Appendix G

Major Assumptions for the Forecasts

The National Energy Modeling System

The projections in the *Annual Energy Outlook 2001* (*AEO2001*) are generated from the National Energy Modeling System (NEMS), developed and maintained by the Office of Integrated Analysis and Forecasting of the Energy Information Administration (EIA). In addition to its use in the development of the *AEO* projections, NEMS is also used in analytical studies for the U.S. Congress and other offices within the Department of Energy. The *AEO* forecasts are also used by analysts and planners in other government agencies and outside organizations.

The projections in NEMS are developed with the use of a market-based approach to energy analysis. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. The time horizon of NEMS is the midterm period, approximately 20 years in the future. In order to represent the regional differences in energy markets, the component models of NEMS function at the regional level: the nine Census divisions for the end-use demand models; production 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 for refineries.

NEMS is organized and implemented as a modular system. 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 between 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 on such areas as economic activity, domestic production activity, and international petroleum supply availability.

The integrating module 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 file. 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, permitting the use of the methodology and level of detail most appropriate for each energy sector. NEMS calls 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 impacts and costs of legislation and environmental regulations that affect that sector and reports key emissions. NEMS represents current legislation and environmental regulations as of July 1, 2000, such as the Clean Air Act Amendments of 1990 (CAAA90) and the costs of compliance with other regulations.

In general, the *AEO2001* projections were prepared by using the most current data available as of July 31, 2000. At that time, most 1999 data were available, but only partial 2000 data were available. Carbon dioxide emissions were calculated by using carbon dioxide coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 1999*, published in October 2000 [*1*].

Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Some definitional adjustments were made to EIA data for the forecasts. For example, the transportation demand sector in *AEO2001* includes electricity used by railroads, which is included in the commercial sector in EIA's consumption data publications. Also, the *State Energy Data Report* classifies energy consumed by independent power producers, exempt wholesale generators, and cogenerators as industrial consumption, whereas *AEO2001* includes cogeneration in the industrial or commercial sector and other nonutility generators in the electricity sector. Footnotes in the appendix tables of this report indicate the definitions and sources of all historical data.

The *AEO2001* projections for 2000 and 2001 incorporate short-term projections from EIA's September 2000 *Short-Term Energy Outlook* (*STEO*). For short-term energy projections, readers are referred to the monthly updates of the *STEO* [*2*].

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.

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 is a kernel regression representation of the Standard and Poor's DRI Macroeconomic Model of the U.S. Economy.

International 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 of NEMS, in response to changes in U.S. import requirements. International petroleum product supply curves, including curves for oxygenates, are also calculated.

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 the changes in the efficiency of energy use for residential end uses and in light-duty vehicle fuel efficiency. Average expenditures estimates are provided for households 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 output 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 that provide the representation of the supply response for biomass (including wood, energy crops, and biomass co-firing), geothermal, municipal solid waste (including landfill gas), solar thermal, solar photovoltaics, and wind energy. The RFM contains natural resource supply estimates representing the regional opportunities for renewable energy development.

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 enhanced oil recovery and unconventional gas recovery from coalbeds and low-permeability formations of sandstone and shale. This framework analyzes cash flow and profitability to compute investment and drilling in 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 and exports with 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 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 noncore 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 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. *AEO2001* reflects legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in 2003 in Arizona, California, Connecticut, Maine, Minnesota, Nebraska, New York, and South Dakota. Because the *AEO2001* reference case assumes current laws and regulations, it assumes that the Federal oxygen requirement for reformulated gasoline in Federal nonattainment areas will remain intact. A new regulation that requires the sulfur content of all gasoline in the United States to be reduced to an annual average of 30 parts per million (ppm) in 2004 and 2007 is also explicitly modeled. Costs include capacity expansion for refinery processing units based on a 15-percent hurdle rate and a 15-percent return on investment. End-use prices are based on the marginal costs of production, plus markups representing product distribution costs, State and Federal taxes, and environmental costs.

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 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.

Major assumptions for the *Annual Energy Outlook 2001*

Table G1 provides a summary of the cases used to derive the *AEO2001* forecasts. For each case, the table gives the name used in this report, a brief description of the major assumptions underlying the projections, a designation of the mode in which the case was run in the NEMS model (either fully integrated, partially integrated, or standalone), and a reference to the pages in the body of the report and in this appendix where the case is discussed.

Assumptions for domestic macroeconomic activity are presented in the “Market Trends” section. The following section describes the key regulatory, programmatic, and resource assumptions that factor into the projections. More detailed assumptions for each sector are available on the Internet at web site www.eia.doe.gov/oiaf/aeo/assumption/. Regional results and other details of the projections are available at web site www.eia.doe.gov/oiaf/aeo/supplement/.

World oil market assumptions

World oil price. The world oil price is assumed to be the annual average acquisition cost of imported crude oils to U.S. refiners. The low, reference, and high price cases reflect alternative assumptions regarding the expansion of production capacity in the nations comprising the Organization of Petroleum Exporting Countries (OPEC), particularly those producers in the Persian Gulf region. The forecast of the world oil price in a given year is a function of OPEC production capacity utilization and the world oil price in the previous year. The three price cases do not assume any disruptions in petroleum supply.

World oil demand. Demand outside the United States is assumed to be total petroleum with no specificity as to individual refined products or sectors of the economy. The forecast of petroleum demand within a region is a Koyck-lag formulation and is a function of world oil price and GDP. Estimates of regional GDPs are from the EIA’s World Energy Projection System (WEPS).

World oil supply. Supply outside the United States is assumed to be total liquids and includes production of crude oils (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, refinery gains, alcohol, and liquids produced from coal and other sources. The forecast of oil supply is a function of the world oil price, estimates of proved oil reserves, estimates of ultimately recoverable oil resources, and technological improvements that affect exploration, recovery, and cost. Estimates of proved oil reserves are provided by the *Oil & Gas Journal* and represent country-level assessments as of January 1, 2000. Estimates of ultimately recoverable oil resources are provided by the United States Geological Survey (USGS) and are part of its “Worldwide Petroleum Assessment 2000.” Technology factors are derived from the DESTINY forecast software and are a part of the International Energy Services of Petroconsultants, Inc.

Table G1. Summary of the *AEO2001* cases

Case name	Description	Integration mode	Reference in text	Reference in Appendix G
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	p. 57	—
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	p. 57	—
Low World Oil Price	World oil prices are $15.10 per barrel in 2020, compared to $22.41 per barrel in the reference case.	Fully integrated	p. 58	—
High World Oil Price	World oil prices are $28.42 per barrel in 2020, compared to $22.41 per barrel in the reference case.	Fully integrated	p. 58	—
Residential: 2001 Technology	Future equipment purchases based on equipment available in 2001. Building shell efficiencies fixed at 2001 levels.	Standalone	p. 69	p. 236
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Existing building shell efficiencies increase by 26 percent from 1997 values by 2020.	Standalone	p. 69	p. 237
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available. Existing building shell efficiencies increase by 26 percent from 1997 values by 2020.	Standalone	p. 69	p. 236
Commercial: 2001 Technology	Future equipment purchases based on equipment available in 2001. Building shell efficiencies fixed at 2001 levels.	Standalone	p. 70	p. 238
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.	Standalone	p. 70	p. 238
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.	Standalone	p. 70	p. 238
Industrial: 2001 Technology	Efficiency of plant and equipment fixed at 2001 levels.	Standalone	p. 71	p. 238
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone	p. 71	p. 238
Transportation: 2001 Technology	Efficiencies for new equipment in all modes of travel are fixed at 2001 levels.	Standalone	p. 71	p. 240
Transportation: High Technology	Reduced costs and improved efficiencies are assumed for advanced technologies.	Standalone	p. 71	p. 240
Consumption: 2001 Technology	Combination of the residential, commercial, industrial, and transportation 2001 technology cases and electricity low fossil technology case.	Fully integrated	p. 49	—
Consumption: High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases, electricity high fossil technology case, and high renewables case.	Fully integrated	p. 49	—

