DOE/EIA-0383(2001)

Annual Energy Outlook 2001

With Projections to 2020

December 2000

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

This publication is on the WEB at:
www.eia.doe.gov/oiaf/aeo/

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For Further Information . . .

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AEO2001 will be available on the EIA web site at www.eia.doe.gov/oiaf/aeo/ by December 22, 2000. Assumptions underlying the projections and tables of regional and other detailed results will also be available on December 22, 2000, at web sites www.eia.doe.gov/oiaf/assumption/ and /supplement/. Model documentation reports for the National Energy Modeling System (NEMS) and the report *NEMS: An Overview* are available at web site www.eia.doe.gov/bookshelf/docs.html.

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Preface

The *Annual Energy Outlook 2001* (*AEO2001*) presents midterm forecasts of energy supply, demand, and prices through 2020 prepared by the Energy Information Administration (EIA). The projections are based on results from EIA's National Energy Modeling System (NEMS).

The report begins with an "Overview" summarizing the *AEO2001* reference case. The next section, "Legislation and Regulations," discusses evolving legislative and regulatory issues. "Issues in Focus" discusses the macroeconomic projections, world oil and natural gas markets, oxygenates in gasoline, distributed electricity generation, electricity industry restructuring, and carbon dioxide emissions. It is followed by the analysis of energy market trends.

The analysis in *AEO2001* focuses primarily on a reference case and four other cases that assume higher and lower economic growth and higher and lower world oil prices than in the reference case. Forecast tables for those cases are provided in Appendixes A through C. Alternative cases explore the impacts of varying key assumptions in NEMS—e.g., technology penetration. The major results for the alternative cases are shown in Appendix F. Appendix G briefly describes NEMS, the *AEO2001* assumptions, and the alternative cases.

The *AEO2001* projections are based on Federal, State, and local laws and regulations in effect on July 1, 2000. Pending legislation and sections of existing legislation for which funds have not been appropriated are not reflected in the forecasts. Historical data used for the *AEO2001* projections were the most current available as of July 31, 2000, when most 1999 data but only partial 2000 data were available. Historical data are presented in this report for comparative purposes; documents referenced in the source notes should be consulted for official data values. The projections for 2000 and 2001 incorporate the short-term projections from EIA's September 2000 *Short-Term Energy Outlook*.

The *AEO2001* projections are used by Federal, State, and local governments, trade associations, and other planners and decisionmakers in the public and private sectors. They are published in accordance with Section 205c of the Department of Energy Organization Act of 1977 (Public Law 95 91), which requires the EIA Administrator to prepare annual reports on trends and projections for energy use and supply.

The projections in *AEO2001* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. Thus, they provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as currently enacted; however, the impacts of emerging regulatory changes, when defined, are reflected.

Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated, including severe weather, political disruptions, strikes, and technological breakthroughs. In addition, future developments in technologies, demographics, and resources cannot be foreseen with any degree of certainty. Many key uncertainties in the *AEO2001* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, analytical processes in the examination of policy initiatives.

The Office of Integrated Analysis and Forecasting dedicates this report in memory of Richard Newcombe (1941-2000). Richard worked on the coal forecasts in past AEOs; his expertise and understanding of the coal industry, as well as his attention to detail, are greatly missed.

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Overview

Key Energy Issues to 2020

Currently, most attention in energy markets is focused on near-term issues of world oil supply and prices, U.S. natural gas prices, and the transition to restructured electricity markets in several regions of the country. The *Annual Energy Outlook 2001* (*AEO2001*) addresses the longer-term trends of electricity industry restructuring, fossil fuel supply and prices, and the impacts of economic growth on projected energy use and carbon dioxide emissions. *AEO2001* does not project short-term events, such as supply disruptions or severe weather.

The *AEO2001* projections assume a transition to full competitive pricing of electricity in States with specific deregulation plans—California, New York, New England, the Mid-Atlantic States, Illinois, Texas, Oklahoma, Michigan, Ohio, Arizona, New Mexico, and West Virginia. Other States are assumed to continue cost-of-service electricity pricing. A transition from regulated to competitive prices over a 10-year period from the beginning of restructuring in each region, and implementation of the provisions of California legislation regarding price caps, are assumed. Increased competition in electricity markets is also represented through assumed changes in the financial structure of the industry and efficiency and operating improvements.

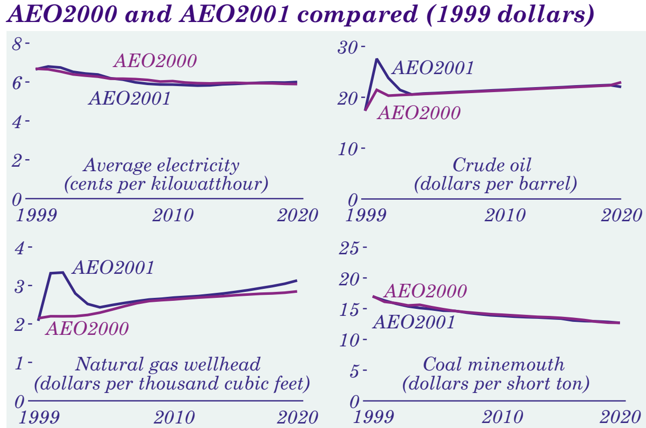
World oil prices fell sharply through most of 1997 and 1998, due in part to economic developments in East Asia and the resulting oversupply of oil. Beginning in 1999, actions by the Organization of Petroleum Exporting Countries (OPEC) and some non-OPEC countries to restrain oil production have increased world oil prices. U.S. natural gas prices have also increased in 2000 due to higher than expected demand and to tight supplies caused by reduced drilling in reaction to low prices in 1998. Oil and gas markets are addressed on pages 27 and 28.

The projected growth rate of the U.S. economy, measured by gross domestic product (GDP), is considerably higher in *AEO2001* than in *AEO2000*, an average annual rate of 3.0 percent from 1999 to 2020, compared with 2.1 percent in *AEO2000*. Although part of the upward revision results from statistical and definitional changes in the National Income and Product Accounts, the projections also reflect a more optimistic view of long-run economic growth, which results in higher forecasts of energy consumption and carbon dioxide emissions in *AEO2001* than in *AEO2000*. The macroeconomic projections are discussed on pages 22 and 56.

Prices

The average world oil price is projected to increase from $17.35 per barrel in 1999 (1999 dollars) to about $27.60 per barrel in 2000, falling to about $20.50 per barrel by 2003. In 2020, the projected price reaches $22.41 per barrel (Figure 1), similar to the *AEO2000* projection of $22.33 per barrel. Higher demand in the forecast is offset by higher resource estimates from the U.S. Geological Survey. Projected prices over the next several years are higher in *AEO2001* than in *AEO2000* due to the production cutbacks by OPEC and several non-OPEC nations, a lag in the response of non-OPEC producers to price increases, and renewed demand growth in Asia.

Figure 1. Fuel price projections, 1999-2020: AEO2000 and AEO2001 compared (1999 dollars)



World oil demand is projected to increase from 75.5 million barrels per day in 1999 to 117.4 million barrels per day in 2020—higher than the *AEO2000* projection of 112.4 million barrels per day—due to higher projected demand in the United States, the Middle East, the former Soviet Union, the Pacific Rim developing countries, and China. Projected growth in production in both OPEC and non-OPEC nations leads to relatively slow projected growth of prices through 2020. OPEC oil production is expected to reach 57.6 million barrels per day in 2020, nearly double the 29.9 million barrels per day in 1999, assuming sufficient capital to expand production capacity. The United Nations resolution limiting Iraqi oil exports is assumed to remain in place through 2001. Once sanctions are lifted, Iraqi oil production is expected to reach 3.5 million barrels per day within 2 years and about 5 million barrels per day within a decade.

The June 2000 recoverable oil resources assessment by the U.S. Geological Survey raised world resources by about 700 billion barrels from the 1994 assessment. As a result, non-OPEC oil production is expected to increase from 44.8 million barrels per day to 59.5 million barrels per day between 1999 and 2020, or 2.9 million barrels per day higher than in *AEO2000*. Production from the Caspian Basin is expected to reach 6 million barrels per day by 2020 with continued expansion of production from the offshore regions of West Africa and the North Sea. Both Brazil and Colombia are expected to be producing 1 million barrels per day before 2005, and production in Mexico and Canada is also expected to increase.

The average wellhead price of natural gas is projected to increase from $2.08 per thousand cubic feet in 1999 to about $3.30 per thousand cubic feet in 2000 and 2001, then decline through 2004. The projected price reaches $3.13 per thousand cubic feet in 2020, $0.28 per thousand cubic feet higher than in *AEO2000*, due to higher projected demand. Price increases are expected to be slowed by technological improvements in natural gas exploration and production. Average delivered prices are projected to increase at a slower rate than the wellhead price due to assumed cost reductions from efficiency improvements in the industry.

In *AEO2001*, the average minemouth price of coal is projected to decline from $16.98 per ton in 1999 to $12.70 per ton in 2020, the same price projected in *AEO2000*. Through 2020, the price is expected to decline due to increasing productivity in mining, a shift to lower-cost western production, and competitive pressures on labor costs.

Average electricity prices are projected generally to decline from 6.7 cents per kilowatthour in 1999 to 6.0 cents in 2020, increasing slightly at the end of the forecast due to rising natural gas prices. In 2020, the projected price is slightly higher than the 5.9 cents per kilowatthour projected in *AEO2000*. Higher projections for natural gas prices and for electricity demand—which would require more investment in new generating capacity—lead to the higher price projections. Electricity industry restructuring is expected to contribute to lower prices through reductions in operating and maintenance, administrative, and other costs. Federal Energy Regulatory Commission actions on open access and other changes for competitive markets enacted by some State public utility commissions are included in the projections, as noted above. Because not all States have deregulated their electricity markets, the projections do not represent a fully restructured electricity market. State legislative actions to deregulate the electricity industry are discussed on page 41.

Consumption

Total energy consumption is projected to increase from 96.1 quadrillion British thermal units (Btu) to 127.0 quadrillion Btu between 1999 and 2020, an average annual increase of 1.3 percent. In 2020, this forecast is about 6 quadrillion Btu higher than projected in *AEO2000*, primarily because higher projected economic growth leads to higher demand forecasts in all end-use sectors.

Total residential energy consumption is projected to grow at an average rate of 1.2 percent per year, with the most rapid growth expected for computers, electronic equipment, and appliances. In 2020, the projected residential demand is 24.4 quadrillion Btu, 1.4 quadrillion Btu higher than in *AEO2000*. Higher projected economic growth results in higher forecasts for both disposable personal income and housing starts, increasing equipment purchases and raising the projected housing stock in 2020 by 1.5 percent. *AEO2001* also forecasts that new houses will become larger over time.

Commercial energy demand is projected to grow at an average annual rate of 1.4 percent, reaching 20.8 quadrillion Btu in 2020, 2.6 quadrillion Btu higher than in *AEO2000*. With higher projected economic growth in *AEO2001*, commercial floorspace is projected to grow more rapidly and, in 2020, is estimated to be 11 percent higher than projected in *AEO2000*. The most rapid increases in energy use are expected for computers, office equipment, and telecommunications and other equipment.

Industrial energy demand is projected to increase at an average rate of 1.0 percent per year, reaching 43.4 quadrillion Btu in 2020, 1.2 quadrillion Btu higher than in *AEO2000*. With higher projected economic growth, total industrial gross output is estimated to grow at an average annual rate of 2.6 percent from 1999 to 2020, compared with 1.9 percent in *AEO2000*; however, recent data indicate more rapid improvements in industrial energy intensity than previously estimated. Also, average annual growth in non-energy-intensive manufacturing is expected to be 3.3 percent, compared with 1.2 percent for energy-intensive manufacturing. Through 2020, more rapid assumed declines in industrial energy intensity, compared with *AEO2000*, are projected to offset some of the increase in demand that might be expected with higher industrial output. Cogeneration capacity is projected to increase by 19 gigawatts by 2020, 10 gigawatts more than in *AEO2000*.

Energy demand for transportation is projected to grow at an average annual rate of 1.8 percent, to 38.5 quadrillion Btu in 2020, 1.0 quadrillion Btu higher than in *AEO2000*. In *AEO2001*, the projections for light-duty vehicle and freight travel are higher than in *AEO2000* as a result of higher projected growth in personal income and industrial output. Higher light-duty vehicle travel in the forecast is partially offset by higher vehicle efficiency. New vehicle efficiency in 2020 is projected to be higher by 0.9 and 1.9 miles per gallon for new cars and light trucks, respectively, than in *AEO2000*, due to a reevaluation of the competitive potential of advanced technology vehicles.

The projections incorporate efficiency standards for new energy-using equipment in buildings and for motors mandated through 1994 by the National Appliance Energy Conservation Act of 1987 and the Energy Policy Act of 1992, including the refrigerator and fluorescent lamp ballast standards that become effective in July 2001 and April 2005, respectively. These are the only standards that are finalized with effective dates and specific efficiency levels.

Electricity demand is projected to grow by 1.8 percent per year from 1999 through 2020, higher than the rate of 1.3 percent forecast for the same period in *AEO2000*. The higher demand projection results from higher projected economic growth and a reevaluation of the potential for growth in electricity use for a variety of residential and commercial appliances and equipment, including personal computers.

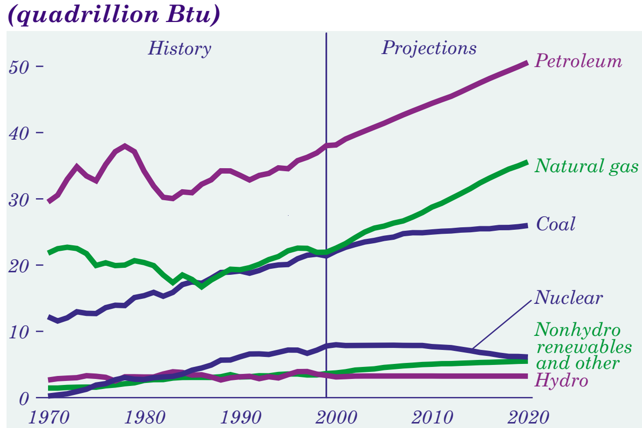
The overall demand for natural gas in the U.S. energy economy is projected to grow by 2.3 percent per year on average (Figure 2), from 21.4 trillion cubic feet in 1999 to 34.7 trillion cubic feet in 2020, primarily as a result of rapid projected growth in demand for electricity generation (excluding cogenerators), which is expected to triple between 1999 and 2020. The *AEO2001* forecast for total natural gas demand in 2020 is 3.2 trillion cubic feet higher than in *AEO2000*, mainly as a result of higher projected demand for natural gas in the electricity generation sector.

In *AEO2001*, total coal consumption is projected to increase from 1,035 million tons in 1999 to 1,297 million tons in 2020, an average increase of 1.1 percent per year. The 2020 projection is 18 million tons higher than in *AEO2000*, due to higher projected demand for industrial uses and for electricity generation, which constitutes about 90 percent of the demand for coal.

Petroleum demand is projected to grow from 19.5 million barrels per day in 1999 to 25.8 million in 2020—an average rate of 1.3 percent per year—led by growth in the transportation sector, which accounts for about 70 percent of U.S. petroleum consumption. Projected demand in 2020 is higher than in *AEO2000* by 730 thousand barrels per day primarily due to a higher projection for transportation fuel use.

Renewable fuel consumption, including ethanol for gasoline blending, is projected to grow at an average rate of 1.1 percent per year through 2020, primarily as a result of State mandates. In 2020, about 55 percent of renewables are used for electricity generation and the rest for dispersed heating and cooling, industrial uses (including cogeneration), and fuel blending. The *AEO2001* forecast for renewable energy demand in 2020 is 0.4 quadrillion Btu higher than in *AEO2000*, mainly due to higher projected use of biomass in the industrial sector.

