, region, and sector. The delivered prices of fuel encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data such as economic activity, domestic production activity, and international petroleum supply availability.

The integrating module of NEMS controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data storage location. This modular design provides the capability to execute modules individually, thus allowing decentralized development of the system and independent analysis and testing of individual modules. This modularity allows use of the methodology and level of detail most appropriate for each energy sector. NEMS solves by calling each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Solution is reached annually through the midterm horizon. Other variables are also evaluated for convergence such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

Each NEMS component also represents the impact and cost of legislation and environmental regulations that affect that sector. NEMS reflects all current legislation and environmental regulations, such as the Clean Air Act Amendments of 1990 (CAAA90), and the costs of compliance with other regulations. NEMS also includes an analysis of the impacts of voluntary programs to reduce energy demand and carbon dioxide emissions, which are separately described under each module.

Figure 1. National Energy Modeling System



Component Modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing the prices of energy delivered to the consuming sectors and the quantities of end-use energy consumption. This section provides brief summaries of each of the modules.

Macroeconomic Activity Module

The Macroeconomic Activity Module provides a set of essential macroeconomic drivers to the energy modules and a macroeconomic feedback mechanism within NEMS. Key macroeconomic variables include gross domestic product (GDP), interest rates, disposable income, and employment. Industrial drivers are calculated for 35 industrial sectors. This module uses the following Global Insight (formerly DRI-WEFA) models: Macroeconomic Model of the U.S. Economy, National Industrial Shipments Model, National Employment Model, and Regional Model. In addition, EIA has constructed a Commercial Floorspace Model to forecast 13 floorspace types in 9 Census Divisions.

International Energy Module

The International Module represents the world oil markets, calculating the average world oil price and computing supply curves for five categories of imported crude oil for the Petroleum Market Module (PMM) of NEMS, in response to changes in U.S. import requirements. International petroleum product supply curves, including curves for oxygenates, are also calculated and provided to the PMM.

Household Expenditures Module

The Household Expenditures Module provides estimates of average household direct expenditures for energy used in the home and in private motor vehicle transportation. The forecasts of expenditures reflect the projections from NEMS for the residential and transportation sectors. The projected household energy expenditures incorporate the changes in residential energy prices and motor gasoline price determined in NEMS, as well as changes in the efficiency of energy use for residential end uses and in light-duty vehicle fuel efficiency. Estimates of average expenditures for households are provided by income group and Census division.

Residential and Commercial Demand Modules

The Residential Demand Module forecasts consumption of residential sector energy by housing type and end use, subject to delivered energy prices, availability of renewable sources of energy, and housing starts. The Commercial Demand Module forecasts consumption of commercial sector energy by building types and nonbuilding uses of energy and by category of end use, subject to delivered prices of energy, availability of renewable sources of energy, and macroeconomic variables representing interest rates and floorspace construction. Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, including representations of renewable energy technologies and effects of both building shell and appliance standards. Both modules include a representation of distributed generation.

Industrial Demand Module

The Industrial Demand Module forecasts the consumption of energy for heat and power and for feedstocks and raw materials in each of 16 industry groups, subject to the delivered prices of energy and macroeconomic variables representing employment and the value of shipments for each industry. The industries are classified into three groups—energy-intensive, non-energy-intensive, and nonmanufacturing. Of the eight energy-intensive industries, seven are modeled in the Industrial Demand Module with components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. A representation of cogeneration and a recycling component are also included. The use of energy for petroleum refining is modeled in the Petroleum Market Module, and the projected consumption is included in the industrial totals.

Transportation Demand Module

The Transportation Demand Module forecasts consumption of transportation sector fuels, including petroleum products, electricity, methanol, ethanol, compressed natural gas, and hydrogen by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and the value of output for industries in the freight sector. Fleet vehicles are represented separately to allow analysis of CAAA90 and other legislative proposals, and the module includes a component to explicitly assess the penetration of alternative-fuel vehicles.

Electricity Market Module

The Electricity Market Module represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, and natural gas; costs of generation by centralized renewables; macroeconomic variables for costs of capital and domestic investment; and electricity load shapes and demand. There are three primary submodules—capacity planning, fuel dispatching, and finance and pricing. Nonutility generation, distributed generation, and transmission and trade are represented in the planning and dispatching submodules. The levelized fuel cost of uranium fuel for nuclear generation is directly incorporated into the Electricity Market Module. All CAAA90 compliance options are explicitly represented in the capacity expansion and dispatch decisions. New generating technologies for fossil fuels, nuclear, and renewables compete directly in the decisions.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing natural resource supply and technology input information for central-station, grid-connected electricity generation technologies, including biomass (wood, energy crops, and biomass co-firing), geothermal, landfill gas, solar thermal, solar photovoltaics, and wind energy. The RFM contains natural resource supply estimates representing the regional opportunities for renewable energy development. Conventional hydroelectricity is represented in the Electricity Market Module (EMM).

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships between the various sources of supply: onshore, offshore, and Alaska by both conventional and nonconventional techniques, including gas recovery from coalbeds and low-permeability formations of sandstone and shale. This framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, subject to the prices for crude oil and natural gas, the domestic recoverable resource base, and technology. Oil and gas production functions are computed at a level of 12 supply regions, including 3 offshore and 3 Alaskan regions. This module also represents foreign sources of natural gas, including pipeline imports, exports to Canada and Mexico, and liquefied natural gas imports and exports. Crude oil production quantities are input to the Petroleum Market Module in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are input to the Natural Gas Transmission and Distribution Module for use in determining natural gas prices and quantities.

Natural Gas Transmission and Distribution Module

The Natural Gas Transmission and Distribution Module represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module tracks the flows of natural gas in an aggregate, domestic pipeline network, connecting the domestic and foreign supply regions with 12 demand regions. This capability allows the analysis of impacts of regional capacity constraints in the interstate natural gas pipeline network and the identification of pipeline and storage capacity expansion requirements. Peak and off-peak periods are represented for natural gas transmission, and core and non-core markets are represented at the burner tip. Key components of pipeline and distributor tariffs are included in the pricing algorithms.

Petroleum Market Module

The Petroleum Market Module (PMM) forecasts prices of petroleum products, crude oil and product import activity, and domestic refinery operations, including fuel consumption, subject to the demand for petroleum products, availability and price of imported petroleum, and domestic production of crude oil, natural gas liquids, and alcohol fuels. The module represents refining activities for three regions—Petroleum Administration for Defense District (PADD) 1, PADD 5, and an aggregate of PADDs 2, 3, and 4. The module uses the same crude oil types as the International Module. It explicitly models the requirements of CAAA90 and the costs of automotive fuels, such as oxygenated and reformulated gasoline, and includes oxygenate production and blending for reformulated gasoline. *AEO2003* reflects legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in the next several years in Arizona, California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Maine, Michigan, Minnesota, Missouri, Nebraska, New York, Ohio, South Dakota, and Washington.

Because the *AEO2003* reference case assumes current laws and regulations, it assumes that the Federal oxygen requirement for reformulated gasoline in Federal nonattainment areas will remain intact. The “Tier 2” regulation that requires the nationwide phase-in of gasoline with a greatly reduced annual average sulfur content, 30 parts per million (ppm), between 2004 and 2007 is explicitly modeled. The new “ultra-low-sulfur diesel” regulation finalized in December 2000 is also explicitly modeled. The diesel regulation requires that 80 percent of the highway diesel produced between June 1, 2006, and May 31, 2010, have a maximum sulfur content of 15 ppm, and that all highway diesel fuel meet the same limit after June 1, 2010. Costs of the regulation include capacity expansion for refinery processing units based on a 10-percent hurdle rate and a 10-percent after-tax return on investment. End-use prices are based on the marginal costs of production, plus markups representing product and distribution costs, State and Federal taxes, and environmental site costs. *AEO2003* assumes that refining capacity expansion may occur on the East Coast, West Coast, and Gulf Coast.

Coal Market Module

The Coal Market Module simulates mining, transportation, and pricing of coal, subject to the end-use demand for coal differentiated by physical characteristics, such as the heat and sulfur content. The coal supply curves include a response to capacity utilization of mines, mining capacity, fuel costs, labor productivity, and factor input costs. Twelve coal types are represented, differentiated by coal rank, sulfur content, and mining process. Production and distribution are computed for 11 supply and 13 demand regions, using imputed coal transportation costs and trends in factor input costs. The Coal Market Module also forecasts the requirements for U.S. coal exports and imports. The international coal market component of the module computes trade in 3 types of coal for 16 export and 20 import regions. Both the domestic and international coal markets are simulated in a linear program.

Cases for the *Annual Energy Outlook 2003*

The *AEO2003* presents five cases which differ from each other due to fundamental assumptions concerning the domestic economy and world oil market conditions. Three alternative assumptions are specified for each of these two factors, with the reference case using the midlevel assumption for each.

- **Economic Growth** - In the reference case, productivity grows at an average annual rate of 2.1 percent from 2001 through 2025 and the labor force at 0.9 percent per year, yielding a growth in real GDP of 3.0 percent per year. In the high economic growth case, productivity and the labor force grow at 2.3 and 1.2 percent per year, respectively, resulting in GDP growth of 3.5 percent annually. The average annual growth in productivity, the labor force, and GDP is 1.8, 0.7 and 2.5 percent, respectively, in the low economic growth case.

- **World Oil Markets** - In the reference case, the average world oil price increases to $26.57 per barrel (in real 2001 dollars) in 2025. Reflecting uncertainty in world markets, the price in 2025 reaches $19.04 per barrel in the low oil price case and $33.05 per barrel in the high oil price case.

In addition to these five cases, additional cases presented in Table 1 explore the impacts of changing key assumptions in individual sectors.

Many of the side cases were designed to examine the impacts of varying key assumptions for individual modules or a subset of the NEMS modules, and thus the full market consequences, such as the consumption or price impacts, are not captured. In a fully integrated run, the impacts would tend to narrow the range of the differences from the reference case. For example, the best available technology side case in the residential demand assumed that all future equipment purchases are made from a selection of the most efficient technologies available in a particular year. In a fully integrated NEMS run, the lower resulting fuel consumption would have the effect of lowering slightly the market prices of those fuels with the concomitant impact of increasing economic growth, thus stimulating some additional consumption. As another example, the higher electricity demand side case results in higher electricity prices. If the end-use demand modules were executed in a full run, the demand for electricity would be reduced slightly as a result of the higher prices and resulting lower economic growth, thus moderating somewhat the input assumptions. The results of these cases should be considered the maximum range of the impacts that could occur with the assumptions defined for the case.

All projections are based on Federal, State, and local laws and regulations in effect on September 1, 2001, including the additional fuels taxes in the Omnibus Budget Reconciliation Act of 1993, the CAAA90, the Energy Policy Act of 1992, the Outer Continental Shelf Deep Water Royalty Relief Act of 1995, the Tax Payer Relief Act of 1997, the Federal Highway Bill of 1998, new standards for gasoline and diesel fuel and heavy-duty vehicle emissions, and the new equipment standards announced in 2001. Pending legislation and sections of existing legislation for which funds have not been appropriated are not reflected in these forecasts.

Table 1. Summary of *AEO2003* Cases

Case name	Description	Integration mode
Reference	Baseline economic growth,world oil price,and technology assumptions	Fully integrated
Low Economic Growth	Gross domestic product grows at an average annual rate of 2.5 percent, compared to the reference case growth of 3.0 percent.	Fully integrated
High Economic Growth	Gross domestic product grows at an average annual rate of 3.5 percent,compared to the reference case growth of 3.0 percent	Fully integrated
Low World Oil Price	World oil prices are $19.04 per barrel in 2025,compared to $26.57 per barrel in the reference case	Fully integrated
High World Oil Price	World oil prices are $33.05 per barrel in 2025,compared to $26.57 per barrel in the reference case	Fully integrated
Residential: 2003 Technology	Future equipment purchases based on equipment available in 2003.Existing building shell efficiencies fixed at 2003 levels	With commercial
Residential: High Technology	Earlier availability,lower costs,and higher efficiencies assumed for more advanced equipment.Heating shell efficiency increases by 12 percent from 1997 values by 2025.	With commercial
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available.Heating shell efficiency increases by 16 percent from 1997 values by 2025.	With commercial
Commercial: 2003 Technology	Future equipment purchases based on equipment available in 2003. Building shell efficiencies fixed at 2003 levels.	With residential
Commercial: High Technology	Earlier availability,lower costs,and higher efficiencies assumed for more advanced equipment. Building shell efficiencies increase 50 percent faster than in the reference case.	With residential
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available. Building shell efficiencies increase 50 percent faster than in the reference case.	With residential
Industrial: 2003 Technology	Efficiency of plant and equipment fixed at 2003 levels.	Standalone
Industrial: High Technology	Earlier availability,lower costs,and higher efficiencies assumed for more advanced equipment.	Standalone
Transportation: 2003 Technology	Efficiencies for new equipment in all modes of travel are fixed at 2003 levels	Standalone
Transportation: High Technology	Reduced costs and improved efficiencies are assumed for advanced technologies.	Standalone
Integrated 2003 Technology	Combination of the residential, commercial, industrial, and transportation 2003 technology cases, electricity low fossil technology case, and assumption of renewable technologies fixed at 2002 levels.	Fully Integrated
Integrated High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases, electricity high fossil technology case, high renewables case, and advanced nuclear cost case.	Fully Integrated
Electricity: Advanced Nuclear Cost	New nuclear capacity is assumed to have both lower capital costs than in the reference case	Partially integrated
Electricity: High Demand	Electricity demand increases at an annual rate of 2.5 percent, compared to 1.8 percent in the reference case.	Partially Integrated
Electricity: High Fossil Technology	New advanced fossil generating technologies are assumed not to improve over time from 2003.	Partially Integrated

Table 1. Summary of *AEO2003* Cases (Continued)

Cases	Description	Integration Mode
Renewables: High Renewables	Lower costs and higher efficiencies for central-station renewable generating technologies and for distributed photovoltaics,approximating U.S.Department of Energy goals for 2025. Includes greater improvements in residential and commercial photovoltaic systems,more rapid improvement in recovery of industrial biomass byproducts,and more rapid improvement in cellulosic ethanol production technology.	Fully integrated
Oil and Gas:Slow Technology	Cost,finding rate,and success rate parameters adjusted for 15-percent slower improvement than in the reference case.	Fully integrated
Oil and Gas: Rapid Technology	Cost,finding rate,and success rate parameters adjusted for 15-percent more rapid improvement than in the reference case.	Fully integrated
Coal: Low Mining Cost	Productivity increases at an annual rate of 3.1 percent, compared to the reference case growth of 1.6 percent. Real wages and real mine equipment costs decrease by 0.5 percent annually,compared to constant real wages and equipment costs in the reference case.	Fully integrated
Coal: High Mining Cost	Productivity increases at an annual rate of 0.1 percent, compared to the reference case growth of 1.6 percent. Real wages and real mine equipment costs increase by 0.5 percent annually,compared to constant real wages and equipment costs in the reference case.	Fully integrated

Emissions

Carbon dioxide emissions from energy use are dependent on the carbon dioxide content of the fuel and the fraction of the fuel consumed in combustion. The product of the carbon dioxide content at full combustion and the combustion fraction yields an adjusted carbon dioxide emission factor for each fuel. The emissions factors are expressed in millions of metric tons carbon equivalent of carbon dioxide emitted per quadrillion Btu of energy use, or equivalently, in kilograms carbon equivalent of carbon dioxide per million Btu. The adjusted emissions factors are multiplied by energy consumption to arrive at the carbon dioxide emissions projections.

For fuel uses of energy, the combustion fractions are assumed to be 0.99 for liquid fuels and 0.995 for gaseous fuels. The carbon dioxide in nonfuel use of energy, such as for asphalt and petrochemical feedstocks, is assumed to be sequestered in the product and not released to the atmosphere. For energy categories that are mixes of fuel and nonfuel uses, the combustion fractions are based on the proportion of fuel use. Any carbon dioxide emitted by renewable sources is considered balanced by the carbon dioxide sequestration that occurred in its creation. Therefore, following convention, net emissions of carbon dioxide from renewable sources are taken as zero, and no emission coefficient is reported. Renewable fuels include hydroelectric power, biomass, photovoltaic, geothermal, ethanol, and wind energy.

Table 2 presents the carbon dioxide coefficients at full combustion, the combustion fractions, and the adjusted carbon dioxide emission factors used for *AEO2003*.

Table 2. Carbon Dioxide Emission Factors
(Kilograms-carbon equivalent per million Btu)

Fuel Type	Carbon Dioxide Coefficient at Full Combustion	Combustion Fraction	Adjusted Emissions Factor
Petroleum			
Motor Gasoline	19.34	0.990	19.15
Liquefied Petroleum Gas			
Used as Fuel	17.18	0.995	17.09
Used as Feedstock	16.87	0.200	3.37
Jet Fuel	19.33	0.990	19.14
Distillate Fuel	19.95	0.990	19.75
Residual Fuel	21.49	0.990	21.28
Asphalt and Road Oil	20.62	0.000	0.00
Lubricants	20.24	0.600	12.14
Petrochemical Feedstocks	19.37	0.200	3.87
Kerosene	19.72	0.990	19.52
Petroleum Coke	27.85	0.500	13.93
Petroleum Still Gas	17.51	0.995	17.42
Other Industrial	20.31	0.990	20.11
Coal			
Residential and Commercial	26.00	0.990	25.74
Metallurgical	25.56	0.990	25.30
Industrial Other	25.63	0.990	25.38
Electric Utility[1]	25.76	0.990	25.50
Natural Gas			
Used as Fuel	14.47	0.995	14.40
Used as Feedstocks	14.47	0.774	11.20

[1]Emission factors for coal used for electricity generation are specified by coal supply region and types of coal, so the average carbon dioxide contents for coal varies throughout the forecast. The 2000 average is 25.50.

Source: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2000*, DOE/EIA-0573(2000), (Washington, DC, November 2001).

Methane emissions from energy-related activities are now estimated in NEMS. Methane emissions occur in various phases of the production and transportation of coal, oil, and natural gas. Additional emissions occur as a result of incomplete combustion of fossil fuels and wood. The methane emissions from each category are calculated as a function of energy production or consumption variables projected in NEMS. The emission factors and coefficients for these calculations are displayed in Tables 3, 4, and 5.

Table 3. Coal-Related Methane Assumptions

		Northern Appalachia	Central Appalachia	Southern Appalachia	Eastern Interior	Western
Fraction of underground coal production at:						
Gassy mines		0.885	0.368	0.971	0.876	0.681
Nongassy mines		0.115	0.632	0.029	0.124	0.319
Production from mines with degasification systems (fraction of underground production)		0.541	0.074	0.810	0.067	0.056
Emission factors (kilograms methane per short ton of coal produced)						
Underground Mining						
Gassy mines		6.047	5.641	27.346	2.988	6.027
Nongassy mines		0.362	0.076	15.959	0.285	0.245
Degassified mines		4.085	37.724	22.025	0.310	0.000
Surface Mining		0.706	0.706	0.706	0.706	0.706
Post-Mining, underground-mined		1.505	1.505	1.505	1.505	1.505
Post-Mining, surface-mined		0.061	0.061	0.061	0.061	0.061
Methane recovery at active coal mines (million metric tons carbon equivalent)		United States				
	2001	4.400				
	2005	4.645				
	2010	4.970				
	2015	5.317				
	2020	5.689				
	2025	6.087				

Source: Emissions factors and data sources from Energy Information Administration, *Emissions of Greenhouse Gases in the United States 20001, DOE/EIA-0573(2001), (Washington, DC, December 2002).*

Table 4. Coefficients of Linear Equations for Natural Gas- and Oil-Related Methane Emissions

Emissions Sources	Intercept	Variable Name and Units	Coefficient	Variable Name and Units	Coefficient
Natural Gas	-38.77	Time trend (calendar year)	.02003	Dry gas production (thousand cubic feet)	.02186
Natural Gas Processing	-0.9454	Natural gas liquids production (million barrels per day)	.9350	Not applicable	
Natural Gas Transmission and Storage	2.503	Pipeline fuel use (thousand cubic feet)	1.249	Dry gas production (thousand cubic feet)	-0.06614
Natural Gas Distribution	-58.16	Time trend (calendar year)	.0297	Natural gas consumption (quadrillion Btu)	.0196
Oil production, Refining, and Transport	0.03190	Oil consumption (quadrillion Btu)	.002764	Not applicable	

Source: Derived from data used in Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2001*, DOE/EIA-0573(2001), (Washington, DC, December 2002).

Table 5. Methane Emissions Factors for Energy Combustion
(Metric tons carbon equivalent per trillion Btu)

	Residential	Commercial	Industrial	Electricity
Stationary Combustion				
Coal	3.61	63.08	15.14	3.78
Residual Fuel	0.00	10.09	18.29	4.42
Distillate Fuel	31.54	3.78	1.01	0.00
Natural Gas	6.02	7.23	8.43	0.60
Liquid Gases	7.27	7.27	8.63	0.00
Wood	5531.11	18.44	16.78	0.00
Mobile Combustion				
Passenger Cars	70.54			
Buses	40.78			
Motorcycles	1115.63			
Light-Duty Trucks	90.46			
Other Trucks	23.98			
Other Transport	46.92			

Source: Emissions factors and data sources from Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2000*, DOE/EIA-0573(2000), (Washington, DC, November 2001).

Notes and Sources

[1] Energy Information Administration, Annual Energy Outlook 2003 (AEO2003), DOE/EIA-0383(2003), (Washington, DC, January 2003).

[2] NEMS documentation reports are available on the EIA Homepage (http://www.eia.doe.gov/bookshelf.html).

[3] Energy Information Administration, The National Energy Modeling System: An Overview 2000, DOE/EIA-0581(2000), (Washington, DC, March 2000).

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) represents the interaction between the U.S. economy as a whole and energy markets. The rate of growth of the economy, measured by the growth in gross domestic product (GDP) is a key determinant of the growth in demand for energy. Associated economic factors, such as interest rates and disposable income, strongly influence various elements of the supply and demand for energy. At the same time, reactions to energy markets by the aggregate economy, such as a slowdown in economic growth resulting from increasing energy prices, are also reflected in this module. A detailed description of the MAM is provided in the EIA publication, *Model Documentation Report: Macroeconomic Activity Module (MAM) of the National Energy Modeling System*, DOE/EIA-M065(2003), (Washington, DC, January 2003).

Key Assumptions

The output of the U.S. economy, measured by GDP, is expected to increase by 3.0 percent between 2001 and 2025 in the reference case. The growth in GDP can be decomposed into two key factors: the growth rate of the labor force and the rate of productivity change associated with the labor force. As Table 6 indicates, GDP growth is slower for the first four years of the forecast period, reflecting current economic conditions. Growth in the economy recovers for the remaining of the forecast period, primarily due to continued increases in productivity growth. The growth of the labor force depends upon the forecast population growth and the labor force participation rate. The Census Bureau's middle series population projection is used as a basis for the *AEO2003*. Total population is expected to grow annually by 0.8 percent between 2001 and 2025, but the share of population over 65 is expected to increase over time. While the projected labor force growth slows down because of demographic changes, it remains relatively strong as more people over 65 decide to stay in the work force.

The productivity of labor is the second major reason for economic growth and reflects the positive effects of a growing capital stock of the economy as well as technological change occurring over time. A key to

Table 6. Growth in Gross Domestic Product, Labor Force, and Productivity
(Percent per Year)

Assumptions	2001-2005	2005-2010	2010-2015	2015-2020	2020-2025	2001-2025
GDP (Billion Chain-Weighted $1996)						
High Growth	3.6	4.1	3.4	3.3	3.3	3.5
Reference	3.0	3.4	3.1	2.9	2.8	3.0
Low Growth	2.4	3.1	2.6	2.2	2.2	2.5
Labor Force						
High Growth	1.4	1.4	1.1	0.9	1.1	1.2
Reference	1.2	1.0	0.9	0.7	0.9	0.9
Low Growth	0.9	0.8	0.7	0.4	0.6	0.7
Productivity						
High Growth	2.1	2.7	2.3	2.3	2.2	2.3
Reference	1.8	2.4	2.2	2.1	1.9	2.1
Low Growth	1.4	2.2	1.9	1.8	1.5	1.8

Source: Energy Information Administration, *AEO2003* National Energy Modeling System runs: *AEO2003*.d110502c; lm2003.d110502c; and hm2003.d110502c.

achieving the reference case's long-run 3.0 percent growth is an anticipated steady growth in labor productivity. In the very short term, productivity growth is relatively weak reflecting current economic uncertainty. As the economy recovers, capital stock is expected to grow at a stronger pace. Business fixed investment as a share of nominal GDP is expected to rise. The resulting growth in the capital stock and the technology base of that capital stock helps to sustain productivity growth just over 2 percent.

For the forecast period, disposable income is projected to grow at an annual rate of 2.9 percent, and disposable income per capita at 2.1 percent. Non-agriculture employment is projected to grow at 1.0 percent per year, while employment in manufacturing is projected to grow more slowly at 0.2 percent per year.

To reflect the uncertainty in forecasts of economic growth, the *AEO2003* forecasts use high and low economic growth cases along with the reference case to project the possible energy markets. The high economic growth case incorporates higher population, labor force and productivity growth rates than the reference case. Due to the higher productivity gains, inflation and interest rates are lower compared to the reference case. Investment, disposable income, and industrial production are increased. Economic output is projected to increase by 3.5 percent per year between 2001 and 2025. The low economic growth case assumes lower population, labor force, and productivity gains, with resulting higher prices and interest rates and lower industrial output growth. In the low economic growth case, economic output is expected to increase by 2.5 percent per year over the forecast horizon.

The regional disaggregation of the economic variables uses regional shares based on a regional model solution. These shares change over time, but do not change as energy prices change from the projected reference price path.

International Energy Module

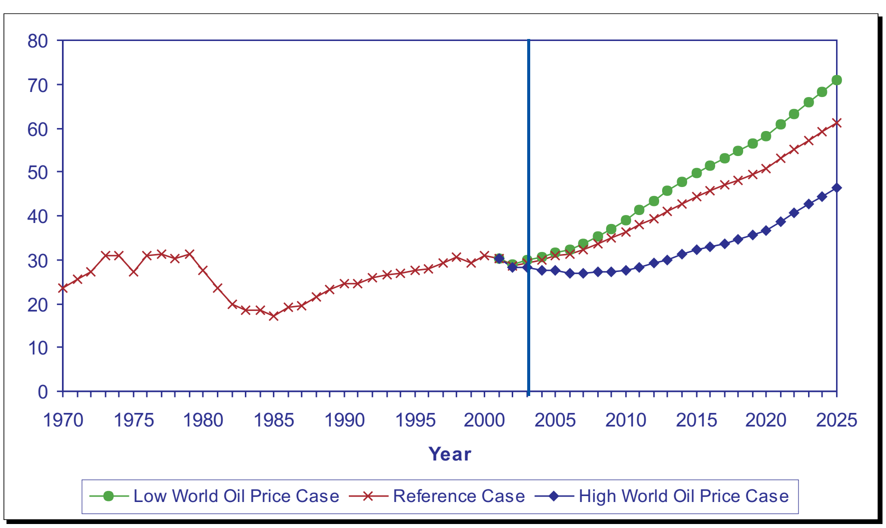
The International Energy Module determines changes in the world oil price and the supply prices of crude oils and petroleum products for import to the United States in response to changes in U.S. import requirements. A market clearing method is used to determine the price at which worldwide demand for oil is equal to the worldwide supply. The module determines new values for oil production and demand for regions outside the United States, along with a new world oil price that balances supply and demand in the international oil market. A detailed description of the International Energy Module is provided in the EIA publication, *Model Documentation Report: The International Energy Module of the National Energy Modeling System*, DOE/EIA-M071(99), (Washington, DC, February 1999).

Key Assumptions

The level of oil production by countries in the Organization of Petroleum Exporting Countries (OPEC) is a key factor influencing the world oil price projections incorporated into *AEO2003*. Non-OPEC production, worldwide regional economic growth rates and the associated regional demand for oil are additional factors affecting the world oil price.

OPEC oil production is assumed to increase throughout the forecast, making OPEC the primary source, satisfying the worldwide increase in oil consumption expected over the forecast period (Figure 2). OPEC is assumed to be the source of additional production because its member nations hold a major portion of the world's total reserves—exceeding 818 billion barrels, more than 79 percent of the world's estimated total, at the end of 2001.[4] For the *AEO2003* forecasts, three different OPEC production paths are the principal assumptions leading to the three world oil price path cases examined: the low oil price case, reference case, and high oil price case. The values assumed for OPEC production for the three world oil price cases are given in Figure 2. Iraq is assumed to continue selling oil only at United Nations Security Council sanction-allowed volumes until at least 2004. Once sanctions are lifted, Iraq will increase production levels to over 4 million barrels per day within 2 years. Within a decade of sanctions being lifted, Iraq is expected to increase production capacity to more than 6 million barrels per day with likely investment help from foreign sources. Non-OPEC oil production is expected to follow a gradually rising path—with an increase of more than 1.1 percent per year over the forecast period—as advances in both exploration and extraction technologies result in this upward trend (Figure 3). One fixed path for non-OPEC oil production is initially

Figure 2. OPEC Oil Production, 1970-2025
(Million Barrels per Day)

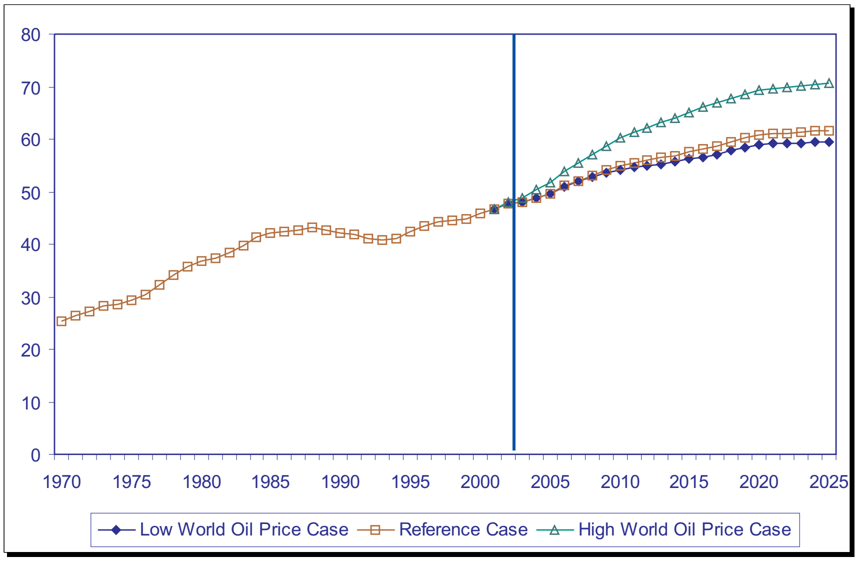


OPEC = Organization of Petroleum Exporting Countries.

Sources: Energy Information Administration. AEO2003 National Energy Modeling System runs lw2003.d110502c, aeo2003.d110502c, and hw2003.d110502c.

input for all three world oil price case projections. Non-OPEC production depends upon world oil prices, so the final forecast solutions of the levels of non-OPEC production for the three oil price cases diverge from the initial assumptions. Production is higher in the high oil price case since more marginal wells are profitable at the higher prices. Likewise, lower world oil prices are associated with lower production levels. The final non-OPEC production paths for the three oil price cases are shown in Figure 3.

Figure 3. Non-OPEC Oil Production, 1970-2025
(Million Barrels per Day)



OPEC = Organization of Petroleum Exporting Countries.

Sources: Energy Information Administration. AEO2003 National Energy Modeling System runs lw2003.d110502c, aeo2003.d110502c, and hw2003.d110502c.

The non-U.S. oil production forecasts in the *AEO2002* begin with country-level assumptions regarding proved oil reserves. These reserve estimates are shown in Table 7 and are compiled by PennWell Publishing Company's *Oil and Gas Journal*.

Table 7. Worldwide Oil Reserves as of January 1, 2002
(Billion Barrels)

Region	Proved Oil Reserves
Western Hemisphere	149.8
Western'Europe	17.1
Asia-Pacific	43.8
Eastern Europe and F.S.U.	58.6
Middle East	685.6
Africa	76.7
Total World	1,031.6
Total OPEC	818.8

Source: PennWell Publishing Co., International Petroleum Encyclopedia, (Tulsa, OK, 2002).

The assumed growth rates for GDP for various regions in the world are shown in Table 8. This set of growth rates for GDP was assumed for all three price cases. The GDP growth rate assumptions are from Global Insight's DRI-WEFA August 2002 World Economic Outlook.

The values for growth in oil demand calculated in the International Energy Module, which depend upon the oil price levels as well as the GDP growth rates, are shown in Table 9 for the three oil price cases by regions.

Table 8. Average Annual Regional Gross Domestic Product Growth Rates, 2001-2025
(Percent per Year)

Region	Gross Domestic Product
Industrialized Countries	2.6
Other Developing Countries	4.2
Eurasia	5.4
China	6.4
Former Soviet Union	3.9
Eastern Europe	4.1
Total World	3.1

Source: Global Insight's DRI-WEFA, World Economic Outlook, (Lexington, MA, August 2002).

Table 9. Average Annual Regional Growth Rates for Oil Demand, 2001-2025
(Percent per Year)

Region	Low Price	Reference	High Price
Industrialized Countries	1.6	1.3	1.1
Other Developing Countries	2.9	2.8	2.6
Eurasia	3.3	3.1	2.9
China	4.2	3.9	3.7
Former Soviet Union	2.1	2.0	1.8
Eastern Europe	2.4	2.2	2.2
Total World	2.3	2.0	1.8

Source: Energy Information Administration, *AEO2003* National Energy Modeling System runs: lw2003.d110502c; aeo2003.d110502c; and hw2003.d110502c.

Petroleum product imports are represented in the projections through a series of curves that present the quantity of each product that the world market is willing to supply to U.S. markets for each of the five Petroleum Administration for Defense Districts (PADDs). Curves are provided for ten products: traditional gasoline (including aviation), reformulated gasoline, No. 2 heating oil, low-sulfur distillate oil, high- and low-sulfur residual oil, jet fuel (including naptha jet), liquefied petroleum gas, petrochemical feedstocks, and other. The curves are calculated using the World Oil Refining Logistics Demand (WORLD) Model.[5] The WORLD model uses as inputs worldwide demand for crude oil and petroleum products for world oil prices that are close to the oil prices assumed for *AEO2003*, as well as values for worldwide petroleum production that are consistent with such prices. The refinery technology incorporated in the model is updated using the most recently available Oil & Gas Journal Database.[6]

Notes and Sources

[4] PennWell Publishing Co., International Petroleum Encyclopedia, (Tulsa, OK, 2002).

[5] EIA, EIA Model Documentation: World Oil Refining Logistics Demand Model, “WORLD” Reference Manual, DOE/EIA-M058, (Washington, DC, March 1994).

[6] Oil & Gas Journal, World Wide Refinery Survey, (data as of January 1, 2002).

Household Expenditures Module

The Household Expenditures Module (HEM) constructs household energy expenditure profiles using historical survey data on household income, population and demographic characteristics, and consumption and expenditures for fuels for various end-uses. These data are combined with NEMS forecasts of household disposable income, fuel consumption, and fuel expenditures by end-use and household type. The HEM disaggregation algorithm uses these combined results to forecast household fuel consumption and expenditures by income quintile and Census Division.

Key Assumptions

The historical input data used to develop the HEM version for the *AEO2003* consists of recent household survey responses, aggregated to the desired level of detail. Two surveys performed by the Energy Information Administration are included in the *AEO2003* HEM database, and together these input data are used to develop a set of baseline household consumption profiles for the direct fuel expenditure analysis. These surveys are the 1997 Residential Energy Consumption Survey (RECS) and the 1991 Residential Transportation Energy Consumption Survey (RTECS).

HEM uses the consumption forecast by NEMS for the residential and transportation sectors as inputs to the disaggregation algorithm that results in the direct fuel expenditure analysis. Household end-use and personal transportation service consumption are obtained by HEM from the NEMS Residential and Transportation Demand Modules. Household disposable income is adjusted with forecasts of total disposable income from the NEMS Macroeconomic Activity Module.

The fundamental assumptions underlying HEM's processing of the historical and NEMS forecast data to obtain its results are:

- Individual households are assumed not to migrate between income quintiles throughout the analysis period.

- All households within a household segment are assumed to consume the average quantity of fuel for that segment. Distributions about, or deviations from, the average are not explicitly modeled.

- The change in average household consumption between forecast year y and survey base year y_0 is captured from the NEMS run at the finest available level of detail, and the same proportional change is assumed to occur in each HEM subsegment of the analysis.

Application of the HEM algorithm produces a direct household fuel expenditure forecast at the finest level of disaggregation; namely, by fuel, end-use service, housing type and vintage, ethnicity, disposable income quintile, Census Division, and year. Results obtained are summed across end-uses to yield total direct fuel expenditures as a function of disposable income for each household segment. The consolidation of these high-resolution results into national average household expenditure results requires a weighted averaging in order to obtain the desired aggregations. The weighing scheme used requires the proportions of households of each type and vintage headed by householders of each ethnicity and income quintile. The survey data provides these historical subsegment proportions, and for the *AEO2003* they are assumed to remain constant throughout the forecast period.

Residential Demand Module

The NEMS Residential Demand Module forecasts future residential sector energy requirements based on projections of the number of households and the stock, efficiency, and intensity of use of energy-consuming equipment. The Residential Demand Module projections begin with a base year estimates of the housing stock, the types and numbers of energy-consuming appliances servicing the stock, and the "unit energy consumption" by appliance (or UEC—in million Btu per household per year). The projection process adds new housing units to the stock, determines the equipment installed in new units, retires existing housing units, and retires and replaces appliances. The primary exogenous drivers for the module are housing starts by type (single-family, multifamily and mobile homes) and Census Division and prices for each energy source for each of the nine Census Divisions. The Residential Demand Module also requires projections of available equipment over the forecast horizon. Over time, equipment efficiency tends to increase because of general technological advances and also because of Federal and/or state efficiency standards. As energy prices and available equipment changes over the forecast horizon, the module includes projected changes to the type and efficiency of equipment purchased as well as projected changes in the usage intensity of the equipment stock.

The end-use services for which equipment stocks are modeled include space conditioning (heating and cooling), water heating, refrigeration, freezers, dishwashers, clothes washers, lighting, furnace fans, cooking, and clothes drying. In addition to the major equipment-driven end-uses, the average energy consumption per household is projected for secondary heating, color televisions, personal computers, and other electric and nonelectric appliances. The module's output includes number of households, equipment stock, average equipment efficiencies, and energy consumed by service, fuel, and geographic location. The fuels represented are distillate fuel oil, liquefied petroleum gas, natural gas, kerosene, electricity, wood, geothermal, coal, and solar energy.