Table G1. Summary of the *AEO2001* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix G
Electricity: Low Nuclear	Relative to the reference case, greater increases in operating costs are assumed to be required after 30 years of operation.	Partially integrated	p. 76	p. 242
Electricity: High Nuclear	Increases in operating costs are smaller than in the reference case.	Partially integrated	p. 76	p. 242
Electricity: Advanced Nuclear Cost 4-Year	New nuclear capacity is assumed to have lower capital costs than in the reference case and the same (4-year) construction lead time.	Partially integrated	p. 77	p. 242
Electricity: Advanced Nuclear Cost 3-Year	New nuclear capacity is assumed to have both lower capital costs than in the reference case and a shorter (3-year) construction lead time.	Partially integrated	p. 77	p. 242
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	p. 77	p. 243
Electricity: Low Fossil Technology	New fossil generating technologies are assumed not to improve over time from 1999.	Partially integrated	p. 78	p. 243
Electricity: High Fossil Technology	Costs and/or efficiencies for advanced fossil-fired generating technologies are assumed to improve from reference case values.	Partially integrated	p. 78	p. 243
Renewables: High Renewables	Lower costs and higher efficiencies are assumed for new renewable generating technologies	Partially integrated	p. 80	p. 244
Oil and Gas: Slow Technology	Cost, finding rate, and success rate parameters adjusted for slower improvement.	Fully integrated	p. 86	p. 245
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate parameters adjusted for more rapid improvement.	Fully integrated	p. 86	p. 245
Oil and Gas: Low Resource	Inferred reserves, technically recoverable undiscovered resources, and unconventional unproved resources are reduced.	Fully integrated	p. 87	p. 245
Oil and Gas: High Resource	Inferred reserves, technically recoverable undiscovered resources, and unconventional unproved resources are increased.	Fully integrated	p. 87	p. 245
Oil and Gas: MTBE Ban	MTBE blended with gasoline is banned from all gasoline by 2004. The Federal requirement for 2.0 percent oxygen in reformulated gasoline is waived.	Standalone	p. 37	p. 247
Coal: Low Mining Cost	Productivity increases at an annual rate of 3.7 percent, compared to the reference case growth of 2.2 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.	Partially integrated	p. 93	p. 248
Coal: High Mining Cost	Productivity increases at an annual rate of 0.6 percent, compared to the reference case growth of 2.2 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.	Partially integrated	p. 93	p. 248

Buildings sector assumptions

The buildings sector includes both residential and commercial structures. The National Appliance Energy Conservation Act of 1987 (NAECA) and the Energy Policy Act of 1992 (EPACT) contain provisions that affect future buildings sector energy use. The most significant are minimum equipment efficiency standards, which require that new heating, cooling, and other specified energy-using equipment meet minimum energy efficiency levels, which change over time. The manufacture of equipment that does not meet the standards is prohibited. Executive Order 13123, "Greening the Government Through Efficient Energy Management," signed in June 1999, is expected to affect future energy use in Federal buildings.

Residential assumptions. The NAECA minimum standards [*3*] for the major types of equipment in the residential sector are:

- Central air conditioners and heat pumps—a 10.0 minimum seasonal energy efficiency ratio for 1992
- Room air conditioners—an 8.7 energy efficiency ratio in 1990, increasing to 9.7 in 2001
- Gas/oil furnaces—a 0.78 annual fuel utilization efficiency in 1992
- Refrigerators—a standard of 976 kilowatthours per year in 1990, decreasing to 691 kilowatthours per year in 1993 and to 483 kilowatthours per year in 2002
- Electric water heaters—a 0.88 energy factor in 1990
- Natural gas water heaters—a 0.54 energy factor in 1990.

The *AEO2001* version of the NEMS residential module is based on EIA's Residential Energy Consumption Survey (RECS) [*4*]. This survey, last conducted in 1997, provides most of the housing stock characteristics, appliance stock information (equipment type and fuel), and energy consumption estimates used to initialize the residential module. The projected effects of equipment turnover and the choice of various levels of equipment energy efficiency are based on tradeoffs between normally higher equipment costs for the more efficient equipment versus lower annual energy costs. Equipment characterizations begin with the minimum efficiency standards that apply, recognizing the range of equipment available with even higher energy efficiency. These characterizations include equipment made available through various green programs, such as the U.S. Environmental Protection Agency (EPA) Energy Star Programs [*5*].

For *AEO2001*, a combined HVAC/shell module replaces the prior methodology for modeling shells in new construction. The new module combines specific heating and cooling equipment with appropriate levels of shell efficiency to model the least expensive ways to meet selected overall efficiency levels. The levels include:

- The current average new house
- The Model Energy Code (MEC95)
- Energy Star Homes using upgraded HVAC equipment and/or shell integrity (combined energy requirements for HVAC must be 30 percent lower than MEC95)
- The PATH home (HUD and DOE's Partnership for Advancing Technology in Housing [*6*])
- A shell intermediate to Energy Star and PATH set to save 40 percent of HVAC energy.

Similar to the choice of end-use equipment, the choice of HVAC/shell efficiency level among the available alternatives is based on a tradeoff between estimated higher initial capital costs for the more efficient combinations and lower estimated annual energy costs.

Also new for *AEO2001*, trends for the average square footage of new construction have been estimated for each Census division and housing type. This change was made to reflect general trends toward increasing square footage in most markets.

In addition to the *AEO2001* reference case, three cases using only the residential module of NEMS were developed to examine the effects of equipment and building shell efficiencies on residential sector energy use:

- The *2001 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2001. Building shell efficiencies are assumed to be fixed at 2001 levels.

- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. Existing building shell efficiencies are assumed to increase by 26 percent over 1997 levels by 2020.

- The *high technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [*7*]. Existing building shell efficiencies are assumed to increase by 26 percent over 1997 levels by 2020.

Commercial assumptions. Minimum equipment efficiency standards for the commercial sector are mandated in the EPACT legislation [*8*]. Minimum standards for representative equipment types are:

- Central air conditioning heat pumps—a 9.7 seasonal energy efficiency rating (January 1994)

- Gas-fired forced-air furnaces—a 0.8 annual fuel utilization efficiency standard (January 1994)

- Fluorescent lamps—a 75.0 lumens per watt lighting efficacy standard for 4-foot F40T12 lamps (November 1995) and an 80.0 lumens per watt efficiency standard for 8-foot F96T12 lamps (May 1994)

- Fluorescent lamp ballasts—a standard mandating electronic ballasts with a 1.17 ballast efficacy factor for 4-foot ballasts holding two F40T12 lamps and a 0.63 ballast efficacy for 8-foot ballasts holding two F96T12 lamps (April 2005 for new lighting systems, June 2010 for replacement ballasts).

Improvements to existing building shells are based on assumed annual efficiency increases. New building shell efficiencies relative to the efficiencies of existing construction vary for each of the 11 building types. The effects of shell improvements are modeled differentially for heating and cooling. For space heating, existing and new shells improve by 4 percent and 6 percent, respectively, by 2020 relative to the 1995 averages.

Among the energy efficiency programs recognized in the *AEO2001* reference case are the expansion of the EPA Green Lights and Energy Star Buildings programs and improvements to building shells from advanced insulation methods and technologies. The EPA green programs are designed to facilitate cost-effective retrofitting of equipment by providing participants with information and analysis as well as participation recognition. Retrofitting behavior is captured in the commercial module through discount parameters for controlling cost-based equipment retrofit decisions in various market segments. To model programs such as Green Lights, which target particular end uses, the *AEO2001* version of the commercial module includes end-use-specific segmentation of discount rates. Federal buildings are assumed to participate in energy efficiency programs and to use the 10-year Treasury Bond rate as a discount rate in making equipment purchase decisions, pursuant to the directives in Executive Order 13123.