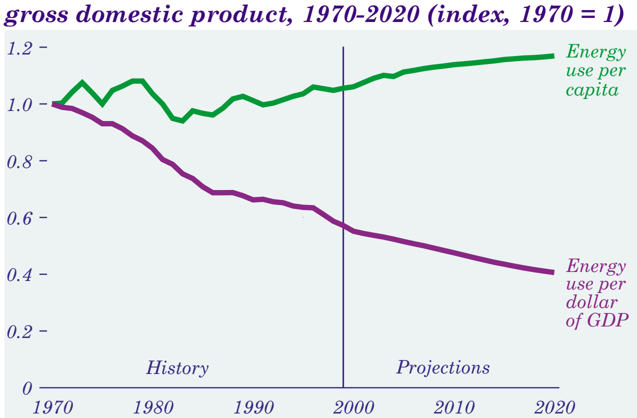
Figure 2. Energy consumption by fuel, 1970-2020 (quadrillion Btu)



Energy Intensity

Between 1970 and 1986, energy intensity, measured as energy use per dollar of GDP, declined at an average annual rate of 2.3 percent as the economy shifted to less energy-intensive industries and more efficient technologies in light of energy price increases (Figure 3). With slower price increases (and price declines in some sectors) and growth of more energy-intensive industries, intensity declines moderated to an average of 1.3 percent per year between 1986 and 1999. Energy intensity is projected to decline at an average annual rate of 1.6 percent through 2020 as efficiency gains and structural shifts in the economy offset the expected growth in demand for energy services. The projected improvement is more rapid than in *AEO2000*, due to more rapid projected efficiency improvements in the industrial sector and growth in the non-energy-intensive industries.

Figure 3. Energy use per capita and per dollar of gross domestic product, 1970-2020 (index, 1970 = 1)



Energy use per person generally declined from 1970 through the mid-1980s, then rose as energy prices fell. Per capita energy use is projected to increase slightly in the forecast as efficiency gains only partially offset higher demand for energy services.

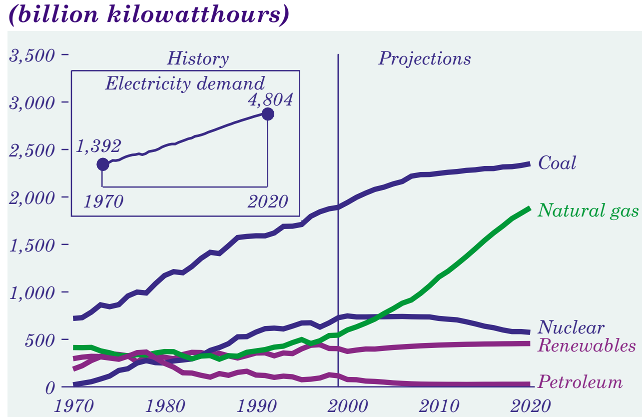
Electricity Generation

Electricity generation fueled by natural gas and coal is projected to increase through 2020 to meet growing demand for electricity and offset the projected retirement of existing nuclear units (Figure 4). The *AEO2001* projections for generation from natural gas, coal, and nuclear power are higher than in *AEO2000* as a result of higher projected electricity demand and improved operating costs and performance of nuclear plants. The share of natural gas generation is projected to increase from 16 percent in 1999 to 36 percent in 2020, and the coal share is projected to decline from 51 percent to 44 percent, because electricity industry restructuring favors the less capital-intensive and more efficient natural gas generation technologies.

Nuclear generating capacity is projected to decline from 1999 to 2020 but remains higher than in *AEO2000* due to a reevaluation of the costs of life extension and higher projected natural gas prices. Retirements of nuclear plants in the forecast are based on operating and life extension costs compared with the cost of new generating capacity. Of the 97 gigawatts of nuclear capacity available in 1999, 26 gigawatts is projected to be retired by 2020, and no new plants are expected to be constructed by 2020.

The use of renewable energy technologies for electricity generation is projected to grow slowly because of the relatively low costs of fossil-fired generation and because electricity restructuring favors less capital-intensive natural gas technologies over coal and baseload renewables. Where enacted, State renewable portfolio standards, which specify a minimum share of generation or sales from renewable sources, contribute to the expected growth of renewables. Total renewable generation, including cogenerators, is projected to increase by 0.7 percent per year and is similar to the projection in *AEO2000*.

Figure 4. Electricity generation by fuel, 1970-2020 (billion kilowatthours)



Production and Imports

U.S. crude oil production is projected to decline at an average annual rate of 0.7 percent from 1999 to 2020, to 5.1 million barrels per day. Advances in exploration and production technologies do not offset declining oil resources. This forecast is 0.2 million barrels per day lower in 2020 than in *AEO2000*. Projected production is higher in the earlier years of the forecast when projected prices are higher, contributing to lower production later. Projected increases in natural gas plant liquids production and refinery gains generally offset the decline in crude oil production (Figure 5). The share of petroleum demand met by net imports is projected to increase from 51 percent in 1999 (measured in barrels per day) to 64 percent in 2020, the same as in *AEO2000*, due to rising demand (Figure 6).

Figure 5. Energy production by fuel, 1970-2020 (quadrillion Btu)

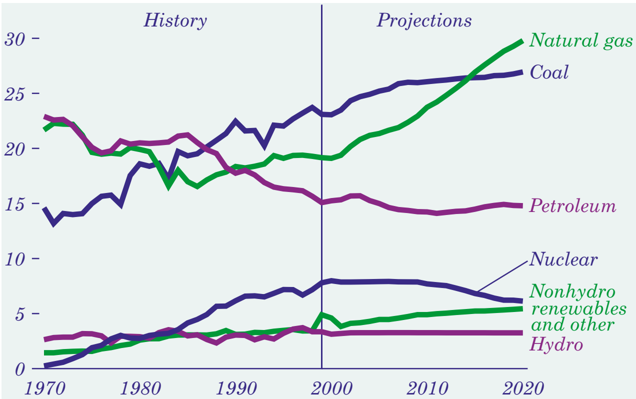
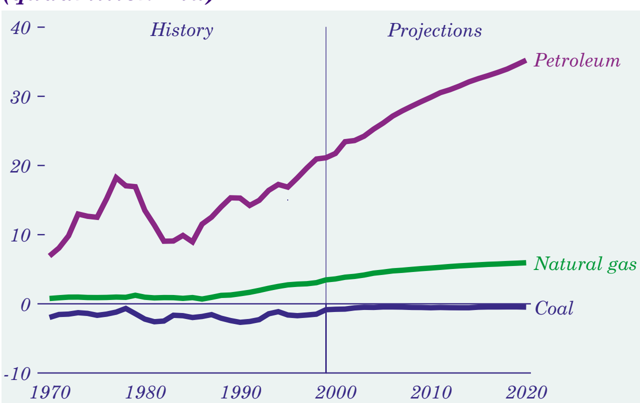


Figure 6. Net energy imports by fuel, 1970-2020 (quadrillion Btu)



U.S. natural gas production is projected to increase from 18.7 trillion cubic feet in 1999 to 29.0 trillion cubic feet in 2020, an average annual rate of 2.1 percent, due to growing demand. Projected production is 2.6 trillion cubic feet higher in 2020 than in *AEO2000*. Net imports of natural gas, primarily from Canada, are projected to increase from 3.4 trillion cubic feet in 1999 to 5.8 trillion cubic feet in 2020. Net imports of liquefied natural gas are expected to increase to 0.7 trillion cubic feet by 2020 as two facilities in the United States—Elba Island, Georgia, and Cove Point, Maryland—are expected to reopen in 2003.

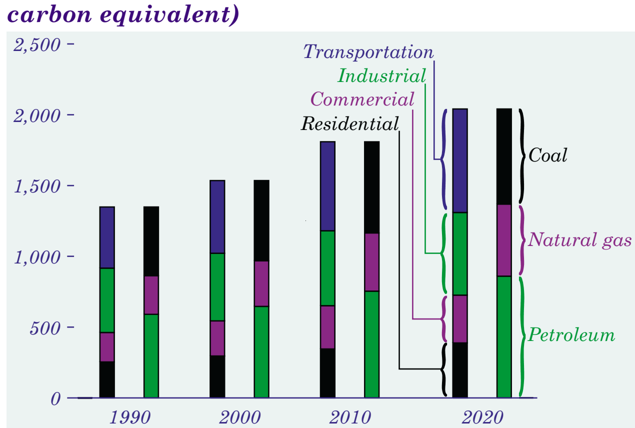
Coal production is projected to increase at an average annual rate of 0.9 percent, from 1,105 million tons in 1999 to 1,331 million tons in 2020, as projected domestic demand grows. Projected production in 2020 is 15 million tons higher than in *AEO2000*, due to higher demand. U.S. net coal exports are projected to decline through 2020, with European demand for U.S. coal expected to decline for environmental reasons and as a result of competition from other producers.

Renewable energy production is projected to increase from 6.6 quadrillion Btu in 1999 to 8.3 quadrillion Btu in 2020, with growth in geothermal, wind, biomass, and landfill gas generation, industrial biomass, and ethanol. Renewables production in 2020 is estimated to be 0.3 quadrillion Btu higher than in *AEO2000*, as a result of higher expected use of biomass in the industrial sector.

Carbon Dioxide Emissions

Carbon dioxide emissions from energy use are projected to increase at an average rate of 1.4 percent per year from 1,511 to 2,041 million metric tons carbon equivalent between 1999 and 2020 (Figure 7). Projected emissions in 2020 are higher by 62 million metric tons carbon equivalent than in *AEO2000*, due mainly to higher projected economic growth. Higher projected growth in households, commercial floorspace, industrial output, and disposable income leads to higher forecasts for end-use demand and electricity generation. Partly offsetting these trends are more rapid projected declines in industrial energy intensity and higher projected nuclear generation than in *AEO2000*.

Figure 7. Projected U.S. carbon dioxide emissions by sector and fuel, 1990-2020 (million metric tons carbon equivalent)



The projections do not include future legislative or regulatory actions that might be taken to reduce carbon dioxide emissions but do include certain voluntary actions to reduce energy demand and emissions. Carbon dioxide emissions and international negotiations for emissions reductions are discussed on pages 45 and 97.

Table 1. Summary of results for five cases

Sensitivity Factors	1998	1999	2020 Reference	2020 Low Economic Growth	2020 High Economic Growth	2020 Low World Oil Price	2020 High World Oil Price
Primary Production (quadrillion Btu)							
Petroleum	15.68	15.08	14.79	14.08	15.42	13.21	16.34
Natural Gas	19.19	19.16	29.79	27.44	31.17	28.99	29.80
Coal	23.76	23.09	26.95	25.97	29.42	26.20	27.66
Nuclear Power	7.19	7.79	6.13	5.91	6.31	6.09	6.09
Renewable Energy	6.62	6.58	8.31	7.91	8.75	8.19	8.37
Other	0.65	1.65	0.34	0.32	0.34	0.33	0.40
Total Primary Production	**73.10**	**73.35**	**86.30**	**81.64**	**91.40**	**83.02**	**88.67**
Net Imports (quadrillion Btu)							
Petroleum (including SPR)	20.95	21.12	35.22	32.18	38.76	39.57	32.38
Natural Gas	3.06	3.46	5.94	5.72	5.96	5.87	5.66
Coal/Other (- indicates export)	-1.41	-0.85	-0.47	-0.52	-0.36	-0.47	-0.47
Total Net Imports	**22.60**	**23.73**	**40.69**	**37.38**	**44.36**	**44.97**	**37.57**
Discrepancy	0.86	0.94	-0.04	0.05	-0.10	0.60	-0.17
Consumption (quadrillion Btu)							
Petroleum Products	37.16	38.03	50.59	46.73	54.82	52.74	49.49
Natural Gas	21.96	21.95	35.57	33.00	36.97	34.68	35.31
Coal	21.61	21.43	26.20	25.19	28.77	25.45	26.92
Nuclear Power	7.19	7.79	6.13	5.91	6.31	6.09	6.09
Renewable Energy	6.63	6.59	8.31	7.92	8.76	8.20	8.38
Other	0.29	0.34	0.23	0.23	0.23	0.23	0.23
Total Consumption	**94.84**	**96.14**	**127.03**	**118.98**	**135.86**	**127.39**	**126.42**
Prices (1999 dollars)							
World Oil Price (dollars per barrel)	12.02	17.35	22.41	21.16	23.51	15.10	28.42
Domestic Natural Gas at Wellhead (dollars per thousand cubic feet)	2.02	2.08	3.13	2.66	3.68	3.01	3.25
Domestic Coal at Minemouth (dollars per short ton)	18.02	16.98	12.70	12.79	12.80	12.84	12.87
Average Electricity Price (cents per kilowatthour)	6.8	6.7	6.0	5.6	6.4	5.9	6.1
Economic Indicators							
Real Gross Domestic Product							
(billion 1996 dollars)	8,516	8,876	16,515	14,757	18,202	16,565	16,474
(annual change, 1999-2020)	—	—	3.0%	2.5%	3.5%	3.0%	3.0%
GDP Chain-Type Price Index							
(index, 1996=1.00)	1.029	1.045	1.680	1.907	1.472	1.674	1.686
(annual change, 1999-2020)	—	—	2.3%	2.9%	1.6%	2.3%	2.3%
Real Disposable Personal Income							
(billion 1996 dollars)	6,165	6,363	11,842	10,907	12,739	11,902	11,786
(annual change, 1999-2020)	—	—	3.0%	2.6%	3.4%	3.0%	3.0%
Gross Manufacturing Output							
(billion 1992 dollars)	3,704	3,749	6,726	6,149	7,735	6,730	6,724
(annual change, 1999-2020)	—	—	2.8%	2.4%	3.5%	2.8%	2.8%
Energy Intensity							
(thousand Btu per 1996 dollar of GDP)	11.14	10.84	7.70	8.07	7.47	7.69	7.68
(annual change, 1999-2020)	—	—	-1.6%	-1.4%	-1.8%	-1.6%	-1.6%
Carbon Dioxide Emissions							
(million metric tons carbon equivalent)	1,495	1,511	2,041	1,916	2,193	2,051	2,033
(annual change, 1999-2020)	—	—	1.4%	1.1%	1.8%	1.5%	1.4%

Notes: Specific assumptions underlying the alternative cases are defined in the Economic Activity and International Oil Markets sections beginning on page 56. Quantities are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, supplemental natural gas, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Some refinery inputs appear as petroleum product consumption. Other consumption includes net electricity imports, liquid hydrogen, and methanol.

Sources: Tables A1, A19, A20, B1, B19, B20, C1, C19, and C20.

Legislation and Regulations

Legislation and Regulations

Introduction

Because analyses by the Energy Information Administration (EIA) are required to be policy-neutral, the projections in this *Annual Energy Outlook 2001* (*AEO2001*) are based on Federal, State, and local laws and regulations in effect on July 1, 2000. The potential impacts of pending or proposed legislation, regulations, and standards—and sections of existing legislation for which funds have not been appropriated—are not reflected in the projections.

Federal legislation incorporated in the projections includes the National Appliance Energy Conservation Act of 1987; the Clean Air Act Amendments of 1990 (CAAA90); the Energy Policy Act of 1992 (EPACT); the Omnibus Budget Reconciliation Act of 1993, which adds 4.3 cents per gallon to the Federal tax on highway fuels [*1*]; the Outer Continental Shelf Deep Water Royalty Relief Act of 1995; the Tax Payer Relief Act of 1997; the Federal Highway Bill of 1998, which includes an extension of the ethanol tax incentive; and the new standards for the sulfur content of motor gasoline. *AEO2001* assumes the continuation of the ethanol tax incentive through 2020. *AEO2001* also assumes that State taxes on gasoline, diesel, jet fuel, M85, and E85 will increase with inflation and that Federal taxes on those fuels will continue at 1999 levels in nominal terms. Although the above tax and tax incentive provisions include "sunset" clauses that limit their duration, they have been extended historically, and *AEO2001* assumes their continuation throughout the forecast.

AEO2001 also incorporates regulatory actions of the Federal Energy Regulatory Commission (FERC), including Orders 888 and 889, which provide open access to interstate transmission lines in electricity markets, and other FERC actions to foster more efficient natural gas markets. State plans for the restructuring of the electricity industry and State renewable portfolio standards are incorporated as enacted. As of July 1, 2000, 24 States and the District of Columbia had passed legislation or promulgated regulations to restructure their electricity markets.