One of the implicit assumptions embodied in the Residential Demand Module is that, through 2025, there will be no radical changes in technology or consumer behavior. No new regulations of efficiency beyond those currently embodied in law or new government programs fostering efficiency improvements are assumed. Technologies which have not gained widespread acceptance today will not achieve significant penetration by 2020. Currently available technologies will evolve in both efficiency and cost. In general, for the same real cost, future technologies will be less expensive than those available today. When choosing new or replacement technologies, consumers will behave similarly to the way they now behave. The intensity of end-uses will change moderately in response to price changes. Electric end uses will continue to expand, but at a decreasing rate.[7]

Key Assumptions

Housing Stock Submodule

A very important determinant of future energy consumption is the projected number of households. Base year estimates for 1997 are derived from the Energy Information Administration's (EIA) *Residential Energy Consumption Survey* (RECS) (Table 10). The forecast for occupied housing units is done separately for each Census Division. It is based on the combination of the previous year's surviving stock with projected housing starts provided by the NEMS Macroeconomic Activity Module. The housing stock submodule assumes a constant survival rate (the percentage of households which are present in the current forecast year, which were also present in the preceding year) for each type of housing unit; 99.6 percent for single-family units, 99.3 percent for multifamily units, and 96.5 percent for mobile home units. Projected fuel consumption is dependent not only on the projected number of housing units, but also on the type and geographic distribution of the houses. The intensity of space heating energy use varies greatly across the various climate zones in the United States. Also, fuel prevalence varies across the country—oil (distillate) is more frequently used as a heating fuel in the New England and Middle Atlantic Census Divisions than in the rest of the country, while natural gas dominates in the Midwest. An example of differences by housing type is the more prevalent use of liquefied petroleum gas in mobile homes relative to other housing types.

Table 10. 1997 Households

Region	Single-family Units	Multi-family Units	Mobile Home Units	Total Units
New England	3,759,905	1,434,960	114,801	5,309,666
Mid Atlantic	9,990,266	4,063,826	370,168	14,424,260
East North Central	12,541,488	3,616,338	748,928	16,906,754
West North Central	5,905,676	893,549	353,749	7,152,974
South Atlantic	13,638,587	3,566,115	1,488,834	18,693,536
East South Central	4,785,180	769,795	788,963	6,343,938
West South Central	8,231,512	1,899,383	708,128	10,839,023
Mountain	4,476,532	1,039,756	663,026	6,179,314
Pacific	10,406,761	4,144,606	1,080,339	15,631,706
United States	73,735,907	21,428,328	6,316,936	101,481,171

Source: Energy Information Administration, *A Look at Residential Energy Consumption in 1997*, DOE/EIA-314(97), (Washington, DC, November 1999).

Technology Choice Submodule

The key inputs for the Technology Choice Submodule are fuel prices by Census Division and characteristics of available equipment (installed cost, maintenance cost, efficiency and equipment life). Fuel prices are determined by an equilibrium process which considers energy supplies and demands and are passed to this submodule from the integrating module of NEMS. Energy price, combined with equipment UEC (which is a function of efficiency), determines the operating costs of equipment. Equipment characteristics are exogenous to the model and are modified to reflect both Federal standards and anticipated changes in the market place. Table 11 lists capital cost and efficiency for selected residential appliances for the years 2001 and 2015.

Table 11. Installed Cost and Efficiency Ratings of Selected Equipment

Equipment Type	Relative Performance[1]	2001 Installed Cost ($2001)[2]	Efficiency[3]	2015 Installed Cost ($2001)[2]	Efficiency[3]	Approximate Hurdle Rate
Electric Heat Pump	Minimum	$2,930	10.0	$3,500	12.0	15%
	Best	$5,600	18.0	$5,600	18.0	
Natural Gas Furnace	Minimum	$1,300	0.80	$1,300	0.80	15%
	Best	$2,700	0.97	$1,950	0.97	
Room Air Conditioner	Minimum	$540	8.7	$540	9.7	140%
	Best	$760	11.7	$760	12.0	
Central Air Conditioner	Minimum	$2,080	10.0	$2,300	12.0	25%
	Best	$3,500	18.0	$3,500	18.0	
Refrigerator (18 cubic ft)	Minimum	$600	690	$600	478	19%
	Best	$950	515	$950	400	
Electric Water Heater	Minimum	$337	0.86	$500	0.90	83%
	Best	$1,200	2.60	$1,100	2.6	
Solar Water Heater	N/A	$3,200	2.0	$2,533	2.0	83%

[1]Minimum performance refers to the lowest efficiency equipment available. Best refers to the highest efficiency equipment available.

[2]Installed costs are given in 2001 dollars.

[3]Efficiency measurements vary by equipment type. Electric heat pumps and central air conditioners are rated for cooling performance using the Seasonal Energy Efficiency Ratio (SEER); natural gas furnaces are based on Annual Fuel Utilization Efficiency; room air conditioners are based on Energy Efficiency Ratio (EER); refrigerators are based on kilowatt-hours per year; and water heaters are based on Energy Factor (delivered Btu divided by input Btu).

Source: Arthur D. Little, *EIA Technology Forecast Updates*, Reference Number 8675309, October 2001.

Table 12 provides the cost and performance parameters for representative distributed generation technologies. The *AEO2003* model also incorporates endogenous "learning" for the residential distributed generation technologies, allowing for declining technology costs as shipments increase. For fuel cell and photovoltaic systems, parameter assumptions for the *AEO2003* reference case result in a 13 percent reduction in capital costs each time the number of units shipped to the buildings sectors (residential and commercial) doubles.

Table 12. Capital Cost and Performance Parameters of Residential Distributed Generation Technologies

Technology Type	Year of Introduction	Average Generating Capacity (kW)	Electrical Efficiency	Combined Efficiency (Elec.+Thermal)	Installed Capital Cost ($1999 per KW of Capacity)	Service Life Years
Solar Photovoltaic	2000	2	0.14	N/A	$7.370	30
	2005	2	0.16	N/A	$6,253	30
	2010	2	0.18	N/A	$5,136	30
	2015	2	0.20	N/A	$3,814	30
Fuel Cell	2000	5	0.360	0.73	$3,674	20
	2002	5	0.378	0.73	$3,282	20
	2006	5	0.401	0.73	$2,834	20
	2010	5	0.430	0.74	$2,329	20
	2015	5	0.473	0.74	$1,713	20

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

The Residential Demand Module projects equipment purchases based on a nested choice methodology. The first stage of the choice methodology determines the fuel and technology to be used, the second stage determines the efficiency of the selected equipment type. For new construction, home heating fuel and technology choices are determined based on life-cycle costs assuming a 20 percent discount rate. The equipment choices for cooling, water heating, and cooking are linked to the space heating choice for new construction. Technology and fuel choice for replacement equipment uses a nested methodology similar to that for new construction, but includes (in addition to the capital and installation costs of the equipment), explicit costs for technology switching (e.g., costs for installing gas lines if switching from electricity or oil to gas, or costs for retrofitting air ducts if switching from electric resistance heat to central heating types). Also, for replacements, there is no linking of fuel choice for water heating and cooking as is done for new construction. Technology switching upon replacement is allowed for space heating, air conditioning, water heating, cooking and clothes drying.

Once the fuel and technology choice for a particular end use is determined, the second stage of the choice methodology determines efficiency. In any given year, there are several available prototypes of varying efficiency (minimum standard, medium low, medium high and highest efficiency). Efficiency choice is based on a functional form and coefficients which give greater or lesser importance to the installed capital cost (first cost) versus the operating cost. Generally, within a technology class, the higher the first cost, the lower the operating cost. For new construction, efficiency choices are made based on the costs of both the heating and cooling equipment and the building shell characteristics.

The parameters for the second stage efficiency choice are calibrated to the most recently available shipment data for the major residential appliances. Shipment efficiency data are obtained from industry associations which monitor shipments such as the Association of Home Appliance Manufacturers. Because of this calibration procedure, the model allows the relative importance of first cost versus operating cost to vary by general technology and fuel type (e.g., natural gas furnace, electric heat pump, electric central air conditioner, etc.). Once the model is calibrated, it is possible to calculate (approximately) the apparent discount rates based on the relative weight given to the operating cost savings versus the weight given to the higher cost of more efficient equipment. Hurdle rates in excess of 30 percent are common in the Residential Demand Module. The prevalence of such high apparent hurdle rates by consumers has led to the notion of the "efficiency gap" that is, there are many investments that could be made that provide rates of return in excess of residential borrowing rates (15 to 20 percent for example). There are several studies which document instances of apparent high discount rates.[8] Once equipment efficiencies for a technology and fuel are determined, the installed efficiency for its entire stock is calculated.

Appliance Stock Submodule

The Appliance Stock Submodule is an accounting framework which tracks the quantity and average efficiency of equipment by end use, technology, and fuel. It separately tracks equipment requirements for new construction and existing housing units. For existing units, this module calculates equipment which survives from previous years, allows certain end uses to further penetrate into the existing housing stock and calculates the total number of units required for replacement and further penetration. Air conditioning and clothes drying are the two end uses not considered to be "fully penetrated."

Once a piece of equipment enters into the stock, an accounting of its remaining life is begun. It is assumed that all appliances survive a minimum number of years after installation. A fraction of appliances are removed from the stock once they have survived for the minimum number of years. Between the minimum and maximum life expectancy, all appliances retire based on a linear decay function. For example, if an appliance has a minimum life of 5 years and a maximum life of 15 years, one tenth of the units (1 divided by 15 minus 5) are retired in each of years 6 through 15. It is further assumed that, when a house is retired from the stock, all of the equipment contained in that house retires as well; i.e., there is no secondhand market for this equipment. The assumptions concerning equipment lives are given in Table 13.

Table 13. Minimum and Maximum Life Expectancies of Equipment

Equipment	Minimum Life	Maximum Life
Heat Pumps	7	21
Central Forced-Air Furnaces	10	25
Hydronic Space Heaters	20	30
Room Air Conditioners	12	19
Central Air Conditioners	8	16
Gas Water Heaters	4	14
Electric Water Heaters	5	22
Cooking Stoves	16	21
Clothes Dryers	11	20
Refrigerators	7	26
Freezers	11	31

Source: Lawrence Berkeley Laboratory, *Baseline Data for the Residential Sector and Development of a Residential Forecasting Database*, May 1994, and analysis of RECS 1997 data.

Fuel Consumption Submodule

Energy consumption is calculated by multiplying the vintage equipment stocks by their respective UECs. The UECs include adjustments for the average efficiency of the stock vintages, short term price elasticity of demand and "rebound" effects on usage (see discussion below), the size of new construction relative to the existing stock, people per household and shell efficiency and weather effects (space heating and cooling). The various levels of aggregated consumption (consumption by fuel, by service, etc.) are derived from these detailed equipment-specific calculations.

Equipment Efficiency

The average energy consumption of a particular technology is initially based on estimates derived from RECS 1997. Appliance efficiency is either derived from a long history of shipment data (e.g., the efficiency of conventional air-source heat pumps) or assumed based on engineering information concerning typical installed equipment (e.g., the efficiency of ground-source heat pumps). When the average efficiency is computed from shipment data, shipments going back as far as 20 to 30 years are combined with assumptions concerning equipment lifetimes. This allows for not only an average efficiency to be calculated, but also for equipment retirements to be vintaged—older equipment tends to be lower in efficiency and also tends to get retired before newer, more efficient equipment. Once equipment is retired, the Appliance Stock and Technology Choice Modules determine the efficiency of the replacement equipment. It is often the case that the retired equipment is replaced by substantially more efficient equipment.

As the stock efficiency changes over the simulation interval, energy consumption decreases in inverse proportion to efficiency. Also, as efficiency increases, the efficiency rebound effect (discussed below) will offset some of the reductions in energy consumption by increased demand for the end-use service. For example, if the stock average for electric heat pumps is now 10 percent more efficient than in 1997, then all else constant (weather, real energy prices, shell efficiency, etc...), energy consumption per heat pump would average about only 9 percent less.

Adjusting for the Size of New Construction

Information derived from RECS 1997 indicates that new construction (post-1980) is on average roughly 17 percent larger than the existing stock of housing. Estimates for the size of each new home built in the projection period vary by type and region, and are determined by a log-trend forecast based on historical data from the Bureau of the Census.[9] The energy consumption for space heating, air conditioning, and lighting is assumed to increase with the square footage of the structure. This results in an increase in the average size of the housing stock from 1,663 to 1,797 square feet from 1997 through 2025.

Adjusting for Weather and Climate

Weather in any given year always includes short-term deviations from the expected longer-term average (or climate). Recognition of the effect of weather on space heating and air conditioning is necessary to avoid inadvertently projecting abnormal weather conditions into the future. In the residential module, adjustments are made to space heating and air conditioning UECs by Census Division by their respective heating and cooling degree-days (HDD and CDD). A 10 percent increase in HDD would increase space heating consumption by 10 percent over what it would have other wise been. The residential module makes weather adjustments for the years 1997 through 2002. After 2002, long term weather patterns are assumed to occur. The residential module uses 30-year averages of HDD and CDD as normal weather conditions.

Short-Term Price Effect and Efficiency Rebound

It is assumed that energy consumption for a given end-use service is affected by the marginal cost of providing that service. That is, all else equal, a change in the price of a fuel will have an opposite, but less than proportional, effect on fuel consumption. The current value for the short-term elasticity parameter is -0.25. This value implies that for a 1 percent increase in the price of a fuel, there will be a corresponding decrease in energy consumption of -0.25 percent. Another way of affecting the marginal cost of providing a service is through altered equipment efficiency. For example, a 10 percent increase in efficiency will reduce the cost of providing the end-use service by 10 percent. Based on the short-term efficiency rebound parameter, the demand for the service will rise by 1.5 percent (-10 percent multiplied by -0.15). Only space heating and cooling are assumed to be affected by both elasticities and the efficiency rebound effect.

Shell Efficiency

The shell integrity of the building envelope is an important determinant of the heating and cooling load for each type of household. In the NEMS Residential Demand Module, the shell integrity is represented by an index, which changes over time to reflect improvements in the building shell. The shell integrity index is dimensioned by vintage of house, type of house, fuel type, service (heating and cooling), and Census Division. The age, type, location, and type of heating fuel are important factors in determining the level of shell integrity. Housing units which heat with electricity tend to be better insulated than homes that use other fuels. The age of homes are classified by new (post-1997) and existing. Existing homes are characterized by the RECS 1997 survey and are assigned a shell index value based on the mix of homes that exist in the base year (1997). The improvement over time in the shell integrity of these homes is a function of two factors—an assumed annual efficiency improvement and improvements made when real fuel prices increase (no price-related adjustment is made when fuel prices fall). For new construction, building shell efficiency is determined by the relative costs and energy bill savings for several levels of heating and cooling equipment, in conjunction with the building shell attributes. The packages represented in NEMS range from homes that meet the Model Energy Code (MEC) to homes that exceed the MEC by 50 percent. Shell efficiency in new homes would increase over time if energy prices rise, or the cost of more efficient equipment falls.

Legislation and Other Federal Programs

Energy Policy Act of 1992 (EPACT)

The EPACT contains several policies which are designed to improve residential sector energy efficiency. The EPACT policies analyzed in the NEMS Residential Demand Module include the sections relating to window labeling programs, low-flow showerheads, and building codes. The impact of building codes is captured in the shell efficiency index for new buildings listed above. Other EPACT provisions, such as home energy efficiency ratings and energy-efficient mortgages, which allow home buyers to qualify for higher loan amounts if the home is energy-efficient, are voluntary, and their effects on residential energy consumption have not been estimated.

The window labeling program is designed to help consumers determine which windows are most energy efficient. These labels already exist for all major residential appliances. Based on analysis of RECS data, it is assumed that the window labeling program will decrease heating loads by 8 percent and cooling loads by 3 percent. Approximately 25 percent of the existing (pre-1998) housing stock is affected by this policy by 2015.

The low-flow showerhead program is designed to cut domestic hot water use for showers. It is assumed that these showerheads cut hot water use by 33 percent for shower use. Since showers account for approximately 30 percent of domestic hot water use, total hot water use decreases by 15 percent. It is further assumed that these showerheads are installed exclusively in new construction.

National Appliance Energy Conservation Act of 1987

The Technology Choice Submodule incorporates equipment standards established by the National Appliance Energy Conservation Act of 1987 (NAECA). Some of the NAECA standards implemented in the module include: a Seasonal Energy Efficiency Rating (SEER) of 10.0 for heat pumps increasing to 12.0 in 2006; an Annual Fuel Utilization Efficiency (energy output over energy input) of 0.78 for oil and gas furnaces; an Efficiency Factor of .88 for electric water heaters; increasing to .90 in 2004; and refrigerator standards that set consumption limits to 976 kilowatt-hours per year in 1990, 691 kilowatt-hours per year in 1993, and 483 kilowatt-hours per year in 2002.

Residential Technology Cases

In addition to the *AEO2003* reference case, three side cases were developed to examine the effect of equipment and building standards on residential energy use—a *2003 technology case,* a *best available technology case*, and a *high technology case*. These side cases were analyzed in stand-alone (not integrated with the supply modules) NEMS runs and thus do not include supply-responses to the altered residential consumption patterns of the two cases. *AEO2003* also analyzed an integrated *high technology case* (*consumption high technology*), which combines the *high technology cases* of the four end-use demand sectors, *electricity high fossil technology case* and *the high renewables case*.

The 2003 technology case assumes that all future equipment purchases are made based only on equipment available in 2003. This case further assumes that existing building shell efficiencies will not improve beyond 2003 levels. In the reference case, the 2025 housing stock shell efficiency is 5 percent higher than in 1997 for heating (3 percent for cooling).

The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than the reference case. Equipment assumptions were developed by engineering technology experts, considering the potential impact on technology given increased research and development into more advanced technologies.[10] In the *high technology case*, heating shell efficiency increases by 12 percent and cooling shell efficiency by 5 percent, relative to 1997.

The *best available technology case* assumes that all equipment purchases from 2003 forward are based on the highest available efficiency in the *high technology case* in a particular simulation year, disregarding the economic costs of such a case. It is merely designed to show how much the choice of the highest-efficiency equipment could affect energy consumption. In this case, heating shell efficiency increases by 16 percent and cooling shell efficiency by 6 percent, relative to 1997.

Notes and Sources

[7] The Model Documentation Report contains additional details concerning model structure and operation. Refer to Energy Information Administration, Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System, DOE/EIA-M065(2003), (January 2003).

[8] Among the explanations often mentioned for observed high average implicit discount rates are: market failures, (i.e., cases where incentives are not properly aligned for markets to result in purchases based on energy economics alone); unmeasured technology costs (i.e., extra costs of adoption which are not included or difficult to measure like employee down-time); characteristics of efficient technologies viewed as less desirable than their less efficient alternatives (such as equipment noise levels or lighting quality characteristics); and the risk inherent in making irreversible investment decisions. Examples of market failures/barriers include: decision makers having less than complete information, cases where energy equipment decisions are made by parties not responsible for energy bills (e.g., landlord/tenants, builders/home buyers), discount horizons which are truncated (which might be caused by mean occupancy times that are less than the simple payback time and that could possibly be classified as an information failure), and lack of appropriate credit vehicles for making efficiency investments, to name a few. The use of high implicit discount rates in NEMS merely recognizes that such rates are typically found to apply to energy-efficiency investments.

[9] U.S. Bureau of Census, Series C25 Data from various years of publications.

[10] The high technology assumptions are based on Energy Information Administration, Technology Forecast Updates-Residential and Commercial Building technologies-Advanced Adoption Case (Arthur D. Little, Inc., October 2001).

Commercial Demand Module

The NEMS Commercial Sector Demand Module generates forecasts of commercial sector energy demand through 2025. The definition of the commercial sector is consistent with EIA's State Energy Data System (SEDS). That is, the commercial sector includes business establishments that are not engaged in transportation or in manufacturing or other types of industrial activity (e.g., agriculture, mining or construction). The bulk of commercial sector energy is consumed within buildings; however, street lights, pumps, bridges, and public services are also included if the establishment operating them is considered commercial. Since most of commercial energy consumption occurs in buildings, the commercial module relies on the data from the EIA Commercial Buildings Energy Consumption Survey (CBECS) for characterizing the commercial sector activity mix as well as the equipment stock and fuels consumed to provide end use services.[11]

The commercial module forecasts consumption by fuel[12] at the Census division level using prices from the NEMS energy supply modules, and macroeconomic variables from the NEMS acroeconomic Activity Module (MAM), as well as external data sources (technology characterizations, for example). Energy demands are forecast for ten end-use services[13] for eleven building categories[14] in each of the nine Census divisions. The model begins by developing forecasts of floorspace for the 99 building category and Census division combinations. Next, the ten end-use service demands required for the projected floorspace are developed. The electricity generation and water and space heating supplied by distributed generation and cogeneration technologies are projected. Technologies are then chosen to meet the projected service demands for the seven major end uses.[15] Once technologies are chosen, the energy consumed by the equipment stock (both previously existing and purchased equipment) chosen to meet the projected end-use service demands is developed.[16]

Key Assumptions

The key assumptions made by the commercial module are presented in terms of the flow of the calculations described above. Each section below will summarize the assumptions in each of the commercial module submodules: floorspace, service demand, technology choice, and end-use consumption. The four submodules are executed sequentially in the order presented, and the outputs of each submodule become the inputs to subsequently executed submodules. As a result, key forecast drivers for the floorspace submodule are also key drivers for the service demand submodule, and so on. The section summarizing the assumptions for the distributed generation submodule are presented following the end-use consumption section.

Floorspace Submodule

Floorspace is forecast by starting with the previous years stock of floorspace and eliminating a certain portion to represent the age-related removal of buildings. Total floorspace is the sum of the surviving floorspace plus new additions to the stock derived from the Macroeconomic Activity Module's floorspace growth projection.[17]

Existing Floorspace and Attrition

Existing floorspace is based on the estimated floorspace reported in the *Commercial Buildings Energy Consumption Survey 1999* (Table 14). Over time, the 1999 stock is projected to decline as buildings are removed from service (floorspace attrition). Floorspace attrition is estimated by a logistic decay function, the shape of which is dependent upon the values of two parameters: average building lifetime and *gamma*. The average building lifetime refers to the median expected lifetime of a particular building type. The *gamma* parameter corresponds to the rate at which buildings retire near their median expected lifetime. The current values for the average building lifetime and *gamma* vary by building type as presented in Table 15. These values are derived from analysis of the age distribution of commercial buildings in the three most recent CBECS.[18]

Table 14. 1999 Total Floorspace by Census Division and Principal Building Activity
(Millions of Square Feet)

	Assem-bly	Educa-tion	Food Sales	Food Service	Health Care	Lodging	Large Office	Small Office	Merc/ Service	Ware-house	Other	Total
New England	376	573	10	40	84	167	558	331	820	428	347	3,715
Middle Atlantic	942	1,134	212	182	283	313	1,069	489	1,792	1,309	840	8,565
East North Central	1,199	1,498	115	463	330	721	1,082	847	2,174	1,974	748	11,150
West North Central	861	742	58	95	172	214	554	555	1,222	777	280	5,529
South Atlantic	845	994	155	302	307	822	1,488	1,076	2,602	1,900	456	10,947
East South Central	780	436	101	166	98	466	330	394	1,283	959	187	5,201
West South Central	1,026	910	135	207	211	301	651	644	1,559	1,080	500	7,224
Mountain	679	755	103	104	111	544	453	389	584	518	321	4,562
Pacific	1,071	1,578	105	292	229	952	1,125	968	1,689	1,487	605	10,102
United States	7,780	8,620	993	1,851	1,825	4,502	7,310	5,673	13,724	10,432	4,285	66,995

Note: totals may not equal sum of components due to independent rounding. Minor CBECS data revisions occurred after forecast development.

Source: Energy Information Administration, Commercial Buildings Energy Consumption Survey 1999 Public Use Data

Table 15. Floorspace Attrition Parameters

	Assem-bly	Educa-tion	Food Sales	Food Service	Health Care	Lodging	Large Office	Small Office	Merc/ Service	Ware-house	Other
Median Expected Lifetime (years)	34	34	20	27	30	28	21	24	34	24	42
gamma	2.2	3.0	1.6	1.9	2.3	2.2	1.7	1.6	2.4	1.9	2.5

Source: Energy Information Administration, Commercial Buildings Energy Consumption Survey 1999, 1995, and 1992 Public Use Data.

New Construction Additions to Floorspace

The commercial module develops estimates of projected commercial floorspace additions by combining the surviving floorspace estimates with the total floorspace forecast from MAM. A total NEMS floorspace projection is calculated by applying the MAM assumed floorspace growth rate within each Census division and MAM building type to the corresponding NEMS Commercial Demand Module's building types based on the CBECS building types shares. The NEMS surviving floorspace from the previous year is then subtracted from the total NEMS floorspace projection for the current year to yield new floorspace additions.[19]

Service Demand Submodule

Once the building stock is projected, the Commercial Demand module develops a forecast of demand for energy-consuming services required for the projected floorspace. The module projects service demands for the following explicit end-use services: space heating, space cooling, ventilation, water heating, lighting, cooking, refrigeration, personal computer office equipment, and other office equipment.[20] The service demand intensity (SDI) is measured in thousand Btu of end-use service demand per square foot and differs across service, Census division and building type. The SDIs are based on a hybrid engineering and statistical approach of CBECS consumption data.[21] Projected service demand is the product of square feet and SDI for all end uses across the eleven building categories with adjustments for changes in shell efficiency for space heating and cooling.

Shell Efficiency

The shell integrity of the building envelope is an important determinant of the heating and cooling loads for each type of building. In the NEMS Commercial Demand Module, the shell efficiency is represented by an index, which changes over time to reflect improvements in the building shell. This index is dimensioned by building type and Census division and applies directly to heating. For cooling, the effects are computed from the index, but differ from heating effects, because of different marginal effects of shell integrity and because of internal building loads. In the *AEO2003* reference case, shell improvements for new buildings are up to 24 percent more efficient than the 1999 stock of similar buildings. Over the forecast horizon, new building shells improve in efficiency by 7 percent relative to their efficiency in 1999. For existing buildings, efficiency is assumed to increase by 5 percent over the 1999 stock average. The shell efficiency index affects the space heating and cooling service demand intensities causing changes in fuel consumed for these services as the shell integrity improves.

Technology Choice Submodule

The technology choice submodule develops projections of the results of the capital purchase decisions for equipment fueled by the three major fuels (electricity, natural gas, and distillate fuel). Capital purchase decisions are driven by assumptions concerning behavioral rule proportions and time preferences, described below, as well as projected fuel prices, average utilization of equipment (the capacity factors), relative technology capital costs, and operating and maintenance (O&M) costs.

Decision Types

In each forecast year, equipment is potentially purchased for three “decision types”. Equipment must be purchased for newly added floorspace and to replace a portion of equipment in existing floorspace projected to wear out.[22] Equipment is also potentially purchased for retrofitting equipment which has become economically obsolete. The purchase of retrofit equipment occurs only if the annual operating costs of a current technology exceed the annualized capital and operating costs of a technology available as a retrofit candidate.

Behavioral Rules

The commercial module allows the use of three alternate assumptions about equipment choice behavior. These assumptions constrain the equipment selections to three choice sets, which are progressively more restrictive. The choice sets vary by decision type and building type:

- **Unrestricted Choice Behavior -** This rule assumes that commercial consumers consider *all* types of equipment that meet a given service, across all fuels, when faced with a capital purchase decision.

- **Same Fuel Behavior -** This rule restricts the capital purchase decision to the set of technologies that consume the *same fuel* that currently meets the decision maker’s service demand.

- **Same Technology Behavior -** Under this rule, commercial consumers consider only the available models of the *same technology and fuel* that currently meet service demand, when facing a capital stock decision.

Under any of the above three behavior rules, equipment that meets the service at the lowest annualized lifecycle cost is chosen. Table 16 illustrates the proportions of floorspace subject to the different behavior rules for space heating technology choices in large office buildings.

Time Preferences

The time preferences of owners of commercial buildings are assumed to be distributed among seven alternate time preference premiums (Table 17). Adding the time preference premiums to the 10-year Treasury Bill rate results in implicit discount rates, also known as hurdle rates, applicable to the assumed proportions of commercial floorspace. The effect of the use of this distribution of discount rates is to prevent

Table 16. Assumed Behavior Rules for Choosing Space Heating Equipment in Large Office Buildings
(Percent)

	Unrestricted	Same Fuel	Same Technology	Total
New Equipment Decision	21	30	49	100
Replacement Decision	8	35	57	100
Retrofit Decision	0	5	95	100

Source: Energy Information Administration, *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M066(2003) (January 2003).

a single technology from dominating purchase decisions in the lifecycle cost comparisons. The distribution used for *AEO2003* assigns some floorspace a very high discount or hurdle rate to simulate floorspace which will never retrofit existing equipment and which will only purchase equipment with the lowest capital cost. Discount rates for the remaining six segments of the distribution get progressively lower, simulating increased sensitivity to the fuel costs of the equipment that is purchased. The proportion of floorspace assumed for the 0.0 time preference premium represents an estimate of the Federally owned commercial floorspace that is subject to purchase decisions in a given year. In accordance with Executive Order 13123 signed in June 1999, the Federal sector uses a rate comparable to the 10-year Treasury Bill rate when making purchase decisions.

Table 17. Assumed Distribution of Time Preference Premiums
(Percent)

Proportion of Floorspace-All Services Except Lighting	Proportion of Floorspace-Lighting	Time Preference Premium
27.0	27.0	1000.0
25.4	25.4	152.9
20.4	20.4	55.4
16.2	16.2	30.9
10.0	8.5	19.9
0.8	2.3	13.6
0.2	0.2	0.0
100.0	100.0	--

Source: Energy Information Administration, *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M066(2003) (January 2003).

The distribution of hurdle rates used in the commercial module is also affected by changes in fuel prices. If a fuel's price rises relative to its price in the base year (1999), the nonfinancial portion of each hurdle rate in the distribution decreases to reflect an increase in the relative importance of fuel costs, expected in an environment of rising prices. Parameter assumptions for *AEO2003* result in a 30 percent reduction in the nonfinancial portion of a hurdle rate if the fuel price doubles. If the time preference premium input by the model user results in a hurdle rate below the assumed financial discount rate for the commercial sector, 15 percent, with base year fuel prices (such as the rate given in Table 17 for the Federal sector), no response to increasing fuel prices is assumed.

Technology Characterization Database

The technology characterization database organizes all relevant technology data by end use, fuel, and Census division. Equipment is identified in the database by a technology index as well as a vintage index, the index of the fuel it consumes, the index of the service it provides, its initial market share, the Census division index for which the entry under consideration applies, its efficiency (or coefficient of performance or efficacy in the case of lighting equipment), installed capital cost per unit of service demand satisfied, operating and maintenance cost per unit of service demand satisfied, average service life, year of initial availability, and last year available for purchase. Equipment may only be selected to satisfy service demand if the year in which the decision is made falls within the window of availability. Equipment acquired prior to the lapse of its availability continues to be treated as part of the existing stock and is subject to replacement or retrofitting. This flexibility in limiting equipment availability allows the direct modeling of equipment efficiency standards. Table 18 provides a sample of the technology data for space heating in the New England Census division.

Table 18. Capital Cost and Efficiency Ratings of Selected Commercial Space Heating Equipment[1]

Equipment Type	Vintage	Efficiency[2]	Capital Cost ($2001 per Mbtu/hour) [3]	Maintenance Cost ($2001 per Mbtu/hour) [3]	Service Life (Years)
Electric Heat Pump	Current Standard	6.8	$81.39	$3.33	14
	2000- typical	7.5	$97.92	$3.33	14
	2000- high efficiency	9.8	$155.56	$3.33	14
	2005- typical	7.5	$97.22	$3.33	14
	2005- high efficiency	9.8	$155.56	$3.33	14
	2010 - typical	7.5	$97.22	$3.33	14
	2010 - high efficiency	9.8	$155.56	$3.33	14
	2020 - typical	7.8	$97.22	$3.33	14
	2020 - high efficiency	10.0	$150.00	$3.33	14
Ground-Source Heat Pump	2000- typical	3.4	$187.50	$1.46	20
	2000- high efficiency	4.0	$229.17	$1.46	20
	2005- typical	3.4	$166.67	$1.46	20
	2005- high efficiency	4.3	$229.17	$1.46	20
	2010- typical	3.4	$166.67	$1.46	20
	2010 - high efficiency	4.3	$208.33	$1.46	20
	2020 - typical	3.8	$166.67	$1.46	20
	2020 - high efficiency	4.5	$197.92	$1.46	20
Electric Boiler	Current Standard	0.98	$21.83	$0.14	21
Packaged Electric	1995	0.93	$19.77	$3.49	18
Natural Gas Furnace	Current Standard	0.80	$9.11	$1.00	15
	2000 - high efficiency	0.92	$14.82	$0.88	15
	2010 - typical	0.81	$8.70	$0.96	15
Natural Gas Boiler	Current Standard	0.80	$18.11	$0.55	25
	2000 - high efficiency	0.87	$33.82	$0.69	25
	2005 - typical	0.81	$17.87	$0.55	25
	2005 - high efficiency	0.90	$31.68	$0.67	25
Natural Gas Heat Pump	2005 - absortion	1.4	$173.61	$4.17	15
Distillate Oil Furnace	Current Standard	0.81	$14.25	$1.00	15
	2000	0.86	$23.46	$1.00	15
	2010	0.89	$22.69	$1.00	15
Distillate Oil Boiler	Current Standard	0.83	$15.76	$0.13	20
	2000 - high efficiency	0.88	$18.83	$0.12	20
	2005 - typical	0.83	$15.76	$013	20
	2005- high efficiency	0.88	$18.83	$0.12	20

[1]Equipment listed is for the New England Census division, but is also representative of the technology data for the rest of the U.S.

[2]Efficiency measurements vary by equipment type. Electric air-source and natural gas heat pumps are rated for heating performance using the Heating Seasonal Performance Factor (HSPF); natural gas and distillate furnaces are based on Annual Fuel Utilization Efficiency; ground-source heat pumps are rated on coefficient of performance; and boilers are based on combustion efficiency.

[3]Capital and maintenance costs are given in 2001 dollars.

Source: Energy Information Administration, “Technology Forecast Updates - Residential and Commercial Building Technologies - Reference Case”, Arthur D. Little, Inc., Reference Number 8675309, October 2001.

Starting with *AEO2000*, an option to allow endogenous price-induced technological change has been included in the determination of equipment costs and availability for the menu of equipment. This concept allows future technologies faster diffusion into the market place if fuel prices increase markedly for a sustained period of time. Although no price-induced change would have been expected using *AEO2003* reference case fuel prices, the option was not exercised for the *AEO2003* model runs.

End-Use Consumption Submodule

The end-use consumption submodule calculates the consumption of each of the three major fuels for the ten end-use services plus fuel consumption for Cogeneration and district services. For the ten end-use services, energy consumption is calculated as the end-use service demand met by a particular type of equipment divided by its efficiency and summed over all existing equipment types. This calculation includes dimensions for Census division, building type and fuel. Consumption of the five minor fuels is forecast based on historical trends.

Equipment Efficiency

The average energy consumption of a particular appliance is based initially on estimates derived from CBECS 1999. As the stock efficiency changes over the model simulation, energy consumption decreases nearly, but not quite proportionally to the efficiency increase. The difference is due to the calculation of efficiency using the harmonic average and also the efficiency rebound effect discussed below. For example, if on average, electric heat pumps are now 10 percent more efficient than in 1999, then all else constant (weather, real energy prices, shell efficiency, etc...), energy consumption per heat pump would now average about 9 percent less. The Service Demand and Technology Choice Submodules together determine the average efficiency of the stocks used in adjusting the initial average energy consumption.

Adjusting for Weather and Climate

Weather in any given year always includes short-term deviations from the expected longer-term average (or climate). Recognition of the effect of weather on space heating and air conditioning is necessary to avoid projecting abnormal weather conditions into the future. In the commercial module, proportionate adjustments are made to space heating and air conditioning demand by Census division. These adjustments are based on National Oceanic and Atmospheric Administration (NOAA) data for Heating Degree Days (HDD) and Cooling Degree Days (CDD). A 10 percent increase in HDD would increase space heating consumption by 10 percent over what it would have been otherwise. The commercial module makes weather adjustments for the years 2000 through 2002. After 2002, long term weather patterns are assumed based on 30-year averages of HDD and CDD.

Short-Term Price Effect and Efficiency Rebound

It is assumed that energy consumption for a given end-use service is affected by the marginal cost of providing that service. That is, all else equal, a change in the price of a fuel will have an inverse, but less than proportional, effect on fuel consumption. The current value for the short-term price elasticity parameter is -0.25 for all major end uses except refrigeration. A value of -0.1 is currently used for commercial refrigeration. A value of -0.05 is currently used for PC and non-PC office equipment and other minor uses of electricity. For example, for lighting this value implies that for a 1 percent increase in the price of a fuel, there will be a corresponding decrease in energy consumption of 0.25 percent. Another way of affecting the marginal cost of providing a service is through equipment efficiency. As equipment efficiency changes over time, so will the marginal cost of providing the end-use service. For example, a 10 percent increase in efficiency will reduce the cost of providing the service by 10 percent. The short-term elasticity parameter for efficiency rebound effects is -0.15 for affected end uses; therefore, the demand for the service will rise by 1.5 percent (-10 percent x -0.15). Currently, all services are affected by the short-term price effect and services affected by efficiency rebound are space heating and cooling, water heating, ventilation and lighting.

Distributed Generation and Combined Heat and Power

Nonutility power production applications within the commercial sector are currently concentrated in education, health care, office and warehouse buildings. Program driven installations of solar photovoltaic systems are based on information from DOE's Photovoltaic and Million Solar Roofs programs as well as DOE news releases and the National Renewable Energy Laboratory's Renewable Electric Plant Information System. Historical data from Form EIA-860B, *Annual Electric Generator Report - Nonutility*, are used to derive electricity generation for 2000 by Census division, building type and fuel. After 2000, a forecast of distributed generation and combined heat and power (CHP) of electricity is developed based on the economic returns projected for distributed generation and CHP technologies. The model uses a detailed cash-flow approach to estimate the number of years required to achieve a cumulative positive cash flow (some technologies may never achieve a cumulative positive cash flow). Penetration assumptions for distributed generation and CHP technologies are a function of the estimated number of years required to achieve a positive cash flow. Table 19 provides the cost and performance parameters for representative distributed generation and CHP technologies.

Table 19. Capital Cost and Performance Parameters of Selected Commercial Distributed Generation Technologies

Technology Type	Year of Introduction	Average Generating Capacity (kW)	Electrical Efficiency	Combined Efficiency (Elec.+Thermal)	Installed Capital Cost ($1999 per kW of Capacity)	Service Life (Years)
Solar Photovoltaic	2000	10	0.14	N/A	$7,870	30
	2005	10	0.16	N/A	$6,700	30
	2010	10	0.18	N/A	$5,529	30
	2015	10	0.20	N/A	$4,158	30
	2020	10	0.22	N/A	$3,178	30
Fuel Cell	2000	200	0.36	0.73	$3,674	20
	2002	200	0.38	0.73	$3,282	20
	2006	200	0.40	0.73	$2,834	20
	2010	200	0.43	0.74	$2,329	20
	2015	200	0.47	0.74	$1,713	20
	2020	200	0.50	0.74	$1,433	20
Natural Gas Engine	2000	200	0.28	0.75	$1,390	20
	2002	200	0.29	0.76	$1,320	20
	2006	200	0.29	0.77	$1,240	20
	2010	200	0.30	0.78	$1,150	20
	2015	200	0.30	0.79	$1,040	20
	2020	200	0.31	0.80	$ 990	20
Oil-Fired Engine	2000	200	0.31	0.83	$1,390	20
	2002	200	0.31	0.83	$1,320	20
	2006	200	0.31	0.82	$1.240	20
	2010	200	0.31	0.82	$1,150	20
	2015	200	0.31	0.81	$1,040	20
	2020	200	0.31	0.81	$ 990	20
Natural Gas Turbine	2000	1000	0.22	0.72	$1,600	20
	2002	1000	0.23	0.72	$1,555	20
	2006	1000	0.24	0.72	$1,503	20
	2010	1000	0.25	0.73	$1,444	20
	2015	1000	0.27	0.73	$1,373	20
	2020	1000	0.28	0.73	$1,340	20
Natural Gas Micro Turbine	2000	100	0.26	0.59	$1,970	20
	2002	100	0.27	0.60	$1,785	20
	2006	100	0.29	0.61	$1,574	20
	2010	100	0.31	0.62	$1,337	20
	2015	100	0.34	0.64	$1.047	20
	2020	100	0.36	0.65	$ 915	20

Sources: US Department of Energy, Office of Energy Efficiency and Renewable Energy, and Electric Power Research Institute, Renewable Energy Technology Characterizations, EPRI-TR-109496, (Washington DC, December 1997), and ONSITE SYCOM Energy Corporation, *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector*, (Washington, DC, January 2000).