The definition of the commercial sector for *AEO2001* is based on data from the 1995 Commercial Buildings Energy Consumption Survey (CBECS) [*9*]. Parking garages and commercial buildings on multibuilding manufacturing sites, included in the previous CBECS, were eliminated from the target building population for the 1995 CBECS. In addition, the CBECS data are estimates based on reported data from representatives of a randomly chosen subset of the entire population of commercial buildings. As a result, the estimates always differ from the true population values and vary from survey to survey. Differences between the estimated values and the actual population values result from both nonsampling errors that would be expected to occur in all possible samples and sampling errors that occur because the survey estimate is calculated from a randomly chosen subset of the entire population [*10*].

Due to the change in the target population and the variability caused by nonsampling and sampling errors, the estimates of commercial floorspace for the 1995 CBECS are lower than previous CBECS estimates. For example, the 1995 CBECS reports 13 percent less commercial floorspace in the United States than was reported in the 1992 CBECS. The most notable effect on *AEO2001* projections is seen in commercial energy intensity. Commercial energy use per square foot reported in *AEO2001* is significantly higher than in *AEO*s before *AEO99*, not because energy consumption is higher but because the 1995 floorspace estimates are lower. The variability between CBECS surveys also results in different estimates of the amount of each major fuel used to provide end-use services such as space heating, lighting, etc., affecting the *AEO2001* projections for fuel consumption within each end use. For example, the 1995 CBECS end-use intensities report more fuel used for heating and less for cooling than the end-use intensities based on the 1992 CBECS.

In addition to the *AEO2001* reference case, three cases using only the commercial module of NEMS were developed to examine the effects of equipment and building shell efficiencies on commercial sector energy use:

- The *2001 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2001. Building shell efficiencies are assumed to be fixed at 2001 levels.
- The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than the reference case [*11*]. Building shell efficiencies are assumed to improve at a rate that is 50 percent faster than the rate of improvement in the reference case.
- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year in the high technology case, regardless of cost. Building shell efficiencies are assumed to improve at a 50 percent faster rate than in the reference case.

Buildings renewable energy. The forecast for wood consumption in the residential sector is based on the RECS. The RECS data provide a benchmark for British thermal units (Btu) of wood energy use in 1997. Wood consumption is then computed by multiplying the number of homes that use wood for main and secondary space heating by the amount of wood used. Ground source (geothermal) heat pump energy consumption is also based on the latest RECS; however, the measure of geothermal energy consumption is represented by the amount of primary energy displaced by using a geothermal heat pump in place of an electric resistance furnace. Residential and commercial solar thermal energy consumption for water heating is represented by displaced primary energy relative to an electric water heater. Residential and commercial solar photovoltaic systems are discussed in the distributed generation section that follows.

Buildings distributed generation. Distributed generation includes photovoltaics and fuel cells for both the residential and commercial sectors, as well as microturbines and conventional combined heat and power technologies for the commercial sector. The forecast of distributed generation is developed on the basis of economic returns projected for investments in distributed generation technologies. The model uses a detailed cash-flow approach for each technology to estimate the number of years required to achieve a cumulative positive cash flow (although some technologies may never achieve a cumulative positive cash flow). Penetration rates are estimated by Census division and building type and vary by building vintage (newly constructed versus existing floorspace). For purchases not related to specific programs, penetration rates are determined by the number of years required for an investment to show a positive economic return: the more quickly costs are recovered, the higher the technology penetration rate. Solar photovoltaic technology specifications for the residential and commercial sectors are based on a joint U.S. Department of Energy and Electric Power Research Institute report published in December 1997. Program-driven installations of photovoltaic systems are based on information from DOE's Photovoltaic and Million Solar Roofs programs, as well as DOE news releases and the Utility PhotoVoltaic Group web site. The program-driven installations incorporate some of the non-economic considerations and local incentives that are not captured in the cash flow model.

Industrial sector assumptions

The manufacturing portion of the industrial sector has been recalibrated to be consistent with the data in EIA's *Manufacturing Consumption of Energy 1994* [*12*]. Compared to the building sector, there are relatively few regulations that target industrial sector energy use. The electric motor standards in EPACT require a 10-percent increase in efficiency above 1992 efficiency levels for motors sold after 1999 [*13*]. It has been estimated that electric motors account for about 60 percent of industrial process electricity use. Thus, these standards, incorporated into the Industrial Demand Module through the analysis of efficiencies for new industrial processes, are expected to lead to significant improvements in efficiency.

High technology and 2001 technology cases. The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*14*]. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changing composition of industrial output. Because the composition of industrial output remains the same as in the reference case, aggregate intensity falls by 1.5 percent annually. In the reference case, aggregate intensity falls by 1.4 percent annually between 1999 and 2020. The *2001 technology case* holds the energy efficiency of plant and equipment constant at the 2001 level over the forecast. Both cases were run with only the Industrial Demand Module rather than as fully integrated NEMS runs. Consequently, no potential feedback effects from energy market interactions were captured.

Transportation sector assumptions

The transportation sector accounts for two-thirds of the Nation's oil use and has been subject to regulations for many years. The Corporate Average Fuel Economy (CAFE) standards, which mandate average miles-per-gallon standards for manufacturers, continue to be widely debated. The *AEO2001* projections assume that there will be no further increase in the CAFE standards from the current 27.5 miles per gallon standard for automobiles and 20.7 miles per gallon for light trucks and sport utility vehicles. This assumption is consistent with the overall policy that only current legislation is assumed.

EPACT requires that centrally fueled light-duty fleet operators—Federal and State governments and fuel providers (e.g., gas and electric utilities)—purchase a minimum fraction of alternative-fuel vehicles [*15*]. Federal fleet purchases of alternative-fuel vehicles must reach 50 percent of their total vehicle purchases by 1998 and 75 percent by 1999. Purchases of alternative-fuel vehicles by State governments must reach 25 percent of total purchases by 1999 and 75 percent by 2001. Private fuel-provider companies are required to purchase 50 percent alternative-fuel vehicles in 1998, increasing to 90 percent by 2001. Fuel provider exemptions for electric utilities are assumed to follow the electric utility provisions, beginning in 1998 at 30 percent and reaching 90 percent by 2001. The municipal and private business fleet mandates, which are proposed to begin in 2002 at 20 percent and scale up to 70 percent by 2005, are not included in *AEO2001*.

In addition to these requirements, the State of California has recently upheld its Low Emission Vehicle Program, which requires that 10 percent of all new vehicles sold by 2003 meet the requirements for zero-emission vehicles (ZEVs). California recently passed legislation to allow 60 percent of the ZEV mandate to be met by ZEV credits from advanced technology vehicles, depending on their degree of similarity to electric vehicles. The remaining 40 percent of the ZEV mandate must be achieved with "true ZEVs," which include only electric vehicles and hydrogen fuel cell vehicles [*16*]. Originally, Massachusetts and New York, and more recently Maine and Vermont, also adopted the California program. The projections currently assume that California, Massachusetts, New York, Maine, and Vermont will formally begin the Low Emission Vehicle Program in 2003.

Technology choice. Conventional light-duty vehicle technologies are chosen by consumers and penetrate the market based on the assumption of cost-effectiveness, which compares the capital cost to the discounted stream of fuel savings from the technology. There are approximately 52 fuel-saving technologies, which vary by capital cost, date of availability, marginal fuel efficiency improvement, and marginal horsepower effect [*17*]. The projections assume that the regulations for alternative-fuel and advanced technology vehicles represent minimum requirements for alternative-fuel vehicle sales; consumers are allowed to purchase more of the vehicles if their cost, fuel efficiency, range, and performance characteristics make them desirable.