CAAA90 requires a phased reduction in vehicle emissions of regulated pollutants, to be met primarily through the use of reformulated gasoline. In addition, under CAAA90, there is a phased reduction in annual emissions of sulfur dioxide by electricity generators, which in general are capped at 8.95 million tons per year in 2010 and thereafter, although "banking" of allowances from earlier years is permitted. CAAA90 also calls for the U.S. Environmental Protection Agency (EPA) to issue standards for the reduction of nitrogen oxide (NO_x) emissions; the forecast includes NO_x caps for States where they have been finalized, as discussed later in this section. The impacts of CAAA90 on electricity generators are discussed in "Market Trends" (see page 99).

The provisions of EPACT focus primarily on reducing energy demand. They require minimum building efficiency standards for Federal buildings and other new buildings that receive federally backed mortgages. Efficiency standards for electric motors, lights, and other equipment are required, and Federal, State, and utility vehicle fleets are required to phase in vehicles that do not rely on petroleum products. The projections include only those equipment standards for which final actions have been taken and for which specific efficiency levels are provided, including the refrigerator standard that goes into effect in July 2001 and the standard for fluorescent lamp ballasts that goes into effect in April 2005. A discussion of the status of efficiency standards is included later in this section.

Energy combustion is the primary source of anthropogenic (human-caused) carbon dioxide emissions. *AEO2001* estimates of emissions do not include emissions from activities other than fuel combustion, such as landfills and agriculture, nor do they take into account sinks that absorb carbon dioxide, such as forests.

The *AEO2001* reference case projections include analysis of the programs in the Climate Change Action Plan (CCAP)—44 actions developed by the Clinton Administration in 1993 to achieve the stabilization of greenhouse gas emissions (carbon dioxide, methane, nitrous oxide, and others) in the United States at 1990 levels by 2000. CCAP was formulated as a result of the Framework Convention on Climate Change, which was adopted at the United Nations on May 9, 1992, and opened for signature at Rio de Janeiro on June 4, 1992. As part of the Framework Convention, the economically developed signatories, including the United States, agreed to take voluntary actions to reduce emissions to 1990 levels. Of the 44 CCAP actions, 13 are not related either to energy combustion or to carbon dioxide and, consequently, are not incorporated in the analysis.

Although CCAP no longer exists as a unified program, most of the individual programs, which are generally voluntary, remain. The impacts of those programs are included in the projections. The projections do not include carbon dioxide mitigation actions that may be enacted as a result of the Kyoto

Protocol, which was agreed to on December 11, 1997, but has not been ratified, or other international agreements (see "Issues in Focus," page 51, for further discussion of carbon dioxide emissions and the Kyoto Protocol).

Nitrogen Oxide Emission Caps

On September 24, 1998, the EPA promulgated rules to limit NO_x emissions in 22 eastern and midwestern States. The rules, commonly referred as the "NO_x SIP Call," called for capping summer season—May through September—power plant NO_x emissions beginning in 2004. The rules were initially represented with the proposed emissions budgets in the *Annual Energy Outlook* beginning in 1999; however, several industry groups challenged the regulations, and the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued an order preventing EPA from implementing them. Consequently, the rules were not represented in *AEO2000*.

On March 3, 2000, the D.C. Circuit issued an order upholding the SIP Call with minor revisions—removing facilities in the State of Wisconsin from the program and asking EPA to review the requirements for facilities in Georgia and Missouri. As a result, *AEO2001* represents the provisions of the SIP Call for the 19 States where the NO_x caps have been finalized. The SIP Call is represented as a cap and trade program under which individual companies can choose to comply by reducing their own emissions or by purchasing allowances from other companies that have more than they need. The specific limits for each State are given in Table 2.

Table 2. Summer season NO_x emissions budgets for 2003 and beyond (thousand tons per season)

State	Emissions cap
Alabama	30.60
Connecticut	5.20
Delaware	5.00
District of Columbia	0.20
Illinois	36.60
Indiana	51.80
Kentucky	38.80
Maryland	13.00
Massachusetts	14.70
Michigan	29.50
New Jersey	8.20
New York	31.20
North Carolina	32.70
Ohio	51.50
Pennsylvania	46.00
Rhode Island	1.60
South Carolina	19.80
Tennessee	26.20
Virginia	21.00
West Virginia	24.05

FERC Order 2000

Throughout the 1990s, the FERC has taken steps to bring competition to wholesale electricity markets. It has attempted to open access to the interstate electricity transmission system to all market participants. In 1996, FERC issued Orders 888 and 889, requiring transmission-owning utilities to make their facilities available to others under the same prices, terms, and conditions they charge themselves. They were also required to develop information systems to provide real-time data on the amount of transmission capacity they had available at any given point in time and the prices, terms, and conditions for using it.

In 1999, the FERC continued its efforts with the issuance of Order 2000, referred to as the "Regional Transmission Organizations (RTO) Order," on December 20, 1999 [*2*]. The FERC has come to believe that many of the operational and reliability issues now facing the electricity industry can best be addressed by regional institutions rather than by individual utilities operating their own systems. As stated by the FERC, "Appropriate regional transmission institutions could: (1) improve efficiencies in transmission and grid management; (2) improve grid reliability; (3) remove remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate lighter handed regulation" [*3*]. As a result, Order 2000 requires that transmission-owning utilities file a proposal for an RTO by October 15, 2000, and have the RTO operating by December 15, 2001.

The FERC has not attempted to define what the appropriate regions are, how many RTOs there should be, or how they should be organized. The details are left to the utilities to propose. Essentially, Order 2000 goes a step beyond the open access provisions of Orders 888 and 889, requiring utilities to put their transmission systems under the control of independent regional institutions.

Although the FERC plans to allow utilities considerable flexibility in their RTO proposals, it has specified certain key functions that an RTO must provide, including tariff administration and design, congestion management, parallel path flow, provision of ancillary services, real-time information on total transmission and available transmission capability, market monitoring, transmission system planning and expansion, and interregional coordination. Essentially, the RTO is responsible for planning, operating, and monitoring the transmission system under its control. It is to operate independently of the transmission-owning utilities and ensure that all market participants have equal access to the services of the transmission system. At this time, the future regional organization of the wholesale electricity market is unclear.

Updates on State Renewable Portfolio Standards and Renewable Energy Mandates

Environmental and other interests have spurred the introduction of 10 State-level renewable portfolio standard (RPS) programs, as well as other mandates to build new electricity generating capacity powered by renewable energy [*4*]. The 10 States identified as having renewable portfolio standards are Arizona, Connecticut, Maine, Massachusetts, Nevada, New Jersey, New Mexico, Pennsylvania, Texas, and Wisconsin. The State RPS programs vary widely in specifics, but all require that increasing percentages of the State's electricity supply be provided from a menu of eligible renewable energy resources. The mandates also vary in detail, but all tend to identify the technologies to be used and the amounts of capacity to be built.

Texas and New Jersey account for the two largest blocks of new renewable energy generating capacity projected to result from RPS programs in *AEO2001*. The Texas RPS specifies that 2,000 megawatts of new renewable energy generating capacity be built in Texas by 2009, with increasing interim requirements and individual utilities' shares assigned in proportion to their retail sales. Utilities may generate the power themselves or purchase credits from others with surplus qualifying generation; production from some existing facilities can also contribute to reducing a utility's requirements. Although the Texas RPS includes biomass, geothermal, hydroelectricity, and solar energy technologies, wind and landfill gas are expected to provide most of the new capacity to meet the RPS. Large new wind facilities already have been announced or contracted in response to the program.

New Jersey's RPS specifies increasing percentages of sales, such that 4 percent of each New Jersey retail electricity provider's sales are to be supplied by renewables (excluding hydroelectric) by 2012. Qualifying generating units located outside New Jersey may contribute to the renewables share, and a trading program is being developed. Biomass and landfill gas are expected to be the primary renewables used to meet New Jersey's RPS, along with some new wind capacity. Estimates for new generating capacity under the RPS are included in *AEO2001*.

California imposes a non-RPS form of renewable energy mandate, using a funding requirement under Assembly Bill 1890 (A.B. 1890) to collect $162 million from ratepayers of investor-owned utilities. Voluntarily proposed renewable energy projects bid competitively for support on a per-kilowatthour incentive basis. Winning capacity in the A.B. 1890 process is expected to include primarily wind, geothermal, and landfill gas projects. In August 2000, California extended the A.B. 1890 mandate, including additional funding. Specifics of a revised implementation plan are expected in early 2001. Estimates for new generating capacity under the original A.B. 1890 are included in *AEO2001*, but because no specifics are available, *AEO2001* does not include estimates for additional new capacity that would result from the August extension.

FERC Order 637

On February 9, 2000, the FERC issued Order 637, which modified the pricing rules for interstate natural gas pipeline services, primarily for short-term services in the secondary market. The Order is intended to allow capacity to be allocated more efficiently during peak periods to those who need it most. Before Order 637, short-term released capacity was subject to a price cap. When the value of the excess held capacity exceeded the price cap, there was no incentive for capacity holders to release the capacity. As a result, the unused capacity was often bundled with gas sales so that it could be sold by marketers at prices that were effectively above the cap, making it difficult for customers who needed additional capacity during peak periods to obtain it. Order 637 waives price ceilings for short-term (less than 1 year) released capacity for a trial period that will end on September 30, 2002. It is anticipated that this will make it much easier for those needing capacity to obtain it directly from holders of firm capacity.

Order 637 also allows pipelines to file for peak/off-peak and term-differentiated rate structures. The increase in revenue recovery from short-term peak period customers paying peak rates will reduce the cost recovery needed from long-term customers paying off-peak rates. The term-differentiated rates will be cost-based rates that, in the aggregate, will meet the annual revenue requirements of pipeline operators. The new rate structures, which are intended to better allocate economic risks, can apply either to long-term services alone or to both long- and short-term services.

Additional changes in regulations contained in Order 637 (1) encourage the increased use of auctions for available capacity by laying down basic principles and guidelines; (2) require pipelines to modify scheduling procedures so that released capacity can be scheduled on a basis comparable with other pipeline services; (3) permit shippers to segment capacity for more efficient capacity release transactions; (4) provide shippers more information on imbalances and services that can be used to avoid imbalance penalties; (5) implement penalties only to the extent necessary to ensure system reliability, with the revenues from such penalties credited to shippers; (6) narrow the right of first refusal to remove economic biases that existed previously; and (7) improve the FERC's reporting requirements to provide more transparent pricing information and permit more effective monitoring of the market. All the changes are intended to improve the competitiveness and efficiency of the interstate pipeline system.

Royalty Rules

Deepwater Royalty Relief

The Deep Water Royalty Relief Act was enacted in 1995 as an incentive for exploration and development of the deep waters of the Gulf of Mexico. The Act contains a mandatory provision, set to expire on November 28, 2000, that requires the Minerals Management Service (MMS) to offer leases with suspended royalties on volumes from certain portions of the deepwater Gulf of Mexico. Another provision, which does not expire, gives the MMS authority to include royalty suspensions as a financial feature of leases sold in the future. In September 2000 the MMS, acting under this authority, issued a set of proposed rules and regulations that provide a framework for continuing deepwater royalty relief on a lease-by-lease basis.

The mandatory provision of the Act provides royalty relief by eliminating royalties for deepwater leases according to a schedule based on both the volumes produced and the depth of the water: 17.5 million barrels oil equivalent for fields in 200 to 400 meters of water, 52.5 million barrels oil equivalent for fields in 400 to 800 meters, and 87.5 million barrels oil equivalent for fields in more than 800 meters. Leasing in the deepwater Gulf increased dramatically after the start of the royalty relief program, more than tripling between 1995 and 1997. Although it has fallen off from the 1997 peak, the levels remain considerably above those seen before the program, and the program has been deemed a success by the MMS and by the industry.

Hoping to enhance the positive effects of the program, the MMS has in the proposed new rules and regulations modified certain provisions to provide increased flexibility. Under the new rules, volumes will be assigned to individual leases rather than to fields, with volumes and depths specified at the time of the lease sale.

Royalty in Kind

Since the August 1996 enactment of the Federal Oil and Gas Royalty Simplification and Fairness Act, the MMS has been evaluating more extensive use of royalty in kind—the acceptance of a portion of oil or gas produced in lieu of cash to satisfy royalties. Benefits of accepting royalty in kind payments could include a reduced administrative burden for both industry and the MMS, fewer disputes over royalty determinations, more accurate royalty determinations, and maximization of Government revenues from royalties.

In addition to the Small Refiners Program, which was initiated in the 1970s to give small refiners access to crude oil at fair prices through the sale of royalty oil, and a more recent program (completed in October 2000) to add 28 million barrels of royalty oil to the Strategic Petroleum Reserve, four pilot projects are being used to assess the feasibility of royalty in kind. The first project, initiated in 1998 for onshore crude oil from Federal leases in the Powder River and Big Horn basins in Wyoming, has moved to operational status. A second 1998 project involves natural gas from leases in the Texas 8(g) zone of the Gulf of Mexico. A more comprehensive 1999 project, which includes natural gas from Federal leases in the entire Gulf of Mexico, allows a portion of the gas that would otherwise be sold competitively on the open market to be transferred to the Government Services Administration (GSA) for use in Government facilities. A fourth pilot project, initiated in 2000, applies to crude oil from Federal leases in the Gulf of Mexico.

The FERC has claimed that the method used to transfer gas to GSA under the third project, conflicts with its open-access policies by potentially circumventing the competitive bidding requirements for securing pipeline capacity. The FERC has granted MMS a waiver until October 31, 2001, so that the program can continue but has insisted that MMS develop a plan by August 2001 to either replace the auction system or contract for its own firm transportation capacity so that the program will conform with FERC policy.

Crude Oil Valuation

On March 15, 2000, the MMS published the final rule for the valuing of crude oil produced on Federal lands for the purpose of determining royalty payments. The rule took effect on June 1, 2000, with a 3-month interest-free grace period to allow industry to make any changes needed to implement the rule. The rule is based on the premise that spot market pricing is the best indicator of the value of crude oil in today's market, and it applies spot market pricing for the major integrated companies and others that refine their oil. The use of spot market rather than posted prices would have increased Government revenues by nearly $67.3 million according to the MMS [*5*], with most of the additional revenues coming from the major integrated oil companies. Because of administrative savings associated with the new rule, MMS maintains that the net increase in costs to the industry will be an estimated $63.5 million. So as not to cause small independent producers undue hardship, they will be allowed to continue to value crude oil using posted prices as they did under the 1988 rule and, thus, will not be affected.

Tier 2 Vehicle Emissions and Gasoline Sulfur Standards

CAAA90 set "Tier 1" exhaust emissions standards for carbon monoxide (CO), hydrocarbons, NO_x, and particulate matter for light-duty vehicles and trucks beginning with model year 1994. CAAA90 also required EPA to study further "Tier 2" emissions standards that would take effect in model year 2004. EPA provided a Tier 2 study to Congress in July 1998, which concluded that tighter vehicle standards are needed to achieve attainment of National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter between 2007 and 2010.

In February 2000, EPA published its Final Rule on "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements [*6*]. The Final Rule includes standards that will significantly reduce the sulfur content of gasoline throughout the United States to ensure the effectiveness of emissions control technologies that will be needed to meet the Tier 2 emissions targets. The inclusion of the new Tier 2 standards and low-sulfur gasoline requirements in the *AEO2001* reference case is a noteworthy change from the *AEO2000* reference case.

In 2004, manufacturers must begin producing vehicles that are cleaner than those being sold today. The standards would also be extended to light-duty trucks, minivans, and sport utility vehicles (SUVs) which currently pollute three to five times more than cars. This is the first time that the same set of emissions standards will be applied to all passenger vehicles. In its Final Rule, EPA notes that the single set of standards is appropriate given the increasing use of light trucks for personal transportation and the increasing number of vehicle-miles traveled by light trucks. The same standards will be applied to vehicles operated on any fuel.

For passenger cars and light-duty trucks rated at less than 6,000 pounds gross vehicle weight, the standards will be phased in beginning in 2004, with full implementation by 2007. For light-duty trucks rated at more than 6,000 pounds gross vehicle weight and medium-duty passenger vehicles (a new class introduced by the rule to include SUVs and passenger vans rated between 8,500 and 10,000 pounds), the standards will be phased in beginning in 2008, with full implementation in 2009. Interim average standards will apply during the phase-in periods, which are from 2004 to 2007 for passenger cars and light-duty trucks less than 6,000 pounds and from 2004 to 2008 for light-duty trucks more than 6,000 pounds and medium-duty passenger vehicles.