The model also incorporates endogenous "learning" for new distributed generation and CHP technologies, allowing for declining technology costs as shipments increase. For fuel cell and photovoltaic systems, parameter assumptions for the *AEO2003* reference case result in a 13 percent reduction in capital costs each time the number of units shipped to the buildings sectors (residential and commercial) doubles. Doubling the number of microturbines shipped results in a 7 percent reduction in capital costs.

Legislation and Other Federal Programs

Energy Policy Act of 1992 (EPACT)

A key assumption incorporated in the technology selection process is that the equipment efficiency standards described in the EPACT constrain minimum equipment efficiencies. The effects of standards are modeled by modifying the technology database to eliminate equipment that no longer meets minimum efficiency requirements. For standards effective January 1, 1994, affected equipment includes electric heat pumps—minimum coefficient of performance of 1.64, furnaces and boilers—minimum annual fuel utilization efficiency of 0.8, fluorescent lighting—minimum efficacy of 75 lumens per watt, incandescent lighting—minimum efficacy of 16.9 lumens per watt, air conditioners—minimum seasonal energy efficiency ratio of 10.5, electric water heaters—minimum energy factor of 0.85, and gas and oil water heaters—minimum energy factor of 0.78. Updated standards are effective October 29, 2003 for gas water heaters—minimum thermal efficiency of 0.8. An additional standard affecting fluorescent lamp ballasts becomes effective April 1, 2005. The standard mandates electronic ballasts with a minimum ballast efficacy factor of 1.17 for 4-foot, 2-lamp ballasts and 0.63 for 8-foot, 2-lamp ballasts.

Energy Efficiency Programs

Several energy efficiency programs affect the commercial sector. These programs are designed to stimulate investment in more efficient building shells and equipment for heating, cooling, lighting and other end uses. The commercial module includes several features that allow projected efficiency to increase in response to voluntary programs (e.g., the distribution of time preference premiums and shell efficiency parameters). Retrofits of equipment for space heating, air conditioning and lighting are incorporated in the distribution of premiums given in Table 17. Also, the shell efficiency of new and existing buildings is assumed to increase from 1999 through 2025. Shells for new buildings increase in efficiency by 7 percent over this period, while shells for existing buildings increase in efficiency by 5 percent.

Commercial Technology Cases and High Renewables Case

In addition to the *AEO2003* reference case, three side cases were developed to examine the effect of equipment and building standards on commercial energy use—a *2003 technology case*, a *high technology case*, and a *best available technology case*. These side cases were analyzed in stand-alone (not integrated with the NEMS demand and supply modules) buildings (residential and commercial) modules runs and thus do not include supply-responses to the altered commercial consumption patterns of the three cases. *AEO2003* also analyzed an integrated high technology case *(consumption high technology)*, which combines the *high technology cases* of the four end-use demand sectors, the *electricity high fossil technology case* and the *high renewables case*.

The *2003 technology case* assumes that all future equipment purchases are made based only on equipment available in 2003. This case further assumes building shell efficiency to be fixed at 2003 levels. In the reference case, existing building shells are allowed to increase in efficiency by 5 percent over 1999 levels, and new building shells improve by 7 percent by 2025 relative to new buildings in 1999.

The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than the reference case. Equipment assumptions were developed by engineering technology experts, considering the potential impact on technology given increased research and development into more advanced technologies. In the *high technology case*, building shell efficiencies are assumed to improve 50 percent faster than in the reference case after 2003. Existing building shells, therefore, increase by 7.0 percent relative to 1999 levels and new building shells by 9.8 percent relative to their efficiency in 1999 by 2025.

The *best available technology case* assumes that all equipment purchases after 2003 are based on the highest available efficiency in the high technology case in a particular simulation year, disregarding the economic costs of such a case. It is merely designed to show how much the choice of the highest-efficiency equipment could affect energy consumption. Shell effects in this case are assumed to be the same as for the *high technology case* above.

Fuel shares, where appropriate for a given end use, are allowed to change in the technology cases as the available technologies from each technology type compete to serve certain segments of the commercial floorspace market. For example, in the *best available technology case*, the most efficient gas furnace technology competes with the most efficient electric heat pump technology. This contrasts with the reference case, in which, a greater number of technologies for each fuel with varying efficiencies all compete to serve the heating end use. In general, the fuel choice will be affected as the available choices are constrained or expanded, and will thus differ across the cases.

The *high renewables case* assumes greater improvements in residential and commercial photovoltaic systems than in the reference case. The high renewables assumptions result in capital cost estimates for 2025 that approximate DOE's Office of Energy Efficiency and Renewable Energy technology characterizations for distributed photovoltaic technologies[23], about 40 percent lower than reference case cost estimates for commercial photovoltaic systems in 2025. The assumptions were used in the integrated *high renewables case* which focuses on electricity generation.

Notes and Sources

[11] Energy Information Administration, *1999 Commercial Buildings Energy Consumption Survey (CBECS) Public Use Files*, web site www.eia.doe.gov/emeu/cbecs/1999publicuse/99microdat.html

[12] The fuels accounted for by the commercial module are electricity, natural gas, distillate fuel oil, residual fuel oil, liquefied petroleum gas (LPG), coal, motor gasoline, and kerosene. In addition to these fuels the use of solar energy is projected based on an exogenous forecast of projected solar photovoltaic system installations under the Million Solar Roofs program, State and local incentive programs, and the potential endogenous penetration of solar photovoltaic systems and solar thermal water heaters.

[13] The end-use services in the commercial module are heating, cooling, water heating, ventilation, cooking, lighting, refrigeration, PC and non-PC office equipment and a category denoted other to account for all other minor end uses.

[14] The 11 building categories are assembly, education, food sales, food services, health care, lodging, large offices, small offices, mercantile/services, warehouse and other.

[15] Minor end uses are modeled based on penetration rates and efficiency trends.

[16] The detailed documentation of the commercial module contains additional details concerning model structure and operation. Refer to Energy Information Administration, Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System, DOE/EIA M066(2003), (January 2003).

[17] The floorspace from the Macroeconomic Activity Model is based on the DRI-WEFA database of historical floorspace estimates which is approximately 15 percent lower than the estimate obtained from the CBECS used for the Commercial module. The DRI-WEFA estimate is developed using the F.W. Dodge data on commercial floorspace. See F.W. Dodge, Building Stock Database Methodology and 1991 Results, Construction Statistics and Forecasts, F.W. Dodge, McGraw-Hill.

[18] The commercial module performs attrition for 9 vintages of floorspace developed from the CBECS 1999 stock estimate and historical floorspace additions data from F.W. Dodge data.

[19] In the event that the computation of additions produce a negative value for a specific building type, it is assumed to be zero.

[20] “Other office equipment” includes copiers, fax machines, typewriters, cash registers, mainframe computers, and other miscellaneous office equipment. A tenth category denoted other includes equipment such as elevators, medical, and other laboratory equipment, communications equipment, security equipment, transformers and miscellaneous electrical appliances. Commercial energy consumed outside of buildings and for cogeneration is also included in the “other” category.

[21] Based on updated estimates using CBECS 1999 building-level consumption data and CBECS 1995 end-use-level consumption data and the methodology described in Estimation of Energy End-Use Intensities, web site www.eia.doe.gov/emeu/cbecs/tech_end_use.html.

[22] The proportion of equipment retiring is inversely related to the equipment life.

[23] For current DOE technology characterizations for photovoltaic systems see web site www.eren.doe.gov/power/pdfs/techchar.pdf.

Industrial Demand Module

The NEMS Industrial Demand Module estimates energy consumption by energy source (fuels and feedstocks) for 9 manufacturing and 6 nonmanufacturing industries. The manufacturing industries are further subdivided into the energy-intensive manufacturing industries and nonenergy-intensive manufacturing industries. The manufacturing industries are modeled through the use of a detailed process flow or end use accounting procedure, whereas the nonmanufacturing industries are modeled with substantially less detail (Table 20). The Industrial Demand Module forecasts energy consumption at the four Census region levels; energy consumption at the Census Division level is allocated by using the SEDS[24] data.

Table 20. Industry Categories

Energy-Intensive Manufacturing		Nonenergy-Intensive Manufacturing		Nonmanufacturing Industries	
Food and Kindred Products	(NAICS 311)	Metals-Based Durables	(NAICS 332-336)	Agricultural Production -Crops	(NAICS 111)
Paper and Allied Products	(NAICS 322)	Balance of Manufacturing	(all remaining manufacturing NAICS)	Other Agriculture Including Livestock	(NAICS112-115)
Bulk Chemicals	(NAICS 32B)			Coal Mining	(NAICS 2121)
Glass and Glass Products	(NAICS 3272)			Oil and Gas Extraction	(NAICS 211)
Hydraulic Cement	(NAICS 32731)			Metal and Other Nonmetallic Mining	(NAICS 2122-2123)
Blast Furnaces and Basic Steel	(NAICS 331111)			Construction	(NAICS 233-235)
Aluminum	(NAICS 3313)				

NAICS = North American Industry Classification System.

32B = Includes the following NAICS codes: 325110, 325120, 325181, 325188, 325192, 325199, 325211, 325212, 325222, 325311, 325312.

Source: Office of Management and Budget, North American Industry classification System (NAICS) - United States (Springfield, VA, National Technical Information Service).

The energy-intensive industries (food and kindred products, paper and allied products, bulk chemicals, glass and glass products, hydraulic cement, blast furnace and basic steel products, and aluminum) are modeled in considerable detail. Each industry is modeled as three separate but interrelated components consisting of the Process Assembly (PA) Component, the Buildings Component (BLD), and the Boiler/Steam/Cogeneration (BSC) Component. The BSC Component satisfies the steam demand from the PA and BLD Components. In some industries, the PA Component produces byproducts that are consumed in the BSC Component. For the manufacturing industries, the PA Component is separated into the major production processes or end uses.

Petroleum refining (North American Industry Classification System 32411) is modeled in detail in the Petroleum Market Module of NEMS, and the projected energy consumption is included in the manufacturing total. Forecasts of refining energy use, and lease and plant fuel and fuels consumed in cogeneration in the oil and gas extraction industry (North American Industry Classification System 211) are exogenous to the Industrial Demand Module, but endogenous to the NEMS modeling system.

Key Assumptions

The NEMS Industrial Demand Module primarily uses a bottom-up process modeling approach. An energy accounting framework traces energy flows from fuels to the industry's output. An important assumption in the development of this system is the use of 1998 baseline Unit Energy Consumption (UEC) estimates based on analysis of the Manufacturing Energy Consumption Survey (MECS) 1998.[25] The UECs represents the energy required to produce one unit of the industry's output. The output may be defined in terms of physical units (e.g., tons of steel) or in terms of the dollar value of shipments.

The module depicts the manufacturing industries (apart from petroleum refining, which is modeled in the Petroleum Market Module of NEMS) with a detailed process flow or end use approach. The dominant process technologies are characterized by a combination of unit energy consumption estimates and "technology possibility curves." The technology possibility curves indicate the energy intensity of new and existing stock relative to the 1998 stock over time. Rates of energy efficiency improvement assumed for new and existing plants vary by industry and process. These assumed rates were developed using professional engineering judgments regarding the energy characteristics, year of availability, and rate of market adoption of new process technologies.

Process/Assembly Component

The Process/Assembly (PA) Component models each major manufacturing production step or end use for the manufacturing industries. The throughput production for each process step is computed as well as the energy required to produce it.

Within this component, the UECs are is adjusted based on the technology possibility curves for each step. For example, state-of-the-art additions to waste fiber pulping capacity in 1998 are assumed to require only 93 percent as much energy as does the average existing plant (Table 21). The technology possibility curve is a means of embodying assumptions regarding new technology adoption in the manufacturing industry and the associated increased energy efficiency of capital without characterizing individual technologies. To some extent, all industries will increase the energy efficiency of their process and assembly steps. The reasons for the increased efficiency are not likely to be directly attributable to changing energy prices but due to other exogenous factors. Since the exact nature of the technology improvement is too uncertain to model in detail, the module employs a technology possibility curve to characterize the bundle of technologies available for each process step.

Fuel shares for process and assembly energy use in the manufacturing industries[26] are adjusted for changes in relative fuel prices. In each industry, two logit fuel-sharing equations are applied to revise the initial fuel shares obtained from the process-assembly component. The resharing does not affect the industry's total energy use, only the fuel shares. The methodology adjusts total fuel shares across all process stages and vintages of equipment to account for aggregate market response to changes in relative fuel prices.

The fuel share adjustments are done in two stages. The first stage determines the fuel shares of electricity and nonelectric energy. (The non-electric energy group excludes boiler fuel and feedstocks.) The second stage determines the fossil fuel shares of nonelectric energy. In each stage, a new fuel-group share, $NEWSHR_i$, is established as a function of the initial, default fuel-group shares, $DEFLTSHR_i$ and fuel-group prices indices, $PRCRAT_i$. The $DEFLTSHR_i$ are the base year shares. The price indices are the ratio of the current year price to the base year price, in real dollars.

The form of the equation results in unchanged fuel shares when the price indices are all 1, or unchanged from their 1998 levels. The implied own-price elasticity of demand is about -0.1.

Byproducts produced in the PA Component serve as fuels for the BSC Component. In the industrial module, byproducts are assumed to be consumed before purchased fuel.

Table 21. Coefficients for Technology Possibility Curve

Industry/ Process Unit	Old Facilities		New Facilities		
	REI 2025	TPC	REI 1998	REI 2025	TPC
Food & Kindred Products					
Process Heating	0.900	-0.0039	0.900	0.800	-0.0044
Process Cooling	0.875	-0.0049	0.850	0.750	-0.0046
Other	0.914	-0.0033	0.915	0.810	-0.0045
Paper & Allied Products					
Wood Preparation	0.923	-0.0030	0.873	0.846	-0.0012
Waste Pulping	0.941	-0.0022	0.936	0.883	-0.0022
Mechanical Pulping	0.917	-0.0032	0.868	0.834	-0.0015
Semi-chemical	0.874	-0.0050	0.876	0.748	-0.0059
Kraft, Sulfite, misc. Chemicals	0.816	-0.0075	0.876	0.632	-0.0121
Bleaching	0.871	-0.0051	0.900	0.743	-0.0071
Paper Making	0.797	-0.0084	0.900	0.594	-0.0154
Bulk Chemicals					
Process Heating	0.900	-0.0039	0.900	0.800	-0.0044
Process Cooling	0.875	-0.0049	0.850	0.750	-0.0046
Electro-Chemical	0.980	-0.0007	0.950	0.850	-0.0041
Other	0.914	-0.0033	0.915	0.810	-0.0045
Glass & Glass Products					
Batch Preparation	0.941	-0.0023	0.882	0.882	0.0000
Melting/Refining	0.713	-0.0125	0.900	0.426	-0.0277
Forming	0.904	-0.0037	0.982	0.809	-0.0072
Post-Forming	0.925	-0.0029	0.968	0.849	-0.0048
Hydraulic Cement					
Dry Process	0.841	-0.0064	0.889	0.682	-0.0098
Wet Process	0.936	-0.0025	NA	NA	NA
Finish Grinding	0.837	-0.0066	0.950	0.675	-0.0127
Blast Furnaces & Basic Steel					
Coke Oven	0.915	-0.0033	0.874	0.830	-0.0019
BF/BOF	0.990	-0.0004	1.000	0.980	-0.0008
EAF	0.995	-0.0002	0.990	0.990	0.0000
Ingot Casting/Primary Rolling	1.000	0.0000	NA	NA	NA
Continuous Casting	1.000	0.0000	1.000	1.000	0.0000
Hot Rolling	0.744	-0.0110	0.750	0.488	-0.0160
Cold Rolling	0.739	-0.0112	0.924	0.479	-0.0244
Aluminum					
Alumina Refining	0.931	-0.0027	0.900	0.861	-0.0016
Primary Smelting	0.909	-0.0035	0.950	0.818	-0.0056
Secondary	0.781	-0.0091	0.750	0.563	-0.0107
Semi-Fabrication, Sheet	0.747	-0.0108	0.900	0.494	-0.0222
Semi-Fabrication, Other	0.875	-0.0050	0.950	0.750	-0.0088
Metal Based Durables					
Process Heating	0.900	-0.0039	0.900	0.800	-0.0044
Process Cooling	0.875	-0.0049	0.850	0.750	-0.0046
Electro-Chemical	0.980	-0.0007	0.950	0.850	-0.0041
Other	0.914	-0.0033	0.915	0.810	-0.0045

Table 21. Coefficients for Technology Possiblity Curves (Continued)

Industry/ Process Unit	Old Facilities		New Facilities		
	REI 2025	TPC	REI 1998	REI 2025	TPC
Balance of Manufacturing					
Process Heating	0.900	-0.0039	0.900	0.800	-0.0044
Process Cooling	0.875	-0.0049	0.850	0.750	-0.0046
Electro-Chemical	0.980	-0.0007	0.950	0.850	-0.0041
Other	0.914	-0.0033	0.915	0.810	-0.0045
Non-Manufacturing	0.973	-0.0010	0.900	0.853	-0.0020

[1]REIs and TPCs apply to virgin and recycled materials.

[2]No new plants are likely to be built with these technologies.

[3]Net shape casting is projected to reduce the energy requirements for hot and cold rolling rather than for the continuous casting step.

REI 1998 New Facilities = For new facilities, the ratio of state-of-the-art energy intensity to average 1998 energy intensity for existing facilities.

REI 2025 Existing Facilities = Ratio of 2025 energy intensity to average 1998 energy intensity for existing facilities.

REI 2025 New Facilities = Ratio of 2025 energy intensity for a new state-of-the-art facility to the average 1998 intensity for existing facilities.

TPC = annual rate of change between 1998 and 2025.

NA = Not applicable.

BF = Blast furnace.

BOF = Basic oxygen furnace.

EAF = Electric arc furnace.

Source: Energy Information Administration, *Model Documentation Report*, *Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M064(2003) (Washington, DC, January 2003).

Machine drive electricity consumption in the food, bulk chemicals, metal-based durables, and balance of manufacturing sectors is calculated by a motor stock model. The beginning stock of motors is modified over the forecast horizon as motors are added to accommodate growth in shipments for each sector, as motors are retired and replaced, and as failed motors are rewound. When a new motor is added, either to accommodate growth or as a replacement, an economic choice is made between purchasing a motor which meets the EPACT minimum for efficiency or a premium efficiency motor. Table 22 provides the beginning stock efficiency for seven motor size groups in each of the four industries, as well as efficiencies for EPACT minimum and premium motors. There are no premium motor options for the two largest size groups because the EPACT standards only apply to motors up to 200 horsepower. As the motor stock changes over the forecast horizon, the overall efficiency of the motor population changes as well.

Buildings Component

The total buildings energy demand by industry for each region is a function of regional industrial employment and output. Building energy consumption was estimated for building lighting, air conditioning, space heating facility support, and onsite transportation. Space heating was further divided to estimate the amount provided by direct combustion of fossil fuels and that provided by steam (Table 23). Energy consumption in the BLD Component for an industry is estimated based on regional employment and output growth for that industry.

Boiler/Steam/Combined Heat and Power Component

The steam demand and byproducts from the PA and BLD Components are passed to the BSC Component, which applies a heat rate and a fuel share equation (Table 24) to the boiler steam requirements to compute the required energy consumption.

The boiler fuel shares apply only to the fuels that are used in non-combined heat and power (CHP) boilers. The portion of the steam demand that is met with cogenerated steam reduces the amount of boiler fuel that would otherwise be required. The non-CHP boiler fuel shares are calculated using a logit formulation. The equation is calibrated to 1998 so that the actual boiler fuel shares are produced for the relative prices that prevailed in 1998.

Table 22. Cost and Performance Parameters for Industrial Motor Choice Model

Industrial Sector Horsepower Range	1998 Stock Efficiency (%)	EPACT Minimum Efficiency (%)	EPACT Minimum Cost (2000$)	Premium Efficiency (%)	Premium Cost (2000$)
Food					
1 - 5 hp	81.3	86.9	376	89.2	429
6 - 20 hp	87.1	91.2	943	92.4	1,030
21 - 50 hp	90.1	93.0	1,500	93.8	1,679
51 - 100 hp	92.7	94.2	4,517	95.5	4,932
101 - 200 hp	93.5	94.7	7,674	95.6	9,527
201 - 500 hp	93.8	95.3	17,609	na	na
> 500 hp	93.0	95.0	28,687	na	na
Bulk Chemicals					
1 - 5 hp	82.0	87.2	376	89.4	429
6 - 20 hp	87.4	91.3	943	92.5	1,030
21 - 50 hp	90.4	93.1	1,500	93.8	1,679
51 - 100 hp	92.4	94.3	4,517	95.6	4,932
101 - 200 hp	93.5	94.8	7,674	95.7	9,527
201 - 500 hp	93.3	95.4	17,609	na	na
> 500 hp	93.2	95.2	28,687	na	na
Metal-Based Durables					
1 - 5 hp	81.9	86.9	376	89.1	429
6 - 20 hp	87.0	91.2	943	92.4	1,030
21 - 50 hp	90.0	93.0	1,500	93.8	1,679
51 - 100 hp	92.0	94.2	4,517	95.5	4,932
101 - 200 hp	93.5	94.6	7,674	95.5	9,527
201 - 500 hp	93.7	95.2	17,609	na	na
> 500 hp	93.0	95.0	28,687	na	na
Balance of Manufacturing					
1 - 5 hp	82.9	86.9	376	89.1	429
6 - 20 hp	88.3	91.2	943	92.4	1,030
21 - 50 hp	90.3	93.0	1,500	93.8	1,679
51 - 100 hp	92.7	94.2	4,517	95.5	4,932
101 - 200 hp	94.3	94.6	7,674	95.5	9,527
201 - 500 hp	94.3	95.2	17,609	na	na
> 500 hp	92.9	95.0	28,687	na	na

Source: Energy Information Administration, *Model Documentation Report, Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M064(2003) (Washington, DC, January 2003).

The byproduct fuels are consumed before the quantity of purchased fuels is estimated. The boiler fuel shares are based on the 1998 MECS.[27]

Combined Heat and Power

Combined heat and power (CHP) plants, which are designed to produce electricity and useful heat, have been used in the industrial sector for many years. The CHP estimates in the module are based on the assumption that the historical relationship between industrial steam demand and CHP will continue in the future.

EIA has comprehensively reviewed and revised how it collects, estimates, and reports fuel use for facilities producing electricity. The review addressed both inconsistent reporting of the fuels used for electric power across historical years and changes in the electric power marketplace that have been inconsistently represented in various EIA survey forms and publications. These changes are reflected in the Annual

Table 23. 1998 Building Component Energy Consumption (Trillion Btu)

Industry	Region	Building Use and Energy Source: Lighting Electricity Consump-ton	HVAC Electricity Consump-ton	HVAC Natural Gas Consump-tion	HVAC Steam Consump-tion	Facility Support Total Consump-tion	Onsite Transportation Total Consump-tion
Food & Kindred Products	1	1.5	1.7	2.5	1.9	0.9	0.4
	2	6,5	7.3	12.1	9.1	4.4	1.8
	3	5.6	6.3	7.7	5.8	2.9	2.6
	4	2.5	2.8	5.6	4.2	1.9	1.3
Paper & Allied Products	1	2.4	2.7	1.5	0.3	0.7	1.7
	2	4.0	4.5	3.4	0.6	1.3	1.0
	3	7.6	8.5	8.8	1.6	2.8	3.0
	4	3.0	3.4	3.3	0.6	1.1	1.0
Bulk Chemicals	1	1.1	1.6	0.4	0.0	0.4	0.0
	2	3.3	4.8	1.5	0.0	1.2	0.0
	3	10.2	14.7	18.3	0.0	4.9	0.0
	4	1.0	1.5	1.0	0.0	0.4	0.0
Glass & Glass Products	1	0.4	0.6	1.5	0.0	0.0	0.0
	2	0.5	0.8	1.6	0.0	0.0	0.0
	3	0.8	1.2	2.3	0.0	0.0	0.0
	4	0.2	0.4	0.6	0.0	0.0	0.0
Hydraulic Cement	1	0.1	0.1	0.0	0.0	0.0	0.1
	2	0.2	0.2	0.0	0.0	0.0	0.5
	3	0.4	0.4	0.0	0.0	0.0	0.5
	4	0.2	0.2	0.0	0.0	0.0	0.3
Blast Furnaces & Basic Steel	1	0.9	0.7	1.9	0.0	0.5	0.5
	2	2.5	2.1	10.8	0.0	2.2	1.5
	3	2.0	1.7	4.4	0.0	1.1	1.2
	4	0.5	0.4	1.0	0.0	0.3	0.2
Aluminum	1	0.3	0.3	0.4	0.0	0.2	0.2
	2	0.9	1.1	1.0	0.0	0.4	0.1
	3	1.4	1.8	3.2	0.0	1.0	0.1
	4	1.4	1.7	0.4	0.0	0.4	0.1
Metal Based Durables	1	12.4	15.7	28.1	10.8	5.2	3.4
	2	39.1	49.4	100.1	38.4	14.4	7.5
	3	25.2	31.8	45.0	17.3	11.3	7.1
	4	13.9	17.6	19.6	7.5	4.6	1.8
Balance of Manufacturing	1	10.0	13.6	18.7	15.5	3.9	6.2
	2	22.0	29.8	38.1	31.5	8.4	3.6
	3	37.1	50.3	53.4	44.2	13.0	11.5
	4	9.4	12.8	21.7	17.9	4.1	3.7

HVAC = Heating, Ventilation, Air Conditioning.

Source: Energy Information Administration, *Model Documentation Report: Industrial Demand Module of the National Energy Modeling System*, DOE/EIA-M064(2003), (Washington, DC, January 2003).

Energy Review 2001 and are discussed in detail in Appendix H of that publication. (www.eia.doe.gov/emeu/aer/pdf/pages/sec_h.pdf)

The projection for additions to fossil-fueled cogeneration is based on assessing capacity that could be added to generate the industrial steam requirements that are not already met by existing CHP. The technical potential for onsite CHP is primarily based on supplying thermal requirements. Capacity additions are then determined by the interaction of payback periods and market penetration rates. Installed cost for the cogeneration systems is given in Table 25.

Technology

The amount of energy consumption reported by the industrial module is also a function of vintage of the capital stock that produces the output. It is assumed that new vintage stock will consist of state-of-the-art technologies that are more energy efficient than the average efficiency of the existing capital stock. Consequently, the amount of energy required to produce a unit of output using new capital stock is less than that required by the existing capital stock. Capital stock is grouped into three vintages: old, middle, and new. The old vintage consists of capital in production prior to 1999 and is assumed to retire at a fixed rate each year (Table 26). Middle vintage capital is that which is added after 1998 but not including the year of the forecast. New production capacity is built in the forecast years when the capacity of the existing stock of capital in the industrial model cannot produce the output projected by the NEMS Regional Macroeconomic Model. Capital additions during the forecast horizon are retired in subsequent years at the same rate as the pre-1999 capital stock.

The energy intensity of the new capital stock relative to 1998 capital stock is reflected in the parameter of the technology possibility curve estimated for the major production steps for each of the energy-intensive industries. These curves are based on engineering judgment of the likely future path of energy intensity changes (Table 21). The energy intensity of the existing capital stock also is assumed to decrease over time, but not as rapidly as new capital stock. The net effect is that over time the amount of energy required to produce a unit of output declines. Although total energy consumption in the industrial sector is projected to increase, overall energy intensity is projected to decrease.

Legislation

Energy Policy Act of 1992 (EPACT)

EPACT and the Clean Air Act Amendments of 1990 (CAAA90) contain several implications for the industrial module. These implications fall into three categories: coke oven standards; efficiency standards for boilers, furnaces, and electric motors; and industrial process technologies. The industrial module assumes the leakage standards for coke oven doors do not reduce the efficiency of producing coke or increase unit energy consumption. The industrial module uses heat rates of 1.25 (80 percent efficiency) and 1.22 (82 percent efficiency) for gas and oil burners respectively. These efficiencies meet the EPACT standards. EPACT mandates minimum efficiencies for all motors up to 200 horsepower purchased after 1998. The choices offered in the motor model are all at least as efficient as the EPACT minimums.

Table 24. Logit Function Parameters for Estimating Boiler Fuel Shares

Industry	Region	Alpha	Natural Gas	Steam Coal	Oil
Food & Kindred Products	1	-0.25	0.84	0.04	0.12
	2	-0.25	0.63	0.36	0.01
	3	-0.25	0.80	0.10	0.10
	4	-0.25	0.77	0.17	0.06
Paper & Allied Products	1	-0.25	0.30	0.18	0.53
	2	-0.25	0.50	0.47	0.03
	3	-0.25	0.52	0.35	0.13
	4	-0.25	0.87	0.09	0.04
Bulk Chemicals	1	-0.25	0.61	0.01	0.38
	2	-0.25	0.55	0.22	0.23
	3	-0.25	0.63	0.09	0.26
	4	-0.25	0.44	0.51	0.05
Glass & Glass Products	1	-0.25	0.99	0.00	0.01
	2	-0.25	0.99	0.00	0.01
	3	-0.25	0.99	0.00	0.01
	4	-0.25	0.99	0.00	0.01
Hydraulic Cement	1	-0.25	0.05	0.95	0.00
	2	-0.25	0.31	0.69	0.00
	3	-0.25	0.40	0.60	0.00
	4	-0.25	0.56	0.44	0.00
Blast Furnaces & Basic Steel	1	-0.25	0.98	0.01	0.01
	2	-0.25	0.69	0.14	0.17
	3	-0.25	0.86	0.06	0.08
	4	-0.25	0.97	0.01	0.02
Aluminum	1	-0.25	1.00	0.00	0.00
	2	-0.25	1.00	0.00	0.00
	3	-0.25	1.00	0.00	0.00
	4	-0.25	1.00	0.00	0.00
Metal Based Durables	1	-0.25	0.68	0.15	0.17
	2	-0.25	0.74	0.24	0.02
	3	-0.25	0.85	0.03	0.12
	4	-0.25	0.97	0.00	0.03
Balance of Manufacturing	1	-0.25	0.06	0.23	0.17
	2	-0.25	0.68	0.28	0.04
	3	-0.25	0.69	0.24	0.07
	4	-0.25	0.80	0.17	0.03

Alpha: User-specified.

Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-064(2003), (Washington, DC, January 2003).

Table 25. Cost Characteristics of Industrial CHP Systems

System	Size (kilowatts)	Installed Cost ($1999 per kilowatt) 1999	Installed Cost ($1999 per kilowatt) 2020	O&M Cost ($1999 per kilowatthour) 1999	O&M Cost ($1999 per kilowatthour) 2020
1 Engine	800	975	690	0.0107	0.009
2 Engine	3000	850	710	0.0103	0.009
3 Gas Turbine	1000	1600	1340	0.0096	0.008
4 Gas Turbine	5000	1075	950	0.0059	0.0049
5 Gas Turbine	10000	965	830	0.0055	0.0046
6 Gas Turbine	25000	770	675	0.0049	0.0043
7 Gas Turbine	40000	700	625	0.0042	0.004
8 Combined Cycle	100000	690	620	0.0036	0.003

Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System,* DOE/EIA-MO64(2003) (Washington, DC, January 2003).

Table 26. Retirement Rates

Industry	Retirement Rate (percent)	Industry	Retirement Rate (percent)
Food and Kindred Products.	1.7	Glass and Glass Products	1.3
Pulp and Paper.	2.3	Hydraulic Cement	1.2
Bulk Chemicals	1.7		
Blast Furnace and Basic Steel Products		Aluminum	1.0
Blast Furnace/Basic Oxygen Furnace . .	1.0	Metal-Based Durables.	1.3
Electric Arc Furnace	1.5		
Coke Ovens	1.5	Other Non-Intensive Manufacturing.	1.3
Other Steel	2.9		

Note: Except for the Blast Furnace and Basic Steel Products Industry, the retirement rate is the same for each process step or end-use within an industry.

Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-MO64(2003), (Washington, DC, January 2003).

High Technology, 2003 Technology Cases, and High Renewables

The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment. (Table 27)[28] The *high technology case* also assumes that the rate at which biomass byproducts will be recovered from industrial processes increases from 0.2 percent per year to 1.0 percent per year. The availability of additional biomass leads to an increase in biomass-based cogeneration. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changes in the composition of industrial output. Since the composition of industrial output remains the same as in the reference case, primary energy intensity declines by 1.5 percent annually compared with the reference case, in which primary energy intensity is projected to decline 1.3 percent annually.

The *2003 technology case* holds the energy efficiency of plant and equipment constant at the 2003 level over the forecast. Both cases were run with only the Industrial Demand Module rather than as a fully integrated NEMS run, (i.e., the other demand models and the supply models of NEMS were not executed). Consequently, no potential feedback effects from energy market interactions were captured.

AEO2003 also analyzed an integrated high technology case (*consumption high technology*), which combines the *high technology cases* of the four end-use demand sectors, the *electricity high fossil technology case,* and *the high renewables case*.

The *high renewables case* assumes that the rate at which biomass byproducts will be recovered from industrial processes increases from 0.2 percent per year to 1.0 percent per year. The availability of additional biomass leads to an increase in biomass-based CHP.

Table 27. Coefficients for Technology Possibility Curves, High Technology Case

Industry/ Process Unit	Old Facilities		New Facilities		
	REI 2025	TPC	REI 1998	REI 2025	TPC
Food & Kindred Products					
Process Heating	0.829	-0.0069	0.900	0.629	-0.0132
Process Cooling	0.829	-0.0069	0.850	0.594	-0.0132
Other	0.829	-0.0069	0.915	0.639	-0.0132
Paper & Allied Products					
Wood Preparation	0.843	-0.0063	0.873	0.789	-0.0037
Waste Pulping	0.899	-0.0039	0.936	0.809	-0.0054
Mechanical Pulping	0.882	-0.0046	0.868	0.804	-0.0028
Semi-chemical	0.815	-0.0076	0.876	0.635	-0.0119
Kraft, Sulfite, misc. Chemicals	0.714	-0.0124	0.876	0.411	-0.0276
Bleaching	0.780	-0.0092	0.900	0.544	-0.0185
Paper Making	0.687	-0.0138	0.900	0.343	-0.0351
Bulk Chemicals					
Process Heating	0.843	0.844	0.900	0.644	-0.0123
Process Cooling	0.843	0.844	0.850	0.608	-0.0123
Electro-Chemical	0.843	0.844	0.950	0.680	-0.0123
Other	0.843	0.844	0.915	0.655	-0.0123
Glass & Glass Products					
Batch Preparation	0.856	-0.0057	0.882	0.646	0.0115
Melting/Refining	0.710	-0.0126	0.900	0.418	-0.0280
Forming	0.866	-0.0053	0.982	0.682	-0.0134
Post-Forming	0.804	-0.0080	0.968	0.530	-0.0220
Hydraulic Cement					
Dry Process	0.788	-0.0088	0.889	0.558	-0.0171
Wet Process	0.788	-0.0088	NA	NA	NA
Finish Grinding	0.822	-0.0072	0.950	0.629	-0.0152
Blast Furnaces & Basic Steel					
Coke Oven	0.592	-0.0192	0.874	0.502	-0.0203
BF/BOF	0.905	-0.0037	1.000	0.678	-0.0143
EAF	0.800	-0.0082	0.990	0.632	-0.0165
Ingot Casting/Primary Rolling	1.000	0.0000	NA	NA	NA
Continuous Casting	0.931	-0.0026	1.000	0.867	-0.0053
Hot Rolling	0.427	-0.0310	0.750	0.093	-0.0743
Cold Rolling	0.383	-0.0349	0.924	0.023	-0.1278
Aluminum					
Alumina Refining	0.859	-0.0056	0.900	0.678	-0.0104
Primary Smelting	0.816	-0.0075	0.950	0.581	-0.0180
Secondary	0.666	-0.0149	0.750	0.388	-0.0241
Semi-Fabrication, Sheet	0.689	-0.0137	0.900	0.353	-0.0341
Semi-Fabrication, Other	0.706	-0.0128	0.950	0.346	-0.0367
Metal Based Durables					
Process Heating	0.814	-0.0076	0.900	0.614	-0.0141
Process Cooling	0.814	-0.0076	0.850	0.580	-0.0141
Electro-Chemical	0.814	-0.0076	0.950	0.648	-0.0141
Other	0.814	-0.0076	0.915	0.624	-0.0141

Table 27. Coefficients for Technology Possibility Curves, High Technology Case (Continued)

Industry/ Process Unit	Old Facilities		New Facilities		
	REI 2025	TPC	REI 1998	REI 2025	TPC
Other Non-Intensive Manufacturing					
Process Heating	0.819	-0.0073	0.900	0.616	-0.0139
Process Cooling	0.819	-0.0073	0.850	0.582	-0.0139
Electro-Chemical	0.819	-0.0073	0.950	0.650	-0.0139
Other	0.819	-0.0073	0.915	0.626	-0.0139
Non-Manufacturing	0.947	-0.0020	0.900	0.808	-0.0040

[1]REIs and TPCs apply to virgin and recycled materials.

[2]No new plants are likely to be built with these technologies.

[3]Net shape casting is projected to reduce the energy requirements for hot and cold rolling rather than for the continuous casting step.

REI 1998 New Facilities = For new facilities, the ratiio of State-of-the-art energy intensity to average 1998 energy intensity for existing facilities.

REI 2025 Existing Facilities = Ratio of 2025 energy intensity to average 1998 energy intensity for existing facilities.

REI 2025 New Facilities = Ratio of 2025 energy intensity for a new State-of-the-art facility to the average 1998 intensity for existing facilities.

TPC = annual rate of change between 1998 and 2025.

NA = Not applicable.

BF = Blast furnace.

BOF = Basic oxygen furnace.

EAF = Electric arc furnace.

Source: Energy Information Administration, *Model Documentation Report*, *Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M064(2003) (Washington, DC, January 2003).

Notes and Sources

[24] Energy Information Administration, State Energy Data Report 1999, DOE/EIA-0214(99), (Washington, D.C., May 2001).

[25] Energy Information Administration, Manufacturing Energy Consumption Survey, web site www.eia.doe.gov/emeu/mecs/mecs98/datatables/contents.html.

[26] Aluminum is excluded due to its almost exclusive reliance on electricity in the process and assembly component.