For freight trucks, technology choice is based on several technology characteristics, including capital cost, marginal fuel improvement, payback period, and discount rate, which are used to calculate a fuel price at which the technologies become cost-effective [*18*]. When the fuel price exceeds this price, the technology will begin to penetrate the market. When technologies are mutually exclusive, the more cost-effective technology will gain market share relative to the less cost-effective technology. Efficiency improvements for both rail and ship are based on recent historical trends [*19*].

Similar to freight trucks, fuel efficiency improvements for new aircraft are also determined by a trigger fuel price, the time the technology becomes commercially available, and the projected marginal fuel efficiency improvement. The advanced technologies are ultra-high bypass, propfan, thermodynamics, hybrid laminar flow, advanced aerodynamics, and weight-reducing materials [*20*].

Travel. Projections for both personal travel [*21*] and freight travel [*22*] are based on the assumption that modal shares (for example, personal automobile travel versus mass transit) remain stable over the forecast and follow recent historical patterns. Important factors affecting the forecast of vehicle-miles traveled for light-duty vehicles are personal disposable income per capita; the ratio of miles driven by females to males in the total driving population, which increases from 56 percent in 1990 to 80 percent by 2010; and the aging of the population, which will slow the growth in vehicle-miles traveled. The projections incorporate recent data indicating that retirees are driving far more than retirees of a decade ago.

Travel by freight truck, rail, and ship is based on the growth in industrial output by sector and the historical relationship between freight travel and industrial output [*23*]. Both rail and ship travel are also based on projected coal production and distribution. Air travel is estimated for domestic travel (both personal and business), international travel, and dedicated air freight shipments by U.S. carriers. Depending on the market segment, the demand for air travel is based on projected disposable personal income, GDP, merchandise exports, and ticket price as a function of jet fuel prices. Load factors, which represent the percentage of seats occupied per plane and are used to convert air travel (expressed in revenue-passenger miles and revenue-ton miles) to seat-miles of demand, remain relatively constant over the forecast period [*24*].

Energy efficiency programs. Four energy efficiency programs focus on transportation energy use: (1) reform Federal subsidy for employer-provided parking; (2) adopt a transportation system efficiency strategy; (3) promote telecommuting; and (4) develop fuel economy labels for tires. The assumed combined effect of the Federal subsidy, system efficiency, and telecommuting policies in the *AEO2001* reference case is a 1.6-percent reduction in vehicle-miles traveled by 2010. The fuel economy tire labeling program improved new fuel efficiency by 4 percent among pre-1999 vehicles that switched to low rolling resistance tires.

2001 technology case. The *2001 technology case* assumes that new fuel efficiency levels are held constant at 2001 levels through the forecast horizon for all modes of travel.

High technology case. For the *high technology case*, light-duty alternative-fuel vehicle characteristics originate from the DOE Office of Energy Efficiency and Renewable Energy, and conventional light-duty vehicle fuel-saving technology characteristics are from the American Council for an Energy-Efficient Economy [*25*]. New technologies in this case include a high-efficiency advanced light-duty direct injection diesel vehicle with attributes similar to gasoline engines; electric and electric hybrid (gasoline and diesel) vehicles with higher efficiencies, lower costs, and earlier introduction dates than in the reference case; and fuel cell gasoline, methanol, and hydrogen light-duty vehicles. In the air travel sector, the high technology case assumes 40-percent efficiency improvement from new aircraft technologies by 2020, as concluded by the Aeronautics and Space Engineering Board of the National Research Council. Based on an analysis by the Federal Aviation Administration, the case also assumes an additional 5-percent fleet efficiency improvement from the Air Traffic Management program.

In the freight truck sector, the high technology case assumes more optimistic costs and incremental fuel efficiency improvements for tires (existing and advanced), drag reduction (existing and advanced), advanced transmissions, lightweight materials, synthetic gear lube, electronic engine control, advanced engines, turbo-compounding, hybrid power trains, and port injection [*26*]. More optimistic assumptions for fuel efficiency improvements are also made for the rail and shipping sectors.

Both cases were run with only the Transportation Demand Module rather than as fully integrated NEMS runs. Consequently, no potential macroeconomic feedback on travel demand was captured, nor were changes in fuel prices.

Electricity assumptions

Characteristics of generating technologies. The costs and performance of new generating technologies are important factors in determining the future mix of capacity. There are 29 fossil, renewable, and nuclear generating technologies included in the *AEO2001* projections. Technologies represented include those currently available as well as those that are expected to be commercially available within the horizon of the forecast. Capital cost estimates and operational characteristics, such as efficiency of electricity production, are used for decisionmaking. It is assumed that the selection of new plants to be built is based on least cost, subject to environmental constraints. The incremental costs associated with each option are evaluated and used as the basis for selecting plants to be built. Details about each of the generating plant options are described in the detailed assumptions, which are available on the Internet at web site www.eia.doe.gov/oiaf/aeo/assumption/.

Regulation of electricity markets. It is assumed that electricity producers comply with CAAA90, which mandates a limit of 8.95 million short tons of sulfur dioxide emissions per year by 2010. Utilities are assumed to comply with the limits on sulfur dioxide 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. The costs for FGD equipment average approximately $195 per kilowatt, in 1999 dollars, although they vary widely across the regions. It is also assumed that the market for trading emissions allowances is allowed to operate without regulation and that the States do not further regulate the selection of coal to be used.

The EPA has issued rules to limit emissions of nitrogen oxide, specifically calling for capping emissions during the summer season in 22 eastern and midwestern States. After an initial challenge, the rules have been upheld, and emissions limits have been finalized for 19 States. In NEMS, electricity generators in those 19 States must comply with the limit either by reducing their own emissions or purchasing allowances from others.

The reference case assumes a transition to full competitive pricing in California, New York, New England, the Mid-Atlantic Area Council, and Texas. In addition, electricity prices in the East Central Area Reliability Council, the Mid-America Interconnected Network, the Southwest Power Pool, and the Rocky Mountain Power Area/ Arizona (Arizona, New Mexico, Colorado, and eastern Wyoming) regions are assumed to be partially competitive. 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. In many deregulated States the legislation has mandated price freezes or reductions over a specified transition period. *AEO2001* includes such agreements in the electricity price forecast. In general, the transition period is assumed to be a 10-year period from the beginning of restructuring in each region, during which prices gradually shift to competitive prices. The transition period reflects the time needed for the establishment of competitive market institutions and recovery of stranded costs as permitted by regulators. The reference case assumes that the competitive price in these regions will be the marginal cost of generation.

Competitive cost of capital. The cost of capital is calculated as a weighted average of the costs of debt and equity. *AEO2001* assumes a ratio of 50 percent debt and 50 percent equity. The yield on debt represents that of an AA corporate bond, and the cost of equity is calculated to be representative of unregulated industries similar to the electricity generation sector. Furthermore, it is assumed that the capital invested in a new plant must be recovered over a 20-year plant life rather than the traditional 30-year life.

Energy efficiency and demand-side management. Improvements in energy efficiency induced by growing energy prices, new appliance standards, and utility demand-side management programs are represented in the end-use demand models. Appliance choice decisions are a function of the relative costs and performance characteristics of a menu of technology options. Utilities reported spending more than $1.4 billion for demand-side management programs in 1998.

Representation of utility Climate Challenge participation agreements. As a result of the Climate Challenge Program, many utilities have announced efforts to reduce their greenhouse gas emissions voluntarily. These efforts cover a wide variety of programs, including increasing demand-side management investments, repowering (fuel-switching) fossil plants, restarting nuclear plants that have been out of service, planting trees, and purchasing emissions offsets from international sources.