Because automotive emissions are linked to the sulfur content of motor fuels, the Final Rule also requires a reduction in average gasoline sulfur levels nationwide. Sulfur reduces the effectiveness of the catalyst used in the emission control systems of advanced technology vehicles, increasing their emissions of hydrocarbons, CO, and NO_x. The sulfur content of gasoline must be reduced to an annual average of 30 parts per million (ppm), and a maximum 80 ppm in any gallon, to accommodate the new emissions control systems and meet the Tier 2 standards. The new Federal standard is equivalent to the current standard for gasoline in California at about one-fourth the sulfur content in areas currently using reformulated gasoline and about one-tenth the current sulfur content of conventional gasoline.

Because the standard will require refiners to invest in sulfur-removing processes, it will be phased in between 2004 and 2007 and, initially, will allow less stringent standards for small refiners. To encourage reductions before 2004, refiners will receive credits for sulfur reductions below a baseline level. The credits can be used later as "allotments," which will allow a refiner to exceed the new sulfur standard by a given amount. Gasoline produced by most refiners will be required to meet corporate average sulfur contents of 120 ppm in 2004 and 90 ppm in 2005. The corporate average will be phased out by 2006, when most refiners must meet a refinery-level average of 30 ppm. Refiners producing most of their gasoline for the Rocky Mountain region will also be allowed a more gradual phase-in because of less severe ozone pollution in the area; they will be required to meet a refinery average of 150 ppm in 2006 and must meet the 30 ppm requirement in 2007. Small refiners will not be required to meet the 30 ppm standard until 2008.

Heavy-Duty Vehicle Emissions and Diesel Fuel Quality Standards

In August 2000 the EPA finalized new regulations to reduce emissions from heavy-duty trucks and buses substantially. In the Final Rule, the standards for all diesel vehicles over 8,500 pounds will reduce NO_x emissions by more than 40 percent through reductions in hydrocarbons beginning in 2004 [*7*]. New test procedures and compliance requirements will begin in the 2007 model year, and on-board diagnostic systems will be required for engines in vehicles between 8,500 and 14,000 pounds, with a phase-in period covering the 2005 through 2007 model years [*8*]. New standards for heavy-duty gasoline engines and vehicles will reduce both hydrocarbons and NO_x for all vehicles above 8,500 pounds not covered in the Tier 2 standards, beginning in 2005. The rule also includes incentives for manufacturers to begin meeting the standards in 2003 or 2004. On-board diagnostic systems will also be required for heavy-duty gasoline vehicles and engines up to 14,000 pounds.

In order to enable diesel engine technology to meet tighter emissions standards, EPA has proposed new standards for diesel fuel quality, which would become effective in mid-2006. The proposed standards would cap diesel fuel sulfur content at 15 ppm from the current maximum standard of 500 ppm. In addition to reduced sulfur content, the standards would also maintain hydrocarbon emissions by continuing to require a minimum cetane index of 40 or a maximum aromatic content of 35 percent by volume [*9*]. EPA estimates that the proposed diesel standards would increase the cost of diesel fuel by 3 to 4 cents per gallon [*10*], although other estimates are higher. Because the proposed changes to diesel fuel standards have not been finalized, they are not included in the *AEO2001* reference case [*11*].

Banning or Reducing the Use of MTBE in Gasoline

Methyl tertiary butyl ether (MTBE) is a chemical compound used as a blending component in gasoline. Since 1979 it has been used to boost the octane of gasoline to prevent “engine knock.” The use of MTBE climbed in the 1990s, when it was used to meet Federal oxygen requirements for cleaner burning reformulated and oxygenated gasoline under CAAA90.

Despite the success of the CAAA90 gasoline programs in improving air quality, concerns about MTBE contamination of water supplies has led to a flurry of legislative and regulatory actions at the State and Federal levels that would either ban or limit the use of MTBE in gasoline. MTBE is the most commonly used “oxygenate” or oxygen booster, used in about 87 percent of reformulated gasoline (RFG); however, CAAA90 does not specify what type of oxygenate should be blended into gasoline. Some refiners, especially those in the Midwest, use ethanol as an oxygenate. Because a ban on MTBE would affect the economics and chemical characteristics of gasoline supplies, the issue has often been tied to proposals to waive the Federal oxygen requirement and to impose a new “renewable standard” that would, in effect, require a certain annual average percentage of ethanol to be blended into gasoline.

The *AEO2001* reference case reflects only changes to legislation or regulations that have been finalized and not those that are proposed. Therefore, the *AEO2001* projections incorporate MTBE bans or reductions in the States where they have passed but do not include any proposed State or Federal actions or the proposed oxygen waiver. Discussion of an alternative case which assumes that all States will ban MTBE is provided in “Issues in Focus” (page 35).

Water contamination by MTBE results primarily from leaking pipelines or gasoline storage tanks. MTBE moves through soil more easily than other gasoline components, and it is difficult and expensive to remove from groundwater. The issue of MTBE contamination of water supplies first captured public attention in 1996, when MTBE was detected in two wells representing half the drinking water supplies in Santa Monica, California. Since that time, a growing number of studies have detected MTBE in drinking water supplies throughout the country. Although about 99 percent of the detections have been well below levels of health concern, the odor and taste of MTBE can make water undrinkable even at very low concentrations. MTBE is five times more likely to be found in water supplies in the areas of the country that use Federal RFG than in those that do not.

In response to rising concerns about MTBE-tainted water supplies, the EPA convened a “Blue Ribbon

Panel" (BRP) in early 1999 to assess the extent of the problem and make recommendations. In addition to tighter safeguards for water protection, the BRP recommended that the use of MTBE be substantially reduced. To ensure a cost-effective phasedown of MTBE, the BRP suggested that Congress waive the 2 percent oxygen requirement for RFG while EPA develops a mechanism to prevent the current air quality benefits of RFG from declining.

In March 2000, the EPA issued an Advanced Notice of Proposed Rulemaking that would regulate the use of MTBE in gasoline under the authority of the Toxic Substances Control Act, which gives EPA the authority to regulate chemical substances to prevent unreasonable risks to health or environment. The Advanced Notice is the initial document in a lengthy rulemaking process and does not provide details about how the use of MTBE might be regulated. Political pressure for a quick resolution to the MTBE water contamination problem has resulted in numerous legislative proposals in the U.S. Congress that would limit or ban MTBE. On September 7, 2000, the Senate Environment and Public Works Committee reported out a bill, but Congress has not yet passed legislation that would address the MTBE issue. Questions of legal authority and time-consuming analysis of air quality benefits have prevented the EPA from granting a waiver to the Federal oxygen requirement.

States have taken the lead in passing legislation related to MTBE. The first law was passed in 1999 in California, where water problems first appeared. In March 1999 California's governor, Gray Davis, initially announced that MTBE would be banned in gasoline in the State by 2003. At that time the California Energy Commission requested that EPA waive the Federal oxygen requirement for California gasoline, and California congressmen introduced bills in the U.S. Congress that would waive the requirement. As of October 2000 no regulatory or legislative action has been taken to waive the Federal oxygen requirement in California or in any other State. The EPA is currently assessing whether an alternative gasoline formulation that does not include oxygen can give similar emissions reductions. In 2000, seven other States—Arizona, Connecticut, Maine, Minnesota, Nebraska, New York, and South Dakota—passed legislation to ban or limit the use of MTBE within the next several years. Unlike in California, the majority of the recent legislation in other States has not been linked to a waiver request. Legislation has also been drafted, but not passed, in Colorado, Hawaii, Iowa, Michigan, and Nebraska. The Maryland, New Hampshire, and Virginia legislatures have also passed bills to study or test for MTBE contamination, and Illinois has passed a bill that would change labeling at the gasoline pump. *AEO2001* incorporates legislation to ban or limit MTBE in the eight States where it has been passed.

The patchwork quilt effect of individual State bans on MTBE will further complicate the gasoline supply and distribution system in the United States, which already handles more than 50 different types of gasoline as a result of State and Federal regulations and market demand for different octane grades [*12*]. One example is in the Northeast, where 65 percent of the gasoline supply is RFG. There is concern that by banning MTBE, New York and Connecticut have effectively created an island around New York City where RFG without MTBE is required. Areas with unique gasoline requirements are more vulnerable to supply disruptions and related price spikes.

Proposed Changes to RFG Oxygen Standard

In June 2000, the EPA published a notice of proposed rule making (NPRM) that would provide refiners with more flexibility for producing RFG. The NPRM would relax the summer volatile organic compound (VOC) compliance standard for ethanol-blended RFG and would also replace the current minimum of 1.5 percent by weight per gallon with an annual average oxygen requirement of 2.1 percent by weight. The change in regulations would make it easier for refiners to produce RFG, especially in the summertime, when VOC standards make it more difficult to produce RFG with ethanol because of its volatility. Under the proposed regulations a refiner using ethanol as an oxygenate could choose to blend no ethanol in the summertime but meet the 2.1-percent annual average oxygen requirement by blending ethanol at higher concentrations during the rest of the year. Such a change might ease some of the tightness in blending that contributed to the gasoline price spikes in the Midwest last spring and summer and might make it easier to meet a renewable fuels standard, which has been discussed as part of the MTBE ban issue [*13*]. Because the rule is not final, *AEO2001* does not incorporate the change to the RFG standard.

Proposed Limits on Benzene in Gasoline

In July 2000 the EPA proposed a rule that identifies 21 mobile source air toxics (MSATs) and would limit the amount of one of those air toxics, benzene, in gasoline [*14*]. CAAA90 includes provisions governing toxic emissions from stationary sources but does not include a list of pollutants that should be classified as motor vehicle toxics. The proposed list of MSATs released by EPA in July 2000 includes compounds that result from fuel combustion in vehicle engines, along with certain metal compounds and diesel exhaust. The list of MSATs includes common gasoline components such as MTBE and benzene.

The EPA proposal includes an evaluation of the ability of other Federal emissions control programs—such as RFG, Tier 2 and gasoline sulfur reductions, and the national low emission vehicles program (NLEV)—to reduce MSATs. Because the evaluation determined that additional measures would be required to control benzene, EPA proposed a maximum limit on the amount of benzene that could be added to gasoline starting in 2002. The proposed standards would require refiners to maintain the average level of benzene that they used in 1998-1999, and they are expected to result in "negligible additional costs" to refiners. Because the rule limiting benzene has not been finalized, it is not reflected in the *AEO2001* projections.

Low-Emission Vehicle Program

The Low-Emission Vehicle Program (LEVP) was originally passed into legislation in 1990 in the State of California. It began as the implementation of a voluntary opt-in pilot program under the purview of CAAA90, which included a provision that other States could opt in to the California program and achieve lower emissions levels than required by CAAA90. Both New York and Massachusetts chose to opt in to the LEVP, implementing the same mandates as California.

The LEVP was an emissions-based policy, setting sales mandates for three categories of low-emission vehicles according to their relative emissions of air pollutants: low-emission vehicles (LEVs), ultra-low-emission vehicles (ULEVs), and zero-emission vehicles (ZEVs). The only vehicles certified as ZEVs by the California Air Resources Board (CARB) were dedicated electric vehicles [*15*].

The LEVP was originally scheduled to begin in 1998, with a requirement that 2 percent of the State's vehicle sales be ZEVs, increasing to 5 percent in 2001 and 10 percent in 2003. In California, however, the beginning of mandated ZEV sales was rolled back to 2003, because it was determined that ZEVs would not be commercially available in sufficient numbers or at sufficiently competitive cost to allow the targets to be met. In September 2000 CARB decided to maintain the 2003 mandated start of the LEVP rather than delay. In Massachusetts and New York, after several years of litigation, the Federal courts overturned the original LEVP mandates in favor of the same deferred schedule adopted by California. For *AEO2001*, Maine and Vermont have been added to the LEVP mandates, because they have adopted programs similar to those in California, Massachusetts, and New York. It is assumed that vehicle sales will meet these mandates.

On November 5, 1998, the CARB amended the original LEVP to include ZEV credits for advanced technology vehicles. According to the CARB, qualifying advanced technology vehicles must be capable of achieving "extremely low levels of emissions on the order of the power plant emissions that occur from charging battery-powered electric vehicles, and some that demonstrate other ZEV-like characteristics such as inherent durability and partial zero-emission range" [*16*]. There are three components in calculating the ZEV credit, which vary by vehicle technology: (1) a baseline ZEV allowance, (2) a zero-emission vehicle-miles traveled (VMT) allowance, and (3) a low fuel-cycle emission allowance. Using advanced technology vehicles in place of ZEVs in order to comply with the LEVP mandates requires assessment of each vehicle characteristic relative to the three criteria.

The baseline ZEV allowance potentially can provide up to 0.2 credit if the advanced technology vehicle meets the following standards: (1) super-ultra-low-emission vehicle (SULEV) standards, which approximate the emissions from power plants associated with recharging electric vehicles; (2) on-board diagnostics (OBD) requirements for indicators on the dashboard that light up when vehicles are out of emissions compliance levels; (3) a 150,000-mile warranty on emission control equipment; and (4) evaporative emissions requirements in California, which prevent emissions during refueling.

The second criterion, the zero-emission VMT allowance, will allow a maximum 0.6 credit if the vehicle is capable of some all-electric operation (to a range of at least 20 miles) that is fueled by off-vehicle sources (i.e., no on-board fuel reformers), or if the vehicle has ZEV-like equipment on board, such as regenerative braking, advanced batteries, or an advanced electric drive train. An emission allowance was also made for vehicle fuels with low fuel-cycle emissions used in advanced technology vehicles. A maximum of 0.2 credit is provided for vehicles that use fuels which emit no more than 0.01 gram of nonmethane organic gases per mile, based on the grams per gallon and the fuel efficiency of the vehicle.

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

Appliance Efficiency Standards

Since 1988, the U.S. Department of Energy (DOE) has promulgated numerous efficiency standards requiring the manufacture of appliances that meet or exceed minimum levels of efficiency as set forth by DOE test procedures. In 1987, Congress passed the National Appliance Energy Conservation Act (NAECA), which permitted DOE to establish test procedures and efficiency standards for 13 consumer products. Under the auspices of NAECA, DOE is responsible for revising the test procedures and efficiency levels as technology and economic conditions evolve over time.

From 1988 to 1995, DOE established and revised efficiency standards almost on an annual basis, as shown in Table 3. In 1995, however, Congress issued a standards moratorium for fiscal year 1996, which prohibited DOE from establishing any new standards. The moratorium caused a delay of several years, with no standards becoming effective from 1996 through July 2000. After a reevaluation of the standards program, DOE established a new process that allows for greater input from stakeholders by creating the Advisory Committee on Appliance Energy Efficiency Standards, which comprises technical experts representing the concerns of industry, environmentalists, and the general public.

With input from stakeholders early in the promulgation process, it was believed that the rulemaking process would become more predictable, more timely, and less controversial. The refrigerator standard issued for July 2001, for example, was promulgated through a series of compromises in December 1996, allowing a later enforcement date but at a higher efficiency level. Achieving similar consensus among disparate concerns such as the gas and electric industries and environmentalists may prove difficult, however, when multi-fuel products, such as water heaters, are considered for review. The debate over end-use efficiency versus total system efficiency is a lively one, with electric and gas concerns generally disagreeing as to how efficiency and environmental benefits should be measured. In fact, the inability to create a single national home energy rating system (HERS) has shown that achieving

Table 3. Effective dates of appliance efficiency standards, 1988-2005

Product	1988	1990	1992	1993	1994	1995	2000	2001	2005
Clothes dryers	X				X				
Clothes washers	X				X				
Dishwashers	X				X				
Refrigerators and freezers		X		X				X	
Kitchen ranges and ovens		X							
Room air conditioners		X					X		
Direct heating equipment		X							
Fluorescent lamp ballasts		X							X
Water heaters		X							
Pool heaters		X							
Central air conditioners and heat pumps			X						
Furnaces									
Central (>45,000 Btu per hour)			X						
Small (<45,000 Btu per hour)			X						
Mobile home		X							
Boilers			X						
Fluorescent lamps, 8 foot					X				
Fluorescent lamps, 2 and 4 foot (U tube)						X			

consensus among these groups is difficult, signaling a continued debate as to how efficiency should be evaluated across fuel types.