[27] Energy Information Administration, Manufacturing Energy Consumption Survey, web site www.eia.doe.gov/emeu/mecs/mecs98/datatables/contents.html.

[28] These assumptions are based in part on Arthur D. Little, Industrial Model: Update on Energy Use and Industrial Characteristics (September 2001).

Transportation Demand Module

The NEMS Transportation Demand Module estimates energy consumption across the nine Census Divisions and over ten fuel types. Each fuel type is modeled according to fuel-specific technology attributes applicable by transportation mode. Total transportation energy consumption is the sum of energy use in eight transport modes: light-duty vehicles (cars, light trucks, sport utility vehicles and vans), commercial light trucks (8501-10,000 lbs gross vehicle weight), freight trucks (>10,000 lbs gross vehicle weight), freight and passenger airplanes, freight rail, freight shipping, and miscellaneous transport such as mass transit. Light-duty vehicle fuel consumption is further subdivided into personal usage and commercial fleet consumption.

Key Assumptions

Macroeconomic Sector Inputs

Macroeconomic sector inputs used in the NEMS Transportation Demand Module (Table 28) consist of the following: gross domestic product (GDP), industrial output by Standard Industrial Classification code, personal disposable income, new car and light truck sales, total population, driving age population, total value of imports and exports, and the military budget. The share of total vehicle sales that represent light truck sales is assumed to approach fifty percent by 2020.

Table 28. Macroeconomic Inputs to the Transportation Module
(Millions)

Macroeconomic Input	2000	2005	2010	2015	2020	2025
New Car Sales	9.0	8.2	8.9	9.5	9.4	9.4
New Light Truck Sales	7.8	7.6	8.5	9.3	9.4	9.3
Real Disposable Income (billion 1996 Chain-Weighted Dollars)	6,630	7,402	8,622	10,093	11,720	13,430
Real GDP (billion 1996 Chain-Weighted Dollars)	9,191	10,337	12,244	14,307	16,461	18,914
Driving Age Population	213.1	224.8	236.6	246.7	256.5	266.6
Total Population	275.7	288.1	300.2	312.7	325.3	338.2

Source: Energy Information Administration, *AEO2003* National Energy Modeling System run: aeo2003.d110502c.

Light-Duty Vehicle Assumptions

The light duty vehicle Fuel Economy Module includes 63 fuel saving technologies with data specific to cars and light trucks including incremental fuel efficiency improvement, incremental cost, first year of introduction, and fractional horsepower change. These assumed technology characterizations are scaled up or down to approximate the differences in each attribute for 6 Environmental Protection Administration (EPA) size classes of cars and light trucks (Tables 29 and 30).

The vehicle sales share module holds vehicle sales shares by import and domestic manufacturers constant within a vehicle size class at the 1999 level from the National Highway Traffic and Safety Administration data.[29]

EPA size class sales shares are projected as a function of income per capita, fuel prices, and average predicted vehicle prices based on endogeous calculations within the Fuel Economy Module.[30]

The Fuel Economy Module utilizes 63 new technologies for each size class and origin of manufacturer (domestic or foreign) based on the cost-effectiveness of each technology and an initial availability year. The

Table 29. Standard Technology Matrix For Cars[1]

	Fractional Fuel Efficiency Change	Incremental Cost (1990$)	Incremental Cost ($/Unit Wt.)	Incremental Weight (Lbs.)	Incremental Weight (Lbs./Unit Wt.)	Introduction Year	Fractional Horsepower Change
Unit Body Construction	4	100	0	0	-6	1980	0
Material Substitution II	3.3	0	0.4	0	-5	1990	0
Material Substitution III	6.6	0	0.6	0	-10	1998	0
Material Substitution IV	9.9	0	0.9	0	-15	2006	0
Material Substitution V	13.2	0	1.2	0	-20	2014	0
Drag Reduction II	2.3	40	0	0	0	1988	0
Drag Reduction III	4.4	85	0	0	0.2	1992	0
Drag Reduction IV	6.3	145	0	0	0.5	2002	0
Drag Reduction V	8	225	0	0	1	2010	0
Roll-Over Technology	-1.5	100	0	0	2.2	2005	0
Side Impact Technology	-1.5	100	0	0	2.2	2005	0
Adv Low Loss Torque Converter	2	25	0	0	0	1999	0
Early Torque Converter Lockup	0.5	8	0	0	0	2002	0
Aggressive Shift Logic	2	60	0	0	0	1999	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	6.5	410	0	20	0	1995	0
6-Speed Automatic	8	495	0	30	0	2004	0
6-Speed Manual	2	100	0	20	0	1995	0
CVT	10.5	415	0	-25	0	1998	0
Automated Manual Trans	8	100	0	0	0	2006	0
Roller Cam	2	16	0	0	0	1980	0
OHC/AdvOHV-4 Cylinder	3	80	0	0	0	1980	10
OHC/AdvOHV-6 Cylinder	3	100	0	0	0	1987	10
OHC/AdvOHV-8 Cylinder	3	120	0	0	0	1986	10
4-Valve/4-Cylinder	8	205	0	10	0	1988	17
4-Valve/6-Cylinder	8	280	0	15	0	1992	17
4 Valve/8-Cylinder	8	320	0	20	0	1994	17
5 Valve/6-Cylinder	8	300	0	18	0	1998	20
VVT-4 Cylinder	2.5	30	0	10	0	1994	5
VVT-6 Cylinder	2.5	90	0	20	0	1993	5
VVT-8 Cylinder	2.5	90	0	20	0	1993	5
VVL-4 Cylinder	5	170	0	25	0	1997	10
VVL-6 Cylinder	5	260	0	40	0	2000	10
VVL-8 Cylinder	5	330	0	50	0	2000	10
Camless Valve Actuation-4cyl	11	450	0	35	0	2009	13
Camless Valve Actuation-6cyl	11	600	0	55	0	2008	13
Camless Valve Actuation-8cyl	11	750	0	75	0	2007	13
Cylinder Deactivation	7.5	250	0	10	0	2004	0
Turbocharging/ Supercharging	7	650	0	-100	0	1980	15
Engine Friction Reduction I	2	25	0	0	0	1992	3
Engine Friction Reduction II	3.5	63	0	0	0	2000	5
Engine Friction Reduction III	5	114	0	0	0	2008	7
Engine Friction Reduction IV	6.5	177	0	0	0	2016	9
Stoichiometric GDI/4-Cylinder	7	300	0	20	0	2006	10
Stoichiometric GDI/6-Cylinder	7	450	0	30	0	2006	10
Lean Burn GDI	5	250	0	20	0	2006	0
5W-30 Engine Oil	1	22.5	0	0	0	1998	0
5W-20 Engine Oil	2	37.5	0	0	0	2003	0
OW-20 Engine Oil	3.1	150	0	0	0	2030	0
Electric Power Steering	2	50	0	0	0	2004	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.3	10	0	0	0	2000	0
Electric Oil/Water Pump	1	50	0	0	0	2007	0
Tires II	2	30	0	-8	0	1995	0
Tires III	4	75	0	-12	0	2005	0
Tires IV	6	135	0	-16	0	2015	0
Front Wheel Drive	6	250	0	0	-6	1980	0
Four Wheel Drive Improvements	2	100	0	0	-1	2000	0
42V-Launch Assist and Regen	3	600	0	80	0	2005	-5
42V-Engine Off at Idle	4.5	800	0	45	0	2005	0
Tier 2 Emissions Technology	-1	120	0	20	0	2006	0
Increased Size/Weight	-1.7	0	0	0	2.55	2001	0
Variable Compression Ratio	4	350	0	25	0	2015	0

N/A = Non Applicable

[1] Fractional changes refer to the percentage change from the 1990 values.

Source: Energy and Environment Analysis, *Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (September, 2002)

Table 30. Standard Technology Matrix For Light Trucks[1]

	Fractional Fuel Efficiency Change	Incremental Cost (1990$)	Incremental Cost ($/Unit Wt.)	Incremental Weight (Lbs.)	Incremental Weight (Lbs./Unit Wt.)	Introduction Year	Fractional Horse-power Change
Unit Body Construction	4	100	0	0	-6	1980	0
Material Substitution II	3.3	0	0.4	0	-5	1994	0
Material Substitution III	6.6	0	0.6	0	-10	2002	0
Material Substitution IV	9.9	0	0.9	0	-15	2010	0
Material Substitution V	13.2	0	1.2	0	-20	2018	0
Drag Reduction II	2.3	40	0	0	0	1992	0
Drag Reduction III	4.4	85	0	0	0.2	1998	0
Drag Reduction IV	6.3	145	0	0	0.5	2006	0
Drag Reduction V	8	225	0	0	1	2014	0
Roll-Over Technology	-1.5	100	0	0	2.2	2006	0
Side Impact Technology	-1.5	100	0	0	2.2	2006	0
Adv Low Loss Torque Converter	2	25	0	0	0	2005	0
Early Torque Converter Lockup	0.5	8	0	0	0	2006	0
Aggressive Shift Logic	2	60	0	0	0	2006	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	6.5	410	0	20	0	1999	0
6-Speed Automatic	8	495	0	30	0	2008	0
6-Speed Manual	2	100	0	20	0	2000	0
CVT	10.5	415	0	-25	0	2008	0
Automated Manual Trans	8	100	0	0	0	2010	0
Roller Cam	2	16	0	0	0	1985	0
OHC/AdvOHV-4 Cylinder	3	80	0	0	0	1980	10
OHC/AdvOHV-6 Cylinder	3	100	0	0	0	1990	10
OHC/AdvOHV-8 Cylinder	3	120	0	0	0	1990	10
4-Valve/4-Cylinder	7	205	0	10	0	1998	17
4-Valve/6-Cylinder	7	280	0	15	0	2000	17
4 Valve/8-Cylinder	7	320	0	20	0	2000	17
5 Valve/6-Cylinder	7	300	0	18	0	2010	20
VVT-4 Cylinder	2.5	30	0	10	0	1998	5
VVT-6 Cylinder	2.5	90	0	20	0	1997	5
VVT-8 Cylinder	2.5	90	0	20	0	1997	5
VVL-4 Cylinder	5	170	0	25	0	2002	10
VVL-6 Cylinder	5	260	0	40	0	2001	10
VVL-8 Cylinder	5	330	0	50	0	2006	10
Camless Valve Actuation-4cyl	11	450	0	35	0	2014	13
Camless Valve Actuation-6cyl	11	600	0	55	0	2012	13
Camless Valve Actuation-8cyl	11	750	0	75	0	2011	13
Cylinder Deactivation	7.5	250	0	10	0	2004	0
Turbocharging/Supercharging	7	650	0	-100	0	1987	15
Engine Friction Reduction I	2	25	0	0	0	1992	3
Engine Friction Reduction II	3.5	63	0	0	0	2000	5
Engine Friction Reduction III	5	114	0	0	0	2010	7
Engine Friction Reduction IV	6.5	177	0	0	0	2016	9
Stoichiometric GDI/4-Cylinder	7	300	0	20	0	2008	10
Stoichiometric GDI/6-Cylinder	7	450	0	30	0	2010	10
Lean Burn GDI	5	250	0	20	0	2010	0
5W-30 Engine Oil	1	22.5	0	0	0	1998	0
5W-20 Engine Oil	2	37.5	0	0	0	2003	0
OW-20 Engine Oil	3.1	150	0	0	0	2030	0
Electric Power Steering	2	50	0	0	0	2005	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.5	10	0	0	0	2000	0
Electric Oil/Water Pump	1	50	0	0	0	2008	0
Tires II	2	30	0	-8	0	1995	0
Tires III	4	75	0	-12	0	2005	0
Tires IV	6	135	0	-16	0	2015	0
Front Wheel Drive	2	250	0	0	-3	1984	0
Four Wheel Drive Improvements	2	100	0	0	-1	2000	0
42V-Launch Assist and Regen	3	600	0	80	0	2005	-5
42V-Engine Off at Idle	4.5	800	0	45	0	2005	0
Tier 2 Emissions Technology	-1	160	0	20	0	2006	0
Increased Size/Weight	-2.5	0	0	0	3.75	2001	0
Variable Compression Ratio	4	350	0	25	0	2015	0

N/A = Non Applicable

[1]Fractional changes refer to the percentage change from the 1990 values.

Source: Energy and Environment Analysis, *Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (September, 2002) discounted stream of fuel savings is compared to the marginal cost of each technology. The fuel economy module assumes the following:

- All fuel saving technologies have a 3-year payback period.
- The real discount rate remains steady at 30 percent.
- Corporate Average Fuel Efficiency standards remain constant at 1998 levels.
- Expected future fuel prices are calculated based on an extrapolation of the growth rate between a five year moving average of fuel price 3 years and 4 years prior to the present year. This assumption is founded upon an assumed lead time of 3 to 4 years to significantly modify the vehicles offered by a manufacturer.

Degradation factors (Table 31) used to convert Environmental Protection Agency-rated fuel economy to actual "on the road" fuel economy are based on application of a logistic curve to the projections of three factors: increases in city/highway driving, increasing congestion levels, and rising highway speeds.[31] Degradation factors are also adjusted to reflect the percentage of reformulated gasoline consumed.

Table 31. Car and Light Truck Degradation Factors

	2000	**2005**	**2010**	**2015**	**2020**	2025
Cars	74.5	76.1	77.7	79.4	81.0	81.0
Light Trucks	81.3	80.9	80.6	80.3	80.0	80.0

Source: Energy Information Administration, *Transportation Sector Model of the National Energy Modeling System, Model Documentation 2002*, DOE/EIA-M070(2002), (Washington, DC, January 2002).

The vehicle miles traveled (VMT) module forecasts VMT as a function of the cost of driving per mile, income per capita, ratio of female to male VMT, and growth in the driving population. Coefficients were re-estimated for *AEO2003.* The ratio of female to male VMT is assumed to asymptotically approach 68 percent by 2020. Total VMT is calibrated to Federal Highway Administration VMT data.[32,33] The fuel price elasticity rises from -0.04 to -0.2 as fuel prices rise above reference case levels in each year.

- The share of light truck sales (Class 1 and Class 2 trucks) is assumed to reach a maximum of 50 percent of total sales by 2020. However, the light truck share will gradually decline to 46 percent if fuel prices rise to approximately $1.55 per gallon. The size class sales shares will also gravitate to 25 percent for subcompacts, 40 percent for compacts, 25 percent for mid size, and 10 percent for luxury if fuel prices exceed reference case levels of approximately $1.55 per/gallon.

Commercial Light-Duty Fleet Assumptions

With the current focus of transportation legislation on commercial fleets and their composition, the Transportation Demand Module is designed to divide commercial light-duty fleets into three types of fleets: business, government, and utility. Based on this classification, commercial light-duty fleet vehicles vary in survival rates and duration in the fleet, before being combined with the personal vehicle stock (Table 32). Sales shares of fleet vehicles by fleet type vary by time period. Automobile fleets are divided into the following shares with the values in years 2000 and through 2025, as follows: business (91.1 percent), government (6.4 percent), and utilities (2.4 percent). Light truck fleets are divided into the following shares: business (56.8 percent), government (12.3 percent), and utilities (31.0 percent)[34,35]. Both cars and light truck fleet sales vary historically over time as a percent of total car and light truck sales, with year 2000 cars being at 23.7 percent and light trucks being at 17.5 percent. Fleet sales of cars vary through 2008 and remain constant thereafter, while light truck sales remain constant over the entire forecast period.

Alternative-fuel shares of fleet sales by fleet type are initially set according to historical shares (business (0.36 percent), government (2.21 percent), utility (2.64 percent))[36,37] then compared to a minimum constraint level of sales based on legislative initiatives, such as the Energy Policy Act of 1992 and the Low Emission Vehicle Program.[38,39] Size class sales shares of vehicles are held constant at anticipated levels (Table 33).[40] Individual sales shares of alternative-fuel fleet vehicles by technology type are assumed to remain at anticipated levels for utility, government, and for business fleets[41,42] (Table 34).

Annual VMT per vehicle by fleet type stays constant over the forecast period based on the Oak Ridge National Laboratory fleet data.

Table 32. The Average Length of Time Vehicles Are Kept Before they are Sold to Others
(Months)

Vehicle Type	Business	Utility	Government
Cars	35	68	81
Light Trucks	56	60	82
Medium Trucks	83	86	96
Heavy Trucks	103	132	117

Source: Oak Ridge National Laboratory, *Fleet Characteristics and Data Issues*, Stacy Davis and Lorena Truett, unpublished final report prepared for the Department of Energy, Energy Information Administration, Office of Integrated Analysis and Forecasting, (Oak Ridge, TN, Draft version, Dec. 10, 2003).

Table 33. Commercial Fleet Size Class Shares by Fleet and Vehicle Type
(Percentage)

Fleet Type by Size Class	Automobiles	Light Trucks
Business Fleet		
Mini	0.04	3.77
Subcompact	25.32	11.91
Compact	23.18	37.87
Midsize	41.93	7.92
Large	9.45	3.58
2-seater	0.08	34.96
Government Fleet		
Minl	0.03	7.76
Subcompact	7.64	42.29
Compact	9.08	9.16
Midsize	29.03	18.86
Large	54.21	0.21
2-seater	0.01	21.72
Utility Fleet		
Mini	0.04	13.50
Subcompact	25.32	42.68
Compact	23.18	5.43
Midsize	41.93	26.14
Large	9.45	1.14
2-seater	0.08	11.11

Source: Oak Ridge National Laboratory, *Fleet Characteristics and Data Issues*, Stacy Davis and Lorena Truett, unpublished final report prepared for the Department of Energy, Energy Information Administration, Office of Integrated Analysis and Forecasting, (Oak Ridge, TN, Draft version, Dec. 10, 2003).

Table 34. Anticipated Purchases of Alternative-Fuel Vehicles by Fleet Type and Technology Type
(Percentage)

AFV Technology	Business	Government	Utility
Ethanol	72.6	54.0	26.8
Methanol	0.0	0.0	0.0
Electric	1.1	3.0	1.1
CNG	4.6	8.5	17.3
LPG	21.7	34.5	54.7

Sources: Energy Information Administration, *Describing Current and Potential Markets for Alternative Fuel Vehicles*, DOE/EIA-0604(96), (Washington, DC, March 1996). Energy Information Administration, *Alternatives to Traditional Transportation Fuels* http://www.eia.doe.gov/cneaf/solar.renewables/alt_trans_fuel98/table14.html.

Fleet fuel economy for both conventional and alternative-fuel vehicles is assumed to be the same as the personal new vehicle fuel economy and is subdivided into six EPA size classes for cars and light trucks.

The Light Commercial Truck Model

The Light Commercial Truck Module of the NEMS Transportation Model is constructed to represent light trucks that weigh 8,501 to 10,000 pounds gross vehicle weight (Class 2B vehicles). These vehicles are assumed to be used primarily for commercial purposes.

The module implements a twenty-year stock model that estimates vehicle stocks, travel, fuel efficiency, and energy use by vintage. Historic vehicle sales and stock data, which constitute the baseline from which the forecast is made, are taken from a recent Oak Ridge National Laboratory study.[43] The distribution of vehicles by vintage, and vehicle scrappage rates is derived from R.L. Polk company registration data.[44],[45] Vehicle travel by vintage was constructed using vintage distribution curves and estimates of average annual travel by vehicle.[46],[47]

The growth in light commercial truck VMT is a function of industrial output for agriculture, mining, construction, trade, utilities, and personal travel. These industrial groupings were chosen for their correspondence with output measures currently being forecast by NEMS. The overall growth in VMT reflects a weighted average based upon the distribution to total light commercial truck VMT by sector. Forecasted fuel efficiencies are assumed to increase at the same annual growth rate as light-duty trucks (<8,500 pounds gross vehicle weight).

Alternative-Fuel Vehicle Technology Choice Assumptions

The Alternative-Fuel Vehicle (AFV) technology choice module utilizes a nested multinomial logit (NMNL) model that predicts sales shares based on relevant vehicle and fuel attributes. The nesting structure first predicts the probability of fuel choice for multi-fuel vehicles within a technology set. The second level nesting predicts penetration among similar technologies within a technology set (i.e. gasoline versus diesel hybrids). The third level choice determines market share among the different technology sets.[48] The technology sets include:

- Conventional fuel capable (gasoline, disel, bi-fuel and flex-fuel),
- Hybrid (gasoline and disel),
- Dedicated alternative fuel (CNG, LPG, methanol, and ethanol),
- Fuel cell (gasoline, methanol, and hydrogen), and
- Electric battery powered (lead acid, nickel-metal hydride, lithium polymer)[49]

The vehicles attributes considered in the choice algorithm include: price, maintenance cost, battery replacement cost, range, multi-fuel capability, home refueling capability, fuel economy, acceleration and luggage space. With the exception of maintenance cost, battery replacement cost, and luggage space vehicle attributes are determined endogenously.[50] The fuel attributes used in market share estimation include availability and price. Vehicle attributes vary by six EPA size classes for cars and light trucks and fuel availability varies by Census division. The NMNL model coefficients were developed to reflect purchase decisions for cars and light trucks separately.

Where applicable, AFV fuel efficient technology attributes are calculated relative to conventional gasoline miles per gallon. It is assumed that many fuel efficiency improvements to conventional vehicles will be transferred to alternative-fuel vehicles. Specific individual alternative-fuel technological improvements are also dependent upon the AFV technology type, cost, research and development, and availability over time. Make and model availability estimates are assumed values according to a logistic curve based on the initial technology introduction date and are based on current offerings. Coefficients summarizing consumer valuation of vehicle attributes were derived from assumed economic valuation compared to vehicle price elasticities. Initial AFV vehicle stocks are set according to EIA surveys.[51,52] A fuel switching algorithm based on the relative fuel prices for alternative fuels compared to gasoline is used to determine the percentage of total VMT represented by alternative fuels in bi-fuel and flex-fuel alcohol vehicles.

Freight Truck Assumptions

The freight truck module estimates vehicle stocks, travel, fuel efficiency and energy use for three size classes; light medium (Class 3), heavy medium (Classes 4 through 6), and heavy (Classes 7 and 8). Within size class, the stock model structure is designed to estimate energy use by four fuel types (diesel, gasoline, LPG, and CNG) and twenty vehicle vintages. Fuel consumption estimates are reported regionally (by Census division) according to the State Energy Data Report distilate regional shares.[53] The module uses projections of dollars of industrial output to estimate growth in freight truck travel. Industrial output is converted to an equivalent measure of volume output using freight adjustment coefficients.[54,55] These freight adjustment coefficients vary by NEMS Standard Industrial Classification (SIC) code, gradually diminishing their deviation over time toward parity. Freight truck load factors (ton-miles per truck) by SIC code are constants formulated from historical data.[56]

New freight truck fuel economy is dependent on the market penetration of various emission control technologies and advanced engine components.[57] For the advanced engine components, market penetration is determined as a function of technology cost effectiveness and introduction year. Cost effectiveness is calculated as a function of fuel price, vehicle travel, fuel economy improvement and incremental capital cost. Emissions control equipment are assumed to enter the market to meet regulated emission standards.

Heavy truck freight travel is estimated by size class and fuel type and is based on matching projected freight travel demand (measured by industrial output) to the travel supplied by the current fleet. Travel by vintage by size class is then adjusted so that total travel meets total demand. Initial heavy vehicle travel by vintage and size class was derived using Vehicle Inventory and Use Survey (VIUS) data.[58]

Initial freight truck stocks by vintage are obtained from R.L. Polk Co. and are distributed by fuel type using VIUS data.[59] Vehicle scrappage rates were also estimated using R.L. Polk Co. Data.[60]

Freight and Transit Rail Assumptions

The freight rail module receives industrial output by SIC code measured in real 1987 dollars and converts these dollars into an adjusted volume equivalent. Specific NEMS coal production from the Coal Market Module is also used to adjust coal rail travel. Freight rail adjustment coefficients, which are used to convert dollars into volume equivalents, remain constant and are based on historical data.[61,62] Initial freight rail efficiencies are based on the freight model from Argonne National Laboratory.[63] The distribution of rail fuel consumption by fuel type remains constant and is based on historical data.[64] Regional freight rail consumption estimates are distributed according to the *State Energy Data Report 1999*.[65]

Freight Domestic and International Shipping Assumptions

The freight domestic shipping module also converts industrial output by SIC code measured in dollars, to a volumetric equivalent by SIC code.[66,67] These freight adjustment coefficients are based on analysis of historical data and remain constant throughout the forecast period. Domestic shipping efficiencies are based on the freight model by Argonne National Laboratory. The energy consumption in the freight international shipping module is a function of the total level of imports and exports. The distribution of domestic and international shipping fuel consumption by fuel type remains constant throughout the analysis and is based on historical data.[68] Regional domestic and international shipping consumption estimates are distributed according to the *State Energy Data Report* residual oil regional shares.[69]

Air Travel Demand Assumptions

The air travel demand module calculates the ticket price for travel as a function of fuel cost. Similar to the light-duty vehicle module, the air travel fuel price elasticity rises from -0.05 to -0.2 if jet fuel prices exceed reference case levels. A demographic index based on the propensity to fly was introduced into the air travel demand equation.[70] The propensity to fly was made a function of the age and gender distribution over the forecast period[71],[72] The air travel demand module assumes that these relationships between the groups and their propensity to fly remain constant over time. International revenue passenger miles are based on historical data.[73] The revenue ton miles of air freight are based on merchandise exports and gross domestic product.

Airport capacity constraints based on the *FAA's Airport Capacity Benchmark Report 2001* were incorporated into the air travel demand module using airport capacity measures. Airport capacity is defined by the maximum number of flights per hour airports can routinely handle, the amount of time airports operate at optimal capacity, and passenger load factors. Capacity is expected to increase over time due to planned infrastructure improvements. If the projected demand in air travel exceeds the capacity constraint, price feedbacks are utilized to reduce demand and achieve market equilibrium.

Aircraft Stock/Efficiency Assumptions

The aircraft stock and efficiency module consists of a stock model of both wide and narrow body planes by vintage. The shifting of passenger load between narrow and wide body aircraft is assumed to occur at a constant historical annual 1-percent rate.[74] The available seat-miles per plane, which measure the carrying capacity of the airplanes by aircraft type, remain constant and are based on holding the seat-miles and the number of planes constant within an aircraft type.[75] The difference between the seat-miles demanded and the available seat-miles represents newly purchased aircraft. Aircraft purchases in a given year cannot exceed historical annual growth rates, a constraint that sets an upper limit on the application of new aircraft to meet the gap between seat-miles demanded and available seat-miles. With a constraint on new aircraft purchases, it is assumed that when the gap exceeds historical aircraft sales levels, planes that have been temporarily stored or retired will be brought back into service. Technological availability, economic viability,

Table 35. Future New Aircraft Technology Improvement List

Proposed Technology	Introduction Year	Jet Fuel Price Necessary For Cost-Effectiveness (1987 dollars per gallon)	Seat-Miles per Gallon Gain Over 1990 (percent)	
			Narrow Body	Wide Body
Engines				
Ultra-high Bypass	1995	$.69	10	10
Propfan	2000	$1.36	23	0
Thermodynamics	2010	$1.22	20	20
Aerodynamics				
Hybrid Laminar Flow	2020	$1.53	15	15
Advanced Aerodynamics	2000	$1.70	18	18
Other				
Weight Reducing Materials	2000	-	15	15

Source: Greene, D.L., *Energy Efficiency Improvement Potential of Commercial Aircraft to 2010*, ORNL-6622, 6/1990., and from data tables in the Air Transportation Energy Use Model (ATEM), Oak Ridge National Laboratory.

and efficiency characteristics of new aircraft are based on the technologies listed in the Oak Ridge National Laboratory Air Transport Energy Use Model. (Table 35)[76] Fuel efficiency of new aircraft acquisitions represents, at a minimum, a 5-percent improvement over the stock efficiency of surviving airplanes.[77] Maximum growth rates of fuel efficiency for new aircraft are based on a future technology improvement list consisting of an estimate of the introduction year, jet fuel price, and an estimate of the proposed marginal fuel efficiency improvement. Regional shares of all types of aircraft fuel are assumed to be constant and are consistent with the *State Energy Data Report* estimate of regional jet fuel shares.

Table 36. EPACT Legislative Mandates for Percentage AFV Purchases by Fleet Type, Year

Year	Municipal & Business	Federal	State	Fuel Providers	Electric Utilities
1996	-	25	-	-	-
1997	-	33	10	30	-
1998	-	50	15	50	30
1999	-	75	25	70	50
2000	-	75	50	90	70
2001	-	75	75	90	90
2002	20	75	75	90	90
2003	40	75	75	90	90
2004	60	75	75	90	90
2005	70	75	75	70	90

Source: EIA, *Alternatives to Traditional Transportation Fuels 1994*, DOE/EIA-0585(94), (Washington, D.C, February 1996).

Legislation

Energy Policy Act of 1992 (EPACT)

Fleet alternative-fuel vehicle sales necessary to meet the EPACT regulations were derived based on the mandates as they currently stand and the Commercial Fleet Vehicle Module calculations. Total projected AFV sales are divided into fleets by government, business, and fuel providers (Table 36). Business fleet EPACT mandates are not included in the projections for AFV sales pending a decision on a proposed rulemaking.

Because the commercial fleet model operates on three fleet type representations (business, government, and utility), the federal and state mandates were weighted by fleet vehicle stocks to create a composite mandate for both. The same combining methodology was used to create a composite mandate for electric utilities and fuel providers based on fleet vehicle stocks.[78],[79] Fleet vehicle stocks by car and light truck were disaggregated to include only fleets of 50 or more (in accordance with EPACT) by using a fleet size distribution function based on The Fleet Factbook and the Truck and Inventory Use Survey.[80],[81] To account for the EPACT regulations which stipulate that "covered" fleets (which refer to fleets bound by the EPACT mandates) include only fleets in the metropolitan statistical areas (MSA's) of 250,000 population or greater, 90 percent of the business and utility fleets were included and 63 percent were included for government fleets.[82] EPACT covered fleets were to only include those fleets that could be centrally fueled, which was assumed to be 50 percent of the fleets for all fleet types, and only fleets of 50 or more that had 20 vehicles or more in those MSA's of 250,000 or greater population; it was assumed that 90 percent of all fleets were within this category except for business fleets, which were assumed to be 75 percent.[83]

Low Emission Vehicle Program (LEVP)

The LEVP, which began in California, was later instituted in New York and Massachusetts, and most recently by Maine and Vermont has now been rolled back to begin in 2005 at the original 10 percent mandate for California, Massachusetts and New York. All of the ULEV sales were assumed to meet the ULEV air standards with reformulated gasoline and a heated catalytic converter.

On November 5, 1998, the California Air Resources Board (CARB) amended the original LEVP to include ZEV credits for advanced technology vehicles. According to CARB these advanced technology vehicles must be capable of achieving extremely low levels of emissions on the order of the power plant emissions that occur from charging battery-powered electric vehicles, and some that demonstrate other ZEV-like characteristics such as inherent durability and partial zero-emission range.[84]

There are three components to calculating the ZEV credit, a baseline ZEV allowance, a zero-emission vehicle-miles traveled (VMT) allowance, and a low fuel-cycle emission allowance. Using these advanced vehicles in place of ZEV's in order to comply with the LEVP mandates requires assessment of each vehicle characteristic relative to the three criteria allowances.

The baseline ZEV allowance potentially can provide up to .2 credits if the advanced technology vehicle meets the: a) Super Ultra Low Emission Vehicle (SULEV) standards contained in the originial LEVP proposal; b) on-board diagnostics requirements (OBD) which illuminates indicators on the dashboard when vehicles are out of emissions compliance levels; c) 150,000 mile emission equipment warranty; and d) evaporative emissions requirements in California which prevent emissions during refueling. SULEV emissions standards approximate the emissions from powerplants associated with recharing electric vehicles.

The second criteria, zero-emission VMT allowance, will allow a maximum .6 credit if the vehicle is capable of some all-electric operation which was fueled by off-vehicle sources (i.e. no on-board fuel reformers), or if the vehicle has ZEV-like equipment on-board such as regenerative braking, advanced batteries, or an advanced electric drivetrain.

An emission allowance was also made for low fuel-cycle vehicle fuels used in the advanced technology vehicles. A maximum of .2 credit is provided for vehicles which use fuel that has less than or equal to .01 nonmethane organic gases (NMOG) grams per mile emissions based on the grams per gallon and the fuel efficiency of the vehicle.

Overall, large volume manufacturers can apply ZEV credits up to a maximum of 60 percent of the original 10 percent ZEV mandate; the original ZEV mandate required that all (100 percent) of the 10 percent of all light-duty vehicle sales must be ZEVs (defined only as dedicated electric vehicles) beginning with the 2003 model year. The remaining 40 percent of the ZEV mandates must still come from electric vehicles, or variants of fuel cell vehicles, which have extremely low emissions such as a hydrogen fuel cell vehicle.

In September of 2000, further modifications were proposed for the ZEV mandate. The proposal was designed to maintain progress towards the 2003 goal while recognizing technology and cost limited ZEV product offerings. The CARB proposal removed ZEV sales requirements prior to 2003, but maintained the 2003 required ZEV sales goal of 10 percent and requires a gradual increase of ZEV sales to 16 percent by year 2018. Additionally, the number of vehicles included in the estimation of required ZEV sales has been increased to include small light duty trucks.

The proposal also provides manufacturers flexibility in meeting the goal through increased vehicle credits and greater allowances for partial ZEVs (PZEVs) and advanced technology ZEVs (AT-PZEVs). Prior to 2006, ZEVs earn 1.25 credits per vehicle and PZEVs get a phase-in multiplier of 4, 2, and 1.3 per vehicle for years 2004 through 2006, respectively. Extra credits will also be allowed for ZEVs with extended range and/or reduced fueling times.

The AFV sales module compares these legislatively mandated sales to the results from the AFV logit market-driven sales shares. The legislatively mandated sales serve as a minimum constraint to AFV sales.

According to the EPA federal register, EPA's Tier II proposed regulations for light-duty vehicles below 6000 pounds must meet a sales weighted average of 0.07 grams/mile nitrogen oxides (NOx) emissions standard by 2004 and approximately a 0.01 to 0.02 grams/mile standard for particulates.[85] The previous Clean Air Act 1990 Tier I emissions standards were set at 0.6 grams per mile for NOx and 0.1 grams per mile for particulates.[86] EPA has estimated the costs to consumers range from $100 per car to $200 per light truck.[87] However, recently the U.S. Circuit Court ruling determined that EPA was not authorized to set new standards without indicating the benefits of the new regulations.

In the National Research Council's (NRC) Fifth Annual Review of Partnership for a New Generation of Vehicles (PNGV)[88], the NRC committee commented,"..the most difficult technical challenge facing the CIDI (compression ignition direct injection diesel) engine program will be meeting the standards for NOx and particulate emissions. In addition, meeting an even more stringent research objective (0.01 grams/mile) for particulate matter instead of the 0.04 grams/mile PNGV target would require additional technological breakthroughs."

The NRC has stated their concern that the Tier II regulations may affect the commercial viability of many advanced vehicles. Meeting the Tier II proposed standards may: require trading-off emissions levels for fuel economy by redesigning engines; add significant cost to a technology due to exhaust catalyst systems and their potential lack of effectiveness; stifle development of diesel technologies as a result of the unknown health effects of particulates; and result in new specifications for diesel fuel or development of advanced low emission fuels.

High Technology and 2003 Technology Cases

In the *high technology case*, the conventional fuel saving technology characteristics came from a study by the American Council for an Energy Efficient Economy.[89] Tables 37 and 38 summarize the High Technology matrix for cars and light trucks. High technology case assumptions for heavy trucks reflect the optimistic values, with respect to efficiency improvement, for advanced engine and emission control technologies as reported by ANL.[90]

The *2003 technology case* assumes that new fuel efficiency technologies are held constant at 2002 levels over the forecast. As a result, the energy use in the transportation sector was 5.9 percent higher (2.34 quadrillion Btu) than in the reference case by 2025. Both cases were run with only the transportation demand module rather than as a fully integrated NEMS run. Consequently, no potential macroeconomic feedback on travel demand, or fuel economy was captured.

The air model in the *high technology case* assumed efficiency from new aircraft could improve by 40 percent from the 1992 level based on the conclusion from the Aeronautics and Space Engineering Board of the National Research Council.[91]

Table 37. High Technology Matrix For Cars

	Fractional Fuel Efficiency Change	Incremental Cost (1990$)	Incremental Cost ($/Unit Wt.)	Incremental Weight (Lbs.)	Incremental Weight (Lbs./Unit Wt.)	Introduction Year	Fractional Horse-power Change
Unit Body Construction	4	100	0	0	-6	1980	0
Material Substitution II	3.3	0	0.4	0	-5	1990	0
Material Substitution III	6.6	0	0.5	0	-10	1998	0
Material Substitution IV	9.9	0	0.5	0	-15	2006	0
Material Substitution V	13.2	0	1.1	0	-20	2014	0
Drag Reduction II	1.6	0	0	0	0	1988	0
Drag Reduction III	3.2	0	0	0	0.2	1992	0
Drag Reduction IV	6.3	145	0	0	0.5	2002	0
Drag Reduction V	8	225	0	0	1	2010	0
Roll-Over Technology	-1.5	100	0	0	2.2	2005	0
Side Impact Technology	-1.5	100	0	0	2.2	2005	0
Adv Low Loss Torque Converter	2	25	0	0	0	1999	0
Early Torque Converter Lockup	2	8	0	0	0	2002	0
Aggressive Shift Logic	5	65	0	0	0	1999	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	9.5	410	0	20	0	1995	0
6-Speed Automatic	11	495	0	30	0	2004	0
6-Speed Manual	2	60	0	20	0	1995	0
CVT	12.5	315	0	-25	0	1998	0
Automated Manual Trans	8	100	0	0	0	2006	0
Roller Cam	2	16	0	0	0	1980	0
OHC/AdvOHV-4 Cylinder	3	40	0	0	0	1980	10
OHC/AdvOHV-6 Cylinder	3	60	0	0	0	1987	10
OHC/AdvOHV-8 Cylinder	3	80	0	0	0	1986	10
4-Valve/4-Cylinder	9.6	165	0	10	0	1988	0
4-Valve/6-Cylinder	9.6	240	0	15	0	1992	17
4 Valve/8-Cylinder	9.6	320	0	20	0	1994	0
5 Valve/6-Cylinder	10	300	0	18	0	1998	20
VVT-4 Cylinder	2.5	30	0	10	0	1994	5
VVT-6 Cylinder	2.5	90	0	20	0	1993	5
VVT-8 Cylinder	2.5	90	0	20	0	1993	5
VVL-4 Cylinder	9.5	130	0	25	0	1997	10
VVL-6 Cylinder	9.5	190	0	40	0	2000	10
VVL-8 Cylinder	9.5	250	0	50	0	2000	10
Camless Valve Actuation-4cyl	12	450	0	35	0	2009	13
Camless Valve Actuation-6cyl	12	600	0	55	0	2008	13
Camless Valve Actuation-8cyl	12	750	0	75	0	2007	13
Cylinder Deactivation	10	250	0	10	0	2004	0
Turbocharging/ Supercharging	5	300	0	-100	0	1980	15
Engine Friction Reduction I	2	25	0	0	0	1992	3
Engine Friction Reduction II	3.5	63	0	0	0	2000	5
Engine Friction Reduction III	5	114	0	0	0	2008	7
Engine Friction Reduction IV	6.5	177	0	0	0	2016	9
Stoichiometric GDI/4-Cylinder	7	300	0	20	0	2006	10
Stoichiometric GDI/6-Cylinder	7	450	0	30	0	2006	10
Lean Burn GDI	7	250	0	20	0	2006	0
5W-30 Engine Oil	1	1.5	0	0	0	1998	0
5W-20 Engine Oil	2	2.5	0	0	0	2003	0
OW-20 Engine Oil	3.1	10	0	0	0	2030	0
Electric Power Steering	2	50	0	0	0	2004	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.5	10	0	0	0	2000	0
Electric Oil/Water Pump	1	50	0	0	0	2007	0
Tires II	1.5	0	0	-8	0	1995	0
Tires III	3	0	0	-12	0	2005	0
Tires IV	6	90	0	-16	0	2015	0
Front Wheel Drive	6	250	0	0	-6	1980	0
Four Wheel Drive Improvements	2	100	0	0	-1	2000	0
42V-Launch Assist and Regen	5	300	0	80	0	2005	-5
42V-Engine Off at Idle	6	400	0	45	0	2005	0
Tier 2 Emissions Technology	-1	120	0	20	0	2006	0
Increased Size/Weight	-1.7	0	0	0	2.55	2001	0
Variable Compression Ratio	4	350	0	25	0	2015	0

Source: Energy and Environmental Analysis, *Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (September, 2002).