To the degree possible, each of the participation agreements was examined to determine whether the commitments made were addressed in the normal reference case assumptions or whether they were addressable in NEMS. Programs such as tree planting and emissions offset purchasing are not addressable in NEMS. The other programs are, for the most part, captured in NEMS. For example, utilities annually report to EIA their plans (over the next 10 years) to bring a plant back on line, repower a plant, extend a plant's life, cancel a previously planned plant, build a new plant, or switch fuel at a plant. Data for these programs are included in the NEMS input data. However, because many of the agreements do not identify the specific plants where action is planned, it is not possible to determine which of the specified actions, together with their greenhouse gas emissions savings, should be attributed to the Climate Challenge Program and which are the result of normal business operations.

Nuclear power. There are no nuclear units actively under construction in the United States. In NEMS, new nuclear plants are competed against other options when new capacity is needed.

It is assumed that the cost of operating older nuclear power plants will increase as they age. Aging-related cost increases could result from increased capital costs, decreases in performance, and/or increased maintenance expenditures to mitigate the effects of aging. The decision to retire a plant is based on the relative economics of the alternatives. In *AEO2001*, the retirement decision for each nuclear unit is evaluated every 10 years, starting after 30 years of operation. It is assumed that operating costs remain level until 30 years of age, at which point they increase by $0.25 per kilowatt per year over the next 10 years. At age 40 the costs increase by $13.50 per kilowatt per year for 10 years, and after 50 years costs increase by about $25 per kilowatt per year. If the newly projected operating costs are lower than the cost of building new capacity, then the nuclear unit continues to operate for another 10 years, until the next evaluation.

The cost increases at plants that have recently incurred a major expenditure (such as a steam generator replacement) are assumed to be 50 percent lower at 30 years and 75 percent lower at 40 years. The same adjustments were made for the newest vintage of nuclear reactors, to reflect improvements in construction and design. An adjustment was also made for the fact that if a plant continues to operate, a portion of the decommissioning costs would be deferred.

Two alternative cases were developed to incorporate the effects of uncertainty about the aging process. In the *low nuclear case* the capital investment was increased to $5 per kilowatt per year from 30 to 40 years. In the *high nuclear case* the aging-related cost increases were assumed to be 25 percent of those in the reference case. These are partially integrated cases, with no feedback from the macroeconomic, international, or end-use demand models.

The average nuclear capacity factor in 1999 was 85 percent, the highest annual average ever in the United States. The average annual capacity factor generally increases throughout the forecast, to a maximum of about 90 percent. Capacity factor assumptions are developed at the unit level, and improvements or decrements are based on the age of the reactor.

For nuclear power plants, a pair of *advanced nuclear cost cases* were used to analyze the sensitivity of the projections to lower costs and construction times for new plants. The cost assumptions for the two cases were consistent with goals endorsed by DOE's Office of Nuclear Energy for Generation III nuclear power plants, including progressively lower overnight construction costs—by 25 percent initially compared with the reference case and by 33 percent in 2020—and shorter lead times. The overnight capital cost of a new advanced nuclear unit is assumed to be $1,500 per kilowatt initially, declining to $1,200 per kilowatt by 2015. The cost assumptions were based on the technology represented by the Westinghouse AP600 advanced passive reactor design. One case assumed a 4-year construction time, as in the reference case, and the other a 3-year lead time, the goal of the Office of Nuclear Energy. Cost and performance characteristics for all other technologies were as assumed in the reference case. These are partially integrated cases, with no feedback from the macroeconomic, international, or end-use demand models.

Fossil steam plant retirement assumptions. Fossil steam plants are retired when it is no longer economical to run them. Each year the model determines whether the market price of electricity is sufficient to support the continued operation of existing plants. If the revenue a plant receives is not sufficient to cover its forward costs (including fuel, operations and maintenance costs, and assumed annual capital additions) the plant is retired.

Biomass co-firing. Coal-fired power plants are allowed to co-fire with biomass fuel if it is economical. Individual plants are assumed to be able replace up to 5 percent of their total consumption with biomass, assuming that sufficient residue fuel is available in the State where the plant is located. Because of regional limitations on available biomass supply, the maximum national average co-firing share throughout the forecast is assumed to be 4 percent.

Distributed generation. *AEO2001* assumes the availability of two generic technologies for distributed electricity generation, as discussed in "Issues in Focus," page 38. To determine the levels of capacity and generation for distributed technologies projected to be used in the forecast, the model compares their costs with the "avoided costs" of electricity producers. The avoided costs are the costs electricity producers would incur if they added the least expensive conventional central station generators rather than distributed generators, as well as the costs of additional transmission and distribution equipment that would be required if the distributed generators were not added. Because there are currently no reliable estimates of the transmission and distribution costs that can be avoided by adding distributed generators, regional estimates were developed for the transmission and distribution investments that would be needed for each kilowatt of central station generating capacity added. It was then assumed that 50 percent of such "growth related" transmission and distribution costs could be avoided by adding distributed generators. In order to account for the uncertainty in the projections for delivered costs of natural gas, it was assumed that distributed generators would pay a premium of 20 cents per million Btu above the price incurred by electricity producers.

International learning. For *AEO2001*, capital costs for all new fossil-fueled electricity generating technologies decrease in response to foreign as well as domestic experience, to the extent that the new plants reflect technologies and firms also competing in the United States. *AEO2001* includes 2,524 megawatts of advanced coal gasification combined-cycle capacity and 5,244 megawatts of advanced combined-cycle natural gas capacity to be built outside the United States from 2000 through 2003.

High electricity demand case. The *high electricity demand case* assumes that the demand for electricity grows by 2.5 percent annually between 1999 and 2020, compared with 1.8 percent in the reference case. No attempt was made to determine changes in the end-use sectors that would result in the stronger demand growth. The high electricity demand case is partially integrated, with no feedback from the macroeconomic, international, or end-use demand models. Rapid growth in electricity demand also leads to higher prices. The price of electricity in 2020 is 6.4 cents per kilowatthour in the high demand case, as compared with 6.0 cents in the reference case. Higher fuel prices, especially for natural gas, are the key factor leading to higher electricity prices.

High and low fossil technology cases. The high and low fossil technology cases are partially integrated cases, with no feedback from the macroeconomic, international, or end-use demand models. In the *high fossil technology case*, capital costs and/or heat rates for coal gasification combined-cycle units, molten carbonate fuel cell units, and advanced combustion turbine and combined-cycle units are assumed to be lower and decline faster than in the reference case. The capital costs and heat rates for renewable, nuclear, and other fossil technologies are assumed to be the same as in the reference case. The values used in the high fossil case for capital costs and heat rates were based on the Vision 21 program for new generating technologies, developed by DOE's Office of Fossil Energy. In the *low fossil technology case*, capital costs and heat rates for coal gasification combined-cycle units, molten carbonate fuel cell units, and advanced combustion turbine and combined-cycle units do not decline during the forecast period and remain fixed at the 1999 values assumed in the reference case. Details about annual capital costs, operating and maintenance costs, plant efficiencies, and other factors used in these assumptions are described in the detailed assumptions, which are available on the Internet at web site www.eia.doe.gov/oiaf/aeo/assumption/.

Renewable fuels assumptions

Energy Policy Act of 1992. The EPACT 10-year renewable electricity production credit of 1.5 cents per kilowatthour for new wind plants originally expired on June 30, 1999, but was extended through December 1, 2001. *AEO2001* applies the credit to all wind plants built through 2001 [*27*]. The 10-percent investment tax credit for solar and geothermal technologies that generate electric power is continued.

Supplemental additions. AEO2001 includes 5,356 megawatts of new central station generating capacity using renewable resources, as reported by utilities and independent power producers or identified by EIA to be built from 2000 through 2020, including 3,130 megawatts of wind capacity, 1,186 megawatts of landfill gas capacity, 856 megawatts of biomass capacity (excluding co-firing capacity, which is included with coal), 117 megawatts of geothermal steam capacity, and 67 megawatts of central station solar capacity (thermal and photovoltaic). It includes the 5,065 megawatts expected to be added after 1999 as a result of State renewable portfolio standards (RPS) and other mandates plus an additional 291 megawatts expected to result from voluntary initiatives by utilities and other generators. In instances where a State RPS defines the percentage of State electricity supply to be reached by renewables before 2020, the additional renewables capacity needed to maintain the percentage through 2020 is estimated. EIA does not estimate new renewables capacity for States highly uncertain of the technologies likely to be chosen.