An agreement between manufacturers and energy efficiency advocates was reached in October 1999 on fluorescent lighting standards for commercial and industrial applications. The notice of the final rule for a fluorescent lamp ballast standard was published in the September 19, 2000, *Federal Register*, and the standard goes into effect in April 2005. It sets a minimum efficacy level for ballasts manufactured for T12 fluorescent lamps that effectively eliminates less efficient magnetic ballasts for those applications. Because the standard has been finalized, it is included for *AEO2001*.

Currently, DOE is in the process of evaluating new efficiency standards for several products. Proposed rules for water heaters, clothes washers, and central air conditioners and heat pumps have been published in the *Federal Register*, and final rules are expected in the coming months. After the final rules are published in the *Federal Register*, a lead time of 3 to 5 years is required for the standards to take effect. The next commercial sector products DOE intends to evaluate for standards include distribution transformers, commercial furnaces and boilers, commercial heat pumps and air conditioners, and commercial water heaters. Because the *AEO2001* reference case includes only standards that have been finalized, with the effective dates and efficiency levels specified in the *Federal Register*, these efficiency standards are not included in the projections.

Petroleum Reserves

After heating oil prices reached extreme highs in the Northeast in January-February 2000, DOE established a heating oil component of the Strategic Petroleum Reserve (SPR) in the Northeast. The heating oil reserve will provide up to 2 million barrels of emergency heating oil supplies. DOE obtained emergency stocks by exchanging crude oil from the SPR with companies that would provide heating oil and storage facilities. In addition to setting up an interim emergency heating oil supply, DOE proposed an amendment to the Strategic Petroleum Reserve Plan that would authorize heating oil storage on a permanent basis. A permanent Heating Oil Reserve was authorized in October 2000 with the passage of the Energy Act of 2000 (H.R. 2884).

In response to the tight supplies of oil and heating oil before the 2000-2001 winter heating season, President Clinton directed DOE to release 30 million barrels of crude oil from the SPR. DOE offered the crude oil reserves in exchange for crude oil to be returned to the SPR between August and November 2001. EIA estimates that the release of SPR crude oil will make available an additional 3 to 5 million barrels of distillate fuel in the market this winter.

Although the creation of the heating oil reserve and release of crude oil reserves are of interest to consumers in the Northeast, they have no impact on the *AEO2001* projections for petroleum, because the long-term annual projections in *AEO2001* do not reflect changes in stocks of crude oil or petroleum products.

Issues in Focus

Macroeconomic Forecasting with the Revised National Income and Product Accounts (NIPA)

The NIPA Comprehensive Revision

Economic activity is a key determinant of growth in U.S. energy supply and demand. The derivation of the forecast of economic activity is therefore a critical step in developing the energy forecast presented in the *Annual Energy Outlook 2001* (*AEO2001*). In turn, the forecast of economic activity is rooted fundamentally in the historical data series maintained by a number of Federal Government agencies. The Bureau of Economic Analysis (BEA) in the U.S. Department of Commerce produces and maintains a series of accounts, with the NIPA being perhaps the most quotable and most often used [*17*]. The following discussion focuses on a major BEA revision of the NIPA historical source data and its implications for projections of energy demand.

The NIPA tables reflect historical data for U.S. gross domestic product (GDP) and its components, both on a nominal basis and in real terms. The derivation of the real activity data relies on a set of price indexes, also maintained by BEA, which show how prices have historically moved for each component of final demand and for the economy at large.

BEA revises the NIPA tables on a periodic basis, both from the perspective of conceptual changes in the way the accounts are prepared and to accommodate new and revised data. On occasion, BEA makes fundamental changes in the accounts. In 1996, NIPA shifted from using fixed-year price deflators to a chain-type deflator [*18*]. This had the effect of removing a substitution bias in the derivation of the measure of real GDP growth in the economy [*19*]. In 1999, BEA made a series of additional changes in the NIPA tables, some resulting in a fundamental change in measures of the historical rate of growth in the economy [*20*]. Table 4 compares the growth rates in GDP and its major components as previously computed and as revised.

In simply looking at the data before and after revision, there is an obvious change in historical rates of real GDP growth. One change is that the accounts are now rebased in 1996 dollars, as compared to 1992 dollars used previously. But this does not account for the difference in calculated growth rates, because the switch to chain-weighting eliminated this type of rebasing as a source of change in the historical growth rates [*21*]. Then where does the change in growth come from? Revisions to real GDP growth reflect two primary factors: (1) revisions to the current dollar components of GDP and (2) revisions to the prices used to estimate components of real GDP, plus revisions to the quantities used to estimate components of real GDP.

Table 4. Historical revisions to growth rates of GDP and its major components, 1959-1998 (percent per year)

Growth rate	*Before revision*	*After revision*	*Difference*
Real GDP	***3.2***	***3.4***	***0.2***
Consumption	*3.4*	*3.6*	*0.2*
Investment	*4.2*	*4.6*	*0.4*
Nonresidential equipment and software	*6.3*	*6.8*	*0.5*
Government	*1.9*	*2.1*	*0.2*
Exports	*6.9*	*7.0*	*0.1*
Imports	*6.5*	*6.5*	*0.0*

Revisions to the nominal series can be divided into two categories of change: definitional and statistical. The definitional changes include such items as recognition of business and government expenditures for software as investment; reclassification of government employee retirement plans; modification of the treatment of private, noninsured pension plans; reclassification of certain transactions as capital transfers; and redefinition of the value of imputed service of regulated investment companies. Of these definitional changes, the major impact comes from the inclusion of business and government expenditures for software in the investment accounts. In the prior NIPA data, business purchases of software were considered as intermediate purchases and not as a final product counted in GDP. The revision places such expenditures in a separate investment category, similar to the manner in which computer hardware is considered as an explicit investment category of final demand.

The statistical changes in NIPA focus primarily on new and revised source data and improved estimating methodologies. The statistical changes include the incorporation of new data from BEA, the Census Bureau, the Bureau of Labor Statistics, the U.S. Department of Agriculture, and the Internal Revenue Service. For example, the new BEA data benchmark 1992 input-output accounts, plus the 1996 annual update of those accounts, provide a better view of sectoral output activity in the economy. In addition, methodological improvements were made in the estimation of the real value of unpriced banking services.

Table 5. Revisions to nominal GDP, 1959-1998

Revision	1959	1982	1987	1992	1996	1997	1998
Change in nominal GDP (billion dollars)	**0.2***	**17.1**	**50.2**	**74.5**	**151.6**	**189.9**	**248.9**
Definitional	-0.1	19.9	44.1	78.3	123.7	140.9	169.0
Statistical	0.3	-2.8	6.0	-3.8	27.9	49.0	80.0
Change relative to previous NIPA-defined nominal GDP (percent)	**0.0**	**0.5**	**1.1**	**1.2**	**2.0**	**2.3**	**2.9**
Definitional	0.0	0.6	1.0	1.3	1.6	1.7	2.0
Statistical	0.0	-0.1	0.1	-0.1	0.4	0.6	0.9

*Total does not equal sum of components due to independent rounding.

Table 5 shows the revisions to the nominal dollar valuation of GDP for various years, breaking down the changes into definitional and statistical components. While the definitional changes tend to be larger, primarily because of the changes made to reflect software purchases, the statistical changes from 1996 and beyond are a growing portion of the overall change.

Table 6 presents a more detailed breakout of the data for 1998, indicating which components of GDP are affected the most and how they change the aggregate value for nominal GDP. The table shows the value of the difference between the old and new valuations, broken out by component of GDP. The table highlights the role of software changes in the revised accounts. For 1998, the incorporation of software as a final demand category—nonresidential equipment and software plus the investment in software for the Government—accounts for 63 percent of the total nominal revision of $248.9 billion.

Implications for Economic Growth and Energy Demand

The revision to the economic data underlying NIPA has implications both for the forecasting of economic growth and for the derivation of energy demand to support the projected growth. From both perspectives, the central question is how to interpret the new data. As highlighted in Tables 5 and 6, much of the revision is definitional in nature, particularly with the new accounting for software purchases. Does this signify a new view of the economy, recognizing that the old accounts undervalued growth in the aggregate economy; or do the new data simply transform how we look at the economy, with no dramatic reassessment of the growth potential of the underlying economy? An early assessment by Standard & Poor's DRI (DRI) of the role of the accounting changes tended to focus on the redefinitional aspects, with no strong feeling that the revisions signaled a "new economy" [*22*]. Later articles from both DRI and the WEFA Group (WEFA) highlight the recent rapid increase in productivity growth in the economy. A series of articles in *The Economist* provides an excellent summary of the debate about recent productivity trends [*23*]. The changes to the accounts reflect a more complete representation of investment through the software revisions and indicate that the true growth potential of the economy was undervalued historically.

Table 6. Revisions to nominal GDP for 1998 (dollars)

Component	Total	Definitional	Statistical
GDP	**248.9***	**169.0**	**80.0**
Consumption	40.7	29.1	11.6
Investment	164.1	123.4	40.7
Nonresidential equipment and software	127.2	123.4	3.8
Government	42.6	16.7	25.9
Investment: software	28.5	28.5	0.0
Net exports	1.6	0.0	1.6

*Total does not equal sum of components due to independent rounding.

Table 7 shows growth rates for the last four decades for three key indicators: real GDP, the labor force, and a simple comprehensive measure of productivity showing the value of real GDP generated per member of the labor force. With the pre-revision data, the growth rate of the economy slowed each decade relative to the 1960s. The rapid labor force growth of the 1970s, due to expanded entry of women into the work force, was offset by low productivity growth. During the 1980s and 1990s, productivity

Table 7. Historical growth in GDP, the labor force, productivity and energy intensity (percent per year)

Growth rate	1960-1970	1970-1980	1980-1990	1990-1998
Before revision				
Real GDP	4.1	3.1	2.9	2.6
Labor force	1.7	2.6	1.6	1.1
Productivity	2.4	0.5	1.2	1.5
Energy intensity	0.0	-1.6	-2.1	-1.1
After revision				
Real GDP	4.2	3.2	3.2	3.0
Labor force	1.7	2.6	1.6	1.1
Productivity	2.4	0.6	1.5	1.9
Energy intensity	0.0	-1.7	-2.4	-1.5

increases partially offset slowing growth in the labor force. With the post-revision data, the view of the economy is altered. The dropoff in real GDP growth is moderated somewhat. The change is attributable to slightly higher measures of productivity growth in the economy.

Three trends are evident: (1) of the four decades, productivity growth was far stronger in the 1960-1970 period than in any subsequent decade (although the second half of the 1990s had comparable productivity growth); (2) the revisions to the NIPA tables substantially increase the perceived growth in output per member of the labor force; and (3) energy intensity per unit of output has declined more rapidly in recent decades than was previously thought. The latter change is directly related to the revised upward growth of the real GDP series.

As the gap between the GDP growth rates before and after revision widens across the decades, the gap between the corresponding productivity growth rates also widens. In the period from 1990 through 1998, the real GDP annual growth rate has been revised upward from 2.6 percent to 3.0 percent, and the annual growth rate in GDP per member of the labor force has moved from 1.5 percent to 1.8 percent. The growth in productivity in the 1990s has been associated by some with the development of a “new economy” associated with continually improving communication and real time information. Future releases of data, based on the new accounting conventions, will shed light on the prospects for sustained rates of GDP growth in the face of slowing population and labor force growth rates.

A measure of the energy intensity of the economy can be computed as the ratio of energy consumption to real GDP. Table 7 shows growth rates for the decline in energy intensity by decade, and Figure 8 shows energy intensity before and after revision, indexed to 1.0 in 1960. During the 1960s, energy consumption grew at roughly the same rate as real GDP. Although energy intensity declined slightly in mid-decade, by 1970 the index returned to approximately the 1960 level. With energy prices rising during the 1970s and early 1980s, however, energy intensities declined rapidly as consumers and producers adjusted their energy use in response to higher prices. In the late 1980s and during the 1990s, the growth in the economy was accompanied by generally declining energy prices, and the rate of energy intensity decline slowed.

The revisions to the NIPA data, by reflecting a higher rate of real GDP growth, lead to a revised view of the rate of decline in the energy intensity of the economy. For each decade since the 1960s, the measure of energy intensity declines at a faster rate than previously thought.

Figure 9 summarizes the effects of the NIPA revisions on both historical growth in the economy and for projections through 2020. The figure shows a moving 21-year average annual growth rate for real GDP, with the value for each year calculated as the average annual growth rate over the preceding 21 years [*24*]. For history, GDP growth between 1959 and 1980 (21 years) averaged 3.6 percent per year. The pre-revision data indicated that, in the period between 1978 and 1999, the real GDP growth rate was 2.7 percent per year; however, with the new revisions to the NIPA data, the growth rate between 1978 and 1999 is now calculated at 3.0 percent, an upward revision of 0.3 percentage points.

Figure 8. Index of energy use per dollar of gross domestic product, 1960-1998 (index, 1960 = 1.0)

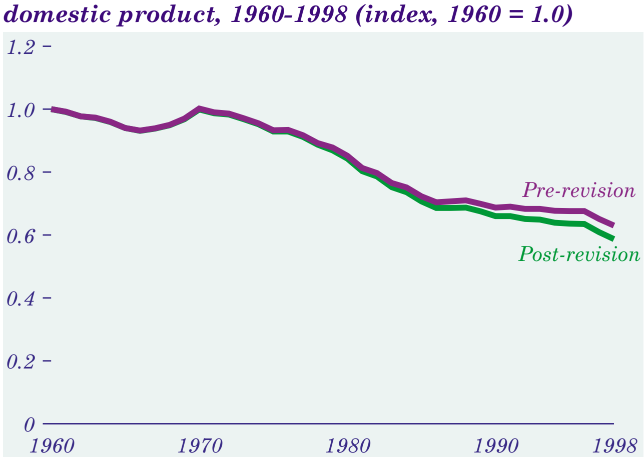
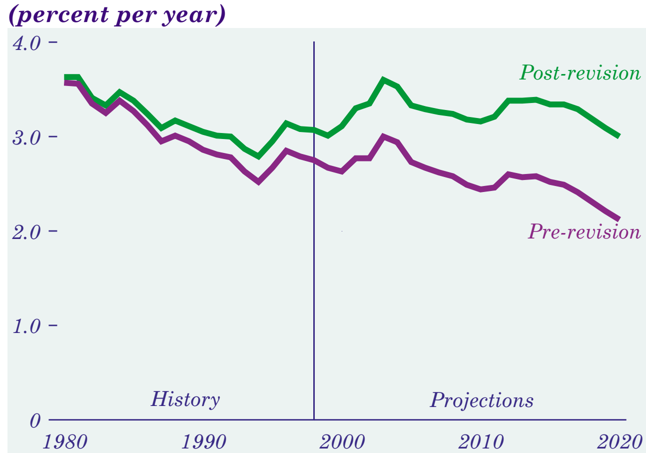


Figure 9. Annual growth in real gross domestic product: 21-year moving average, 1980-2020 (percent per year)



The revisions to the NIPA data do not represent a one-time shift in historical growth rates but, instead, show a growing differential over time. The differential is expected to continue growing over the forecast period. The forecast portion of the pre-revision line in Figure 9 shows the GDP growth rates projected in the *Annual Energy Outlook 2000* (*AEO2000*). The forecast portion of the post-revision line shows the GDP growth rates projected in *AEO2001*. The 21-year average annual growth rate between 1999 and 2020 has been revised upward from 2.1 percent in *AEO2000* to 3.0 percent in *AEO2001*, for a revision difference of 0.9 percentage points.

What implications will the revisions have for the U.S. energy system and, specifically, for the derivation of energy demand in the forecast? Table 8 presents a forecast comparison of key macroeconomic variables for the energy system. The table compares the projected growth rates of the key variables from 1999 through 2020 in the *AEO2000* and *AEO2001* forecasts. The table also shows historical data for the periods 1980-1990 and 1990-1999. The projected growth rates for population and the labor force are essentially the same, but the projected annual growth rate for real GDP, which was 2.1 percent in the *AEO2000* forecast, is 3.0 percent in *AEO2001*, reflecting the underlying changes in the NIPA data.