Table 38. High Technology Matrix For Light Trucks

	Fractional Fuel Efficiency Change	Incremental Cost (1990$)	Incremental Cost ($/Unit Wt.)	Incremental Weight (Lbs.)	Incremental Weight (Lbs./Unit Wt.)	Introduction Year	Fractional Horse-power Change
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Drag Reduction V	8	225	0	0	1	2014	0
Roll-Over Technology	-1.5	100	0	0	2.2	2006	0
Side Impact Technology	-1.5	100	0	0	2.2	2006	0
Adv Low Loss Torque Converter	2	25	0	0	0	2005	0
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Aggressive Shift Logic	5	65	0	0	0	2006	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	9.5	410	0	20	0	1999	0
6-Speed Automatic	11	495	0	30	0	2008	0
6-Speed Manual	2	60	0	20	0	2000	0
CVT	12.5	315	0	-25	0	2008	0
Automated Manual Trans	8	100	0	0	0	2010	0
Roller Cam	2	16	0	0	0	1985	0
OHC/AdvOHV-4 Cylinder	3	40	0	0	0	1980	0
OHC/AdvOHV-6 Cylinder	3	60	0	0	0	1990	10
OHC/AdvOHV-8 Cylinder	3	80	0	0	0	1990	10
4-Valve/4-Cylinder	9.6	165	0	10	0	1998	17
4-Valve/6-Cylinder	9.6	240	0	15	0	2000	17
4 Valve/8-Cylinder	9.6	320	0	20	0	2000	17
5 Valve/6-Cylinder	10	300	0	18	0	2010	20
VVT-4 Cylinder	2.5	30	0	10	0	1998	5
VVT-6 Cylinder	2.5	90	0	20	0	1997	5
VVT-8 Cylinder	2.5	90	0	20	0	1997	5
VVL-4 Cylinder	9.5	130	0	25	0	2002	10
VVL-6 Cylinder	9.5	190	0	40	0	2001	10
VVL-8 Cylinder	9.5	250	0	50	0	2006	10
Camless Valve Actuation-4cyl	12	450	0	35	0	2014	13
Camless Valve Actuation-6cyl	12	600	0	55	0	2012	13
Camless Valve Actuation-8cyl	12	750	0	75	0	2011	13
Cylinder Deactivation	10	250	0	10	0	2004	0
Turbocharging/Supercharging	5	300	0	-100	0	1987	15
Engine Friction Reduction I	2	25	0	0	0	1992	3
Engine Friction Reduction II	3.5	63	0	0	0	2000	5
Engine Friction Reduction III	5	114	0	0	0	2010	7
Engine Friction Reduction IV	6.5	177	0	0	0	2016	9
Stoichiometric GDI/4-Cylinder	7	300	0	20	0	2008	10
Stoichiometric GDI/6-Cylinder	7	450	0	30	0	2010	10
Lean Burn GDI	7	250	0	20	0	2010	0
5W-30 Engine Oil	1	1.5	0	0	0	1998	0
5W-20 Engine Oil	2	2.5	0	0	0	2003	0
OW-20 Engine Oil	3.1	10	0	0	0	2030	0
Electric Power Steering	2	50	0	0	0	2005	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.5	10	0	0	0	2000	0
Electric Oil/Water Pump	1	50	0	0	0	2008	0
Tires II	1.5	0	0	-8	0	1995	0
Tires III	3	0	0	-12	0	2005	0
Tires IV	6	90	0	-16	0	2015	0
Front Wheel Drive	2	250	0	0	-3	1984	0
Four Wheel Drive Improvements	2	100	0	0	-1	2000	0
42V-Launch Assist and Regen	5	300	0	80	0	2005	-5
42V-Engine Off at Idle	6	400	0	45	0	2005	0
Tier 2 EmissionsTechnology	-1	160	0	20	0	2006	0
Increased Size/Weight	-2.5	0	0	0	3.75	2001	0
Variable Compression Ratio	4	350	0	25	0	2015	0

Source: Energy and Enviromental Analysis, *Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (September, 2002).

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Electricity Market Module

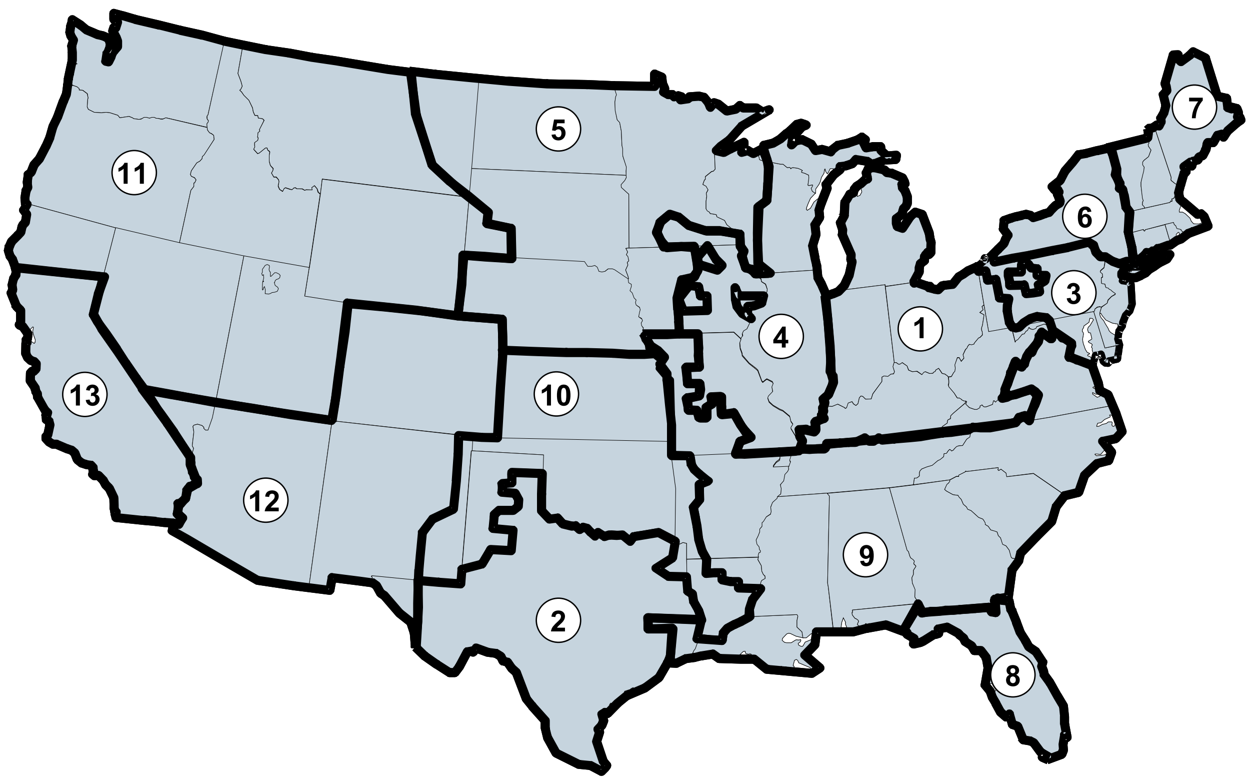
The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules—electricity capacity planning, electricity fuel dispatching, load and demand-side management, and electricity finance and pricing. It includes nonutility 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 2003*, DOE/EIA-M068(2003) April 2003.

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 Councils shown in Figure 4.

Figure 4. Electricity Market Model Supply Regions



1 East Central Area Reliability Coordination Agreement
2 Electric Reliability Council of Texas
3 Mid-Atlantic Area Council
4 Mid-America Interconnected Network
5 Mid-Continent Area Power Pool
6. New York
7 New England
8 Florida Reliability Coordinating Council
9 Southeastern Electric Reliability Council
10 Southwest Power Pool
11 Northwest Power Pool
12 Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada
13 California

Model Parameters and Assumptions

Generating Capacity Types

The capacity types represented in the EMM are shown in Table 39. Assumptions for the renewable technologies are discussed in a later chapter.

Table 39. 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
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
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

[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 40). 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 decline linearly through 2010.

The overnight costs shown in Table 40 are the cost estimates to build a plant in a typical region of the country *(Middletown, U.S.A*). Differences in plant costs due to regional distinctions are calculated by applying regional multipliers (Table 41) 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 used for the capacity choice decision.

Table 40. Cost and Performance Characteristics of New Electricity Generating Technologies

Technology	Online Years[1]	Size (mW)	Leadtimes (Years)	Overnight Costs[2] in 2002 ($2001/kW)	Contingency Factors: Project Contingency Factor	Contingency Factors: Technological Optimism Factor[3]	Total Overnight Cost including Contingencies in 2002[4] (2001 $/kW)	Variable O&M[5] ($2001 mills/kWh)	Fixed O&M[5] ($2001/kW)	Heatrate in 2002 (Btu/kWhr)	Heatrate nth-of-a-kind (Btu/kWr)
Scrubbed Coal Newl	2006	600	4	1,079	1.07	1.00	1,154	3.07	24.52	9,000	8,600
Integrated Coal-Gasification Combined Cycle	2006	550	4	1,277	1.07	1.00	1,367	2.04	33.72	8,000	7,200
Conventional Gas/Oil Combined Cycle	2005	250	3	510	1.05	1.00	536	2.04	12.26	7,500	7,000
Adv Gas/Oil Combined Cycle	2005	400	3	563	1.08	1.00	608	2.04	10.22	7,000	6,350
Conv Combustion Turbine[6]	2004	160	2	389	1.05	1.00	409	4.09	10.22	10,939	10,450
Adv Combustion Turbine	2004	230	2	439	1.05	1.00	460	3.07	8.17	9,394	8,550
Fuel Cells	2005	10	3	1,850	1.05	1.10	2,137	20.43	7.15	7,500	6,750
Advanced Nuclear	2007	1000	5	1,750	1.10	1.10	2,117	0.43	58.48	10,400	10,400
Distributed Generation - Base	2005	2	3	766	1.05	1.00	804	6.13	13.79	9,400	8,900
Distributed Generation - Peak	2004	1	2	919	1.05	1.00	965	6.13	13.79	10,400	9,880
Biomass	2006	100	4	1,569	1.07	1.05	1,763	2.96	45.94	8,911	8,911
MSW - Landfill Gas	2005	30	3	1,365	1.07	1.00	1,460	0.01	98.42	13,648	13,648
Geothermal [7,8]	2006	50	4	1,681	1.05	1.00	1,766	0.00	71.75	32,320	31,797
Wind	2005	50	3	938	1.07	1.00	1,003	0.00	26.10	10,280	10,280
Solar Thermal[8]	2005	100	3	2,204	1.07	1.10	2,594	0.00	48.91	10,280	10,280
Solar Photovoltaic[8]	2004	5	2	3,389	1.05	1.10	3,915	0.00	10.06	10,280	10,280

[1]Online year represents the first year that a new unit could be completed, given an order date of 2002.

[2]Costs reflect market status and penetration as of 2002.

[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 2002.

[5]O&M = Operation and maintenance.

[6]Combustion turbine units can be built by the model prior to 2004 if necessary to meet a given region's reserve margin.

[7]Because geothermal 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.

[8]Capital costs for geothermal and solar technologies are net of (reduced by) the ten percent investment tax credit.

Source: 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

Table 41. Regional Multipliers for Construction of Fossil-Fueled, Nuclear, and Renewable[1] Generating Technologies

EMM Region	NE, NY	MAAC	STV	MAPP, ECAR, MAIN	SPP
	1.043	0.996	0.96	1.004	0.997
EMM Region	**RA**	**NWP**	**FL**	**CNV**	**ERCOT**
	1.003	1.026	0.961	1.058	0.986

[1]Regional multipliers are not applied to geothermal technologies because costs are site specific.

Source: Argonne National Laboratory, *Cost and Performance Database for Electric Power Generating Technologies*..

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. For each generating technology available for new capacity in a region, the overnight cost used by the model is calculated using the base cost, technological optimism and contingency factors for the technology from Table 40, the regional factors from Table 41, and the learning parameters from Table 42.

Table 42. Learning Parameters for New Generating Technologies

Technology	Period 1 Learning Rate	Period 2 Learning Rate	Period 3 Learning Rate	Period 1 Doublings	Period 2 Doublings	Minimum Total Learning by 2020
Conventional Pulverized Coal	-	-	0.01	-	-	0.05
Integrated Coal-Gasification Combined Cycle	-	0.05	0.01	-	5	0.10
Gas/Oil Steam Turbine	-	-	0.01	-	-	0.05
Conv Gas/Oil Combined Cycle	-	-	0.01	-	-	0.05
Adv Gas/Oil Combined Cycle	-	0.05	0.01	-	5	0.10
Conv Combustion Turbine	-	-	0.01	-	-	0.05
Adv Combustion Turbine	-	0.05	0.01	-	5	0.10
Fuel Cells	0.1	0.05	0.01	3	5	0.20
Adv Nuclear	-	0.05	0.01	-	5	0.10
Distributed Generation - Base	-	0.05	0.01	-	5	0.10
Distributed Generation - Peak	-	0.05	0.01	-	5	0.10
Biomass	0.1	0.05	0.01	3	5	0.20
MSW - Landfill Gas	-	-	0	-	-	0.05
Geothermal	-	0.05	0.01	-	5	0.10
Wind	-	-	0.01	-	-	0.01
Solar Thermal	0.1	0.05	0.01	3	5	0.20
Photovoltaic	0.1	0.05	0.01	3	5	0.20

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 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 has the nonlinear form:

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

where C is the cumulative capacity for the technology.

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 technology Table 42. 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 technologies receive a minimal amount of learning, even if new capacity additions are not projected. This could represent cost reductions due to future international development or increased research and development.

International Learning. In *AEO2003*, capital costs for all new electricity generating technologies (fossil, nuclear, and renewable) decrease in response to foreign and domestic experience. Foreign units of new 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.

AEO2003 includes 784 megawatts of advanced coal gasification combined-cycle capacity, 4,199 megawatts of advanced combined-cycle natural gas capacity, and 11 megawatts of biomass capacity to be built outside the United States from 2001 through 2003.

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). Use Table 40 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. However, unlike traditional load duration curves where the demands for an entire period would be ordered from highest to lowest, losing their chronological order, the load duration curves in the EMM are segmented into the 9 time periods shown in Table 43. The summer and winter peak periods are represented in the model by 2 vertical slices each (a peak slice and an off-peak slice) while the remaining 7 periods are represented by 1 vertical slice each, resulting in a total of 11 vertical slices. The time periods shown were chosen to accommodate intermittent generating technologies (i.e., solar and wind facilities) and demand-side management programs.

Table 43. Load Segments in the Electricity Market Module

Season	Months	Period	Hours
Summer	June-September	Daytime	0700-1800
		Morning/Evening	0500-0700 and 1800-2400
		Night	0000-0500
Winter	December-March	Daytime	0800-1600
		Morning/Evening	0500-0800 and 1600-2400
		Night	0000-0500
Off-peak	April-May	Daytime	0700-1700
	October-November	Morning/Evening	0500-0700 and 1700-2400
		Night	0000-0500

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

Reserve margins—the percentage of capacity required in excess of peak demand needed for unforeseeable outages—are also assumed for each regulated EMM region. A 13 percent reserve margin is assumed for MAPP and STV, 9 percent for FL, 15 percent for NWP, and 14 percent for CNV. In the other regions where competition has replaced regulation in all or a majority of the region, the EMM determines the reserve margin by equating the marginal cost of capacity and the cost of unserved energy.

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 operating 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 $11 per kilowatt (kW) for oil and gas steam plants, $6/kW for combined-cycle plants, and combustion turbines, $16/kW for coal plants and $18/kW for nuclear plants. These costs are added to existing plants regardless of their age. Beyond 30 years of age an additional $5/KW capital charge for fossil plants, and $50/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 $100 to $200 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 forecast 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 are meant to 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 EIA accounts for this uncertainty by requiring that the capital cost estimates be symmetric in the sense that there is an equal probability that they could turn out to be either “too high” or “too low.” For that reason, the estimate used for AEO2003 is an average of the ones reviewed from various sources (See ‘Notes and Sources’ at the end of the Chapter for a full list of sources reviewed).

It is also important to note that there is a great deal of uncertainty about how the nuclear technology will evolve over the next 20 years. Currently, two conventional light water reactors along with the smaller, passively safe, Westinghouse AP600 power plant have had their designs certified by the NRC. A larger version of the Westinghouse design is also under review with the NRC. Additionally, the process to certify a number of more revolutionary reactor designs is just beginning. Thus, it is quite possible that within the next 20 years there will be wide range of designs that have been licensed by the NRC and could be built. Rather than attempting to “pick the winners” the cost estimates used here are more general, and do not deal with any one design.

Interregional Electricity Trade

Both firm and economy electricity transactions among utilities in different regions are represented within the EMM. In general, firm power transactions involve the trading of capacity and energy to help another region satisfy its reserve margin requirement, while economy transactions involve energy transactions motivated by the marginal generation costs of different regions. The flow of power from region to region is constrained by the existing and planned capacity limits as reported in the NERC and WSCC 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 2000*. They are locked in for the term of the contract. Contracts that are scheduled to expire by 2010 are assumed not to be renewed. Because there is no information available about expiration dates for contracts that go beyond 2010, they are assumed to be phased out by 2020. 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 2000*. 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 as reported in the Canadian National Energy Board report *Energy Supply and Demand to 2025.*

Electricity Pricing

The reference case assumes a transition to full competitive pricing in New York, New England, Mid-Atlantic Area Council, and Texas. California is assumed to return to fully regulated pricing in 2002, after beginning to transition to completition in 1998. In addition electricity prices in the East Central Area Reliability Council, the Mid-American Interconnected Network (Illinois, plus parts of Missouri, Michigan and Wisconsin), the Southwest Power Pool, and the Rocky Mountain Power Area/ Arizona are a weighted average of both competitive and regulated prices. Some of the States in each of these regions have not taken action to deregulate their pricing of electricity, and in those States prices are assumed to continue to be based on traditional cost-of-service pricing. The price for the region will be a weighted average of the competitive price and the regulated price, with the weight based on the percent of 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 or where states representing less than half of regional electricity sales have introduced competition, electricity prices are assumed to remain regulated. The cost-of-service calculation is used to determine electricity prices in regulated regions.

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 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, operating and maintenance, taxes, and a reliability price adjustment, which represents the value of capacity in periods of high demand. Therefore, the price of electricity in the regulated regions consists of the average cost of generation, transmission, and distribution for each customer class. The price of electricity in the four regions with a competitive generation market consists of the marginal cost of generation summed with the average costs of transmission and distribution. In the four partially competitive regions the price is a combination of cost-of-service pricing and marginal pricing weighted by the share of sales.

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 *AEO2002*. The key trends are discussed below:

- Reduced General and Administrative Expenses (G&A) - Over the 1990 through 1999 period, utilities have reduced their employment at fossil steam plants at a rate of 4 percent per year. This trend has been incorporated by reducing total G&A expenditures at a rate of 2.5 percent annually through 2005. No further reductions are assumed to occur after 2005.

- Reduced Fossil Plant Operations Expenditures (O&M) - Again, over the 1990 through 1999 period, utility fossil plant operation and maintenance costs (all operating costs other than fuel) fell at a rate of about 3 percent annually. As with G&A, this trend has been incorporated by reducing fossil O&M expenditures at a rate of 2.5 percent annually through 2005. No further reductions are assumed to occur after 2005.

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 adaptive expectations, in which future prices are extrapolated from recent historical trends.[92] For each oil product, future prices are estimated by applying a constant markup to an external forecast of world oil prices. The markups are calculated by taking the differences between the regional product prices and the world oil price for the previous forecast year. 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 expected demand changes throughout the forecast horizon, resulting in updated mining utilization and different supply curves.

For natural gas, expected wellhead prices are based on a nonlinear function that relates the expected price to the expected cumulative domestic gas production. Delivered prices are developed by applying a constant markup, which represents the difference between the delivered and wellhead prices from the prior forecast year.

The approach for natural gas was developed to have the following properties:

1. The natural gas wellhead price should be upward sloping as a function of cumulative gas production.

2. The rate of change in wellhead prices should increase as fewer economical reserves remain to be discovered and produced.

The approach assumes that at some point in the future a given target price, PF, results when cumulative gas production reaches a given level, QF. The target values for PF and QF were assumed to be $7.00 per thousand cubic feet (1995 dollars) and 2000 trillion cubic feet (tcf), respectively. Gas hydrates are included in the resource base at a level of 60 tcf, and geopressurized aquifers are included at 500 tcf. The future annual production is assumed to be constant at the prior year's level. There is also the flexibility to assume a different path in the short term and longer term by choosing an inflection price at which new competitors would enter the market.

The expected wellhead gas price equation is of the following form:

$$P_k = A * Q_k^{exp} + B$$

where P is the wellhead price for year k, Q_k is the cumulative production from 1991 to year k, and A and B are determined each year such that the price equation will intersect the future target point (PF, QF). The exponent, exp, is assumed to be 0.70 as long as P_k is below an assumed inflection price of $3.50. Above this price, the exponent is assumed to be 1.30. The cumulative production calculation assumes that future growth in production will be equal to most recent 3 year average growth rate.

The point (P_k , Q_k) therefore represents the expected wellhead price given the expected cumulative production. A series of supply steps are then developed around this point to represent changes in the expected price that could occur if the cumulative production differs from the expected value. The expected quantity is varied by assuming different levels of consumption, which could result from capacity additions, fuel switching, or other operating decisions. After determining the relative change from the expected production for each step, the corresponding price is derived by applying an elasticity to the expected wellhead price.

Legislation and Regulations

Clean Air Act Amendments of 1990 (CAAA90)

It is assumed that electricity producers comply with the CAAA90, which mandate a limit of 8.95 million tons by 2010. Utilities are assumed to comply with 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 to be used.

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 (Table 44). 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. All of these NO_x limits are incorporated in EMM.

Table 44. NO_x Emissions Standards
(Pounds per million Btu)

Boiler Type	# Boilers	Phase I Limit	Phase II Limit
Group 1 Boilers			
Dry Bottom Wall-Fired	284	0.50	0.45
Tangential	296	0.45	0.38
Group 2 Boilers			
Cell Burners	35	NA	0.68
Cyclones	88	NA	0.94
Wet Bottom Wall-Fired	38	NA	0.86
Vertically Fired	29	NA	0.80
Fluidized Bed	5	NA	0.29

NA = Not Applicable.

Source: Environmental Protection Agency, Nitrogen Oxide Emission Reduction Program.

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 45). 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 45. 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 tend to decline with plant size and this is shown in table 46.

Table 46. Coal Plant Retrofit Costs
(2001 Dollars)

Coal Plant Size (MW)	FGD Capital Costs ($/KW)	SCR Capital Costs ($/KW)
300	**267**	**93**
500	**204**	**82**
700	**168**	**74**

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.

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

Planned FGD (SO2 scrubber) 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, nearly 23,000 megawatts of capacity are assumed to add these controls (Table 47). The greatest number of retrofits is expected to occur in Region 9 because of the Clean Smokestacks bill passed by the North Carolina General Assembly.

Table 47. Planned SO_2 Scrubber Additions Represented by Region

Region	Capacity (Megawatts)
1	1,715
2	1,160
3	1,906
4	173
5	0
6	105
7	837
8	524
9	12,638
10	0
11	1,340
12	2,421
13	0
Total	22,819

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

Energy Policy Act of 1992 (EPACT)

The provisions of the EPACT include revised licensing procedures for nuclear plants and the creation of exempt wholesale generators (EWGs).

The Public Utility Holding Company Act of 1935 (PUHCA)

Prior to the passage of EPACT, PUHCA required that utility holding companies register with the Securities and Exchange Commission (SEC) and restricted their business activities and corporate structures.[93] Entities that wished to develop facilities in several States were regulated under PUHCA. To avoid the stringent SEC regulation, nonutilities had to limit their development to a single State or limit their ownership share of projects to less than 10 percent. EPACT changed this by creating a class of generators that, under certain conditions, are exempt from PUHCA restrictions. These EWGs can be affiliated with an existing utility (affiliated power producers) or independently owned (independent power producers). In general, subject to State commission approval, these facilities are free to sell their generation to any electric utility, but they cannot sell to a retail consumer. These EWGs are represented in NEMS.

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 a 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 and Technology Cases

High Electricity Demand Case

The *high electricity demand case* assumes that electricity demand grows at 2.5 percent annually between 2001 and 2025. In the reference case, electricity demand is projected to grow 1.8 percent annually between 2001 and 2025. No attempt was made to determine the changes needed in the end-use sectors to result in the stronger demand growth.

The *high electricity demand case* is a partially integrated run. The end-use demand modules are not operated, but all of the electricity end-use demands from the reference case are multiplied by the same factor to achieve the higher growth rate. Using the higher electricity demand and all other reference case demand projections as inputs, the EMM, Petroleum Marketing, Oil and Gas, Natural Gas Transmission and Distribution, Coal Market, and Renewable Fuels Modules are allowed to interact.

Low and High Fossil Cases

The *low 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 2002 levels. Capital costs of conventional generating technologies are the same as those assumed in the reference case (Table 48).

In the *high fossil case*, efficiencies of advanced fossil generating technologies are higher than the reference case, based on the Department of Energy, Office of Fossil Energy's Vision 21 program goals, while efficiencies of conventional technologies are the same as used in the reference case. The costs of advanced coal are also assumed to be lower than in the reference case.

In the high fossil case, the efficiency improvements may be achieved through a new design, for example, inlcuding a fuel cell in addition to a combined cycle. It is assumed that research and development will bring the costs of these new designs down to the levels of the current technology.

The *low and high fossil* runs are partially-integrated runs, i.e., the reference case values for the Macroeconomic Activity, Petroleum Market, International Energy, and end-use demand modules are used and are not affected by changes in generating capacity mix. Conversely, the Oil and Gas Supply, Natural Gas Transmission and Distribution, Coal Market, and Renewable Fuels Modules are allowed to interact with the EMM in the *low and high fossil cases*.

Advanced Nuclear Cost Case

An advanced nuclear cost case was used to analyze the sensitivity of the projections to lower costs for new nuclear plants. The cost assumptions are consistent with the goals endorsed by the Department of Energy's Office of Nuclear Energy and indicated as requirements for cost-competitiveness by the Offices Near-Term Deployment Working Group. In this case, the overnight capital cost, including contingencies, of a new advanced nuclear unit is assumed to be $1500/kilowatt initially, and to fall to $1200/kilowatt by 2020, (costs in year 2000 dollars)[94] (Table 49). The cost and performance characteristics for all other technologies are as assumed in the reference case.

Table 48. Cost and Performance Characteristics for Fossil-Fueled Generating Technologies: Three Cases

	Total Overnight Cost in 2002 (Reference)	Total Overnight Cost[1] Reference	High Fossil	Low Fossil	Heatrate in 2002 (Reference)	Heat Rate Reference	High Fossil	Low Fossil
	(2001$/kW)	(2001$/kW)	(2001$/kW)	(2001$/kW)	Btu/kWhr	Btu/kWhr	Btu/kWhr	Btu/kWhr
Pulverized Coal	1155				9000			
2010		1128	1134	1128		8689	8689	8689
2015		1101	1022	1095		8600	8600	8600
2020		1086	1109	1079		8600	8600	8600
2025		1080	1097	1072		8600	8600	8600
Adv. Coal	1367				8000			
2010		1320	1023	1367		7378	6799	7911
2015		1290	998	1367		7200	6104	7911
2020		1260	973	1367		7200	5687	7911
2025		1231	949	1367		7200	5687	7911
Conv Combined Cycle	536				7500			
2010		527	527	527		7056	7056	7056
2015		521	521	521		7000	7000	7000
2020		515	515	515		7000	7000	7000
2025		509	509	509		7000	7000	7000
Adv. Gas Technology	608				7000			
2010		549	549	608		6422	5717	6928
2015		513	513	608		6350	4960	6928
2020		503	503	608		6350	4960	6928
2025		494	494	608		6350	4960	6928
Conv. Combustion Turbine	409				10939			
2010		402	402	402		10450	10450	10450
2015		397	397	397		10450	10450	10450
2020		393	393	393		10450	10450	10450
2025		388	388	388		10450	10450	10450
Adv. Combustion Turbine	461				9394			
2010		391	391	461		8550	6669	9394
2015		355	355	461		8550	6669	9394
2020		351	351	461		8550	6669	9394
2025		348	348	461		8550	6669	9394

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

Source: AEO2003 National Energy Modeling System runs: AEO2003.D110502C, HFOSS03.D110602A, LFOSS03.D110602A.

Table 49. Cost Characteristics for Advanced Nuclear Technology: Two Cases

Advanced Nuclear	Overnight Cost in 2002 (Reference) (2001$/kW)	Total Overnight Cost[1]	
		Reference Case (2001$/kW)	Adv Nuclear Case (2001$/kW)
	2118		
2010		2044	1535
2015		1998	1380
2020		1952	1228
2025		1906	1228

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

Source: AEO2003 National Energy Modeling System runs: AEO2003.D110502C, ADVNUC03.D110602A.

Notes and Sources

[93] Energy Information Administration, Integrating Module of the National Energy Modeling System: Model Documentation, DOE/EIA-M057(2000), (Washington, DC, December 1999).

[93] A registered utility holding company is defined as any company that owns or controls 10% of the voting securities of a public utility company. PUHCA defines a public utility company as any company that owns or operates generation, transmission, or distribution facilities for the sale of electricity to the public.

[94] Year 2000 dollars are shown here to be consistent with program office goals.

Sources reference in Table 40

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Characterisation of Power Generation Options For the 21st Century (CPG), ECN-C-98-085, prepared in December 1998 for the European Union

Experience Curves for Energy Policy Assessments, IEA (2000) (IEA)

Oil and Gas Supply Module

The NEMS Oil and Gas Supply Module (OGSM) constitutes a comprehensive framework with which to analyze oil and gas supply. A detailed description of the OGSM is provided in the EIA publication, *Model Documentation Report: The Oil and Gas Supply Module (OGSM)*, DOE/EIA-M063(2003), (Washington, DC, February 2003). The OGSM provides crude oil and natural gas short-term supply parameters to both the Natural Gas Transmission and Distribution Module and the Petroleum Market Module. The OGSM simulates the activity of numerous firms that produce oil and natural gas from domestic fields throughout the United States, acquire natural gas from foreign producers for resale in the United States, or sell U.S. gas to foreign consumers.

OGSM encompasses domestic crude oil and natural gas supply by both conventional and nonconventional recovery techniques. Nonconventional recovery includes unconventional gas recovery from low permeability formations of sandstone and shale, and coalbeds. Foreign gas transactions may occur via either pipeline (Canada or Mexico) or transport ships as liquefied natural gas (LNG).

Primary inputs for the module are varied. One set of key assumptions concerns estimates of domestic technically recoverable oil and gas resources. Other factors affecting the projection include the assumed rates of technological progress, supplemental gas supplies over time, and natural gas import and export capacities.

Key Assumptions

Domestic Oil and Gas Technically Recoverable Resources

Domestic oil and gas technically recoverable resources[95] consist of proved reserves,[96] inferred reserves,[97] and undiscovered technically recoverable resources.[98] OGSM resource assumptions are based on estimates of technically recoverable resources from the United States Geological Survey (USGS), the Minerals Management Service (MMS) of the Department of the Interior, and the National Petroleum Council (NPC).[99] Resource estimates for subsalt plays in the Gulf of Mexico are from the National Petroleum Council. Supplemental adjustments to the USGS nonconventional resources are made by Advanced Resources International (ARI), an independent consulting firm. While undiscovered resources for Alaska are based on USGS estimates, estimates of recoverable resources are obtained on a fiel-by-field basis from a variety of sources including trade press. Published estimates in Tables 50 and 51 reflect the removal of intervening reserve additions between the dates of the USGS (1/1/94), MMS (1/1/95, 1/1/99), and NPC (1/18/98) estimates and January 1, 2002.

Alaskan Crude Oil and Natural Gas from Arctic Areas

Alaskan crude oil production is determined by the estimates of available resources in undeveloped areas and the time and expense required to begin production in these areas. Alaskan production includes existing producing fields, fields that have been discovered but are not currently being produced, and fields that are projected to exist, based upon the region's geology. The first category of field includes expansion fields in the Prudhoe Bay region, accounting for 800 million barrels of oil. These fields are projected to be relatively small, and development of these fields is projected to begin as early as 2002 and continue throughout the forecast. The estimated size of these expansion fields corresponds to projections made by the State of Alaska and other analysis by EIA.

Fields in the second category include fields in the National Petroleum Reserve Alaska, or NPR-A. In 1999 and 2002, northeastern portions of the NPR-A were leased by the Federal government for oil and gas exploration and production. According to a recent USGS assessment[100] NPR-A is estimated to contain a mean resource level of 10.6 billion barrels. These resources are assumed not able to be brought into production until after 2010. Finally, a total of roughly 800 million barrels of additional resources are projected to be developed in other fields yet to be discovered, both on the North Slope of Alaska and offshore in the Beaufort Sea. These fields are expected to be smaller than recent finds like the Alpine field. Oil and gas exploration and production currently are not permitted in the Alaskan National Wildlife Refuge. The

Table 50. Crude Oil Technically Recoverable Resources (Billion barrels)

Crude Oil Resource Category	As of January 1, 2002
Undiscovered	49.29
Onshore	19.34
Offshore	29.94
Deep (>200 meter W.D.)	25.88
Shallow (0-200 meter W.D.)	4.06
Inferred Reserves	43.67
Onshore	37.31
Offshore	6.36
Deep (>200 meter W.D.)	3.94
Shallow (0-200 meter W.D.)	2.42
Total Lower 48 States Unproved	92.96
Alaska	24.45
Total U.S. Unproved	117.41
Proved Reserves	23.92
Total Crude Oil	141.33

WD= Water Depth

Note: Resources in areas where drilling is officially prohibited are not included in this table. Also, the Alaska values are not explicitly utilized in the OGSM, but are included here to complete the table. The Alaska value does not include resources from the Arctic Offshore Outer Continental shelf. Resource values in the table vary from comparable values in the AEO2002 Assumptions Document crude oil resource table because of (1) an accounting for net reserve additions and production in 2000 and 2001, (2) revised new field values from 1/1/90 to 1/1/98, (3) an updating of resources in the National Petroleum Reserve-Alaska (NPRA), and (4) the inclusion of resources for the subsalt areas of the Federal OCS Offshore.

Source: Conventional Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS); Federal (Outer Continental Shelf) Offshore - Minerals Management Service (MMS); Subsalt plays in the Gulf of Mexico--National Petroleum Council (NPC); Proved Reserves - EIA, Office of Oil and Gas. Table values reflect removal of intervening reserve additions between the dates of the USGS (1/1/94), MMS (1/1/95, 1/1/99), and NPC (1/1/98) estimates and January 1, 2002.

AEO2003 projections for Alaskan oil and gas production presume that this prohibition remains in effect throughout the forecast period.

The outlook for natural gas production from the North Slope of Alaska is affected strongly by the unique circumstances regarding its transport to market. Unlike virtually all other identified deposits of natural gas in the United States, North Slope gas lacks a means of economic transport to major commercial markets. The lack of viable marketing potential at present has led to the use of Prudhoe Bay gas to maximize crude oil recovery in that field. Recent high natural gas prices raised the potential economic viability of a major Alaskan pipeline from the North Slope into Alberta, Canada. While several routes have been proposed, the model allows for the construction of a more generic pipeline, should the economic stimulus be sufficient. The primary assumptions associated with estimating the cost of North Slope Alaskan gas in Alberta, as well as for MacKenzie Delta gas into Alberta, are shown in Table 52. A simple calculation is performed to estimate a regulated, levelized, tariff for each pipeline. Additional items are added to account for the wellhead price, treatment costs, pipeline fuel costs, and a risk premium to reflect the potential of a 20 percent higher initial capitalization and market price uncertainty. Finally, a price differential of $0.70 (2001 dollars per Mcf) is assumed between the price in Alberta and the average lower 48 price for comparison purposes. The resulting cost of Alaskan gas, relative to the lower 48 wellhead price, is approximately $3.48 (2001 dollars per Mcf), with some variation across the forecast due to the change in the gross domestic product. Construction of an Alaska-to-Alberta pipeline is set to commence if the assumed total costs for Alaskan gas in the lower 48 States, exceed the average lower 48 price, over the previous 3 planning years, and initial construction of a pipeline from the MacKenzie Delta of Canada to Alberta is complete. Once construction is complete, expansion can occur if the price has exceeded the initial trigger price by $0.08 and if expansion of the MacKenzie pipeline is complete. When the Alaska to Alberta pipeline is built in the model, additional pipeline is added to bring the gas across the border into the United States. For accounting purposes, the model assumes that all of the Alaskan gas will be consumed in the United States. It is assumed that sufficient economical supplies are available at the North Slope to fill the pipeline over the depreciation period.

Table 51. Natural Gas Technically Recoverable Resources
(Trillion cubic feet)

Natural Gas Resource Category	As of January 1, 2002
Nonassociated Gas	
Undiscovered	269.49
Onshore	114.86
Offshore	154.63
Deep (>200 meters W.D.)	107.38
Shallow (0-200 meters W.D)	47.25
Inferred Reserves	221.79
Onshore	180.33
Offshore	41.46
Deep (>200 meters W.D.)	4.65
Shallow (0-200 (meters W.D.)	36.82
Unconventional Gas Recovery	445.08
• Tight Gas	317.95
• Shale	52.45
• Coalbed	74.68
Associated-Dissolved Gas	137.22
Total Lower 48 Unproved	1073.58
Alaska	31.86
Total U.S. Unproved	1105.43
Proved Reserves	183.46
Total Natural Gas	1288.89

WD = Water Depth

Note: Resources in areas where drilling is officially prohibited are not included in this table. Also, the Associated-Dissolved Gas and the Alaska values are not explicitly utilized in the OGSM, but are included here to complete the table. The Alaska value does not include stranded Arctic gas. Resource values in the table vary from comparable values in the AEO2002 Assumptions Document natural gas resource table because of: (1) an accounting for net reserve additions and production in 2001 and 2002 and (2) the inclusion of resources for the subsalt areas of the Federal OCS Offshore.