Renewable resources. Although conventional hydroelectricity is the largest source of renewable energy in U.S. electricity markets today, the lack of available new sites, environmental and other restrictions, and costs are assumed to halt the expansion of U.S. hydroelectric power. Solar, wind, and geothermal resources are theoretically very large, but economically accessible resources are much less available.

Solar energy (direct normal insolation) for thermal applications is considered economical only in drier regions west of the Mississippi River. Photovoltaics can be economical in all regions, although conditions are also superior in the West. Wind energy resource potential, while large, is constrained by wind quality differences, distance from markets, power transmission costs, alternative land uses, and environmental objections. The geographic distribution of available wind resources is based on work by the Pacific Northwest Laboratory [*28*], enumerating winds among average annual wind-power classes. Geothermal energy is limited geographically to regions in the western United States with hydrothermal resources of hot water and steam. Although the potential for biomass is large, transportation costs limit the amount of the resource that is economically productive, because biomass fuels have a low thermal conversion factor (Btu content per weight of fuel).

The *AEO2001* reference case incorporates capital cost adjustment factors (proxies for supply elasticities) for biomass, geothermal, and wind technologies, in recognition of the higher costs of consuming increasing proportions of a region's resources. Capital costs are assumed to increase in response to (1) declining natural resource quality, such as rough or steep terrain or turbulent winds, (2) increasing costs of upgrading the existing transmission and distribution network, and (3) market conditions that increase wind costs in competition with other land uses, such as for crops, recreation, or environmental or cultural preferences. These factors have no effect on the *AEO2001* reference case results but can affect results in cases assuming rapid growth in demand for renewable energy technologies.

AEO2001 features new forecasting submodules for geothermal and landfill gas technologies. The revised geothermal submodule develops regional geothermal technology supply functions based on cost and performance characteristics of 51 known geothermal resource areas in the Western United States and Hawaii [*29*]. A new landfill gas submodule allows new landfill gas facilities to compete economically with other generating technologies, using supply curves estimating landfill methane production by region.

High renewables case. For the *high renewables case*, greater improvements are assumed for central station nonhydroelectric generating technologies using renewable resources than in the reference case, including capital costs falling below reference case estimates by 2020 or to approximate DOE's Office of Energy Efficiency and Renewable Energy December 1997 *Renewable Energy Technology Characterizations* [*30*] or more recently stated goals. This case also incorporates reduced operations and maintenance costs, improvements in capacity factors for wind technologies, and increased biomass supplies. Other generating technologies and forecast assumptions remain unchanged from the reference case. The case also includes similarly lower capital costs for residential and commercial distributed (demand side) photovoltaic systems. This is a partially integrated case, with no feedback from the macroeconomic, international, or demand models other than buildings.

Oil and gas supply assumptions

Domestic oil and gas technically recoverable resources. The levels of available oil and gas resources assumed for *AEO2001* are based on estimates of the technically recoverable resource base from the U.S. Geological Survey (USGS) and the Minerals Management Service (MMS) of the Department of the Interior, with supplemental adjustments to the USGS nonconventional resources by Advanced Resources International (ARI), an independent consulting firm. Resources for the Gulf of

Mexico were also adjusted on the basis of estimates in a December 1999 report by the National Petroleum Council [*31*].

Technological improvements affecting recovery and costs. Productivity improvements are simulated by assuming that drilling, success rates, and finding rates will improve and the effective cost of supply activities will be reduced. The assumed increase in recovery is due to the development and deployment of new technologies, such as three-dimensional seismology and horizontal drilling and completion techniques.

Drilling, operating, and lease equipment costs are expected to decline due to technological progress, at econometrically estimated rates that vary somewhat by cost and fuel categories, ranging roughly from 0.5 percent to 2.0 percent. These technological impacts work against increases in costs associated with drilling to greater depths, higher drilling activity levels, and rig availability. Success rates are assumed to improve by 6.7 to 8.5 percent per year, and finding rates are expected to improve by 4.2 to 6.9 percent per year because of technological progress.

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, conventional oil and natural gas reference case parameters for the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates were adjusted by plus or minus 25 percent. For unconventional gas, a number of key exploration and production technologies were also adjusted by plus or minus 25 percent in the *rapid and slow technology cases*. Key Canadian supply parameters were adjusted to simulate the assumed impacts of rapid and slow oil and gas technology penetration on Canadian supply potential.

Two impacts of technology improvements were modeled to determine the economics for development of inferred enhanced oil recovery reserves: (1) an overall reduction in the costs of drilling, completing, and equipping production wells and (2) the field-specific penetration of horizontal well technology. The corresponding cost decline and penetration rates assumed in the reference case were varied to reflect slower and more rapid penetration for the technology cases. The remaining undiscovered recoverable resource base determined to be technically amenable to gas miscible recovery methods was assumed to increase over the forecast period with advances in technology, at assumed rates dependent on the region and the technology case.

All other parameters in the model were kept at the reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of liquefied natural gas and natural gas trade between the United States and Mexico. Specific detail by region and fuel category is presented in the *Assumptions to the Annual Energy Outlook 2001*, which is available on the Internet at web site at www.eia.doe.gov/oiaf/aeo/assumption/.

High and low resource cases. To demonstrate the sensitivity of the *AEO2001* results to underlying assumptions about the size of the oil and gas resource base, *high and low resource cases* were created by adjusting the assumed size of the oil and gas resource base by a percentage across all regions. As in the other *AEO2001* cases, resources in areas restricted from exploration and development are not included in the resource base in these cases. For conventional onshore and offshore resources, estimates of both undiscovered technically recoverable resources and inferred reserves were adjusted by plus or minus 20 percent. Because the estimates for unconventional gas resources are even more uncertain, the unproved resource estimates for unconventional gas recovery were adjusted by plus and minus 40 percent in the high and low resource cases, respectively. Thus, the assumed levels of technically recoverable natural gas resources, including proved reserves, were 1,583 trillion cubic feet in the high resource case and 979 trillion cubic feet in the low resource case, as compared with 1,281 trillion cubic feet in the reference case. The assumed levels of technically recoverable crude oil resources were 165 billion barrels in the high resource case, 144 billion barrels in the reference case, and 122 billion barrels in the low resource case. The recoverable volumes assumed for the high and low resource cases were specified to exhibit significant variation in this key assumption without exceeding a reasonable range. The high and low resource cases should not be construed as extreme cases that would be expected to bound most, if not all, feasible projections.

Methane capture. The *AEO2001* projections include a program started in 1995 to promote the capture of methane from coal mining activities to reduce carbon dioxide emissions. The captured methane is assumed to be marketed as part of the domestic natural gas supply, reaching production levels of 29 billion cubic feet in 2010 and 35 billion cubic feet in 2020.

Leasing and drilling restrictions. The projections of crude oil and natural gas supply assume that current restrictions on leasing and drilling will continue to be enforced throughout the forecast period. At present, drilling is prohibited along the entire East Coast, the west coast of Florida, and the West Coast except for the area off Southern California. In Alaska, drilling is prohibited in a number of areas, including the Arctic National Wildlife Refuge. The projections also assume that coastal drilling activities will be reduced in response to the restrictions of CAAA90, which requires that offshore drilling sites within 25 miles of the coast, with the exception of areas off Texas, Louisiana, Mississippi, and Alabama, meet the same clean air requirements as onshore drilling sites.