The projected annual growth in disposable income has also been revised upward, from 2.4 percent in *AEO2000* to 3.0 percent in *AEO2001*; and the expected growth in commercial floorspace has increased from 1.0 percent to 1.3 percent per year. Industrial output (agriculture, mining, construction, and manufacturing) has also been revised upward, from 1.9 percent to 2.6 percent growth annually, and the growth rate for manufacturing output has been revised from 2.0 percent to 2.8 percent. Within manufacturing, the change in growth is predominantly within the non-energy-intensive sectors of the economy, with only a small upward revision in the energy-intensive sectors. Figure 10 shows the projected sectoral composition of growth for *AEO2001*.

How does the revised view of historical economic growth and energy intensity decline translate into changes to the forecasts for the four basic energy demand sectors of the economy? In the residential sector, increased growth in disposable income will influence consumer demand for energy, particularly for miscellaneous electrical appliances such as home theater systems and personal computers. The projected increase in disposable income and the slight increase in population in *AEO2001* lead to an increase in the number of housing starts expected over the forecast period relative to *AEO2000*. The increase in the projection for population growth stimulates the rise in housing starts, and the increase in the projection for disposable income influences the type and size of house built. Single-family homes

Figure 10. Projected average annual growth in sectoral output, 1999-2020 (percent per year)

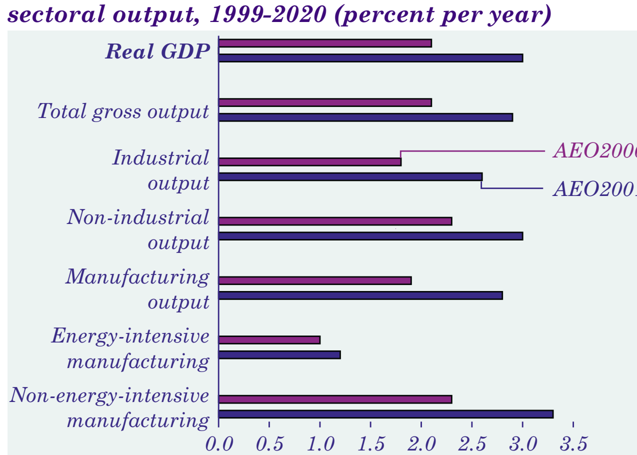


Table 8. Forecast comparison of key macroeconomic variables

	History		Projections, 1999-2020	
	1980-1990	*1990-1999*	*AEO2000*	*AEO2001*
	Growth rate (percent per year)			
Real GDP	***3.2***	***3.2***	***2.1***	***3.0***
Population age 16 and over	*1.1*	*1.0*	*0.9*	*0.9*
Labor force	*1.6*	*1.1*	*0.9*	*0.9*
Disposable income	*3.0*	*2.9*	*2.4*	*3.0*
Commercial floorspace	*2.0*	*1.5*	*1.0*	*1.3*
Industrial output	*1.6*	*2.6*	*1.9*	*2.6*
Manufacturing output	*1.6*	*2.8*	*2.0*	*2.8*
Energy-intensive sector output	*0.9*	*1.6*	*1.0*	*1.2*
Non-energy-intensive sector output	*1.9*	*3.3*	*2.3*	*3.3*
	Period average (million per year)			
Total housing starts	*1.75*	*1.67*	*1.86*	*2.01*
Unit sales of light-duty vehicles	*13.49*	*14.54*	*16.02*	*16.70*

tend to be larger and more energy-intensive than either multifamily or mobile homes, increasing the need for energy to heat, cool, and light the larger living spaces. On average, the projected use of delivered energy per household by 2020 is roughly 6 percent higher in *AEO2001* than it was in *AEO2000*; however, energy use per square foot is expected to decline slightly over the forecast horizon, with gains in energy efficiency projected to offset growth in consumer electronics.

Commercial floorspace is also projected to expand more rapidly in the *AEO2001* forecast, but with little change in the projections for population growth and labor force growth, the change in projected growth in total floorspace is not as great as the change in projected real GDP growth. In *AEO2001*, commercial floorspace is projected to grow by 1.3 percent per year over the forecast period, up from 1.0 percent per year in the *AEO2000* forecast. Figure 11 illustrates the *AEO2001* projections for commercial energy intensity by major fuel. Intensity is defined in terms of delivered energy use per square foot of floorspace, reflecting the direct influence of floorspace on commercial energy demand for major services such as space conditioning and lighting. The continuing trend toward greater use of computers and new types of electronic equipment in conducting business transactions and providing services is reflected in the projected increase in the intensity of electricity use in commercial buildings.

Industrial output in the economy is projected to grow more rapidly in *AEO2001* than was projected in *AEO2000*; however, the definitional portion of the NIPA revisions is not the primary reason. Whether an industry's output is defined as an intermediate good (not included in GDP) or a final demand good (included in GDP) does not by itself affect the inputs required to produce the output, but increased GDP growth resulting from higher productivity does lead to increased growth in industrial output. All sectors of the economy are projected to grow faster, but the most rapid growth is projected to occur outside the energy-intensive sectors. The energy-intensive industries' share of industrial output is projected to fall more rapidly in *AEO2001* (1.3 percent per year) than in *AEO2000* (0.9 percent per year) as a result of expected higher growth in computer-related manufacturing industries. Delivered energy intensity, measured as thousand Btu per dollar of output, is projected to fall by 1.4 percent per year in *AEO2001*, as compared with 0.8 percent per year in *AEO2000*, over the 1999-2020 period. The *AEO2001* projected trends in industrial energy intensity by major fuel are all downward sloping over the next two decades, as shown in Figure 12.

In the transportation sector, the higher expected growth rates for disposable income and GDP in *AEO2001* lead to higher travel forecasts than in *AEO2000*. Light-duty vehicle travel is projected to increase at an annual rate of 1.9 percent from 1999 through 2020, as opposed to the 1.7 percent projected in *AEO2000*. Air travel, including personal, business, and international flights, is projected to expand at 3.6 percent per year, almost twice the rate of increase in light-duty vehicle travel. In *AEO2001*, freight truck travel which is very dependent on industrial output growth, is projected to grow more rapidly than projected in *AEO2000*. Although vehicle sales for all travel modes are projected to increase in the forecast as a result of higher travel levels, improvements in stock efficiency proceed more

Figure 11. Projected commercial delivered energy intensity by fuel, 1999-2020 (thousand Btu per square foot)

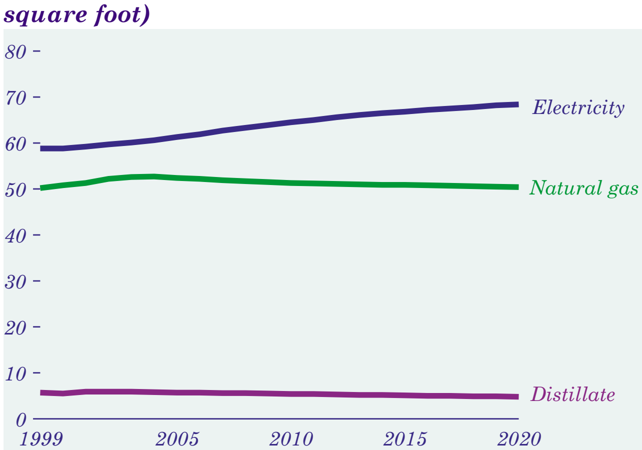
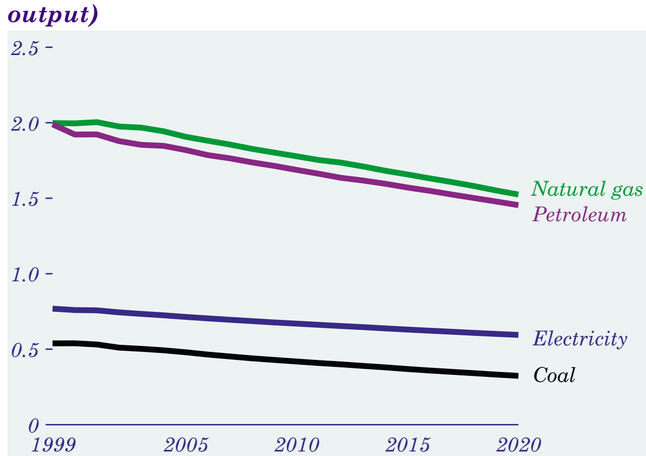


Figure 12. Projected industrial energy intensity by fuel, 1999-2020 (thousand Btu per 1992 dollar of output)



slowly for most modes of transportation. Slow turnover of the vehicle stocks and the magnitude of the stocks relative to the volume of new vehicle sales limit the expected improvements in stock efficiency (Figure 13).

The change in energy demand forecasts as a result of the NIPA revisions does not correspond exactly to the change in the forecast for real GDP growth. The NIPA statistical changes reflect different approaches to measuring growth in economic activity as well as a direct upward revision of the actual growth rate of the economy. Definitional changes, which reflect a movement of previously measured activity from one account to another, do not automatically increase energy consumption; however, if the definitional changes help to explain underlying productivity changes in the economy, then they may serve to revise the prospects for growth in economic activity and energy demand. *AEO2001* presents a forecast of future economic growth that takes into account the revised BEA view of historical growth in the economy.

World Oil Demand and Prices

AEO2000 was released in November 1999, during a period in which world oil prices were beginning to rise from some of the lowest levels of the past 50 years. The major contributors to the low price environment had been reduced growth in oil demand by the developing economies of the Pacific Rim and increased production by the Organization of Petroleum Exporting Countries (OPEC) that resulted in an oil supply surplus. *AEO2000* anticipated that the rebounding oil prices would stabilize at about $21 per barrel (1998 dollars); however, the upward movement of oil prices has been persistently robust. In August 2000 the refiner acquisition cost of imported crude oils was almost $29 per barrel in nominal dollars. Figure 14 illustrates the oil-price turbulence that has defined the world oil market over the past 3 years.

Three factors have contributed to the continuing surge in world oil prices. First, OPEC members exhibited uncharacteristic discipline in adhering to their announced oil production cutback strategies in 1998 and 1999. Joined by several non-OPEC producers (Mexico, Norway, Oman, and Russia), OPEC cut oil production in order to boost prices and increase revenues. Second, the increase in non-OPEC production brought about by higher oil prices has been only modest. In the aftermath of the low price environment of 1998 and early 1999, oil companies have been slow to commit capital to major oil field development efforts, especially for riskier offshore, deepwater projects. Profitability standards appear to have been somewhat tightened, resulting in a greater lag time between higher prices and increases in drilling activity and an even slower reaction time between drilling and production. Third, the renewed growth in oil demand in the recovering economies of the Pacific Rim has been stronger than anticipated.

The turbulence of world oil prices has a significant impact on short-term markets. The oil market perspective presented in *AEO2001*, however, is a business-as-usual perspective that does not incorporate oil price volatility brought about by unforeseen political or social circumstances. Historically, only disruptions in oil supply brought about by politically motivated actions (such as the oil embargo of 1974) or conflicts involving major oil producers (such as the Iranian Revolution and the Iran-Iraq War) have had

Figure 13. Projected new light-duty vehicle and on-road stock fuel efficiency, 1999-2020 (miles per gallon)

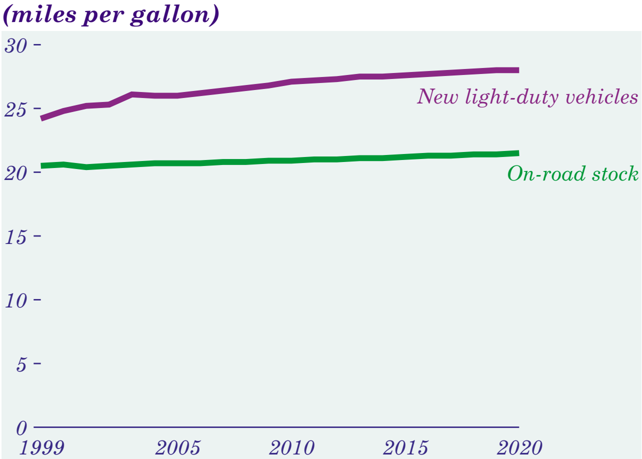
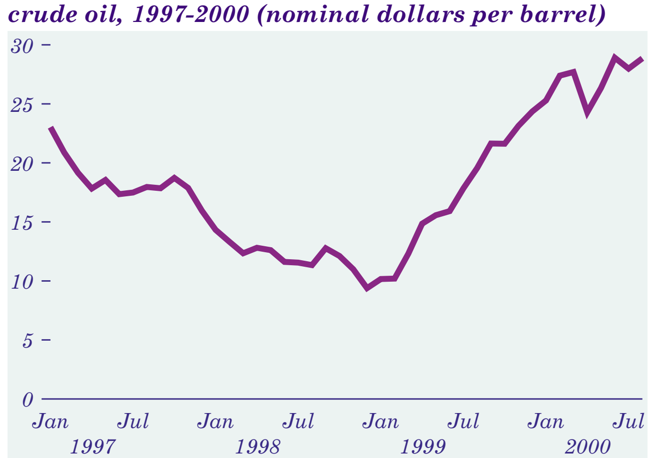


Figure 14. Refiner acquisition cost of imported crude oil, 1997-2000 (nominal dollars per barrel)



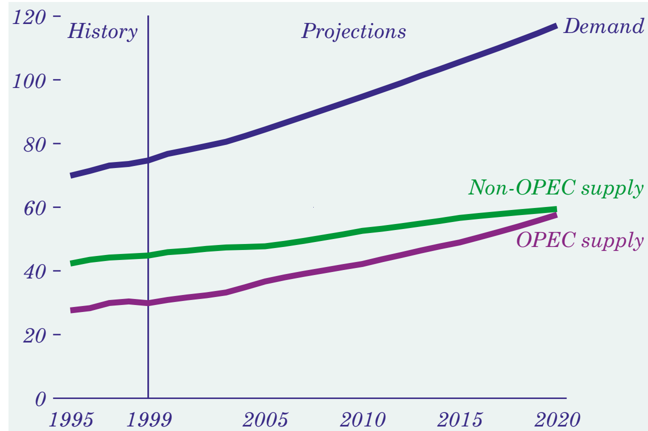
lingering, long-term impacts on oil prices. The oil market volatility over the past several years has been the result of oil market fundamentals that are reasonably well understood but nearly impossible to predict. Traditionally, such near-term oil market gyrations are considered unlikely to have significant impact on long-term markets. Because of this assumption, the *AEO2001* price path converges with last year's path by 2003.

Current high prices are expected to fall for three reasons. First, sustained high oil prices have the potential to damage the economic strength of industrialized and developing nations and delay the full economic recovery of the Pacific Rim nations. OPEC has attempted to avoid those outcomes by easing production restraints during 2000 in order to soften prices somewhat. Second, continued high prices cannot help but have a downward impact on worldwide oil demand due to higher prices and the resulting higher inflation, rising interest rates, and eroding consumer confidence. Third, although non-OPEC producers have been somewhat slow in reacting to higher oil prices, there remains significant untapped production potential worldwide, especially in deepwater areas of the Caspian Basin and the Atlantic Basin off West Africa and Latin America.

Although the long-term price paths in *AEO2000* and *AEO2001* are similar, the *AEO2001* projections of world oil demand are higher—by about 5 million barrels per day in 2020—than those in *AEO2000*. Demand expectations for China, the developing countries of the Pacific Rim, and the Middle East have been revised upward, based on a more optimistic long-term assessment of economic growth in those regions. Even with the increases in the demand forecast, however, the long-term expectations for world oil prices remain virtually unchanged as a result of an equivalent increase in worldwide oil production potential that is based on a recent assessment (June 2000) of ultimately recoverable oil resources prepared by the U.S. Geological Survey (USGS) [*25*].

The June 2000 USGS assessment of world oil production potential identifies about 700 billion barrels of ultimately recoverable oil over and above the previous (1994) USGS assessment. About one-third of the newly identified oil is located in the Caspian Basin region, and the Atlantic Basin (deepwater offshore production potential in West Africa and Latin America) accounts for almost another third. Middle East natural gas liquids and additional volumes from enhanced oil recovery technologies make up

Figure 15. World oil supply and demand forecast in the AEO2001 reference case, 1995-2020 (million barrels per day)



most of the remainder of the incremental oil. Figure 15 illustrates the long-term outlook for oil demand, OPEC supply, and non-OPEC supply in *AEO2001*.