Source: Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS) with adjustments to Unconventional Gas Recovery resources by Advanced Resources, International, Federal (Outer Continental Shelf) Offshore - Minerals Management Service (MMS) with subsalt resources from the National Petroleum Council; Proved Reserves - EIA, Office of Oil and Gas. Table values reflect removal of intervening reserve additions between the dates of the USGS (1/1/94) and MMS (1/1/99) estimates and January 1, 2002.

Table 52. Primary Assumptions for Natural Gas Pipelines from Alaska and MacKenzie Delta into Alberta, Canada

	Alaska to Alberta	MacKenzie Delta to Alberta
Initial flow into Alberta	4.5 Bcf/d	1.5 Bcf/d
Expansion potential	23 percent	23 percent
Initial capitalization	11.6 billion (2002 dollars)	3.6 billion (2002 dollars)
Discount rate	0.075	0.075
Depreciation period	15 years	15 years
Minimum wellhead price	$0.80 (2001 dollars per Mcf)	$1.00 (2001 dollars per Mcf)
Treatment and fuel costs	$0.46 (2001 dollars per Mcf)	$0.40 (2001 dollars per Mcf)
Risk Premium	$0.56 (2001 dollars per Mcf)	$0.39 (2001 dollars per Mcf)
Additional cost for expansion	$0.08 (2001 dollars per Mcf)	$0.08 (2001 dollars per Mcf)
Construction period	4 years	3 years
Planning period	3 years	2 years

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Alaska pipeline data are partially based on information from British Petroleum/ExxonMobil/Phillips.

Supplemental Natural Gas

The projection for supplemental gas supply is identified for three separate categories: synthetic natural gas (SNG) from liquids, SNG from coal, and other supplemental supplies (propane-air, coke oven gas, refinery gas, biomass air, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas). SNG from the currently operating Great Plains Coal Gasification Plant is assumed to continue through the forecast period, at an average historical level of 50.0 billion cubic feet per year. Other supplemental supplies are held at a constant level of 38.2 billion cubic feet per year throughout the forecast because this level is consistent with historical data and there is no reason to believe this will change significantly in the context of a reference case forecast. Synthetic natural gas from liquid hydrocarbons in Hawaii is assumed to continue over the forecast at the average historical level of 2.4 billion cubic feet per year.

Natural Gas Imports and Exports

U.S. natural gas trade with Mexico is determined endogenously based on various assumptions about the natural gas market in Mexico. U.S. natural gas exports from the United States to Canada are set exogenously to NEMS at 256 billion cubic feet per year, post 2008. Canadian production and U.S. import flows from Canada are determined endogenously within the model and can be constrained by pipeline capacities.

Canadian consumption and production in Eastern Canada are set exogenously in the model and are shown in Table 53. Production in the Western Canadian Sedimentary Basin (WCSB) is calculated endogenously to the model. Reserve additions are set equal to the product of successful natural gas wells (based on an econometric estimation) and a finding rate (set as a function of the cumulative number of successful wells drilled and the assumed economically recoverable resource base). In addition, the general decline in the finding rate is dampened by assumed technological improvements. The unconventional and conventional WCSB economically recoverable resource base estimates assumed in the model for the beginning of 1998 are 176 trillion cubic feet and 75 trillion cubic feet, respectively.[101] For both sources, the initial resource level is assumed to grow by 0.5 percent per year throughout the projection period to reflect improvements in and penetration of technology. Production from unconventional sources is established based on an assumed production path which varies in response to the level of remaining resources and the solution price in the previous forecast year.

Table 53. Exogenously Specified Canadian Production and Consumption
(Billion cubic feet per year)

Year	Consumption	Production Eastern Canada
2000	3,291	131
2005	3,300	400
2010	3,600	640
2015	3,900	690
2020	4,300	680
2025	4,580	655

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

Natural gas production from the frontier areas (e.g., MacKenzie Delta) is assumed to be sufficient to fill a pipeline over the projection period should one be built connecting the area to markets in the south. The basic methodology used to represent the decision to build a MacKenzie pipeline is similar to the process used for an Alaskan-to-lower 48 pipeline, with the primary assumed parameters listed in Table 52. The average lower 48 wellhead price assumed necessary to stimulate construction of the MacKenzie Delta pipeline is $3.37 (2001 dollars per Mcf).

Annual U.S. exports of liquefied natural gas (LNG) to Japan are assumed to be constant at 65.0 billion cubic feet per year. LNG imports are determined endogenously within the model. The model provides for the construction of new facilities should gas prices be high enough to make construction economic — the prices at the facility that are needed to trigger new LNG construction vary by region and range from $3.40 to $4.64/Mcf.

Currently there are three LNG facilities in operation, located at Everett, Massachusetts; Lake Charles, Louisiana; and Elba Island, Georgia. These three facilities have a combined design capacity of 1,880 million cubic feet per day (687 billion cubic feet per year) and an assumed combined sustainable sendout of 487 billion cubic feet per year. An additional facility, at Cove Point, Maryland, with a design capacity of 1 billion cubic feet per day (365 billion cubic feet per year) and an assumed sustainable capacity of 292 billion cubic feet per year, is assumed to reopen in 2003, bringing maximum combined sustainable sendout for U.S. facilities to 779 billion cubic feet per year. Additional combined proposed expansions of 396 billion cubic feet per year as early as 2005 brings the total existing and proposed capacity to 1,175 billion cubic feet per year. The maximum load factor for all LNG facilities is assumed to be 90 percent, which effectively reduces the total available LNG from existing and proposed capacity from 1,175 to 1,057 billion cubic feet per year.

It is assumed that existing facilities would expand beyond what has been proposed prior to the construction of new facilities. Assumed expansions of up to 131 billion cubic per year at Cove Point, 95 at Elba Island, and 187 at Lake Charles (taking into account the 90 percent load factor) could increase available LNG from existing terminals to 1,470 billion cubic feet per year. Trigger prices for these expansions range from a $3.31 minimum at Elba Island to $3.41 at Cove Point and $3.50 at Lake Charles. It is assumed that the Everett, Massachusetts facility cannot expand beyond what is currently proposed.

The model also has a provision for the construction of new facilities in all United States coastal regions and in Baja California, Mexico. Supplies from a Baja California, Mexico facility are assumed to enter the United States as pipeline imports from Mexico destined for the California market. As with expansion of existing facilities, construction is triggered when the regional LNG tailgate[102] price meets or exceeds a trigger price. Trigger prices for new facilities are indicated in Table 54.

Table 54. Regional Trigger Prices for Construction of New LNG Facilities

(2001 dollars per mcf)

New England	$4.12
Middle Atlantic	$3.93
South Atlantic	$3.79
Florida/Bahamas	$4.06
East South Central	$3.81
West South Central	$3.84
Washington/Oregon	$4.64
California	$4.37
Baja California/Mexico	$3.40

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

Since LNG does not compete with wellhead prices, trigger prices are compared with regional prices in the vicinity of the LNG facility (i.e., the tailgate price) rather than with wellhead prices. With the exception of the Baja facility, the individual trigger prices represent the lowest feasible combination of production, liquefaction, and transportation costs, as set forth in Table 55, to the facility plus the regasification cost at the facility. Regasification costs at new facilities include capital costs for construction of the facility.

The assumed production costs are production costs for various stranded gas[103] locations and represent expert judgments based on sources that include the 2001 World LNG/GTL Review report and the *Oil & Gas Journal's* March 5, 2001, article titled "Asian Gas Prospects-1."

Table 55. Components of LNG Trigger Prices for New Facilities
(2001 dollars per mcf)

	Low	High
Production	$0.25	$0.60
Liquefaction	$1.22	$1.65
Shipping	$0.74	$3.57
Regasification	$0.43	$0.64

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

Liquefaction cost data also vary by source and are based on an average liquefaction capital cost for one train (3 million metric tons of LNG or 143 Bcf per year) of $1 billion amortized over a 20-year period with a 12 percent discount rate and a 3-year construction period. These liquefaction costs are adjusted to account for individual plant factors such as the plant's age and location.

LNG per-mile transportation costs are based on the distance-weighted average of two per-mile shipment costs: From Australia to Japan and from Indonesia to Japan. The shipment costs are drawn from the *Oil & Gas Journal's* March 5, 2001, article titled "Asian Gas Prospects-1." This per unit average cost is applied to the different distances from the supply sources to the different LNG receiving terminals in the United States to arrive at initial transportation costs. Final transportation costs are then computed taking into account the return on capital (12 percent rate of return) based on a $165 million dollar capital cost per ship, depreciation over a 20-year period, and an assumed 3 Bcf per trip tanker capacity.

Regasification costs are based on capital and operating expenses developed by PTL Associates for a generic 183 Bcf/year, two storage tank LNG import terminal at a non-seismically active site with no requirement for dredging or piling. The provided costs were adjusted for each region to account for land purchase, rate of return, site-specific permitting, special land and waterway preparation and/or acquisitions, and regulatory costs.

New facilities are assumed to vary in size from 90 Bcf/year capacity to 183 Bcf/year capacity, to have a 3-year construction period, and to require 3 years to ramp up to full capacity. Once they have ramped up to full capacity, it is assumed that each facility can undergo two expansions of from 90 to 275 Bcf/year.

Offshore Royalty Relief

The Outer Continental Shelf Deep Water Royalty Act (Public Law 104-58) gave the Secretary of Interior the authority to suspend royalty requirements on new production from qualifying leases and required that royalty payments be waived automatically on new leases sold in the 5 years following its November 28, 1995, enactment. The volume of production on which no royalties were due for the 5 years was assumed to be 17.5 million barrels of oil equivalent (BOE) in water depths of 200 to 400 meters, 52.5 million BOE in water depths of 400 to 800 meters, and 87.5 million BOE in water depths greater than 800 meters. In any year during which the arithmetic average of the closing prices on the New York Mercantile Exchange for light sweet crude oil exceeded $28 per barrel or for natural gas exceeded $3.50 per million Btu, any production of crude oil or natural gas was subject to royalties at the lease stipulated royalty rate. Although automatic relief expired on November 28, 2000, the act provided the MMS the authority to include royalty suspensions as a feature of leases sold in the future. In September 2000, the MMS issued a set of proposed rules and regulations that provide a framework for continuing deep water royalty relief on a lease by lease basis. In the model it is assumed that relief will be granted at roughly the same levels as provided during the first 5 years of the act.

Rapid and Slow Technology Cases

Two alternative cases were created to assess the sensitivity of the projections to changes in the assumed rates of progress in oil and natural gas supply technologies. To create these cases a number of parameters representing technological penetration in the reference case were adjusted to reflect a more rapid and a slower penetration rate. In the reference case, the underlying assumption is that technology will continue to penetrate at historically observed rates. Since technologies are represented somewhat differently in different submodules of the Oil and Gas Supply Module, the approach for representing rapid and slow technology penetration varied as well. For instance, the effects of technological progress on conventional oil and natural gas parameters in the reference case, such as finding rates, drilling, lease equipment and operating costs, and success rates, were adjusted upward and downward by 15 percent (Table 56), for the rapid and slow technology cases, respectively. The approach taken in unconventional natural gas is discussed below. In the Canadian supply submodule, successful natural gas wells and finding rates for

Table 56. Assumed Annual Rates of Technological Progress on Costs, Finding Rates, and Success Rates for Conventional Sources

	Natural Gas			Crude Oil		
Category	Slow	Reference	Rapid	Slow	Reference	Rapid
Costs						
Drilling						
Onshore	1.59	1.87	2.15	1.59	1.87	2.15
Offshore	1.28	1.50	1.73	1.28	1.50	1.73
Alaska	0.85	1.00	1.15	0.85	1.00	1.15
Lease Equipment						
Onshore	1.02	1.20	1.38	1.02	1.20	1.38
Offshore	1.28	1.50	1.73	1.28	1.50	1.73
Alaska	0.85	1.00	1.15	0.85	1.00	1.15
Operating						
Onshore	0.46	0.54	0.62	0.46	0.54	0.62
Offshore	1.28	1.50	1.73	1.28	1.50	1.73
Alaska	0.85	1.00	1.15	0.85	1.00	1.15
Finding Rates						
New Field Wildcats	0.00	0.00	0.00	0.00	0.00	0.00
Other Exploratory	2.55	3.00	3.45	3.01	3.54	4.07
Developmental	0.00	0.00	0.00	0.00	0.00	0.00
Success Rates						
Developmental	0.57	0.67	0.77	0.57	0.67	0.77
Exploratory	2.23	2.62	3.01	2.23	2.62	3.01

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

conventional gas in the WCSB are assumed to be progressively greater in the rapid technology case and lesser in the slow technology case across the forecast horizon. By 2025, wells are approximately 4 percent higher and lower than in the reference case, directly due to differences in assumed technological improvements. The resulting finding rates are between 2 and 3 percent higher or lower in the rapid and slow technology cases, respectively. The resource base levels for the WCSB were assumed not to vary across technology cases. Production from unconventional natural gas wells is adjusted under the rapid and slow technology cases using the same parameters that are used for conventional wells. All other parameters in the model were kept at their reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of LNG and natural gas trade between the United States and Mexico.

Unconventional Gas

The Unconventional Gas Recovery Supply Submodule (UGRSS) relies on Technology Impacts and Timing functions to capture the effects of technological progress on costs and productivity in the development of gas from deposits of coalbed methane, gas shales, and tight sands. The numerous research and technology initiatives are combined into 11 specific "technology groups," that encompass the full spectrum of key disciplines — geology, engineering, operations, and the environment. The technology groups utilized for the *Annual Energy Outlook 2003* are characterized for three distinct technology cases — Slow Technological Progress, Reference Case, and Rapid Technological Progress — that capture three different futures for technology progress. The 11 technology groups are presented below. Their treatment under the different technology cases are described in Table 57.

Unconventional Gas Recovery Technology Groups

1. Basin Assessments: Basin assessments increase the available resource base by a) accelerating the time that hypothetical plays in currently unassessed areas become available for development and b) increasing the play probability for hypothetical plays - that portion of a given area that is likely to be productive.

2. Play Specific, Extended Reservoir Characterizations: Extended reservoir characterizations increase the pace of new development by accelerating the pace of development for emerging plays, where projects are assumed to require extra years for full development compared to plays currently under development.

3. Advanced Well Performance Diagnostics and Remediation: Well performance diagnostics and remediation expand the resource base by increasing reserve growth for already existing reserves.

4. Advanced Exploration and Natural Fracture Detection R&D: Exploration and natural fracture detection R&D increases the success of development by a) improving exploration/development drilling success rates for all plays and b) improving the ability to find the best prospects and areas.

5. Geology Technology Modelling and Matching: Geology/technology modelling and matching matches the "best available technology" to a given play with the result that the expected ultimate recovery (EUR) per well is increased.

6. More Effective, Lower Damage Well Completion and Stimulation Technology: Improved drilling and completion technology improves fracture length and conductivity, resulting in increased EUR's per well.

7. Targeted Drilling and Hydraulic Fracturing R&D: Targeted drilling and hydraulic fracturing R&D results in more efficient drilling and stimulation which lowers well drilling and stimulation costs.

8. New Practices and Technology for Gas and Water Treatment: New practices and technology for gas and water treatment result in more efficient gas separation and water disposal which lowers water and gas treatment operation and maintenance (O&M) costs.

9. Advanced Well Completion Technologies such as Cavitation, Horizontal Drilling, and Multi-lateral Wells: R&D in advanced well completion technologies a) defines applicable plays, thereby accelerating the date such technologies are available and b) introduces an improved version of the particular technology, which increases EUR per well.

10. Other Unconventional Gas Technologies, such as Enhanced Coalbed Methane and Enhanced Gas Shales Recovery: Other unconventional gas technologies introduce dramatically new recovery methods that a) increase EUR per well and b) become available at dates accelerated by increased R&D with c) increased operation and maintenance (O&M) costs (in the case of Coalbed Methane) for the incremental gas produced.

11. Mitigation of Environmental Constraints: Environmental mitigation removes development constraints in environmentally sensitive basins, resulting in an increase in basin areas available for development.

Table 57. Assumed Rates of Technological Progress for Unconventional Gas Recovery

Technology Group	Item	Type of Deposit	Technology Case		
			Slow	Reference	Rapid
1	Year Hypothetical Plays Become Available	All Types	NA	2025	2021
2	Decrease in Extended Portion of Development Schedule for Emerging Plays (per year)	Coalbed Methane & Gas Shales	2.83%	3.33%	3.83%
		Tight Sands	3.54%	4.16%	4.78%
3	Expansion of Existing Reserves (per year -declining 0.1% per year; eg., 3.0, 2.0...)	Coalbed Methane & Tight Sands	1.70%	2.0%	2.3%
		Gas Shales	2.55%	3.0%	3.45%
4	Increase in Percentage of Wells Drilled Successfully (per year)	All Types	0.21%	0.25%	0.29%
	Year that Best 30 Percent of Basin is Fully Identified	All Types	2021	2017	2014
5	Increase in EUR per Well (per year)	All Types	0.14%	0.17%	0.19%
6	Increase in EUR per Well (per year)	All types	0.28%	0.33%	0.38%
7	Decrease in Drilling and Stimulation Costs per Well (per year)	All types	0.28%	0.33%	0.38%
8	Decrease in Water and Gas Treatment O&M Costs per Well (per year)	All Types	0.57%	.67%	0.77%
9	Year Advanced Well Completion Technologies Become Available	Coalbed Methane & Tight Sands	2020	2016	2013
		Gas Shales	NA	NA	2023
	Increase in EUR per well (total increase)	Coalbed Methane	17%	20%	23%
		Tight Sands	8.5%	10%	11.5%
		Gas Shales	NA	NA	NA
10	Year Advanced Recovery Technologies Become Available	Coalbed Methane	NA	NA	2022
		Tight Sands	NA	NA	2022
	Increase in EUR per well (total increase)	Coalbed Methane	NA	NA	34.5%
		Tight Sands	NA	NA	11.5%
		Gas Shales	NA	NA	NA
	Increase in Costs ($1998/Mcf) for Incremental CBM production	Coalbed Methane	NA	NA	0.75
		Tight Sands & Gas Shales	NA	NA	NA
11	Proportion of Areas Currently Restricted that Become Available for Development (per year)	All types	0.85%	1%	1.15%

EUR = Estimated Ultimate Recovery.

O&M = Operation & Maintenance.

CBM = Coalbed Methane.

Source: Reference Technology Case-Advanced Resources, International; Slow and Rapid Technology Cases, Energy Information Administration, Office of Integrated Analysis and Forecasting.

Notes and Sources

[95] Technically recoverable resources are resources in accumulations producible using current recovery technology but without reference to economic profitability.

[96] Proved reserves are the estimated quantities that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

[97] Inferred reserves are that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves.

[98] Undiscovered resources are located outside oil and gas fields in which the presence of resources has been confirmed by exploratory drilling; they include resources from undiscovered pools within confirmed fields when they occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions.

[99] Donald L. Gautier and others, U.S. Department of Interior, U.S. Geological Survey, 1995 National Assessment of the United States Oil and Gas Resources, (Washington, D.C., 1995); U.S. Department of Interior, Minerals Management Service, an Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf, OGS Report MMS 96-0034 (June 1996); 2000 Assessment of Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 2001; and unreported data from Natural Petroleum Council, Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand, (Washington, D.C., December 1999.).

[100] U.S. Geological Survey, 2002 Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (NPRA): Play Maps and Technically Recoverable Resource Estimates, Open- File Report 02-207 (May 2002).

[101] Case 1 resource estimates from the National Energy Board's, Canadian Energy, Supply and Demand to 2025, 1999.

[102] Tailgate LNG prices represents the price when natural gas exists the regasification facility.

[103] Gas reserves that have been located but are isolated from potential markets, commonly referred to as "stranded" gas, are likely to provide most of the natural gas for LNG in the future. Reserves that can be linked to sources of demand via pipeline are unlikely candidates to be developed for LNG.

Natural Gas Transmission and Distribution Module

The NEMS Natural Gas Transmission and Distribution Module (NGTDM) derives domestic natural gas production, wellhead and border prices, end-use prices, and flows of natural gas through the regional interstate network, for both a peak (December through March) and off peak period during each forecast year. These are derived by solving for the market equilibrium across the three main components of the natural gas market: the supply component, the demand component, and the transmission and distribution network that links them. In addition, natural gas flow patterns are a function of the pattern in the previous year, coupled with the relative prices of gas supply options as translated to the represented market "hubs." The major assumptions used within the NGTDM are grouped into five general categories. They relate to (1) the classification of demand into core and noncore transportation service classes, (2) the pricing of transmission and distribution services, (3) pipeline and storage capacity expansion and utilization, and (4) the implementation of recent regulatory reform. A complete listing of NGTDM assumptions and in-depth methodology descriptions are presented in *Model Documentation: Natural Gas Transmission and Distribution Model of the National Energy Modeling System, Model Documentation 2003,* DOE/EIA-M062(2003) (Washington, DC, January 2003).

Key Assumptions

Demand Classification

Customers demanding natural gas are classified as either core or noncore customers, with core customers assumed to transport their gas under firm (or near firm) transportation agreements and noncore customers assumed to transport their gas under interruptible or short-term capacity release transportation agreements. A distinction is made between core and noncore customers because the price differentials can be significant and it allows for a different algorithm to be used in setting the prices. All residential, commercial, and transportation (vehicles using compressed natural gas) end-use customers are assumed to be core customers. Industrial customers fall into both categories, with industrial boilers and refineries assumed to be noncore and all other industrial users assumed to be core. Likewise, customers in the electric generator sector are assumed to be both core and noncore. Gas steam and gas combined-cycle units are considered to be core; and the remaining units are classified as noncore.

End-use sector specific load patterns are based on recent historical patterns and do not change over the forecast, with the exception of the electric generation sector[104] (i.e., there is no representation of changes in load patterns from new technologies like natural gas cooling.) However, pipeline load factors do change over the forecast as the composition of end-use consumption changes across sectors and as more pipeline and storage capacity becomes available.

Pricing of Services

Transportation rates for interstate pipeline services (both between NGTDM regions and within a region) are calculated assuming that the costs of new pipeline capacity will be rolled into the existing rate base. While cost-of-service still forms the basis for pricing these services, an adjustment to the tariffs is made based on changes in utilization to reflect a more market-based approach. Capital expenditures for refurbishment are generally relatively small, are offset by retirements, and are therefore not considered, nor are potential future expenditures for pipeline safety (refurbishment costs include any expenditures for repair and/or replacement of existing pipe). Existing gross plant in service is only based on new capacity additions.

End-use prices for residential, commercial, and core industrial customers are derived by adding a markup to the average regional market price of natural gas in both peak and off-peak periods. (Prices are only reported on an annual basis and represent quantity-weighted averages of the two seasons.) These markups include the cost of service provided by intraregional interstate pipelines, intrastate pipelines, and local distributors. The intrastate tariffs are accounted for endogenously through historical model benchmarking. Distributor tariffs represent the difference between the regional end-use and citygate price, independent of whether or not a customer class typically purchases gas through a local distributor. The distribution tariffs are initially based on average historical values (Table 57). For residential, commercial, and core industrial customers, distributor tariffs are adjusted throughout the forecast in response to changes in consumption levels and cost of labor and capital. Although the markups in Table 58 represent annual averages, the model actually uses separate markups for the peak and offpeak periods.

Table 58. Base Level Annual Distributor Markup for Local Transportation Service
(2001 Dollars per thousand cubic feet)

Region	Residential	Commercial	Core Industrial
New England	5.42	2.93	-0.14
Mid Atlantic	5.09	2.46	0.69
East North Central	2.54	1.95	0.05
West North Central	2.80	1.67	0.00
South Atlantic	4.39	2.84	0.06
East South Central	3.57	2.54	-0.18
West South Central	3.48	1.94	0.28
Mountain	2.74	1.88	0.68
Pacific	3.66	2.37	1.91
Florida	8.32	3.02	-1.56
Arizona/New Mexico	4.34	2.35	0.54
California	4.32	3.81	1.06

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from Form EI-857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers" for residential, commercial, and citygate, and from various Manufacturing Energy Consumption Surveys for core industrial.

End-use prices for noncore industrial and electric generator customers are simularly established by adding a markup to the regional natural gas market price. These markups are endogenously derived as the difference between estimated historical end-use prices,[105] and the NGTDM regional market price. For noncore industrial customers, these markups are held constant throughout the forecast. For electric generator customers, these markups are adjusted each forecast year by a fraction (0.15 for core, 0.05 for noncore) of the annual percentage change in the associated electric generator consumption. This adjustment is intended to reflect anticipated additional infrastructure devoted to serving core electric generation consumption growth.

The vehicle natural gas (VNG) sector is divided into fleet and non-fleet vehicles. The distributor tariffs for natural gas to fleet vehicles are set to *EIA's Natural Gas Annual* historical end-use minus citygate prices plus Federal and State VNG taxes (Table 59). The price to non-fleet vehicles is based on the industrial sector firm price plus an assumed $4.23 (2001 dollars per thousand cubic feet) dispensing charge plus Federal and State taxes, set constant in nominal dollars. It is assumed that the retailer will lower the dispensing charge by up to 20 percent if needed to be competitive with gasoline prices.

Table 59. Vehicle Natural Gas (VNG) Pricing
(Nominal dollars per thousand cubic feet)

Modified Census Divisions	Total Federal and State VNG Tax[1]
New England	0.51
Middle Atlantic	2.23
East North Central	2.18
West North Central	1.65
South Atlantic (excludes Florida)	1.29
East South Central	1.68
West South Central	1.84
Mountain (excludes Arizona and New Mexico)	1.16
Pacific (excludes California)	1.11
Florida	0.88
Arizona and New Mexico	0.69
California	1.04

[1]Assuming a $0.4844 (nominal dollars per thousand cubic feet) Federal tax.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, based on the Federal tax published in the Information Resources, Inc., publication *Octane Week*, August 9, 1993, and State taxes posted at Hart Energy Networks Motor Fuels Information Center at www.hartenergynetwork.com/motorfuels/state/doc/glance/glnctax.htm.

Capacity Expansion and Utilization

For the first 2 forecast years of the model, announced pipeline and storage capacity expansions (that are deemed highly likely to occur) are used to establish limits on flows and storage in the model. Subsequently, pipeline and storage capacity is added when increases in demand, coupled with anticipated price impacts, warrant such additions (i.e., flow is allowed to exceed current capacity if the demand still exists given the adjusted tariff, thus indicating an expansion). When the decision to add capacity is made, a simple representation is incorporated to capture the average capital costs for pipeline and storage expansion and the resulting tariff. Once it is determined that an expansion will occur, the associated capital costs are estimated based on costs of recent expansions in that area and are used in the revenue requirement calculations in future years.

It is assumed that pipelines and local distribution companies build and subscribe to a portfolio of pipeline and storage capacity to serve a region-specific colder-than-normal winter demand level, currently set at 5 percent for all pipeline area. Maximum pipeline capacity utilization in the peak period is set at 99 percent. In the off-peak period, the maximum is assumed to vary between 75 and 99 percent of the design capacity. The overall level and profile of consumption as well as the availability and price of supplies generally cause realized pipeline utilization levels to be lower than the maximum. For each sector, consumption is disaggregated into peak and off-peak periods based on average historical patterns.

Additions to underground storage capacity are constrained to capture limitations of geology in each of the market regions. The constraints limit total storage additions to be less than an expansion factor times the 1990 storage capacity. The model methodology represents net injections of natural gas into storage in the off-peak period and net withdrawals during the peak period. Total annual net storage withdrawals equal zero in all years of the forecast.

Legislation and Regulation

The methodology for setting reservation fees for transportation services is consistent with FERC's alternative ratemaking and capacity release position in that it allows flexibility in the rates pipelines charge. The methodology is market-based in that prices for transportation services will respond positively to increased demand for services while prices will decline (reflecting discounts to retain customers) should the demand for services decline. The model also reflects current legislation and regulation.

Notes and Sources

[104] Natural gas consumption by electric generators is established in the Electricity Market Module of NEMS on a seasonal basis. These values are used as a basis for adjusting the related load patterns throughout the forecast.

[105] Historical core and noncore industrial prices were based on data from various Energy Information Administration Manufacturing Energy Consumption Surveys.

Petroleum Market Module

The NEMS Petroleum Market Module (PMM) forecasts petroleum product prices and sources of supply for meeting petroleum product demand. The sources of supply include crude oil (both domestic and imported), petroleum product imports, other refinery inputs including alcohol and ethers, natural gas plant liquids production, and refinery processing gain. In addition, the PMM estimates capacity expansion and fuel consumption of domestic refineries.

The PMM contains a linear programming representation of refining activities in three U.S. regions. This representation provides the marginal costs of production for a number of traditional and new petroleum products. The linear programming results are used to determine end-use product prices for each Census Division using the assumptions and methods described below.[106]

Key Assumptions

Regionality

PMM reflects three refining regions: PADD I, PADD V, and a third region including PADD II-IV. Individual refineries are aggregated into one linear programming representation for each region. In order to interact with other NEMS modules with different regional representations, certain PMM inputs and outputs are converted from a PMM region to a non-PMM regional structure and vice versa.

Product Types and Specifications

The PMM models refinery production of the products shown in Table 60.

The costs of producing different formulations of gasoline and diesel fuel that are required by State and Federal regulations are determined within the linear programming representation by incorporating specifications and demands for these fuels. The PMM assumes that the specifications for these fuels will remain the same as currently specified, except that the sulfur content of all gasoline and on-highway diesel fuel will be phased down to reflect EPA regulations.

Table 60. Petroleum Product Categories

Product Category	Specific Products
Motor Gasoline	Conventional Unleaded, Oxygenated, Reformulated
Jet Fuel	Kerosene-type
Distillates	Kerosene, Heating Oil, Highway Diesel, Ultra-low-sulfur-diesel
Residual Fuels	Low Sulfur, High Sulfur
Liquefied Petroleum Gases	Propane, Liquefied Petroleum Gases Mixed
Petrochemical Feedstocks	Petrochemical Naptha, Petrochemical Gas Oil, Propylene, Aromatics
Others	Lubricating Products and Waxes, Asphalt/Road Oil, Still Gas Petroleum Coke, Special Naphthas

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

Motor Gasoline Specifications and Market Shares

The PMM models the production and distribution of three different types of gasoline: conventional, oxygenated, and reformulated (Phase 2). The following specifications are included in PMM to differentiate between conventional and reformulated gasoline blends (Table 61): oxygen content, Reid vapor pressure (Rvp), benzene content, aromatic content, sulfur content, olefin content, and the percent evaporated at 200 and 300 degrees Fahrenheit (E200 and E300). The sulfur specification for gasoline is reduced to reflect recent regulations requiring the average annual sulfur content of all gasoline used in the United States to be phased-down to 30 parts per million (ppm) between the years 2004 and 2007.[107] PMM assumes that RFG has an average annual sulfur content of 135 ppm in 2000 and will meet the 30 ppm requirement in 2004. The

Table 61. Year Round Gasoline Specifications by Petroleum Administration for Defense Districts (PADD)

PADD	Reid Vapor Pressure (Max PSI)	Oxygen Weight Percent (Min)	Oxygen Weight Percent (Max)	Aromatics Volume Percent (Max)	Benzene Volume Percent (Max)	Initial Sulfur PPM (Max)	Olefin Volume Percent (Max)	Percent Evaporated at 200°	Percent Evaluated at 300°
Conventional									
PADD I	9.65	—	—	28.6	1.5	338.4	10.8	41.0	83.0
PADD II-IV	9.83	—	—	28.6	1.5	338.4	10.8	41.0	83.0
PADD V	9.7	—	—	28.6	1.5	338.4	10.8	41.0	83.0
Reformulated									
PADD I-IV	8.55	2.0	2.1	25.0	0.66	135.0	12.0	49.0	87.0
PADD V									
Nonattainment	7.90	2.0	2.1	22.0	0.70	15.0	4.0	49.0	85.0
CARB (attainment)	7.9	—	1.2	22.0	0.70	15.0	4.0	49.0	85.0

Max = Maximum.

Min = Minimum.

PADD = Petroleum Administration for Defense District.

PPM = Parts per million by weight.

PSI = Pounds per Square Inch.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived using U.S. EPA's Complex Model.

reduction in sulfur content between now and 2004 is assumed to reflect incentives for "early reduction". The regional assumptions for phasing-down the sulfur in conventional gasoline account for less stringent sulfur requirements for small refineries and refineries in the Rocky Mountain region. The 30 ppm annual average standard is not fully realized in conventional gasoline until 2008 due to allowances for small refineries. The sulfur specifications assumed for each region and type are provided in Table 62.

Table 62. Gasoline Sulfur Content Assumptions, by Region and Gasoline Type, Parts per Million (PPM)

	2004	2005	2006	2007	2008-2025
Conventional					
PADD I	-143.4	-117.3	-53.4	-41.7	-30
PADD II-I	-114.5	-88.7	-34.8	-32.4	-30
PADD V	-122.8	-95.6	-37.4	-33.7	-30
Reformulated					
PADD I	-30	-30	-30	-30	-30
PADD II-I	-30	-30	-30	-30	-30
PADD V	-15	-15	-15	-15	-15

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from Form EI-810 "Monthly Refinery Report" and U.S. Environmental Protection Agency, "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control requirements, February 2000, (Washington, DC).

Conventional gasoline must comply with antidumping requirements aimed at preventing the quality of conventional gasoline from eroding as the reformulated gasoline program is implemented. Conventional gasoline must meet the Complex Model compliance standards which cannot exceed average 1990 levels of toxic and nitrogen oxide emissions.[108]

Oxygenated gasoline, which has been required during winter in many U.S. cities since October of 1992, requires an oxygenated content of 2.7 percent by weight. Oxygenated gasoline is assumed to have specifications identical to conventional gasoline with the exception of a higher oxygen requirement. Some areas that require oxygenated gasoline will also require reformulated gasoline. For the sake of simplicity, the areas of overlap are assumed to require gasoline meeting the reformulated specifications.

Cellulosic biomass feedstock supplies and costs are taken from the NEMS Renewable Fuels Model. Capital and operating costs for biomass ethanol are derived from an Oak Ridge National Laboratory report.[109]

Reformulated gasoline has been required in many areas in the United States since January 1995. In 1998, the EPA began certifying reformulated gasoline using the "complex model," which allows refiners to specify reformulated gasoline based on emissions reductions from their company; 1990 baseline or the EPA's 1990 baseline. The PMM reflects "Phase II" reformulated gasoline requirements which began in 2000. The PMM uses a set of specifications that meet the "complex model" requirements, but it does not attempt to determine the optimal specifications that meet the "complex model." (Table 61).

The Clean Air Act Amendments of 1990 (CAAA90) provided for special treatment of California that would allow different specifications for oxygenated and reformulated gasoline in that State. In 1992, California requested a waiver from the winter oxygen requirements of 2.7 percent to reduce the requirement to a range of 1.8 to 2.2 percent. The PMM assumes that Petroleum Administration for Defense District (PADD) V refiners must meet the California Air Resources Board (CARB) phase 3 specifications after 2002. The CARB3 specifications reflect the removal of the oxygen requirement designed to complement the State's plans to ban the oxygenate, methyl tertiary butyl ether (MTBE) by the end of 2003. Without a waiver from the U.S. EPA, a minimum oxygen content will still be required in the areas of California covered by the Federal reformulated gasoline program (Los Angeles, San Diego, Sacramento, and the recently added San Jonquin Valley). *AEO2003* assumes that the oxygen requirement remains intact in these areas because no waiver had been granted at the time of the development of the forecast.

AEO2003 reflects legislation which bans or limits the use of MTBE in 16 additional States: Arizona, Colorado, Connecticut, Illinois, Iowa, Kansas, Michigan, Minnesota, Nebraska, New York, South Dakota, Washington, Indiana, Kentucky, Ohio, and Missouri. Since the oxygen requirement on RFG is assumed to continue in these States, the MTBE ban is modeled as a requirement to produce ethanol blended RFG. Ethanol blends were assumed to account for the following market percentages:

— 29.0 percent of RFG in Census Division 1
— 36.5 percent of RFG in Census Division 2
— 97.7 percent of RFG in Census Division 8
— 100.0 percent of RFG(with 2.0 percent oxygen requirement) in Census Division 9
— 100.0 percent of oxygenated gasoline in Census Division 4
— 100.0 percent of oxygenated gasoline in Census Division 8
— 100.0 percent of oxygenated gasoline in Census Division 9

Rvp limitations are effective during summer months, which are defined differently in different regions. In addition, different Rvp specifications apply within each refining region, or PADD. The PMM assumes that these variations in Rvp are captured in the annual average specifications, which are based on summertime Rvp limits, wintertime estimates, and seasonal weights.

Within the PMM, total gasoline demand is disaggregated into demand for conventional, oxygenated, and reformulated gasoline by applying assumptions about the annual market shares for each type. The shares are able to change over time based on assumptions about the market penetration of new fuels. In *AEO2003,* the annual market shares for each region reflect actual 2000 market shares and are held constant throughout the forecast. (See Table 63 for *AEO2003* market share assumptions.)

Diesel Fuel Specifications and Market Shares

In order to account for diesel desulfurization regulations related to CAAA90, low-sulfur diesel is differentiated from other distillates. In NEMS, Census Division 9 is required to meet CARB standards. Both Federal and CARB standards limit sulfur to 500 ppm.

AEO2003 also incorporates the "ultra-low-sulfur diesel" (ULSD) regulation finalized in December 2000. ULSD is highway diesel that contains no more than 15 ppm sulfur at the pump. The ULSD regulation includes a phase-in period under the "80/20" rule, that requires the production of 80 percent ULSD and 20 percent 500 ppm highway diesel between June 2006 and June 2010, and a 100 percent requirement for ULSD thereafter. As NEMS is an annual average model, only a portion of the production of highway diesel in 2006 is subject to the 80/20 rule and the 100 percent requirement does not cover all highway diesel until 2011.

Table 63. Market Share for Gasoline Types by Census Division

	Census Division								
Gasoline Type/Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
Conventional Gasoline	20	42	80	69	82	94	71	70	20
Oxygenated Gasoline (2.7% oxygen)	0	0	0	24	0	0	0	15	6
Reformulated Gasoline (2.0% oxygen)	80	58	20	7	18	6	29	15	74*

*Note: 59 percent is assumed to continue the 2.0 percent Federal oxygen requirement. 15 percent is the result of State requirements.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from EIA-782C, "Monthly Report of Prime Supplier Sales of Petroleum Products Sold for Local Consumption," January-December 2000.

NEMS models ULSD as containing 7 ppm sulfur at the refinery gate. This lower sulfur limit at the refinery reflects the general consensus that refiners will need to produce diesel with a sulfur content below 10 ppm to allow for contamination during the distribution process.

Revamping (retrofitting) existing units to produce ULSD will be undertaken by refineries representing two-thirds of highway diesel production; the remaining refineries will build new units. The capital cost of the revamp is assumed to be 50 percent of the cost of adding a new unit.

The capital cost for new distillate hydrotreaters reflected in *AEO2003* is $1,690 to $2,545 (2000 dollars) per barrel per day, ISBL. The lower estimate is for a 25,000 barrel per day unit processing low-sulfur streams with incidental dearomatization. The higher estimate is for a 10,000 barrel per day unit processing higher sulfur feed streams with greater aromatics improvement.