Gas supply from Alaska and LNG imports. The Alaska Natural Gas Transportation System is assumed to come on line no earlier than 2009 and only after the U.S.-Canada border price reaches $3.99 (in 1999 dollars) per thousand cubic feet. The liquefied natural gas (LNG) facilities at Everett, Massachusetts, and Lake Charles, Louisiana (the only ones currently in operation) have a combined operating capacity of 359 billion cubic feet per year, including a 1999 expansion of 48 billion cubic feet at the Massachusetts facility. LNG facilities at Elba Island, Georgia, and Cove Point, Maryland, are assumed to reopen in 2003, bringing maximum sustainable operating capacity to 840 billion cubic feet per year.

Natural gas transmission and distribution assumptions. Transportation rates for pipeline services are calculated with the assumption that the costs of new pipeline capacity will be rolled into the existing ratebase. The rates based on cost of service are adjusted according to pipeline utilization, to reflect a more market-based approach.

In determining interstate pipeline tariffs, capital expenditures for refurbishment over and above those included in operations and maintenance costs are not considered, nor are potential future expenditures for pipeline safety. (Refurbishment costs include any expenditures for repair or replacement of existing pipe.) Distribution markups to core customers (not including electricity generators) change over the forecast in response to changes in consumption levels and in the costs of capital and labor.

The vehicle natural gas (VNG) sector is divided into fleet and non-fleet vehicles. The distributor tariffs for natural gas to fleet vehicles are based on historical differences between end-use and citygate prices from EIA's *Natural Gas Annual* plus Federal and State VNG taxes. The price to non-fleet vehicles is based on the industrial sector firm price plus an assumed $3 (1987 dollars) dispensing charge plus taxes. Federal taxes are set and held at $0.49 in nominal dollars per thousand cubic feet.

Initiatives to increase the natural gas share of total energy use through Federal regulatory reform are reflected in the methodology for the pricing of pipeline services. Initiatives to expand the Natural Gas Star program are assumed to recover 35 billion cubic feet of natural gas per year from 2000 through the end of the forecast period that otherwise might be lost as fugitive emissions.

Petroleum market assumptions

The petroleum refining and marketing industry is assumed to incur environmental costs to comply with CAAA90 and other regulations. Investments related to reducing emissions at refineries are represented as an average annualized expenditure. Costs identified by the National Petroleum Council [*32*] are allocated among the prices of liquefied petroleum gases, gasoline, distillate, and jet fuel, assuming that they are recovered in the prices of light products. The lighter products, such as gasoline and distillate, are assumed to bear a greater share of the costs, because demand for light products is less price-responsive than that for the heavier products.

Petroleum product prices also include additional costs resulting from requirements for cleaner burning fuels, including oxygenated and reformulated gasolines and 500 parts per million (ppm) on-highway diesel. The recent regulation requiring a reduction in gasoline sulfur content to a 30 ppm annual average between 2004 and 2007 is also reflected. The additional costs are determined in the representation of refinery operations by incorporating specifications and demands for the fuels. Demands for traditional, reformulated, and oxygenated gasolines are disaggregated from composite gasoline consumption on the basis of their 1999 market shares in each Census division. The expected oxygenated gasoline market shares assume continued wintertime participation of carbon monoxide nonattainment areas and State-wide participation in Minnesota. Oxygenated gasoline represents about 3 percent of gasoline demand in the forecast.

Reformulated gasoline (RFG) is assumed to continue to be consumed in the 10 serious ozone nonattainment areas required by CAAA90 and in areas that voluntarily opted into the program [*33*]. Since St. Louis, Missouri, joined the RFG program in June 1999 an adjustment of 33 million barrels per day of RFG demand is assumed to account for the remainder of the year. RFG projections also reflect a State-wide requirement in California and RFG required by State law in Phoenix, Arizona. RFG is assumed to account for about 32 percent of annual gasoline sales throughout the *AEO2001* forecast, reflecting the 1999 market share with adjustments for the opt-in of St. Louis in June 1999.

RFG reflects the “Complex Model” definition as required by the EPA and the tighter Phase 2 requirements beginning in 2000. Throughout the forecast, traditional gasoline is blended according to 1990 baseline specifications, to reflect CAAA90 “anti-dumping” requirements aimed at preventing traditional gasoline from becoming more polluting. The *AEO2001* projections also reflect California’s State-wide requirement for severely reformulated gasoline first required in 1996 and incorporate the California phaseout of MTBE by 2003 in areas not covered by Federal RFG regulations. In keeping with an overall assumption of current laws and regulations, it is assumed that the Federal oxygen requirement will remain intact in Federal nonattainment areas, including Los Angeles, San Diego, and Sacramento. *AEO2001* also reflects legislation in seven other States that will ban or limit MTBE in the next several years [*34*].

AEO2001 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. *AEO2001* assumes that RFG has an average annual sulfur content of 135 ppm in 2000 and will meet the 30 ppm requirement in 2004. The reduction in sulfur content between 2000 and 2004 is assumed to reflect incentives for “early reduction.” The regional assumptions for phasing down the sulfur content of 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.

State taxes on gasoline, diesel, jet fuel, M85, and E85 are assumed to increase with inflation, as they have tended to in the past. Federal taxes, which have increased sporadically in the past, are assumed to stay at 1999 nominal levels (a decline in real terms). Extension of the excise tax exemption for blending corn-based ethanol with gasoline, passed in the Federal Highway Bill of 1998, is incorporated in the projections. The bill extends the tax exemption through 2007 but reduces the current exemption of 54 cents per gallon by 1 cent per gallon in 2001, 2003, and 2005. It is assumed that the tax exemption will be extended beyond 2007 through 2020 at the nominal level of 51 cents per gallon (a decline in real terms).

AEO2001 assumes that refining capacity expansion may occur on the east and west coasts, as well as the Gulf Coast.

MTBE ban case. The alternative *MTBE ban case* reflects recommendations from a Blue Ribbon Panel (BRP) of experts convened by the EPA to study problems associated with methyl tertiary butyl ether (MTBE) in water supplies. In addition to tighter controls on leaking underground storage tanks, the BRP recommended a substantial reduction in MTBE in gasoline and removal of the Federal oxygen requirement for RFG. The BRP further noted that other ethers, such as ethyl tertiary butyl ether (ETBE) and tertiary amyl methyl ether (TAME), have similar but not identical characteristics and recommended studying the health effects and characteristics of those compounds before they are allowed to be placed in widespread use. Because of the greater scrutiny, refiners and blenders are unlikely to increase the use of these ethers significantly. As a result, the use of all ethers in gasoline is assumed to be limited in this case. Although the BRP recommendations did not specify that MTBE should be banned entirely, all recent legislative proposals regarding MTBE have aimed at a total ban. In this standalone case it is assumed that the use of MTBE and other ethers in gasoline is totally prohibited.

The elimination of the oxygen specification in RFG requires that other specifications be adjusted in order to maintain air quality. In order to maintain current emissions levels of air toxics, as recommended by the BRP, the MTBE ban case assumes tighter limits on benzene in RFG than does the *AEO2001* reference case. Gasoline consumption and crude oil price projections remain the same as in the *AEO2001* reference case. The only changes relative to the reference case are gasoline specifications and the ban on ether use.

Coal market assumptions

Productivity. Technological advances in the coal industry, such as improvements in coal haulage systems at underground mines, contribute to increases in productivity, as measured in average tons of coal per miner per hour. Productivity improvements are assumed to continue but to decline in magnitude over the forecast horizon. Different rates of improvement are assumed by region and by mine type (surface and underground). On a national basis, labor productivity is assumed to improve on average at a rate of 2.2 percent per year, declining from an estimated annual improvement rate of 5.9 percent achieved in 1999 to approximately 1.2 percent over the 2010 to 2020 period.

Coal transportation costs. Transportation rates are escalated or de-escalated over the forecast period to reflect projected changes in input factor costs. The escalators used to adjust the rates year by year are generated endogenously from a regression model based on the current-year diesel price, employee wage cost index, price index for transportation equipment, and a producer time trend.