Natural Gas Supply Availability

The record high for U.S. annual consumption of natural gas—22.1 trillion cubic feet—was set in 1972. It was followed by a decline to a low of 16.2 trillion cubic feet in 1986, from which the market has been recovering ever since. Preliminary estimates indicate that the 1972 record may be broken in 2000. The 1972-1986 decline in natural gas consumption was brought on in part by a cumbersome regulatory structure that did not allow the market to respond to price signals in a timely and efficient manner. Producers were constrained by price controls that discouraged production, and consumers were constrained by moratoria placed on the construction of new gas-burning units.

Curtailments of natural gas supplies during the bitterly cold winter of 1976-1977 fueled a perception among consumers that natural gas was a scarce and unreliable resource. In response to the curtailments, Congress in 1978 passed the Natural Gas Policy Act (NGPA), the objective of which was to provide a phased decontrol of natural gas wellhead prices. NGPA signaled the beginning of an era of industry restructuring that is still proceeding. In addition to wellhead price decontrol, which was completed with the passage of the Wellhead Decontrol Act of 1989, restructuring of the interstate pipeline industry was undertaken.

The first phase of restructuring began in 1985 with Federal Energy Regulatory Commission (FERC) Order 436, requiring pipelines to provide open access to transportation services. It was followed by FERC Order 636 in 1992, which allowed for a major restructuring of interstate pipeline operations. The most notable provisions of Order 636 were the separation of sales from transportation services, rate redesign, and capacity release authority. In February 2000, FERC's most recent ruling, Order 637, further refined the remaining pipeline regulations in an effort to address inefficiencies in the capacity release market. FERC has indicated that it will continue a dialog with both industry and consumers in order to promulgate future changes that will foster market efficiency.

The restructuring of the natural gas industry has been effective, leading to open competition in the industry and to a much healthier market that is driven by supply and demand forces rather than by regulation. The market has grown steadily since 1986, with both production and pipeline deliverability showing significant increases. Natural gas is now perceived as an abundant, reliable resource that is expected to fuel an increasing share of domestic energy consumption well into the future.

Natural gas consumption, which accounted for 23 percent of domestic energy use in 1999, is expected to grow more rapidly than any other major fuel source from 1999 to 2020, mainly because of projected growth in gas-fired electricity generation. Consumption is projected to reach 30 trillion cubic feet in 2013 and continue rising to almost 35 trillion cubic feet in 2020. Gas consumption by electricity generators (excluding cogenerators) in 2020 is expected to be triple the 1999 level. As demand increases, pressure on natural gas supply will grow.

Technically recoverable natural gas resources in North America are believed to be adequate to sustain the production volumes projected in *AEO2001*. The current high prices are expected to come down once the effects of increased drilling are realized, and advances in technology over the long term are expected to make it possible to produce more of the technologically recoverable resources economically. Domestic consumption still is expected to increase at a faster rate than domestic production over the forecast period, with imports making up the difference. Natural gas imports have been rising significantly in recent years, and in percentage terms they are expected to outpace domestic production over the forecast. In addition, generally rising wellhead prices, relatively abundant natural gas resources, and technology improvements, particularly for producing offshore and unconventional gas, are expected to contribute to production increases that will keep pace with the remainder of the projected increase in demand.

Short-Term Situation

Natural gas prices have increased sharply in 2000, especially in the spot market, where prices since the summer have generally exceeded $5.00 per thousand cubic feet. The average wellhead price for 2000 is expected to be relatively high, at about $3.37 per thousand cubic feet. This is because of a tight natural gas supply situation resulting from low gas storage levels, an increase in natural gas use for electricity generation as new gas-fired power plants have come on line, and a decline in natural gas drilling that has resulted from generally low prices over the past few years. Low storage levels have resulted from injection rates that have run about 10 percent below historically average rates throughout the refill season. Underground working gas storage levels in September 2000 were about 12 percent below September 1999 levels and about 10 percent below the average for the past 5 years [*26*]. In nominal terms, the expected 2000 wellhead price would be the highest annual wellhead price on record, although it would be lower in inflation-adjusted terms than the prices faced in the early 1980s. Average natural gas wellhead prices this coming winter are projected to be nearly double those seen last year.

Recent higher prices have caused U.S. exploration and drilling to rebound, but the 6- to 18-month lag between drilling increases and market availability of additional product makes it unlikely that a significant amount of additional natural gas supply will be available before mid-2001. Prices in 1998 were low enough to cause cash flow problems in the industry that will delay the response to higher prices longer than usual. Production companies had to replenish investment funds and, in many cases, pay off debt before investing in new projects [*27*].

Slight production increases from increased drilling are already being seen, however, and the Energy Information Administration (EIA) anticipates that further increases will eventually lead to lower prices. Nevertheless, prices over the next year are likely to remain above $3.00 per thousand cubic feet. The current situation is the result of short-term supply imbalances that are expected to even out over the longer term, moving the market toward equilibrium. Natural gas supplies to meet the forecast demand are available from numerous sources, including imports.

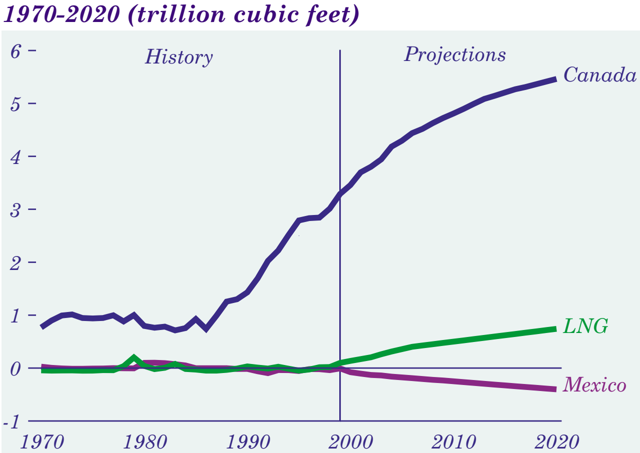
Imports

In the *AEO2001* forecast, net imports of natural gas are expected to make up the difference between domestic production and consumption (Figure 16). In general, imports are expected to be priced competitively with domestic sources. Imports from Canada, primarily from western Canada and from the Scotian Shelf in the offshore Atlantic, are expected to make up most of the increase in U.S. imports.

Canadian resources of natural gas are substantial. According to a December 1999 study published by the National Petroleum Council, *Meeting the Challenges of the Nation's Growing Natural Gas Demand*, Canada has 64 trillion cubic feet of proved reserves and 603 trillion cubic feet of assessed additional reserves. With most Canadian oil- and gas-producing regions less mature than those in the United States, the potential for additional low-cost production is strong, and imports from Canada are projected to remain competitive with U.S. domestic supplies in the forecast. It is anticipated that current U.S. price levels will entice Canadian suppliers to fill new export capacity on the Alliance pipeline and help alleviate the current tight supply situation.

Although Mexico has a considerable natural gas resource base, gas trade with Mexico has until recently consisted primarily of exports. Although cross-border capacity has recently increased, and Mexican sources predict a continuing growth in exports to the United States, EIA expects Mexico to remain a net importer of natural gas, with imports from Mexico growing by 3.9 percent per year over the forecast period and exports to Mexico growing by 10.8 percent per year. Given the existing cross-border capacity and the size of the resource base, however, Mexico does hold promise for the future as a source of natural gas supply for the United States.

Figure 16. Net U.S. imports of natural gas, 1970-2020 (trillion cubic feet)



Liquefied natural gas (LNG) is not expected to become a major source of U.S. supply between 1999 and 2020, but it is projected to provide a growing percentage of natural gas imports. Imports of LNG, at first primarily from Algeria, peaked at 253 billion cubic feet in 1979 and then dropped to 18 billion cubic feet in 1995. The decline resulted both from low natural gas prices that made LNG uneconomical and from the more recent refurbishment of Algerian liquefaction facilities that temporarily reduced supply availability. With the completion of the refurbishment and the advent of new sources of supply (such as Australia, Trinidad and Tobago, and Qatar), imports have been growing and are projected to continue to grow through 2020.

In the past, LNG imports were purchased under long-term contracts with suppliers. More recently, the development of a spot market has made the LNG market more flexible and more able to respond to the short-term needs of both buyers and sellers. Once used primarily to satisfy peaking needs, LNG use for baseload requirements is on the rise. In 1999, U.S. buyers purchased 27 cargos of LNG under spot sales, 19 more than in 1998 [*28*]; and the trend is expected to continue. There is an aggregate existing sustainable capacity of 840 billion cubic feet per year at four U.S. LNG import facilities, all of which are expected to be operational by 2003. Two of the four U.S. facilities—at Cove Point, Maryland, and Elba Island, Georgia—have been mothballed for many years, but plans to reopen both have been announced. As a result, it is anticipated that substantial unused capacity (and expansion potential) will allow LNG imports to grow significantly in the future. In the *AEO2001* reference case, the four U.S. LNG import facilities are projected to be operating at their maximum sustainable capacity by 2020.

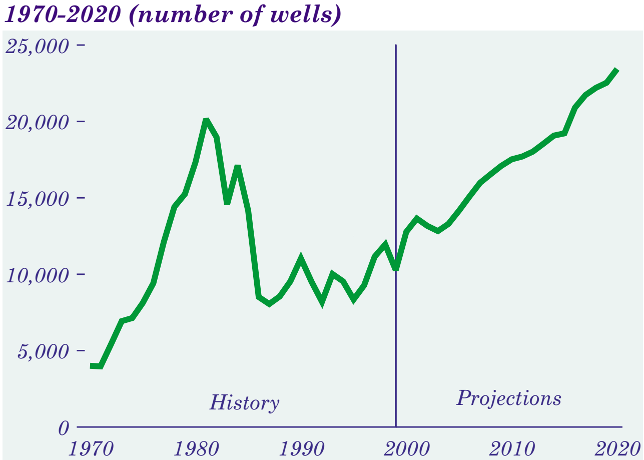
Domestic Production

One of the key activities in producing natural gas is drilling. Price increases are a powerful incentive for increased drilling and the purchase of new drilling equipment. For example, the number of available oil and gas drilling rigs increased by almost 16 percent annually between 1974 and 1982—from 1,767 to 5,644—as natural gas prices more than quadrupled in real terms and oil prices more than doubled [*29*]. In April 1999, after 9 consecutive months of natural gas wellhead prices below $2.00 per thousand cubic feet, the U.S. natural gas rig count for the month was down to 371. Since May 1999, however, wellhead prices have climbed steadily, reaching about $4.25 per thousand cubic feet in September, with preliminary estimates for October of about $4.65 per thousand cubic feet. By November 10, the U.S. natural gas rig count had climbed to 840.

High capital requirements and uncertainty about the actual demand for new rigs have so far limited investment in rig construction. Cost estimates ranging from $115 million for a 350-foot jackup rig up to $325 million for a deepwater semisubmersible rig have been reported [*30*]. Exploration and production budgets for many natural gas producers are expected to increase sharply in the latter part of 2000 and into 2001, however, spurred by higher prices and greatly improved current and expected revenues from producing assets. In the *AEO2001* forecast, the number of natural gas wells drilled is projected to increase from 10,200 in 1999 to 23,400 in 2020 (Figure 17). In view of the historical and current responses to rising prices, it is assumed that the rigs needed to meet such drilling levels will be constructed. It is also assumed that, in the long term, improvements in technology will make individual rigs more productive and temper the need for additional rigs.

The U.S. natural gas industry does face a challenge in terms of expanding its work force. According to the U.S. Bureau of Labor Statistics, employment in the U.S. oil and gas extraction sector peaked in 1982 and, subsequently, lost almost 390,000 jobs from 1982 to 1995. It is true that productivity improvements are reducing the number of employees needed, but the industry must recognize its potential manpower needs and take steps to maintain an appropriate level of oil and gas expertise so as not to be caught short when the expertise is needed. It takes considerable time and effort to attract and train qualified personnel, especially in a cyclic industry where a history of layoffs has discouraged entry into the workforce. The number of jobs needed to support the projected level of production in 2020 is estimated at 411,500 or roughly a 40-percent increase over 1999 employment levels.

Figure 17. Lower 48 natural gas wells drilled, 1970-2020 (number of wells)



Most of the projected increase in U.S. natural gas production is expected to come from lower 48 onshore nonassociated sources, with unconventional sources —primarily tight sands and coalbed methane in the Rocky Mountain region—also making a significant contribution. Offshore production, mainly from wells in the Gulf of Mexico, is also expected to contribute to the increase.

Natural gas production is obtained from “proved reserves.” Proved or “measured” reserves are the estimated quantities of natural gas that “geological and engineering data demonstrate with reasonable certainty” to be recoverable from known reservoirs under existing economic and operating conditions. At the end of 1999, U.S. proved reserves totaled 167 trillion cubic feet. While proved reserves are diminished each year by the amount of natural gas actually produced, they are also replenished by additions to existing fields through extensions, revisions, and the discovery of new pools or reservoirs within existing fields. Proved reserves are also added through the discovery of new fields.

“Technically recoverable resources” are a broader category of resources that includes proved reserves and consists of estimated quantities of gas that are technically recoverable without reference to economic profitability (Figure 18). As technology advances, identified resources that were once not economically recoverable become economically recoverable. Current estimates of technically recoverable natural gas resources indicate that the resource base is adequate to sustain growing production volumes for many years.

Natural gas resource estimates are derived from assessments by the U.S. Geological Survey for onshore regions and by the Minerals Management Service for offshore areas [*31*]. As of January 1, 1999, U.S. technically recoverable resources were estimated at 1,281 trillion cubic feet, including 164 trillion cubic feet of proved reserves, 244 trillion cubic feet of inferred reserves from known fields, 319 trillion cubic feet of undiscovered conventional resources not associated with oil deposits, and 393 trillion cubic feet of undeveloped resources of unconventional gas from coalbeds and low-permeability sandstone and shale formations. Gas associated with

Figure 18. Technically recoverable U.S. natural gas resources as of January 1, 1999 (trillion cubic feet)

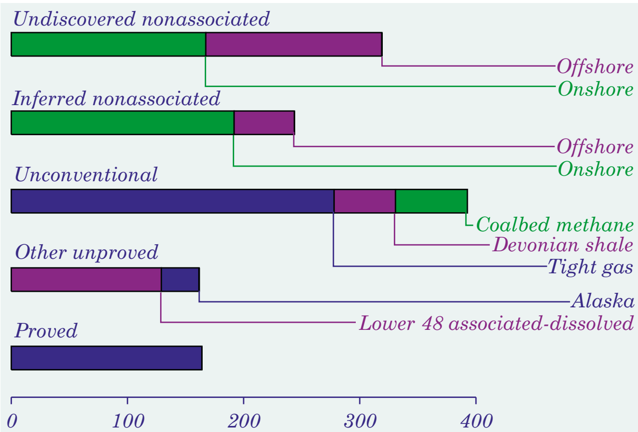
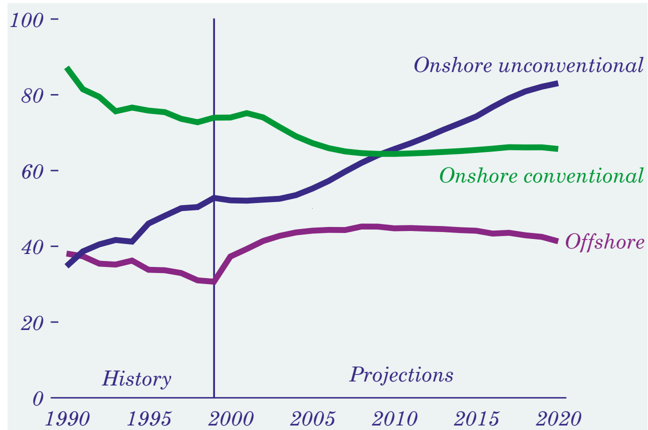


Figure 19. Lower 48 end-of-year natural gas reserves, 1990-2020 (trillion cubic feet)



oil makes up most of the balance of the total technically recoverable resource base.