The amount of ULSD downgraded to a lower value product because of sulfur contamination in the distribution system is assumed to be 10 percent at the start of the program, declining to 4.4 percent at full implementation. The decline reflects that expectation that the distribution system will become more efficient at handling ULSD with experience.

A revenue loss is assumed to occur when a portion of ULSD that is put into the distribution system is contaminated and must be sold as lower value product. The amount of the revenue loss is estimated offline based on earlier NEMS results and is included in *AEO2003* ULSD price projections as a distribution cost. The revenue loss associated with the 10 percent downgrade assumption for 2007 is 0.7 cents per gallon. The revenue loss estimate declines to 0.2 cents per gallon after 2010 when the downgrade assumption declines to 4.4 percent.

The capital and operating costs associated with ULSD distribution are based on assumptions used by the EPA in the Regulatory Impact Analysis (RIA) of the rule.[110] Capital costs of 0.7 cents per gallon are assumed for additional storage tanks to handle ULSD during the transition period. These capital expenditures are assumed to be fully amortized by 2011. Additional operating costs for distribution of highway diesel of 0.2 cents per gallon are assumed for the entire forecast. Another 0.2 cents per gallon is assumed for the cost of lubricity additives. Lubricity additives are needed to compensate for the reduction of aromatics and high-molecular-weight hydrocarbons stripped away by the severe hydrotreating used in the desulfurization process.

Demand for highway-grade diesel, both 500 ppm and ULSD combined, is assumed to be equivalent to total transportation distillate demand. Historically, highway-grade diesel supplied has nearly matched total transportation distillate sales, although some highway-grade diesel has gone to nontransportation uses such as construction and agriculture.

The energy content of ULSD is assumed to decline by 0.5 percent because undercutting and severe desulfurization will result in a lighter stream composition than that for 500 ppm diesel.

No change in the sulfur level of non-road diesel is assumed because the EPA has not yet promulgated these standards.

End-Use Product Prices

End-use petroleum product prices are based on marginal costs of production plus production-related fixed costs plus distribution costs and taxes. The marginal costs of production are determined by the model and represent variable costs of production including additional costs for meeting reformulated fuels provisions of the CAAA90. Environmental costs associated with controlling pollution at refineries (Table 64) are reflected as fixed costs (associated operation and maintenance costs prior to 1996 are excluded).[111] Assuming that refinery-related fixed costs are recovered in the prices of light products, fixed costs are allocated among the prices of liquefied petroleum gases, gasoline, distillate, kerosene, and jet fuel. These costs are based on average annual estimates and are assumed to remain constant over the forecast period.

The costs of distributing and marketing petroleum products are represented by adding fixed distribution costs to the marginal and refinery fixed costs of products. The distribution costs are applied at the Census Division level (Table 65) and are assumed to be constant throughout the forecast and across scenarios.

Distribution costs for each product, sector, and Census Division represent average historical differences between end-use and wholesale prices. The distribution costs for kerosene are the average difference between end-use prices of kerosene and wholesale distillate prices. Distribution costs for M85 are assumed to be equal to distribution costs for gasoline.

Table 64. Summary of Refinery Site Environmental Costs by Petroleum Administration for Defense Districts (PADD)
(1998 dollars per barrel)

Cost Category	PADD I	PADD II	PADD III	PADD IV	PADD V
Environmental Costs	0.66	0.67	0.53	0.97	0.74

PADD = Petroleum Administration for Defense District.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from estimated costs from the National Petroleum Council, U.S. Petroleum Refining-Meeting Requirement for Cleaner Fuels and Refineries, Volume 1, (Washington, DC, August 1993).

State and Federal taxes are also added to transportation fuels to determine final end-use prices (Tables 66 and 67). Recent tax trend analysis indicated that State taxes increase at the rate of inflation, therefore, State taxes are held constant in real terms throughout the forecast. This assumption is extended to local taxes which are assumed to average 2 cents per gallon.[112] Federal taxes are assumed to remain at current levels in accordance with the overall *AEO2003* assumption of current laws and regulation. Federal taxes are deflated as follows:

$$\text{Federal Tax}_{\text{product, year}} = \text{Current Federal Tax}_{\text{product}} / \text{GDP Deflator}_{\text{year}}$$

Table 65. Petroleum Product End-Use Markups by Sector and Census Division
(2001 dollars per gallon)

Sector/Product	Census Division 1	2	3	4	5	6	7	8	9
Residential Sector									
Distillate Fuel Oil	0.40	0.47	0.34	0.27	0.45	0.30	0.21	0.28	0.41
Kerosene	0.17	0.31	0.43	0.26	0.32	0.40	0.23	0.19	0.08
Liquefied Petroleum Gases	0.91	0.96	0.53	0.36	0.82	0.69	0.61	0.56	0.83
Commercial Sector									
Distillate Fuel Oil	0.15	0.12	0.06	0.03	0.07	0.04	0.04	0.04	0.07
Gasoline	0.15	0.13	0.14	0.15	0.13	0.17	0.17	0.16	0.16
Kerosene	0.16	0.26	0.46	0.26	0.30	0.41	0.19	0.20	0.10
Liquefied Petroleum Gases	0.56	0.57	0.48	0.35	0.57	0.45	0.37	0.48	0.61
Low-Sulfur Residual Fuel Oil	0.00	0.03	0.01	0.01	0.00	0.03	-0.01	0.03	0.09
Utility Sector									
Distillate Fuel Oil	0.02	0.03	0.02	0.01	0.02	0.06	0.03	0.07	0.02
High-Sulfur Residual Fuel Oil[2]	0.00	0.03	0.09	-0.04	0.01	-0.06	0.07	0.01	0.08
Low-Sulfur Residual Fuel Oil[3]	-0.01	0.00	0.08	-0.07	0.01	-0.10	0.10	0.23	0.19
Transportation Sector									
Distillate Fuel Oil	0.24	0.18	0.14	0.12	0.14	0.16	0.13	0.14	0.20
E85[1]	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41
Gasoline	0.15	0.13	0.14	0.15	0.13	0.17	0.17	0.17	0.13
High-Sulfur Residual Fuel Oil[2]	-0.02	0.04	0.12	-0.04	0.00	-0.08	0.06	0.28	0.05
Jet Fuel	0.02	-0.01	-0.02	-0.04	-0.03	0.00	0.00	-0.02	0.00
Liquefied Petroleum Gases	0.51	0.53	0.59	0.33	0.51	0.39	0.32	0.42	0.55
Industrial Sector									
Asphalt and Road Oil	0.23	0.18	0.29	0.17	0.16	0.09	0.19	0.36	0.18
Distillate Fuel Oil	0.16	0.14	0.14	0.11	0.11	0.09	0.10	0.08	0.13
Gasoline	0.15	0.13	0.14	0.16	0.13	0.18	0.17	0.16	0.14
Kerosene	0.10	0.11	0.15	0.18	0.15	0.17	0.08	0.13	0.11
Liquefied Petroleum Gases	0.44	0.49	0.55	0.29	0.48	0.39	0.24	0.28	0.54
Low-Sulfur Residual Fuel Oil	0.00	0.00	0.03	0.02	0.01	-0.01	0.01	0.09	0.09

[1]85 percent ethanol and 15 percent gasoline.

[2]Negative values indicate that average end-use sales prices were less than wholesale prices. This often occurs with residual fuel which is produced as a biproduct when crude oil is refined to make higher value products like gasoline and heating oil.

Sources: Markups based on data from Energy Information Administration (EIA), Form EIA-782A, *Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report*; EIA, Form EIA-782B, *Resellers'/Retailers' Monthly Petroleum Report Product Sales Report*; EIA, Form FERC-423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*; EIA, Form EIA-759 *Monthly Power Plant Report; EIA, State Energy Data Report 1999*, DOE/EIA-0214(99), (Washington, DC, May 2001); EIA, *State Energy Price and Expenditures Report 1999*, DOE/EIA-0376(99), (Washington, DC, November 2001).

Table 66. State and Local Taxes on Petroleum Transportation Fuels by Census Division
(2001 dollars per gallon)

Year/Product	Census Division 1	2	3	4	5	6	7	8	9
Gasoline[1]	0.25	0.23	0.26	0.22	0.19	0.21	0.22	0.23	0.27
Diesel	0.21	0.24	0.22	0.20	0.19	0.16	0.20	0.22	0.24
Liquefied Petroleum Gases	0.21	0.12	0.16	0.19	0.17	0.16	0.15	0.09	0.05
E85[2]	0.27	0.19	0.16	0.17	0.14	0.17	0.20	0.14	0.13
Jet Fuel	0.03	0.03	0.01	0.03	0.05	0.03	0.00	0.03	0.03

[1]Tax also applies to gasoline consumed in the commercial and industrial sectors.

[2] 85 percent ethanol and 15 percent gasoline.

Source: Gasoline, diesel and LPG aggregated from Federal Highway Administration, Tax Rates on Motor Fuel, Table MF-121T, http://www.fhwa.dot.gov/ohim/hs00/pdf/mf121t.pdf, (Washington, DC, October 2001). E85 obtained from Energy Futures, Inc., Boulder, CO. Jet fuel from EIA, Office of Oil and Gas.

Table 67. Federal Taxes
(Nominal dollars per gallon)

Product	Tax
Gasoline	0.18
Diesel	0.24
Jet Fuel	0.04
Liquefied Petroleum Gases	0.14
M85[1]	0.09
E85[2]	0.13

[1]85 percent methanol and 15 percent gasoline.

[2] 85 percent ethanol and 15 percent gasoline.

Sources: Omnibus Budget Reconciliation Act of 1993 (H.R. 2264); Tax Payer Relief Act of 1997 (PL 105-34) and *Clean Fuels Report* (Washington, DC, April 1998).

Crude Oil Quality

In the PMM, the quality of crude oil is characterized by average gravity and sulfur levels. Both domestic and imported crude oil are divided into five categories as defined by the ranges of gravity and sulfur shown in Table 68.

Table 68. Crude Oil Specifications

Crude Oil Categories	Sulfur (percent)	Gravity (degrees API)
Low Sulfur Light	0 - 0.5	> 24
Medium Sulfur Heavy	0.35 - 1.1	> 24
High Sulfur Light	> 1.1	> 32
High Sulfur Heavy	> 1.1	24 - 33
High Sulfur Very Heavy	> 0.7	0 - 23

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from EI-810, "Monthly Refinery Report" data.

A "composite" crude oil with the appropriate yields and qualities is developed for each category by averaging the characteristics of specific crude oil streams that fall into each category. While the domestic and foreign categories are the same, the composite crudes for each category may differ because different crude streams make up the composites. For domestic crude oil, estimates of total regional production are made first, then shared out to each of the five categories based on historical data. For imported crude oil, a separate supply curve is provided for each of the five categories.

Capacity Expansion

PMM allows for capacity expansion of all processing units including distillation capacity, vacuum distillation, hydrotreating, coking, fluid catalytic cracking, hydrocracking, alkylation, and methyl tertiary butyl ether manufacture. Capacity expansion occurs by processing unit, starting from base year capacities established by PADD using historical data.

Expansion occurs in NEMS when the value received from the additional product sales exceeds the investment and operating costs of the new unit. The investment costs assume a10-percent hurdle rate in the decision to invest and a 10-percent rate of return over a 15-year plant life. Expansion through 2002 is determined by adding to the existing capacities of units planned and under construction that are expected to begin operating during this time. Capacity expansion plans are done every 3 years. The PMM looks ahead in 2002 and determines the optimal capacities given the estimated demands and prices expected in the 2005 forecast year. The PMM then allows one-third of that capacity to be built in each of the forecast years 2003, 2004, and 2005. At the end 2005 the cycle begins anew, looking ahead to 2008.

Strategic Petroleum Reserve Fill Rate

AEO2003 assumes no additions for the Strategic Petroleum Reserve (SPR) during the forecast period. Any SPR draw is assumed to be in the form of a swap with a zero net annual change.

Biofuels Supply

The PMM provides supply functions on an annual basis through 2025 for ethanol produced from both corn and cellulosic biomass to produce transportation fuel. It also assumes that small amounts of vegetable oil and animal fats are processed into biodiesel, a blend of methyl esters suitable for fueling diesel engines.

- Corn feedstock supplies and costs are provided exogenously to NEMS. Feedstock costs reflect credits for co-products (livestock feed, corn oil, etc.). Feedstock supplies and costs reflect the competition between corn and its co-products and alternative crops, such as soybeans and their co-products.

- Current U.S ethanol production capacity is aggregated by Census Division in the PMM. Cellulose ethanol demonstration plants are modeled in Census Divisions 2 and 7. However, the majority of cellulose ethanol growth is projected in Census Divisions 3 and 4 using corn stover as feedstock, and in Census Division 9 with rice straw and forest residue as the primary feedstock.

- The tax subsidy to ethanol of $0.53 per gallon of ethanol (5.3 cents per gallon subsidy to gasohol at a 10-percent volumetric blending portion) is applied within the model. This subsidy is scheduled to be reduced to 51 cents by 2007. The tax subsidy is held constant in nominal terms, decreasing with inflation throughout the forecast. The subsidy is assumed not to expire during the forecast period.

Interregional transportation is assumed to be by rail, ship, barge, and truck and the associated costs are included in PMM. A subsidy is offered by the Department of Agriculture's Commodity Credit Corporation for new or expanded production of biodiesel. Based on data through the third quarter of 2002, biodiesel output is projected to grow by 7.2 million gallons per year until the subsidy expires at the end of 2006. Thereafter, biodiesel output is projected to grow by 1.9 percent per year.

Gas-To-Liquids and Coal-To-Liquids

If prices for lower sulfur distillates reach a high level, it is assumed that gas-to-liquids (GTL) facilities will be built on the North Slope of Alaska to convert stranded natural gas into distillates, to be transported on the Trans-Alaskan Pipeline System (TAPS) to Valdez and shipped to markets in the lower 48 States. The facilities are assumed to be built incrementally, no earlier than 2005, with output volumes of 50,000 barrels per day, at a cost of $21,500 per barrel of daily capacity (2001 dollars). Operating costs are assumed to be

$3.99 per barrel. Transportation costs to ship the GTL product from the North Slope to Valdez along the TAPS range from $2.75 to $4.45 per barrel, depending on total oil flow on the pipeline and the potential need for GTL to maintain the viability of the TAPS line if Alaskan oil production declines. Initially, the natural gas feed is assumed to cost $0.82 per thousand cubic feet (2001 dollars).

It is also assumed that coal-to-liquids (CTL) facilities will be built when low-sulfur distillate prices are high. One CTL facility is capable of processing 16,400 tons of bituminous coal per day, with a production capacity of 33,200 barrels of synthetic fuels per day and 696 megawatts of capacity for electricity cogeneration sold to the grid [*37*]. CTL facilities could be built near existing refineries. For the East Coast, potential CTL facilities could be built near the Delaware River basin; for the Central region, near the Illinois River basin or near Billings, Montana; and for the West Coast, in the vicinity of Puget Sound in Washington State. The CTL yields are assumed to be similar to those from a GTL facility, because both involve the Fischer-Tropsch process to convert syngas ($CO + H_2$) to liquid hydrocarbons. The primary yields would be distillate and kerosene, with additional yields of naphthas and liquefied petroleum gases. Petroleum products from CTL facilities are assumed to be competitive when distillate prices rise above the cost of CTL production (adjusted for credits from the sale of cogenerated electricity). CTL capacity is projected to be built only in the *AEO2003* high world oil price case.

Combined Heat and Power (CHP)

Electricity consumption in the refinery is a function of the throughput of each unit. Sources of electricity consist of refinery power generation, utility purchases, refinery CHP, and merchant CHP. Power generators and CHP plants are modeled in the PMM linear program as separate units which are allowed to compete along with purchased electricity. Both the refinery and merchant CHP units provide estimates of capacity, fuel consumption, and electricity sales to grid based on historical parameters.

Refinery sales to the grid are estimated using the following percentages which are based on 1998 data:

Region	Percent Sold To Grid
1 (PADD I)	56.9
2 (PADD's II, III, and IV)	4.3
3 (PADD V)	20.1

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived using EI-860B, "Annual Electric Generators Report-Nonutility".

The PMM is forced to sell electricity back to the grid in these percentages at a price equal to the average price of electricity.

Merchant CHP plants are defined as non-refiner owned facilities located near refineries to provide energy to the open market and to the neighboring refinery. The PMM assumes that 66 percent of electricity from merchant CHP in every region is sold to the grid. These sales occur at a price equal to the average of the generation price and the industrial price of electricity for each PMM region. Electricity prices are obtained from the Electricity Market Model.

Short-term Methodology

Petroleum balance and price information for the years 2002 and 2003 are projected at the U.S. level in the *Short-term Energy Outlook, (STEO*). The PMM assumes the *STEO* results for 2002 and 2003, using regional estimates derived from the national *STEO* projections.

Legislation and Regulations

The Tax Payer Relief Act of 1997 reduced excise taxes on liquefied petroleum gases and methanol produced from natural gas. The reductions set taxes on these products equal to the Federal gasoline tax on a Btu basis.

Title II of CAAA90 established regulations for oxygenated and reformulated gasoline and reduced-sulfur (500 ppm) on-highway diesel fuel, which are explicitly modeled in the PMM. Reformulated gasoline represented in the PMM meets the requirements of phase 2 of the Complex Model, except in the Pacific region where it meets CARB 3 specifications. The reformulated gasoline in areas of the Pacific region covered by the Federal RFG program continue to require 2.0 percent oxygen.

AEO2003 reflects legislation which bans or limits the use of the gasoline blending component MTBE in the following states: Arizona, California, Colorado, Connecticut, Illinois, Iowa, Kansas, Michigan, Minnesota, Nebraska, New York, South Dakota, Washington, Indiana, Kentucky, Ohio, and Missouri.

AEO2003 reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements finalized by EPA in February 2000. This regulation requires that the average annual sulfur content of all gasoline used in the United States be phased-down to 30 ppm between the years 2004 and 2007. The 30 ppm annual average standard is not fully realized in conventional gasoline until 2008 due to allowances for small refineries.

AEO2003 reflects Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements finalized by the EPA in December 2000. Between June 2006 and June 2010, this regulation requires 80 percent of highway diesel contain no more than 15 ppm sulfur while the remaining 20 percent of highway diesel contain no more than 500 ppm sulfur. After June 2010, all highway diesel is required to contain no more than 15 ppm sulfur at the pump.

A number of pieces of legislation are aimed at controlling air, water, and waste emissions from refineries themselves. The PMM incorporates related environmental investments as refinery fixed costs. The estimated expenditures are based on results of the 1993 National Petroleum Council Study.[113] These investments reflect compliance with Titles I, III, and V of CAAA90, the Clean Water Act, the Resource Conservation and Recovery Act, and anticipated regulations including the phaseout of hydrofluoric acid and a broad-based requirement for corrective action. No costs for remediation beyond the refinery site are included.

Lifting the ban on exporting Alaskan crude oil was passed and signed into law (PL 104-58) in November 1995. Alaskan exports of crude oil have represented about 60 percent of U.S. crude oil exports since November 1995 and are assumed to equal 60 percent of total U.S. crude oil exports in the forecast.

High Renewables Case

The high renewables case uses more optimistic assumptions about renewable energy sources. The supply curve for cellulosic ethanol is shifted in each forecast year relative to the reference case, making larger quantities available at any given price than are available in the reference case.

Notes and Sources

[106] Energy Information Administration, *EIA Model Documentation: Petroleum Market Model of the National Energy Modeling System*, DOE/EIA-M059 (2002), (Washington, DC, January 2002).

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[109] U.S. Environmental Protection Agency, Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements, EPA420-R-00-026 (Washington, DC, December 2000).

[110] Environmental cost estimates are based on National Petroleum Council, U.S. Petroleum Refining: Meeting Requirements for Cleaner Fuels and Refineries, Volume I, (Washington, DC, August 1993). Associated operating and maintenance base costs predating 1995 are excluded as they are reflected in the refinery fixed operating cost estimates.

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[112] National Petroleum Council, *U.S. Petroleum Refining: Meeting Requirements for Cleaner Fuels and Refineries*, Volume 1, (Washington, DC, August 1993).

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Coal Market Module

The NEMS Coal Market Module (CMM) provides forecasts of U.S. coal production, consumption, exports, distribution, and prices. The CMM comprises three functional areas: coal production, coal distribution, and coal exports. A detailed description of the CMM is provided in the EIA publication, *Coal Market Module of the National Energy Modeling System 2003,* DOE/EIA-M060(2003) (Washington, DC, January 2003*).*

Key Assumptions

Coal Production

The coal production submodule of the CMM generates a different set of supply curves for the CMM for each year of the forecast. Separate supply curves are developed for each of 11 supply regions and 12 coal types (unique combinations of thermal grade, sulfur content, and mine type). The modeling approach used to construct regional coal supply curves addresses the relationship between the minemouth price of coal and corresponding levels of capacity utilization of mines, mining capacity, labor productivity, and the cost of factor inputs (mining equipment, mine labor, and fuel requirements).

The key assumptions underlying the coal production modeling are:

- Mining costs are assumed to vary with changes in capacity utilization of mines, mining capacity, labor productivity, and factor input costs. Factor input costs are represented by projections of electricity prices from the Electricity Market Module (EMM) and estimates of future coal mine labor and mining equipment costs.

- Between 1979 and 2001, U.S. coal mining productivity (measured in short tons of coal produced per miner per hour) increased at an estimated average rate of 6.2 percent per year. The major factors underlying these gains were interfuel price competition, structural change in the industry, and technological improvements in coal mining.[114] Based on the expectation that further penetration of certain more productive mining technologies, such as longwall methods and large capacity surface mining equipment, will gradually level off, productivity improvements are assumed to continue, but to decline in magnitude. Different rates of improvement are assumed by region and by mine type, surface and underground. On a national basis, labor productivity increases on average at a rate of 1.6 percent a year over the entire forecast, declining from an estimated annual rate of 2.4 percent between 2001 and 2010 to approximately 1.1 percent over the 2010 to 2025 period. These estimates are based on recent historical data reported on Form EIA-7A, *Coal Production Report*, and expectations regarding the penetration and impact of new coal mining technologies.[115]

- Between 1985 and 1993, the average hourly wage for U.S. coal miners (in 2001 dollars) declined at an average rate of 1.5 percent per year, falling from $22.63 to $20.09.[116] During this same time period the producer price index (PPI) for mining machinery and equipment (in 2001 dollars) declined by 0.6 percent per year, falling from 166.2 to 159.0.[117] In the reference case, both the wage rate for U.S. coal miners and mine equipment costs are assumed to remain constant in 2001 dollars (i.e., increase at the general rate of inflation) over the forecast. This assumption reflects the more recent trend in wages and mine equipment costs that has prevailed since 1993. In 2001, the average hourly wage rate for coal miners was $18.94, and the PPI for mining machinery and equipment was 157.8.

Coal Distribution

The coal distribution submodule of the CMM determines the least-cost (minemouth price plus transportation cost) supplies of coal by supply region for a given set of coal demands in each demand sector in each demand region using a linear programming algorithm. Production and distribution are computed for 11 supply and 16 demand regions for 21 demand subsectors.

The projected levels of industrial, coking, and residential/commercial coal demand are provided by the industrial, commercial, and residential demand modules; electricity coal demands are provided by the EMM, and coal export demands are provided from the CMM itself.

The key assumptions underlying the coal distribution modeling are:

- Base-year transportation costs are estimates of average transportation costs for each origin-destination pair. These costs are computed as the difference between the average delivered price for a demand region (by sector and for export) and the average minemouth price for a supply curve. Delivered price data are from Form EIA-3, *Quarterly Coal Consumption Report-Manufacturing Plants*, Form EIA-5, *Coke Plant Report-Quarterly*, Federal Energy Regulatory Commission (FERC) Form 423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*, and the U.S. Bureau of the Census' Monthly Report EM-545. Minemouth price data are from Form EIA-7A, *Coal Production Report*.

Coal transportation costs are modified over time in response to projected variations in reference case fuel costs (No. 2 diesel fuel in the industrial sector), labor costs, the producer price index for transportation equipment, and a time trend. The transportation rate multipliers used for all five *AEO2003* cases are shown in Table 69.

Table 69. Transportation Rate Multipliers
(2001=1.000)

Year	Reference Case	High Oil Price	Low Oil Price	High Economic Growth	Low Economic Growth
2001	1.0000	1.0000	1.0000	1.0000	1.0000
2005	0.9661	0.9786	0.9647	0.9683	0.9664
2010	0.9304	0.9525	0.9189	0.9428	0.9222
2015	0.8739	0.8916	0.8598	0.9006	0.8566
2020	0.7954	0.8107	0.7810	0.8277	0.7703
2025	0.7487	0.7604	0.7339	0.7824	0.7143

Source: Energy Information Administration. Based on methodology described in "Forecasting Annual Energy Outlook Coal Transportation Rates", *Issues in Midterm Analysis and Forecasting 1997*, DOE/EIA-0607(97), (Washington, DC, July 1997).

- Electric generation demand received by the CMM is subdivided into "coal groups" representing demands for different sulfur and thermal heat content categories. This process allows the CMM to determine the economically optimal blend of different coals to minimize delivered cost, while meeting the sulfur emissions requirements of the Clean Air Act Amendments of 1990. Similarly, nongeneration demands are subdivided into subsectors with their own coal groups to ensure that, for example, lignite is not used to meet a coking coal demand.

Coal Exports

Coal exports are modeled as part of the CMM's linear program that provides annual forecasts of U.S. steam and metallurgical coal exports, in the context of world coal trade. The linear program determines the pattern of world coal trade flows that minimize the production and transportation costs of meeting a prespecified set of regional world coal import demands. It does this subject to constraints on export capacity and trade flows.

The CMM projects steam and metallurgical coal trade flows from 16 coal-exporting regions of the world to 20 import regions for three coal types (coking, bituminous steam, and subbituminous). It includes five U.S. export regions and four U.S. import regions.

The key assumptions underlying coal export modeling are:

- The coal market is competitive. In other words, no large suppliers or groups of producers are able to influence the price through adjusting their output. Producers' decisions on how much and who they supply are driven by their costs, rather than prices being set by perceptions of what the market can bear. In this situation, the buyer gains the full consumer surplus.

- Coal buyers (importing regions) tend to spread their purchases among several suppliers in order to reduce the impact of potential supply disruption, even though this adds to their purchase costs. Similarly, producers choose not to rely on any one buyer and instead endeavor to diversify their sales.

- Coking coal is treated as homogeneous. The model does not address quality parameters that define coking coals. The values of these quality parameters are defined within small ranges and affect world coking coal flows very little.

Data inputs for coal export modeling:

- U.S. coal exports are determined, in part, by the projected level of world coal import demand. World steam and metallurgical coal import demands for the *AEO2003* forecast cases are shown in Tables 70 and 71.

Table 70. World Steam Coal Import Demand by Import Region, 2001-2025
(Million metric tons of coal equivalent)

Import Regions[1]	2001	2005	2010	2015	2020	2025
The Americas	38.5	36.7	40.2	42.2	44.8	44.5
United States	15.7	13.5	16.0	18.5	21.0	23.5
Canada	15.0	11.2	10.1	9.4	9.1	5.6
Mexico	2.1	6.0	6.4	6.6	7.0	7.7
South America	5.7	6.0	7.7	7.7	7.7	7.7
Europe	132.5	133.5	137.4	130.3	126.3	122.4
Scandinavia	11.7	8.4	5.6	4.3	3.6	2.9
U.K/Ireland	25.1	24.1	22.1	18.5	16.7	16.7
Germany/Austria	15.4	17.9	21.5	22.4	24.2	26.0
Other NW Europe	24.1	23.0	20.6	16.2	12.6	9.0
Iberia	19.4	25.3	27.4	26.4	24.7	22.9
Italy	11.4	8.6	8.2	7.7	7.3	6.8
Med/E Europe	25.4	26.2	32.0	34.8	37.2	38.1
Asia	195.0	226.1	261.6	279.0	296.1	311.9
Japan	75.2	83.3	96.0	101.5	106.9	112.3
East Asia	84.3	94.3	106.1	109.7	113.3	117.9
China/Hong Kong	9.8	9.7	14.5	19.0	23.6	25.4
ASEAN	15.5	23.9	28.5	30.5	32.2	33.5
Indian Sub	10.2	14.9	16.5	18.3	20.1	22.8
Total	366.0	396.3	439.2	451.5	467.2	478.8

[1]Import Regions: **South America:** Argentina, Brazil, Chile; **Scandinavia:** Denmark, Finland, Norway, Sweden; **Other NW Europe:** Belgium, France, Luxembourg, Netherlands; **Iberia:** Portugal, Spain; **Med/E Europe:** Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia, Turkey; **East Asia:** North Korea, South Korea, Taiwan; **ASEAN:** Malaysia, Philippines, Thailand; **Indian Sub:** Bangladesh, India, Iran, Pakistan, Sri Lanka.

Notes: One "metric ton of coal equivalent" contains 27.78 million Btu. Totals may not equal sum of components due to independent rounding.

Source: Projections: Energy Information Administration, Office of Integrated Analysis and Forecasting; and SSY Consultancy and Research, "Data Updates for the International Coal Trade Component of the National Energy Modeling System", June 1999.

- Step-function coal export supply curves for all non-U.S. supply regions. The curves provide estimates of export prices per metric ton, inclusive of minemouth and inland freight costs, as well as the capacities for each of the supply steps.

Table 71. World Metallurgical Coal Import Demand by Import Region, 2001-2025
(Million metric tons of coal equivalent)

Import Regions[1]	2001	2005	2010	2015	2020	2025
The Americas	20.6	22.3	24.7	27.5	30.0	29.9
United States	2.1	2.0	1.8	1.7	1.5	1.4
Canada	3.9	4.0	3.9	3.7	3.5	3.4
Mexico	1.1	1.3	2.3	2.9	3.8	3.9
South America	13.5	15.0	16.7	19.2	21.2	21.2
Europe	53.4	53.3	52.9	51.4	49.6	49.1
Scandinavia	3.3	2.8	2.8	2.8	1.8	1.6
U.K/Ireland	10.4	7.7	7.7	7.2	7.2	7.2
Germany/Austria	3.6	6.4	7.0	7.0	7.0	7.0
Other NW Europe	16.6	15.2	13.4	12.4	11.4	10.9
Iberia	4.4	4.5	3.9	3.9	3.9	3.9
Italy	8.6	7.3	7.2	6.4	6.4	6.4
Med/E Europe	6.5	9.4	10.9	11.7	11.9	12.1
Asia	109.0	109.4	109.4	111.7	113.5	116.3
Japan	69.2	63.5	59.6	58.2	56.7	54.8
East Asia	25.6	28.1	31.4	33.4	35.7	37.6
China/Hong Kong	0.0	0.6	0.6	0.6	0.6	0.6
ASEAN	0.0	0.0	0.0	0.0	0.0	0.0
Indian Sub	14.2	17.2	17.8	19.5	20.5	23.3
Total	183.0	185.0	187.0	190.6	193.1	195.3

[1]Import Regions: **South America:** Argentina, Brazil, Chile; **Scandinavia:** Denmark, Finland, Norway, Sweden; **Other NW Europe:** Belgium, France, Luxembourg, Netherlands; **Iberia:** Portugal, Spain; **Med/E Europe:** Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia, Turkey; **East Asia:** North Korea, South Korea, Taiwan; **ASEAN:** Malaysia, Philippines, Thailand; **Indian Sub:** Bangladesh, India, Iran, Pakistan, Sri Lanka.

Notes: One "metric ton of coal equivalent" contains 27.78 million Btu. Totals may not equal sum of components due to independent rounding.

Source: Projections: Energy Information Administration, Office of Integrated Analysis and Forecasting; and SSY Consultancy and Research, "Data Updates for the International Coal Trade Component of the National Energy Modeling System", June 1999.

- Ocean transportation rates (in dollars per metric ton) for feasible coal shipments between international supply regions and international demand regions. The rates take into account maximum vessel sizes that can be handled at export and import piers and through canals and reflect route distances in thousand nautical miles.

Coal Quality

Each year the values of base year coal production, heat, sulfur and mercury (Hg) content and carbon dioxide emissions for each coal source in CMM are calibrated to survey data. Surveys used for this purpose are the FERC Form 423, a survey of the origin, cost and quality of fossil fuels delivered to electric utilities, the Form EIA 860B which records the quality of coal consumed at independent power producers, the Form EIA5 and 5a which record the origin, cost, and quality of coal receipts at domestic coke plants, and the Forms EIA 3 and 3a, which record the origin, cost and quality of coal delivered to domestic industrial consumers. Estimates of coal quality for the export and residential/commercial sectors are made using the survey data for coal delivered to coking coal and industrial steam coal consumers. Hg content data for coal by supply region and coal type, in units of pounds of Hg per trillion Btu in Table 72, were derived from shipment-level data reported by electricity generators to the Environmental Protection Agency in its 1999 Information Collection Request. The database included approximately 40,500 Hg samples reported for 1,143 generating units located at 464 coal-fired facilities. Carbon dioxide emissions levels for each coal type are listed in Table 68 in pounds of carbon dioxide emitted per million Btu.[118]

Legislation

It is assumed that provisions of the Energy Policy Act of 1992 that relate to the future funding of the Health and Benefits Fund of the United Mine Workers of America will have no significant effect on estimated production costs, although liabilities of company's contributions will be redistributed. Electricity sector demand for coal, which represented 91 percent of domestic coal demand in 2001, incorporates the provisions of the Clean Air Act Amendments of 1990. It is assumed that electricity producers will be granted full flexibility to meet the specified reductions in sulfur dioxide emissions. The reference case excludes any potential environmental actions not currently mandated such as mercury reductions or other rules or regulations not finalized.

Mining Cost Cases

In the reference case, labor productivity is assumed to increase at an average rate of 1.6 percent per year through 2025, while wage rates and mine equipment costs remain constant in 2001 dollars. Two alternative cases were modeled in the NEMS CMM, assuming different growth rates for both labor productivity and miner wages. In a low mining cost sensitivity case, productivity increases at 3.1 percent per year, and real wages and mine equipment costs decline by 0.5 percent per year. In a high mining cost sensitivity case, productivity increases by 0.1 percent per year, and real wages and mine equipment costs increase by 0.5 percent per year. In the alternative cases, the annual growth rates for productivity were increased and decreased by mine type (underground and surface), based on historical variations in labor productivity. Both cases were run as fully integrated NEMS runs.

Table 72. Production, Heat Content, and Sulfur, Mercury and Carbon Dioxide Emissions by Coal Type and Region

Coal Supply Region	States	Coal Rank and Sulfur Level	Mine Type	2000 Production (Million Short tons)	Heat Content (Million Btu per Short Ton)	Sulfur Content (Pounds Per Million Btu)	Mercury Content (Pounds Per Trillion Btu)	CO2 Emissions (Pounds Per Million Btu)
Northern Appalachia	PA, OH, MD, WV (North)	Metallurgical	Underground	4.7	27.43	0.74	N/A	205.4
		Low-Sulfur Bituminous	All	0.4	26.06	0.51	11.62	203.6
		Mid-Sulfur Bituminous	All	72.7	25.54	1.22	11.16	205.4
		High-Sulfur Bituminous	All	61.4	24.28	2.41	11.67	203.6
		Waste Coal (Gob and Culm)	Surface	10.1	12.44	1.72	63.90	203.6
Central Appalachia	KY(East), WV (South), VA	Metallurgical	Underground	47.2	27.43	0.55	N/A	203.8
		Low-Sulfur Bituminous	All	65.9	25.16	0.55	5.61	203.8
		Mid-Sulfur Bituminous	All	145.3	24.94	0.81	7.58	203.8
Southern Appalachia	AL, TN	Metallurgical	Underground	6.8	27.43	0.40	N/A	203.3
		Low-Sulfur Bituminous	All	6.0	25.02	0.56	3.87	203.3
		Mid-Sulfur Bituminous	All	9.1	24.53	1.08	10.15	203.3
East Interior	IL, IN, KY (West), MS	Mid-Sulfur Bituminous	All	30.9	23.02	1.13	5.60	202.8
		High-Sulfur Bituminous	All	56.3	22.78	2.76	6.35	202.5
		Mid-Sulfur Lignite	Surface	0.6	10.59	1.10	14.11	211.4
West Interior	IA, MO, KS, AR, OK. TX (Bit)	High-Sulfur Bituminous	Surface	2.4	22.32	2.59	21.55	202.4
Gulf Lignite	TX (Lig), LA	Mid-Sulfur Lignite	Surface	36.4	12.94	1.32	14.11	211.4
		High-Sulfur Lignite	Surface	16.6	12.67	2.18	15.28	211.4
Dakota Lignite	ND, MT(Lig)	Mid-Sulfur Lignite	Surface	31.6	13.23	1.08	8.38	216.6
Powder River, Green River, and Hannah Basins	WY, MT(Sub)	Low-Sulfur Subbituminous	Surface	345.7	17.51	0.34	5.68	210.7
		Mid-Sulfur Subbituminous	Surface	29.9	17.61	0.78	5.82	210.7
		Low-Sulfur Bituminous	Underground	1.2	21.93	0.51	2.08	204.4
Rocky Mountain	CO, UT	Low-Sulfur Bituminous	Underground	46.6	23.46	0.40	3.82	203.0
		Low-Sulfur Subbituminous	Surface	9.2	20.70	0.41	2.04	210.6
Southwest	AZ, NM	Low-Sulfur Bituminous	Surface	19.6	21.37	0.46	4.66	205.4
		Mid-Sulfur Subbituminous	Surface	20.8	18.52	0.88	7.18	206.7
		Mid-Sulfur Subbituminous	Underground	*	19.80	0.88	7.18	206.7
Northwest	WA, AK	Mid-Sulfur Subbituminous	Surface	5.9	16.32	0.85	6.99	207.9

*Indicates that quantity is less than 50,000 short tons.

N/A = not available.

Source: Energy Information Administration, Form EIA-3, “Quarterly Coal Consumption Report—Manufacturing Plants”; Form EIA-3A, “Annual Coal Quality Report—Manufacturing Plants”; Form EIA-5, “Coke Plant Report Quarterly”; Form EIA-5A, “Annual Coal Quality Report—Coke Plants”; Form EIA-860B, “Annual Electric Generator Report—Nonutility”; Form EIA-6A, “Coal Distribution Report—Annual”; and Form EIA-7A, “Coal Production Report.” Federal Energy Regulatory Commission, Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.” U.S. Department of Commerce, Bureau of the Census, “Monthly Report EM-545.” U.S. Environmental Protection Agency, Emission Standards Division, *Information Collection Request for Electric Utility Steam Generating Unit, Mercury Emissions Information Collection Effort* (Research Triangle Park, NC, 1999). B.D. Hong and E.R. Slatick, “Carbon Dioxide Emission Factors for Coal,” in Energy Information Administration, *Quarterly Coal Report*, January-March 1994, DOE/EIA-0121 (94/Q1) (Washington, DC, August 1995).

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Renewable Fuels Module

The NEMS Renewable Fuels Module (RFM) provides natural resources supply and technology input information for forecasts of new central-station U.S. electricity generating capacity using renewable energy resources. The RFM has five submodules representing various renewable energy sources, biomass, geothermal, landfill gas, solar, and wind; a sixth renewable, conventional hydroelectric power, is represented in the Electricity Market Module (EMM).[119]

Some renewables, such as landfill gas (LFG) from municipal solid waste (MSW) and other biomass materials, are fuels in the conventional sense of the word, while others, such as wind and solar radiation, are energy sources that do not involve the production or consumption of a fuel. Renewable technologies cover the gamut of commercial market penetration, from hydroelectric power, which was an original source of electricity generation, to newer power systems using biomass, geothermal, LFG, solar, and wind energy. In some cases, they require technological innovation to become cost effective or have inherent characteristics, such as intermittency, which make their penetration into the electricity grid dependent upon new methods for integration within utility system plans or upon low-cost energy storage.