Coal exports. Coal exports are modeled as part of a linear program that provides annual forecasts of U.S. steam and coking coal exports in the context of world coal trade. The linear program determines the pattern of world coal trade flows that minimizes the production and transportation costs of meeting a specified set of regional world coal import demands.

Mining cost cases. Two alternative mining cost cases were run to examine the impacts of different labor productivity, labor cost, and equipment cost assumptions. The annual growth rates for productivity were increased and decreased by region and mine type, based on historical variations in labor productivity. The high and low mining cost cases were developed by adjusting the *AEO2001* reference case productivity path by one standard deviation. The resulting national average productivities in 2020 (in short tons per hour) were 14.20 in the *low mining cost case* and 7.47 in the *high mining cost case*, compared with 10.31 in the reference case. These are partially integrated cases, with no feedback from the macroeconomic, international, or end-use demand models.

In the reference case, labor wage rates for coal mine production workers and equipment costs are assumed to remain constant in real terms over the forecast period. In the alternative low and high mining cost cases, wages and equipment costs were assumed to decline and increase by 0.5 percent per year in real terms, respectively. With the exception of the electricity generation sector, the mining cost cases were run without allowing demands to shift in response to changing prices. If demands also had been allowed to shift in the energy end-use sectors, the price changes would be smaller, because minemouth prices vary with the levels of production required to meet demand.

Notes

[*1*] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1999*, DOE/EIA-0573(99) (Washington, DC, October 2000).

[*2*] Energy Information Administration, *Short-Term Energy Outlook*, web site www.eia.doe.gov/emeu/steo/pub/contents.html.

[*3*] Lawrence Berkeley Laboratory, *U.S. Residential Appliance Energy Efficiency: Present Status and Future Direction*; and U.S. Department of Energy, Office of Codes and Standards.

[*4*] Energy Information Administration, *A Look at Residential Energy Consumption in 1997*, DOE/EIA-0321(97) (Washington, DC, 1999).

[*5*] For additional information on green programs see web site www.epa.gov/energystar.html.

[*6*] For further information see web site www.pathnet.org/about/about.html.

[*7*] High technology assumptions are based on Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Arthur D. Little, Inc., September 1998).

[*8*] National Energy Policy Act of 1992, P.L. 102-486, Title I, Subtitle C, Sections 122 and 124.

[*9*] Energy Information Administration, 1995 CBECS Micro-Data Files (February 17, 1998), web site www.eia.doe.gov/emeu/cbecs/.

[*10*] A detailed discussion of the nonsampling and sampling errors for CBECS is provided in Energy Information Administration, *A Look at Commercial Buildings in 1995: Characteristics, Energy Consumption, and Energy Expenditures*, DOE/EIA-0625(95) (Washington, DC, October 1998), Appendix B, web site www.eia.doe.gov/emeu/cbecs/.

[*11*] High technology assumptions are based on Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Arthur D. Little, Inc., September 1998).

[*12*] Energy Information Administration, *Manufacturing Consumption of Energy 1994*, DOE/EIA-0512(94) (Washington, DC, December 1997).

[*13*] National Energy Policy Act of 1992, P.L. 102-486, Title II, Subtitle C, Section 342.

[*14*] These assumptions are based in part on Energy Information Administration, *Aggressive Technology Strategy for the NEMS Model* (Arthur D. Little, Inc., September 1998).

[*15*] National Energy Policy Act of 1992, P.L. 102-486, Title III, Section 303, and Title V, Sections 501 and 507.

[*16*] California Air Resources Board, *Proposed Amendments to California Exhaust and Evaporative Emissions Standards and Test Procedures for Passenger Cars, Light-Duty Trucks and Medium-Duty Trucks "LEVII," and Proposed Amendments to California Motor Vehicle Certification, Assembly-Line and In-Use Test Requirements "CAP2000"* (El Monte, CA, September 18, 1998).

[*17*] Energy and Environmental Analysis, *Changes to the Fuel Economy Module Final Report*, prepared for the Energy Information Administration (Washington, DC, June 1998).

[*18*] F. Stodolsky, A. Vyas, and R. Cuenca, *Heavy- and Medium-Duty Truck Fuel Economy and Market Penetration Analysis*, Draft Report (Chicago, IL: Argonne National Laboratory, August 1999).

[*19*] S. Davis, *Transportation Energy Databook No. 19*, prepared for the Office of Transportation Technologies, U.S. Department of Energy (Oak Ridge, TN: Oak Ridge National Laboratory, September 1999).

[*20*] D. Greene, *Energy Efficiency Improvement Potential of Commercial Aircraft to 2010*, ORNL-6622 (Oak Ridge, TN: Oak Ridge National Laboratory, June 1990), and Oak Ridge National Laboratory, Air Transportation Energy Use Model.

[*21*] Vehicle-miles traveled are the miles traveled yearly by light-duty vehicles.

[*22*] Ton-miles traveled are the miles traveled and their corresponding tonnage for freight modes, such as trucks, rail, air, and shipping.

[*23*] U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC97TV (Washington, DC, October 1999); Federal Highway Administration, *Highway Statistics 1998* (Washington, DC, November 1999); and S. Davis, *Transportation Energy Databook No. 19*, prepared for the Office of Transportation Technologies, U.S. Department of Energy (Oak Ridge, TN: Oak Ridge National Laboratory, September 1999).

[*24*] Federal Aviation Administration, *FAA Aviation Forecasts, Fiscal Years 1998-2009*.

[*25*] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond*, ORNL/CON-444 (Washington, DC, September 1997); Office of Energy Efficiency and Renewable Energy, Office of Transportation Technologies, *OTT Program Analysis Methodology: Quality Metrics 2000* (Washington, DC, November 1998); and J. DeCicco and M. Ross, *An Updated Assessment of the Near-Term Potential for Improving Automotive Fuel Economy* (Washington, DC: American Council for an Energy-Efficient Economy, November 1993).

[*26*] F. Stodolsky, A. Vyas, and R. Cuenca, *Heavy- and Medium-Duty Truck Fuel Economy and Market Penetration Analysis*, Draft Report (Chicago, IL: Argonne National Laboratory, August 1999).

[*27*] National Energy Policy Act of 1992, P.L. 102-486, Title XIX, Section 1916, and extended in Section 507 of the Tax Relief Extension Act of 1999 (Title V of the Ticket to Work and Work Incentives Improvement Act of 1999, December 1999).

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

[*29*] DynCorp Corporation, "Recommendations for Data Replacements," Deliverable #DEL-99-548 (Contract DE-AC01-95-AD34277) (Washington, DC, July 30, 1999).

[*30*] U.S. 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).

[*31*] D.L. Goutier et al., *1995 National Assessment of the United States Oil and Gas Resources* (Washington, DC: U.S. Department of the Interior, U.S. Geological Survey, 1995); U.S. Department of the Interior, Minerals Management Service, *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf*, OCS Report MMS 96-0034 (Washington, DC, June 1997); National Petroleum Council, *Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand*, Volume II (Washington, DC, December 1999).

[*32*] Estimated from National Petroleum Council, *U.S. Petroleum Refining—Meeting Requirements for Cleaner Fuels and Refineries*, Volume I (Washington, DC, August 1993). Excludes operations and maintenance base costs before 1997.

[*33*] Required areas: Baltimore, Chicago, Hartford, Houston, Los Angeles, Milwaukee, New York City, Philadelphia, San Diego, and Sacramento. Opt-in areas are in the following States: Connecticut, Delaware, Kentucky, Massachusetts, Maryland, Missouri, New Hampshire, New Jersey, New York, Rhode Island, Texas, Virginia, and the District of Columbia. Excludes areas that "opted-out" prior to June 1997.

[*34*] MTBE will be banned in Arizona, California, Connecticut, Maine, Minnesota, Nebraska, and New York, and will be limited to 2 percent volume in South Dakota.