The submodules of the RFM interact primarily with the Electricity Market Module (EMM). Because of the high level of integration with the EMM, the final outputs (levels of consumption and market penetration over time) for renewable energy technologies are largely dependent upon the EMM.

Projections for residential and commercial grid-connected photovoltaic systems are developed in the end-use demand modules and not in the RFM; see the Distributed Generation and Combined Heat and Power descriptions in the "Commercial Demand Module" section of the report.

Key Assumptions

Nonelectric Renewable Energy Uses

In addition to projections for renewable energy used in central station electricity generation, the *AEO2003* contains projections of nonelectric renewable energy uses for industrial and residential wood consumption, solar residential and commercial hot water heating, blending in transportation fuels, and residential and commercial geothermal (ground-source) heat pumps. Assumptions for their projections are found in the residential, commercial, industrial, and petroleum marketing sections of this report. Additional minor renewable energy applications occurring outside energy markets, such as direct solar thermal industrial applications or direct lighting, off-grid electricity generation, and heat from geothermal resources used directly (e.g., district heating and greenhouses) are not included in the projections.

Electric Power Generation

The RFM considers only grid-connected central station electricity generation. The RFM submodules that interact with the EMM are the central station grid-connected biomass, geothermal, landfill gas, solar (thermal and photovoltaic), and wind submodules. Most provide specific data or estimates that characterize that resource in a useful manner. In addition, a set of technology cost and performance values is provided directly to the EMM. These values are central to the build and dispatch decisions of the EMM. The values are presented in Table 40. Overnight capital costs and other extended performance characteristics are presented in Table 73.

Conventional Hydroelectricity

The Hydroelectric Power Data File in the EMM represents reported plans for new conventional hydroelectric power capacity connected to the transmission grid and reported on Form EIA-860, *Annual Electric Generator Report*, and Form EIA-867, *Annual Nonutility Power Producer Report*. It does not estimate pumped storage hydroelectric capacity, which is considered a storage medium for coal and nuclear power and not a renewable energy use. However, the EMM allows new conventional hydroelectric capacity to be built in addition to reported plans. Converting Idaho National Engineering and Environmental Laboratory information on U.S. hydroelectric potential, the EMM contains regional conventional hydroelectric supply estimates at increasing capital costs. All the capacity is assumed available at a uniform capacity factor of 45 percent. Data maintained for hydropower include the available capacity, capacity factors, and costs (capital, and fixed and variable operating and maintenance). The fossil-fuel heat rate equivalents for hydropower are provided to the report writer for energy consumption calculation purposes only. Because of hydroelectric power's position in the merit order of generation, it is assumed that all available installed hydroelectric capacity will be used within the constraints of available water supply and general operating requirements (including environmental regulations).

Table 73. Cost and Performance Characteristics for Renewable Energy Generating Technologies: Two Cases

		Total Overnight Costs[1]		Best Available Capacity Factors	
Technology/Decision Year	Overnight Costs in 2001 (Reference) ($2000/kW)	Reference ($2000/kW)	High Renewable ($2000/kW)	Reference (%)	High Renewable (%)
Biomass	1,764				
2005		1,718	1,669	80	80
2010		1,635	1,573	80	80
2015		1,547	1,461	80	80
2020		1,464	1,352	80	80
2025		1,265	1,272	80	80
MSW - Landfill Gas[2]	1,461				
2005		1,451	1,451	90	90
2010		1,436	1,436	90	90
2015		1,420	1,420	90	90
2020		1,404	1,404	90	90
2025		1,388	1,388	90	90
Geothermal[3]	1,766				
2005		1,736	1,498	95	95
2010		1,624	1,236	95	95
2015		1,684	1,218	95	95
2020		1,614	1,240	95	95
2025		1,802	1,240	95	95
Wind	1,004				
2005		997	984	40	42
2010		994	951	41	44
2015		992	919	42	46
2020		990	886	42	47
2025		989	853	42	48
Solar Thermal	2,595				
2005		2,528	2,970	42	52
2010		2,413	3,056	42	63
2015		2,292	2,999	42	75
2020		2,170	2,942	42	77
2025		2,047	2,866	42	77
Photovoltaic	3,460				
2005		2,733	3,260	30	30
2010		2,462	1,686	30	30
2015		2,346	1,466	30	30
2020		2,270	1,246	30	30
2025		2,219	1,142	30	30

[1]Overnight capital cost (i.e.excluding interest charges), plus contingency factors and learning, excluding regional multipliers.

[2]Provided to show evolution of landfill gas costs through 2025; for landfill gas, assumptions in the high renewables case are unchanged from the reference case

[3]Because geothermal cost and performance characteristics are specific for each site, the table entries represent the least cost units available in the Northwest Power Pool region, where most of the proposed sites are located.

Source: Capital Costs: AEO2002 National Energy Modeling System runs: aeo2003.d110502c, hirenew03.d110602b; capacity factors: Energy Information Administration, Office of Integrated Analysis and Forecasting, as described in text in this report for each technology.

Capital Costs

The capital costs of renewable energy technologies are modified to represent two phenomena:

- Short-term cost adjustment factors, which increase technology capital costs as a result of rapid U.S. buildup in a single year, reflect limitations on the infrastructure (for example, manufacturing, resource assessment, construction expertise) to accommodate unexpected demand growth. These short-term factors are invoked when demand for new capacity in any year exceeds 50 percent of the prior year's total U.S. capacity. For every 1 percent increase in total U.S. capacity over the previous year greater than 50 percent, capital costs rise 0.5 percent for wind, 0.33 percent for biomass, and 1 percent for solar technologies.

- For geothermal and wind, higher costs are assumed to result from large cumulative increases in these resources' use, reflecting any or all of three general longer-term costs: (1) resource degradation, (2) transmission network upgrades, and (3) market factors. Presumably best land resources are used first. Increasing resource use necessitates resort to less efficient land - less accessible, less productive, more difficult to use (e.g, land roughness, slope, terrain variability, or productivity, wind turbulence or wind variability). Second, as capacity increases, especially for intermittent technologies like wind power, existing local and long-distance transmission networks require upgrading, increasing overall costs. Third, market pressures from competing land uses increase costs as cumulative capacity increases, including competition from agricultural or other production alternatives, residential or recreational use, aesthetics, or from broader environmental preferences. As a result, for *AEO2003*, each EMM region's wind resource estimates are parceled into five cost levels, 0, 20, 50, 100 and 200 percent respectively. For geothermal, four successive increments incur neither, either, or both of 33 percent increases in the drilling and field cost portions of capital costs and doubling of the relatively small exploration cost component. The size of the resource increments varies by technology and region.

For a description of NEMS algorithms lowering generating technologies' capital costs as more units enter service (learning), see "Technological Optimism and Learning" in the Electricity Market Module section of this report. A detailed description of the RFM is provided in the EIA publication, *Renewable Fuels Module of the National Energy Modeling System, Model Documentation 2003*, DOE/EIA-M069(2003) (Washington, DC, January 2003).

Solar Electric Submodule

Background

The Solar Electric Submodule (SOLES) currently includes both concentrating solar power (thermal) and photovoltaics, including two solar technologies: 50 megawatt central receiver (power tower) solar thermal (ST) and 5 megawatt single axis tracking-flat plate thin-film copper-indium-diselenide (CIS) photovoltaic (PV) technologies. PV is assumed available in all thirteen EMM regions, while ST is available only in the six primarily Western regions where direct normal solar insolation is sufficient. Capital costs for both technologies are determined by EIA using multiple sources, including 1997 technology characterizations by the Department of Energy's Office of Energy Efficiency and Renewable Energy and the Electric Power Research Institute (EPRI).[120] Most other cost and performance characteristics for ST are obtained or derived from the August 6, 1993, California Energy Commission memorandum, *Technology Characterization for ER 94*; and, for PV, from the Electric Power Research Institute, *Technical Assessment Guide (TAG) 1993*. In addition, capacity factors are obtained from information provided by the National Renewable Energy Laboratory (NREL).

Projections for residential and commercial grid-connected photovoltaic systems are developed in the end-use demand modules and not in the RFM; see the Distributed Generation and Cogeneration description in the "Commercial Demand Module" section of the report.

Assumptions

- Capacity factors for solar technologies are assumed to vary by time of day and season of year, such that nine separate capacity factors are provided for each modeled region, three for time of day and for each of three broad seasonal groups (summer, winter, and spring/fall). Regional capacity factors vary from national averages. The current reference case solar thermal annual capacity factor for California, for example, is assumed to average 40 percent; California's current reference case PV capacity factor is assumed to average 24.6 percent.

- Because solar technologies are more expensive than other utility grid-connected technologies, early penetration will be driven by broader economic decisions such as the desire to become familiar with a new technology or environmental considerations. Minimal early years' penetration for such reasons is included by EIA as "floor" additions to new generating capacity (see "Supplemental and Floor Capacity Additions" below).

- Solar resources are well in excess of conceivable demand for new capacity; therefore, energy supplies are considered unlimited within regions (at specified daily, seasonal, and regional capacity factors). Therefore, solar resources are not estimated in NEMS. In the seven regions where ST technology is not modeled, the level of direct, normal insolation (the kind needed for that technology) is insufficient to make that technology commercially viable through 2025.

- NEMS represents the Energy Policy Act of 1992 (EPACT) permanent 10-percent investment tax credit for solar electric power generation by tax-paying entities.

Wind-Electric Power Submodule

Background

Because of limits to windy land area, wind is considered a finite resource, so the submodule calculates maximum available capacity by Electricity Market Module Supply Regions. The minimum economically viable wind speed is about 13 mph, and wind speeds are categorized into three wind classes according to annual average wind speed. The RFM tracks wind capacity (megawatts) within a region and moves to the next best wind class when one category is exhausted. Wind resource data on the amount and quality of wind per EMM region come from a Pacific Northwest Laboratory study and a subsequent update.[121] The technological performance, cost, and other wind data used in NEMS are derived by EIA from consultation with industry experts.[122] Maximum wind capacity, capacity factors, and incentives are provided to the EMM for capacity planning and dispatch decisions. These form the basis on which the EMM decides how much power generation capacity is available from wind energy. The fossil-fuel heat rate equivalents for wind are used for energy consumption calculation purposes only.

Assumptions

- Only grid-connected (utility and nonutility) generation is included. The forecasts do not include off-grid or distributed electric generation.

- In the wind submodule, wind supply is constrained by three modeling measures, addressing (1) average wind speed, (2) distance from existing transmission lines, and (3) resource degradation, transmission network upgrade costs, and market factors.

- Availability of wind power (among three wind classes) is based on the Pacific Northwest Laboratory Environmental and Moderate Land-Use Exclusions Scenario, in which some of the windy land area is not available for siting of wind turbines. The percent of total windy land unavailable under this scenario consists of all environmentally protected lands (such as parks and wilderness areas), all urban lands, all wetlands, 50 percent of forest lands, 30 percent of agricultural lands, and 10 percent of range and barren lands.

- Wind resources are mapped by distance from existing transmission capacity among three distance categories, accepting wind resources within (1) 0-5, (2) 5-10, and (3) 10-20 miles on either side of the transmission lines. Transmission cost factors are added to the resources further from the transmission lines.

- Capital costs for wind technologies are also assumed to increase in response to (1) declining natural resource quality, such as terrain slope, terrain roughness, terrain accessibility, wind turbulence, wind variability, or other natural resource factors, (2) increasing cost of upgrading existing local and network distribution and transmission lines to accommodate growing quantities of intermittent wind power, and (3) market conditions, the increasing costs of alternative land uses, including for aesthetic or environmental reasons. Capital costs are left unchanged for some initial share, then increased 20, 50, 100 percent, and finally 200 percent, to represent the aggregation of these factors. Proportions in each category vary by EMM region.

- Depending on the EMM region, the cost of competing fuels and other factors, wind plants can be built to meet system capacity requirements or as "fuel savers" to displace generation from existing capacity. For wind to penetrate as a fuel saver, its total capital and fixed operations and maintenance costs minus applicable subsidies must be less than the variable operating and fuel costs for existing (non-wind) capacity. When competing in the new capacity market, wind is assigned a capacity credit that declines with increasing market penetration.

- Because of downwind turbulence and other aerodynamic effects, the model assumes an average spacing between turbine rows of 5 rotor diameters and a lateral spacing between turbines of 10 rotor diameters. This spacing requirement determines the amount of power that can be generated from windy land area and is factored into requests for generating capacity by the EMM.

- Capacity factors are assumed to increase, as a function of market penetration, to a national average of about 42 percent in the best wind class resulting from taller towers, more reliable equipment, and advanced control technologies. However, as better wind resources are depleted, capacity factors are assumed to go down.

- *AEO2003* includes the 1.5 (adjusted for inflation to 1.8) cent per kilowatthour Federal production tax credit (PTC) received for the first 10 years of a new wind unit's production; the PTC is applied to all taxpayer-owned wind units entering service from 1993 through 2003. The PTC is represented in NEMS as a 2.8 cent per kilowatthour reduction in required electricity plant revenue in order to more accurately represent its after-tax market value. Although a similar Federal incentive exists for publicly-owned (non tax paying) units, all wind units are assumed owned by taxpaying entities in the RFM.

For *AEO2003*, capacity factors for each wind class are no longer determined outside the model and input, but rather calculated as a function of overall wind market growth. This growth is assumed to be limited to about a 45 percent capacity factor for an average Class 6 site. However, the level of wind growth achieved in the Reference Case results in a final Class 6 capacity factor of 42 percent.

Geothermal-Electric Power Submodule

Background

The Geothermal-Electric Submodule (GES), represents the generating capacity and output potential of 51 hydrothermal resource areas in the Western United States based on updated estimates provided in 1999 by DynCorp Corporation and subsequently modified by EIA.[123] Hot dry rock resources are not considered cost effective until after 2025 and are therefore not modeled in the GES. Both dual flash and binary cycle technologies are represented. The GES distributes the total capacity for each site within each EMM region among four increasing cost categories, with the lowest cost category assigned the base estimated costs, the next assigned higher (double) exploration costs, the third assigned a 33 percent increase in drilling and field costs, and the highest assigned both double exploration and 33 percent increased drilling and field costs. Drilling and field costs vary from site to site but are roughly half the total capital cost (along with plant costs) of new geothermal plants; exploration costs are a relatively minor additional component of capital costs. All quantity-cost groups in each region are assembled into increasing-cost supplies. When a region needs new generating capacity, all remaining geothermal resources available in that region at or below an avoided cost level determined in the EMM are submitted (in three increasing cost subgroups) to compete with other technologies for selection as new generating supply. Geothermal capital costs decline with learning as for other technologies. For estimating costs for building new plants, new dual-flash capacity – the lower cost technology - is assigned an 80 percent capacity factor, whereas binary plants are assigned a 95 percent capacity factor; both are assigned an 87 percent capacity factor for actual generation.

For *AEO2002* and retained in *AEO2003*, the GES was modified and estimates of available supply were reduced. First, to more realistically reflect each of the 51 sites' capacity availability through 2020, the 40-year estimates included for *AEO2001* were reduced, usually to about 100 megawatts for each of four cost levels for each site. Second, annual maximum capacity builds were established for each site, reflecting industry practice of expanding development gradually. For the reference case, each site was permitted a maximum development of 25 megawatts per year through 2015 and 50 megawatts per year thereafter; for the high renewables case, the 50 megawatt annual limit applies to all years.

Assumptions

- Existing and identified planned capacity data are obtained directly by the EMM from Forms EIA-860A (utilities) and EIA-860B (nonutilities) and from supplemental additions (See Below).

- The permanent investment tax credit of 10 percent available in all forecast years based on the EPACT applies to all geothermal capital costs.

- Plants are not assumed to retire unless their retirement is reported to EIA. Geysers units are not assumed to retire but instead have the 35 percent capacity factors reported to EIA reflecting declining performance in recent years.

- Capital and operating costs vary by site and year; values shown in Table 40 are indicative of those used by EMM for geothermal build and dispatch decisions.

Biomass Electric Power Submodule

Background

Biomass consumed for electricity generation is modeled in two parts in NEMS. Capacity in the wood products and paper industries, the so-called captive capacity, is included in the industrial sector module as cogeneration. Generation by the electricity sector is represented in the EMM, with capital and operating costs and capacity factors as shown in Table 40, as well as fuel costs, being passed to the EMM where it competes with other sources. Fuel costs are provided in sets of regional supply schedules. Projections for ethanol are produced by the Petroleum Market Module (PMM), with the quantities of biomass consumed for ethanol decremented from, and prices obtained from, these same supply schedules.

Assumptions

- Existing and planned capacity data are obtained from Forms EIA-860A and EIA-860B.

- The conversion technology represented, upon which the costs in Table 40 are based, is an advanced gasification-combined cycle plant that is similar to a coal-fired gasifier. Costs in the reference case were developed by EIA to be consistent with coal gasifier costs. Short-term cost adjustment factors are used.

- Biomass cofiring can occur up to a maximum of 15 percent of fuel used in coal-fired generating plants.

Fuel supply schedules are a composite of four fuel types; forestry materials, wood residues, agricultural residues and energy crops. The first three are combined into a single supply schedule for each region which does not change for the full forecast period. Energy crops data are presented in yearly schedules from 2010 to 2020 in combination with the other material types for each region. The forestry materials component is made up of logging residues, rough rotten salvable dead wood and excess small pole trees.[124] The wood residue component consists of primary mill residues, silvicultural trimmings and urban wood such as pallets, construction waste and demolition debris that are not otherwise used.[125] Agricultural residues are wheat straw and corn stover only, which make up the great majority of crop residues.[126] Energy crops data are for hybrid poplar, willow and switchgrass grown on crop land, pasture land, or on Conservation Reserve lands.[127] The maximum amount of resources in each supply category is shown in Table 74.

Table 74. U.S. Biomass Resources, by Region and Type, 2025
(Trillion Btu)

	Forest Resources	Urban Wood Waste/ Mill Residue	Energy Crops	Agricultural Residue	Total
1. ECAR	363	156	183	407	1,110
2. ERCOT	29	45	78	57	210
3. MAAC	44	50	19	28	142
4. MAIN	125	36	112	439	712
5. MAPP	191	39	398	946	1,573
6. NPCC/NY	40	63	59	3	165
7. NPCC/NE	81	50	38	0	170
8. SERC/FL	32	42	4	0	79
9. SERC	342	307	217	61	927
10. SPP	225	138	387	264	1,014
11. NWP	414	180	0	53	647
12. W/RA	105	30	6	54	195
13. W/CNV	43	94	0	23	161
Total US	**2,036**	**1,231**	**1,501**	**2,335**	**7,103**

Sources: Urban Wood Wastes/Mill Residues: Antares Group Inc., *Biomass Residue Supply Curves for the U.S (updated),* prepared for the National Renewable Energy Laboratory, June 1999; all other biomass resources: Oak Ridge National Laboratory, personal communication with Marie Walsh, August 20, 1999.

Landfill-Gas-to-Electricity Submodule

Background

Landfill-gas-to-electricity capacity competes with other technologies using supply curves that are based on the amount of "high", "low", and "very low" methane producing landfills located in each EMM region. An average cost-of-electricity for each type of landfill is calculated using gas collection system and electricity generator costs and characteristics developed by EPA's "Energy Project Landfill Gas Utilization Software" (E-PLUS).[128]

Assumptions

- Gross domestic product (GDP) and population are used as the drivers in an econometric equation that establishes the supply of landfill gas.
- Recycling is assumed to account for 35 percent of the total waste stream by 2005 and 50 percent by 2010 (consistent with EPA's recycling goals).
- The waste stream is characterized into three categories: readily, moderately, and slowly decomposable material.
- Emission parameters are the same as those used in calculating historical methane emissions in the EIA's *Emissions of Greenhouse Gases in the United States 2000*[129].

- The ratio of "high", "low", and "very low" methane production sites to total methane production is calculated from data obtained for 156 operating landfills contained in the Government Advisory Associates METH2000 database[130].

- Cost-of-electricity for each site was calculated by assuming each site to be a 100-acre by 50-foot deep landfill and by applying methane emission factors for "high", "low", and "very low" methane emitting wastes.

High Renewables Case

The High Renewables case examines the effect on energy supply of using cost and performance assumptions for nonhydro, non-landfill gas renewable energy technologies approximating published goals of the relevant program offices of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy (DOE/EE). For electric power sector technologies, the High Renewables assumptions are designed to correspond to year 2020 cost and performance goals in the *Renewable Energy Technology Characterizations* document jointly published by the DOE/EE and the Electric Power Research Institute (EPRI). [131] These assumptions, summarized in Table 70, include:

- Biomass: For biomass in the high renewables case, capital costs are modified from reference case values such that they are similar to those in the EE/EPRI *Technology Characterization* costs for biomass gasification by 2025. In addition, biomass supplies are increased 10 percent across all price steps for the four types of biomass. Fixed operations and maintenance costs are reduced about 14 percent to be consistent with *Technology Characterization* costs. Biomass capacity factors are unchanged from the reference case.

- Geothermal: For geothermal in the high renewables case, EIA assumes that (1) capital costs for all 51 sites in 2000 match higher EIA rather than EE *Technology Characterization* estimates for this "base" year, (2) EIA assumptions for capital costs decline at a rate sufficient to match *Technology Characterization* estimates by 2010, meaning that high renewables case assumptions remain higher than DOE/EE assumed costs through 2009 and (3) the lowest cost geothermal site available in 2000 (Roosevelt Hot Springs), would, if available for selection in 2020 (decision year), meet the 2020 *Technology Characterization* capital cost goal in that year, about 36 percent below its current $1800 per kilowatt ($99) cost. Finally, because each of the 51 sites is separately priced, EIA applies the rates (rather than amounts) of capital cost decline necessary for Roosevelt Hot Springs to meet these requirements to all other 50 sites. Overall, each site's capital cost declines by 3 percentage points per decision year from 2000-2010, and by 0.6 percentage point per year from 2011-2020, using the capital cost weights:

Decision Year	Weight
2000	1.00
2005	0.85
2010	0.70
2015	0.67
2020	0.64

Least cost geothermal sites in any case result from the interaction of (a) baseline cost estimates for each site, (b) cost adjustment factors, and (c) increased costs as least-cost units are taken and higher cost sites are chosen. Therefore, in the high renewables case results, actual 2020 marginal capital costs by 2020 will not necessarily be lower than in the reference case but will instead show greater quantities of geothermal available and chosen before again attaining the higher marginal costs.

In the high renewables case, geothermal capacity factors and fixed operations and maintenance costs (O&M) are unchanged from the reference case.

- Photovoltaics (Central Station): For photovoltaics, EIA assumes reduced capital and operations and maintenance costs, corresponding to utility scale flat plate "Thin Film" technology in the EE/EPRI *Technology Characterizations*. Performance is assumed unchanged from the reference case.

- Solar Thermal: For solar thermal in the high renewables case, EIA assumes increased capital costs compared to the reference case, with significantly improved performance (as measured by capacity factor); in addition, operations and maintenance costs are reduced. This corresponds with the Central Receiver (Solar Power Tower) technology in the EE/EPRI *Technology Characterization*, which incorporates, at additional cost, increasing levels of thermal energy storage in the forecast years. To reflect the improved dispatch characteristics of integrated thermal storage, the capacity credit for solar thermal technologies in this case is set equal to the regional capacity factor during the peak load period.

- Wind: EIA assumes reduced capital and operations and maintenance costs, with increased performance (as measured by capacity factor and energy capture per swept rotor area) in all wind classes. The maximum allowable capacity factor is set to 49 percent, and the growth rate parameters are increased to allow the model to achieve capacity factor goals specified in the EE/EPRI *Technology Characterizations*. Because the *Technology Characterizations*, which were published in 1997, substantially underestimate the observed 2002 capital cost range for wind turbines, the capital cost decline used in this case reflects the rate of decline through 2025 implied by the *Technology Characterizations,* but using the Reference Case assumption for current capital cost.

Because costs are assumed to decline (or increase, in the case of Solar Thermal) based on the exogenous cost trajectory of the *Technology Characterizations*, the normal learning function of the EMM does not apply to these capacity types. Thus cost targets are achieved regardless of actual market penetration.

For the high renewables case, demand-side improvements are also assumed in the renewable energy technology portions of residential and commercial buildings, industrial processes, and refinery fuels modules. Details on these assumptions can be found in the corresponding sections of this report.

Legislation

Energy Policy Act of 1992 (EPACT)

The RFM includes the investment tax and energy production credits established in the EPACT for the appropriate energy types. EPACT provides a renewable electricity production tax credit (PTC) of 1.5 cents per kilowatt-hour for electricity produced by wind, applied to plants that become operational between January 1, 1994, and June 30, 1999; *AEO2003* includes extension of the PTC (adjusted for inflation to 1.8 cents) through December 31, 2003, as provided in section 507 of the Tax Relief Extension Act of 1999 as well as by the Job Creation and Worker Assistance Act of 2002. The credit extends for 10 years after the date of initial operation. EPACT also includes provisions that allow an investment tax credit of 10 percent for solar and geothermal technologies that generate electric power. This credit is represented as a 10-percent reduction in the capital costs in the RFM.

Supplemental and Floor Capacity Additions

In addition to capacity projected through the use of the EMM and RFM, including 6.7 gigawatts additional renewables in the electric power sector, 4.3 gigawatts added in the large end-use heat and power sector, and another 900 megawatts in the small end-use sector, *AEO2003* also includes 6,680 megawatts additional renewables generating capacity identified by EIA as entering service through 2025 (Supplemental Additions). Summarized in Table 75 and detailed in Table 76, some of the capacity represents mandated new capacity required by state laws, EIA estimates for expected new capacity under state-enacted renewable portfolio standards (RPS), estimates of winning bids in California's renewables funding program (Assembly Bill 1890), expected new capacity under known voluntary programs, such as "green marketing" efforts, and other publicly stated plans. The additions do not include off-grid or distributed photovoltaics or hydroelectric power.

In addition to the Supplemental Additions, projections also include 75.5 megawatts central station thermal-electric and 332.5 megawatts central station photovoltaic (PV) generating capacity ("Floors") assumed by EIA to be installed for reasons in addition to least-cost electricity supply 2001-2025.

Table 75. Post-2001 Supplemental Capacity Additions (Megawatts, Net Summer Capability)

Rationale	Biomass	Conven-tional Hydro-electric	Geothermal	Landfill Gas	Solar Thermal	Solar Photovoltaic	Wind	Total
Mandates[1]	156.8	0.0	0.0	9.1	0.0	0.0	928.6	1094.5
RenewablePortfolio Standards	198.6	0.0	332.5	545.5	89.0	3.0	2319.5	3488.1
California AB1890[2]	28.5	0.0	47.4	93.7	0.0	0.0	453.9	623.5
Other Reported Plans[3]	28.5	560.0	177.7	168.7	0.0	2.4	537.4	1474.7
Total	412.4	560.0	557.6	816.9	89.0	5.4	4239.3	6679.7

[1]includes mandates and goals.

[2]Partially supported by funding under California Assembly Bill 1890.

[3]Other non mandated plans, including "green marketing" efforts and other activities known to EIA.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, based on publicly available information about specific projects, state renewable portfolio standards, and other plans.

Table 76. Planned 2002+ U.S. Central Station Generating Capacity Using Renewable Resources[1]

Technology	Plant Identification	Program[2]	State	Net Summer Capability (Megawatts)	On-Line Years
Biomass (Including mass-burn waste)	Env. Forest Solutions	Commercial	Arizona	2.9	2002
	Arizona (various)	RPS	Arizona	17.1	2003-2007
	Mesquite Lake	AB1890	California	28.5	2002
	Jacobs Energy	Commercial	Illinois	5.3	2002
	Ware Cogeneration	Commercial	Massachusetts	7.8	2003
	Massachusetts (various)	RPS	Massachusetts	70.3	2003, 2006 2012-2020
	St. Paul Cogen (A)	Mandate	Minnesota	23.8	2002
	St. Paul Cogen (B)	Commercial	Minnesota	7.6	2002
	Fibromin Poultry Litter	Mandate	Minnesota	47.5	2004
	NSP Biomass II	Mandate	Minnesota	23.8	2004
	Beck LLC (Whole Tree)	Mandate	Minnesota	47.5	2005
	New Jersey (various)	RPS	New Jersey	63.7	2005-2016
	Nevada (various)	RPS	Nevada	47.5	2005-2016
	Gorge Energy	Commercial	Washington	5.0	2002
	Five Site Waste-Energy	Mandate	Wisconsin	14.3	2003
Landfill Gas	Arizona (various)	RPS	Arizona	17.1	2003-2007
	California (various)	Commercial	California	22.6	2002
	California (various)	AB1890	California	93.7	2002-2005
	SW Alachua	Commercial	Florida	2.4	2002
	Georgia (various)	Commercial	Georgia	9.1	2002
	Illinois (various)	Commercial	Illinois	16.9	2002
	Com-Ed BioEnergy	Goal	Illinois	5.2	2002
	South Side	Commercial	Indiana	0.3	2002
	Jefferson Davis	Commercial	Louisiana	4.0	2002
	Plainville	Commercial	Massachusetts	5.3	2002
	Massachusetts (various)	RPS	Massachusetts	251.8	2002-2020
	Eastern (White Marsh)	Commercial	Maryland	4.0	2002
	Southeast Berrien County	Commercial	Michigan	4.6	2002
	Spruce Ridge	Commercial	Minnesota	3.0	2003
	Douglas County Landfill	Commercial	Nebraska	3.0	2002
	New Jersey (various)	RPS	New Jersey	136.8	2005-2016
	Broome County Nanticoke	Commercial	New York	0.7	2002
	Blackburn Cogen.	Commercial	North Carolina	1.0	2002
	Glenwillow	Commercial	Ohio	2.7	2002
	Wyandotte	Commercial	Ohio	2.0	2003
	Finley Buttes	Commercial	Oregon	2.0	2003
	Three Mile Canyon Farms	Mandate	Oregon	3.9	2004
	PPL Northern Tier	Commercial	Pennsylvania	0.8	2002
	Pioneer Crossing	Commercial	Pennsylvania	0.3	2003
	Enoree, Phase II	Commercial	South Carolina	1.7	2002

Table 76. Planned 2002+ U.S. Central Station Generating Capacity Using Renewable Resources (Continued)

Technology	Plant Identification	Program[2]	State	Net Summer Capability (Megawatts)	On-Line Years
	Reliant Ennergy	Commercial	Texas	25.5	2002
	Texas (various)	Commercial	Texas	34.9	2002, 2003
	Texas (various)	RPS	Texas	109.4	2003-2020
	Virginia (various)	Commercial	Virginia	16.5	2002
	Ridgeview Recycling	Commercial	Wisconsin	2.4	2002
	Brown County West	Commercial	Wisconsin	3.0	2003
	Wisconsin (various)	RPS	Wisconsin	30.4	2008-2011
Geothermal	Four Mile Hill	AB1890	California	47.4	2004
	Salton Sea Unit 6	Commercial	California	175.8	2005
	Animas	Commercial	New Mexico	1.0	2003
	Empire	Commercial	Nevada	1.0	2003
	Nevada (various)	RPS	Nevada	332.5	2003-2015
Conventional Hydroelectric	Low Impact Hydro Unit	Commercial	Arizona	0.8	2003
	Smithland, Phase I	Commercial	Kentucky	16.0	2004
	Arizona Falls	Commercial	Nebraska	0.7	2002
	Swift Creek Power	Commercial	Wyoming	0.7	2003
Central Station Photovoltaics	Tucson Electric	Commercial	Arizona	1.5	2002
	Salt River Project, I	Commercial	Arizona	0.03	2002
	Salt River Project, II	Commercial	Arizona	0.1	2003
	Arizona (various)	RPS	Arizona	3.0	2007
	LA Dept. Water and Power	Commercial	California	0.8	2003-2005
Solar Thermal	Welton-Mohawk	RPS	Arizona	35.0	2005
	Arizona (various)	RPS	Arizona	4.0	2004-2007
	Nevada (various)	RPS	Nevada	50.0	2005
Wind	Alta Mesa IV	AB1890	California	25.2	2002
	Tehachapi	Commercial	California	0.3	2002
	Cal Wind	AB1890	California	8.7	2002
	McIntosh	AB1890	California	280.0	2003
	McIntosh	AB1890	California	140.0	2005
	Gobblers Knob	Commercial	Colorado	162.0	2003
	Maui Electric	Commercial	Hawaii	20.3	2002
	Clarion-Goldfield School	Commercial	Iowa	0.1	2002
	Eldora-New Prov. School	Commercial	Iowa	0.8	2002
	Hancock County Wind	Mandate	Iowa	91.0	2002
	Turbodynamx (IIT)	Goal	Illinois	0.01	2002
	Crescent Ridge	Goal	Illinois	51.0	2003
	Equinox Mountain	Commercial	Maine	4.6	2002
	Equinox	RPS	Massachusetts	25.0	2003
	Massachusetts (various)	RPS	Massachusetts	765.0	2006-2020
	NSP Mandate Phase IV	Mandate	Minnesota	80.0	2002

Table 76. Planned 2002+ U.S. Central Station Generating Capacity Using Renewable Resources (Continued)

Technology	Plant Name	Program[2]	State	Net Summer Capacity (Megawatts)	On-Line Years
	Dodge County (5 sites)	Mandate	Minnesota	9.5	2002
	Worthington Municipal	Commercial	Minnesota	4.5	2002
	Pipestone County (9 sites)	Mandate	Minnesota	17.0	2002
	JJN Windfarm LLC	Mandate	Minnesota	1.8	2002
	Chanarambie Power	Mandate	Minnesota	85.5	2003
	Murray County (8 sites)	Mandate	Minnesota	12.0	2003
	Navitas Project (Murray)	Mandate	Minnesota	51.0	2003
	Montana Wind Harness	Mandate	Montana	150.0	2003
	Minot	Commercial	North Dakota	2.6	2002
	Petersburg (Valley City)	Commercial	North Dakota	0.9	2002
	Dickey County	Commercial	North Dakota	20.0	2003
	Kimball County Mun.	Commercial	Nebraska	10.5	2002
	New Jersey (various)	RPS	New Jersey	140.0	2001-2016
	Nevada (various)	RPS	Nevada	348.0	2005-2013
	Atlantic Renewable	Mandate	New York	18.0	2002
	Zilhka, Erie County	Mandate	New York	50.0	2003
	Atlantic Ren. (Lewis Cty.)	Mandate	New York	100.0	2003
	Global Wind Harvest I	Mandate	New York	75.0	2003
	Global Wind Harvest II	Mandate	New York	40.5	2003
	York Wind (Chautauqua)	Mandate	New York	51.0	2003
	Condon Part II	Commercial	Oregon	25.2	2002
	Stateline Expansion Part I	Commercial	Oregon	39.6	2002
	Nine Mile Canyon	Commercial	Oregon	48.0	2002
	Stateline Expansion (FPL)	Commercial	Oregon	40.0	2003
	Combine Hills (Umatilla)	Commercial	Oregon	104.0	2003
	Energy Trust 2003	Mandate	Oregon	25.0	2003
	Humbolt Industries	Commercial	Pennsylvania	0.1	2002
	Chamberlain Unit	Commercial	South Dakota	2.6	2002
	Indian Mesa	RPS	Texas	82.5	2002
	Noelke Hills Wind Ranch	RPS	Texas	240.0	2003
	Cielo Austin Energy	Commercial	Texas	25.0	2003
	Texas (various)	RPS	Texas	569.0	2002-2009
	Stateline Expansion Part II	Commercial	Washington	19.8	2002
	Nine Canyon Wind	Commercial	Washington	26.8	2002
	Wisconsin (various)	RPS	Wisconsin	32.0	2008-2011
	Mountaineer Backbone	RPS*	West Virginia	66.0	2002
	PoconoWaymart	RPS*	West Virginia	52.0	2003

[1]includes reported information and EIA estimates for goals, mandates, renewable portfolio standards (RPS), and California Assembly Bill 1890 required renewables.

[2]RPS" represents state renewable portfolio standards; "AB 1890" represents California Assembly Bill 1890; "Mandate" identifies other forms of identified state legal requirements; "Commercial" identifies other new capacity, not know by EIA to be required, including "green marketing" efforts and other voluntary programs and plans. Publicly available information does not always specify whether a project is mandated or a commercial build.

*Located in West Virginia to meet Pennsylvania RPS.

Notes and Sources

[119] For a comprehensive description of each submodule, see Energy Information Administration, Office of Integrated Analysis and Forecasting, *Model Documentation, Renewable Fuels Module of the National Energy Modeling System*, DOE/EIA-M069(2002), (Washington, DC, January 2002).

[120] Electric Power Research Institute and U.S. Department of Energy, Office of Utility Technologies, *Renewable Energy Technology Characterizations* (EPRI TR-109496, December 1997) or www.eren.doe.gov/utilities/techchar.html.

[121] D.L. Elliott, L.L. Wendell, and G.L. Gower, *An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States*, Richland, WA: Pacific Northwest Laboratory, (PNL-7789), prepared for the U.S. Department of Energy under Contract DE-AC06-76RLO 1830, (August 1991); and Schwartz, N.N.; Elliot, O.L.; and Gower, G.L., *Gridded State Maps of Wind Electric Potential Proceedings Wind Power 1992*, (Seattle, WA, October 19-23, 1992).

[122] Energy Information Administration analysts discussed input values with the Electric Power Research Institute, U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, the National Renewable Energy Laboratory, and others.

[123] Dyncorp Corporation, deliverable #DEL-99-548 (Contract #DE-AC01-95-ADF34277), Alexandria, Virginia, July, 1997).

[124] United States Department of Agriculture, U.S. *Forest Service, Forest Resources of the United States, 1992*, General Technical Report RM-234, (Fort Collins CO, June 1994).

[125] Antares Group Inc., *Biomass Residue Supply Curves for the U.S* (updated), prepared for the National Renewable Energy Laboratory, June 1999.

[126] Walsh, M.E., et.al., Oak Ridge National Laboratory, *The Economic Impacts of Bioenergy Crop Production on U.S. Agriculture*, (Oak Ridge, TN, May 2000). http://bioenergy.ornl.gov/papers/wagin/index.html.

[127] Graham, R.L., et.al., Oak Ridge National Laboratory, "The Oak Ridge Energy Crop County Level Database", (Oak Ridge TN, December, 1996).

[128] U.S. Environmental Protection Agency, Atmospheric Pollution Prevention Division, Energy Project Landfill Gas Utilization Software (E-PLUS) Version 1.0, EPA-430-B-97-006 (Washington, DC, January 1997).

[129] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2000*, DOE/EIA-0573(2000) (Washington, DC, November 2001).

[130] Governmental Advisory Associates, Inc., METH2000 Database, Westport, CT, January 25, 2000.

[131] Department of Energy assumptions are obtained or derived from Electric Power Research Institute and U.S. Department of Energy, Office of Utility Technologies, *Renewable Energy Technology Characterizations* (EPRI TR-109496, Dec. 1997) or www.eren.doe.gov/utilities/techchar.html.