From the early 1980s until the mid-1990s, yearly production of natural gas in the United States exceeded reserve additions, and U.S. natural gas proved reserves were declining. The downward trend was reversed in 1994, and reserves have increased in 5 of the past 6 years. Reserves are expected to increase through most of the forecast period, with increasing onshore unconventional reserves compensating for declines in onshore conventional reserves (Figure 19). As a result, reserves are anticipated to be adequate to sustain the projected levels of production throughout most of the *AEO2001* forecast period, with the average lower 48 production-to-reserves ratio projected to increase from 11.6 percent in 1999 to 15.0 percent in 2020. Lower 48 end-of-year reserves in 2020 are projected to be 21 percent above current levels. The relatively high levels of annual reserve additions reflect increased exploratory and developmental drilling as a result of higher prices and expected strong growth in demand, as well as productivity gains from technological improvements.

Natural Gas Resource and Technology Cases

Uncertainty with regard to estimates of the Nation's natural gas resources has always been an issue in projecting production, and it is widely acknowledged that assessing actual resource levels is a difficult task. To evaluate the sensitivity of the *AEO2001* projections to the estimate of the underlying resource base, high and low resource cases were created. As in the other *AEO2001* cases, resources in areas restricted from exploration and development were not included in the resource base for the sensitivity cases. For conventional onshore and offshore resources, the estimates of undiscovered technically recoverable resources and inferred reserves were adjusted by plus and minus 20 percent in the high and low resource cases. The estimates of unproved resources for unconventional gas recovery, which are more uncertain, were adjusted by plus and minus 40 percent. Thus, the assumed levels of technically recoverable resources 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 resource assumptions for the high and low resource cases are intended to represent significant variations without exceeding a reasonable range. They should not be regarded as representing the upper and lower bounds of possible values for technically recoverable U.S. natural gas resources.

The projections in the high and low resource sensitivity cases suggest that, as would be expected, a larger natural resource base would lead to lower wellhead prices and higher production levels, and a smaller resource base would lead to higher wellhead prices and lower production than projected in the reference case. Natural gas production in 2020 is projected to be 1.3 trillion cubic feet higher in the high resource case and 4.4 trillion cubic feet lower in the low resource case than in the reference case (Figure 20). The average natural gas wellhead price in 2020 is projected to be $2.62 per thousand cubic feet in the high resource case (16 percent lower than projected in the reference case) and $4.53 per thousand cubic feet in the low resource case (45 percent higher than in the reference case) (Figure 21). As expected, reduced resource levels have a more dramatic effect on prices and production than do increased resource levels in the forecast period. In the high resource case, although higher overall productivity puts

Figure 20. Lower 48 natural gas production in three resource cases, 2000-2020 (trillion cubic feet)

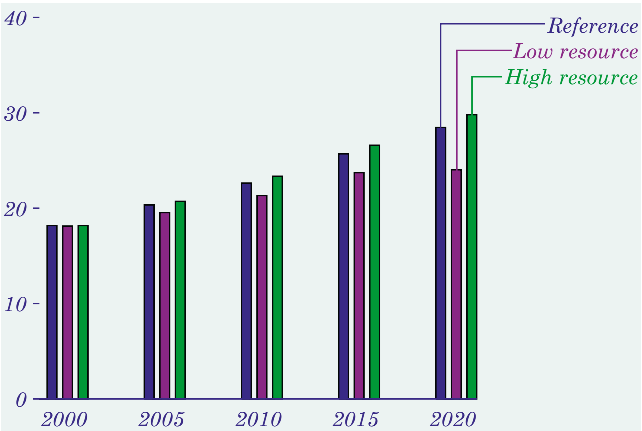
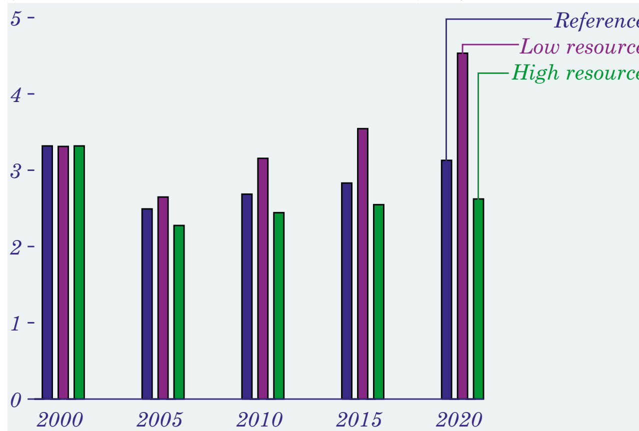


Figure 21. Average lower 48 natural gas wellhead prices in three resource cases, 2000-2020 (1999 dollars per thousand cubic feet)



downward pressure on prices, not all the additional resources are available in the projection period because of restraints on growth in rig and drilling activity.

Another area of uncertainty is the future impact of advances in exploration and drilling technologies. In the past, improvements in technology have both reduced exploration and development costs and increased the recoverability of in-place resources. Major advances in data acquisition, data processing, and the technology of displaying and integrating seismic data with other geologic data—combined with lower cost computer power and growing experience with new techniques—have lowered the costs of finding and producing natural gas. Advances in technology over the past 15 years have improved success rates by as much as 50 percent and have allowed higher quality prospects to be targeted, thus improving the overall well productivity.

One significant technological advance, adopted in the latter part of the 1980s, was horizontal drilling. Drilling a horizontal well, as opposed to a conventional vertical well, enables more of the reservoir to be exposed to the wellbore. Another advanced cost-saving technology is fracturing, which involves injecting fluids under high pressure to create new fractures and enlarge existing ones. Fracturing is now widely used to stimulate oil and natural gas production from wells that have declined in productivity. Modern drill bits, such as polycrystalline diamond drill bits, significantly reduce the time required to drill a well and allow drilling in more difficult geologic formations. Other substantial boosts to successful exploration and development have come from the increased use of three- and four-dimensional seismology [*32*] to delineate prospective areas of a formation and the use of remote sensing systems to improve the identification of promising geologic structures. New rig designs, such as jackup rigs, semisubmersible drilling rigs, and modular rigs, and the introduction of subsea well technologies, tension leg platforms, and production spars have opened up vast new and promising areas for exploration in the deepwater areas of the offshore that had been inaccessible.

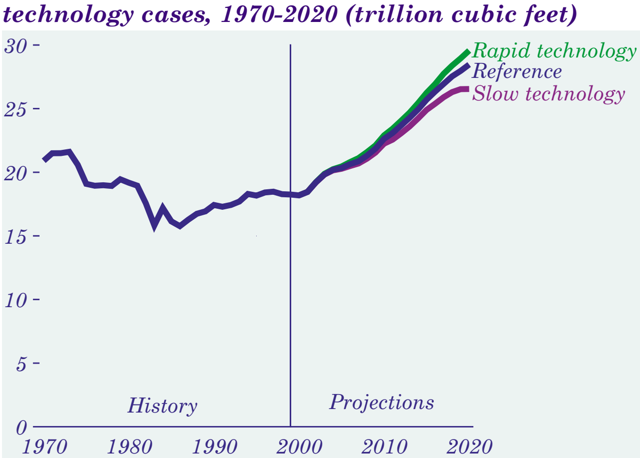
Continued improvements in technology have the potential to provide low-cost, efficient tools that will increase production in a manner that will be profitable to the industry while providing supplies to consumers at reasonable prices. The *AEO2001* reference case assumes that improvements in technology will continue at historical rates. More rapid improvements could yield benefits in the form of both lower prices and increased production. To assess the sensitivity of the *AEO2001* projections to the potential effects of changes in success rates, exploration and development costs, and finding rates as a result of technological progress, rapid and slow technology cases were developed, using the same resource base as in the reference case. The technology improvement rates assumed in the reference case were increased and decreased by 25 percent in the rapid and slow technology cases, which were analyzed as fully integrated model runs. All other parameters in the model were kept at their reference case values, including technology parameters in other energy markets, parameters affecting foreign oil supply, and assumptions about foreign natural gas trade, excluding Canada.

In the rapid technology sensitivity case for natural gas, the assumption of a more rapid pace of technological improvement than assumed in the reference case leads to projections of lower wellhead prices and more production (Figure 22). Slower technology improvements are projected to have the opposite effects in the slow technology case. The projections for total U.S. natural gas production in 2020 are 3.8 percent higher in the rapid technology case and 6.6 percent lower in the slow technology case than in the reference case. The most pronounced effects are on the projections of production from unconventional sources, which are 13.5 percent higher in the rapid technology case and 9.8 percent lower in the slow technology case in 2020 than projected in the reference case.

Although not represented in the rapid and slow technology cases—which assume the same resource base as in the reference case—it is also possible that the rate of future technological advances could affect the amount of natural gas produced from environmentally sensitive areas. At least 551 trillion cubic feet of the remaining untapped natural gas resource base in the United States underlies federally owned lands, almost evenly split between onshore and offshore locations. Approximately 217 trillion cubic feet of gas under Federal lands is estimated to be unavailable for development due to moratoria and/or restrictions and therefore is not included in the resource base assumed in the *AEO2001* reference case.

Offshore drilling is prohibited along the entire East Coast (31 trillion cubic feet, according to the National Petroleum Council), the west coast of Florida (24 trillion cubic feet), and most of the West Coast (21 trillion cubic feet). The National Petroleum Council estimates that 137 trillion cubic feet of gas in the Rocky Mountain area is subject to access restrictions, 29 trillion cubic feet is closed to development, and 108 trillion cubic feet is available with restrictions. As technological improvements make it possible to produce gas while meeting environmental restrictions, some of the resources in those areas may become available. The reference case assumes that approximately 36 trillion cubic feet of gas in the Rocky Mountain area will become available for development by 2015.

Figure 22. Lower 48 natural gas production in three technology cases, 1970-2020 (trillion cubic feet)



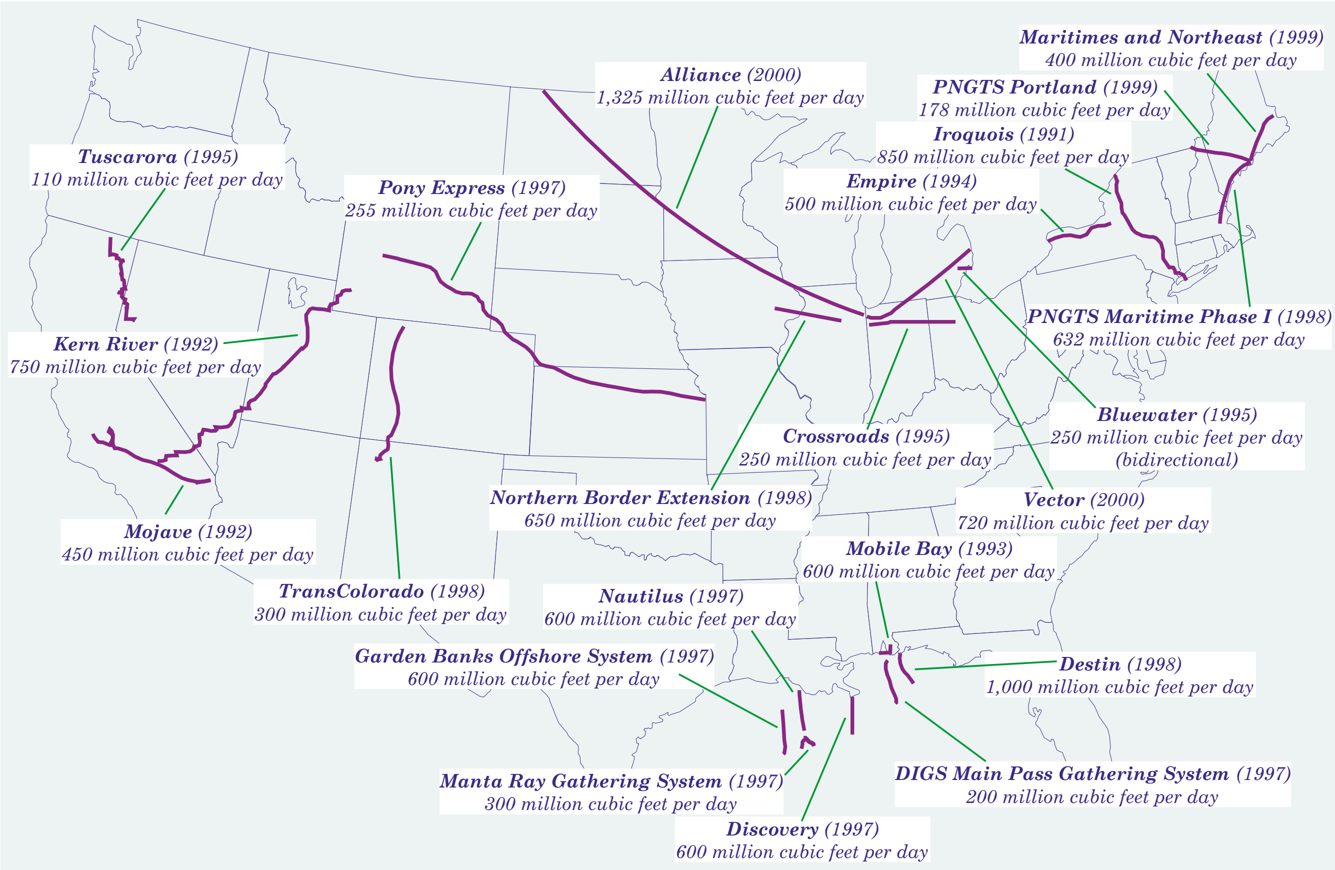
Pipeline Capacity Expansion

The U.S. interstate natural gas pipeline grid grew substantially between 1990 and 2000, with 22 major new interstate pipelines entering service (Figure 23). Additional expansion of the grid would be needed to transport the increased volumes of annual production projected in *AEO2001*. Transportation corridors would have to be expanded to provide access to new and increasing sources of supply. Indeed, much of the expansion projected in the reference case is either already in progress or scheduled to be completed by the end of 2001.

Preliminary estimates indicate that investment in pipeline expansion in 1999 exceeded $2 billion, and that investment in 2000 will reach approximately the same level. Several pipeline projects have already provided producers in the Rocky Mountain region with new access to customers in the Midwest. KN Interstate's Pony Express project and the Trailblazer system expansion have provided access from the Wyoming and Montana production regions, and Transwestern Pipeline and El Paso Natural Gas expansions have increased the capacity to move supplies out of New Mexico's San Juan Basin. Transwestern has increased its capacity by expanding its Gallup, New Mexico, compressor station. The completion in 1998 of a large-scale gathering system in the Powder River Basin significantly increased access to supplies, as did the Frontrunner intrastate expansion. To use the new gathering system, both the Wyoming Interstate and Colorado Interstate pipelines have increased their capacity. Significant increases in flows from the region to markets on the East and West Coasts have already occurred, and additional increases are projected through 2020. In the Gulf Coast offshore region, there has been a considerable increase in gathering systems and short-haul pipelines to move supplies onshore.

The most significant recent additions to pipeline capacity have been made to increase import capacity between the United States and Canada. Capacity has increased by 15 percent since 1998, with the major addition being the Northern Border expansion through Montana into the Midwest. In 1999, U.S. imports from Canada increased by 8.9 percent over the 1998 level, largely due to increased capacity on

Figure 23. Major new U.S. natural gas pipeline systems, 1990-2000



the expanded Northern Border Pipeline. Other major expansions are the Alliance Pipeline, also providing access to Western Canada, and the Maritimes and Northeast system to transport Sable Island supplies to markets in New England. The Alliance Pipeline is projected to open in late 2000 with an initial capacity of 1.325 billion cubic feet per day, expanding to 1.83 billion cubic feet per day in the future [*33*]. The Maritimes and Northeast Pipeline became operational on December 31, 1999, with a capacity of about 400 million cubic feet per day at the border. By March 2000, approximately 282 million cubic feet per day was being shipped to New England markets on the Maritimes and Northeast system. Cross-border capacity between the United States and Mexico has also grown, with the major increase resulting from the opening of the Tennessee pipeline near Alamo, Texas. A number of additional projects have been proposed and may proceed if the current trend of increased trade with Mexico continues.

Given the efficiencies that industry restructuring has brought to the U.S. natural gas market, the abundant technically recoverable domestic resource base, the growing availability of natural gas imports, the role of technology in making additional supplies available and reducing costs, and the continuing expansion of the U.S. pipeline grid, the natural gas industry is expected to be able to respond to the challenge of substantial increases in future demand. As long as the industry is confident that the demand will be there and that natural gas can be produced and delivered at prices that are competitive with those of other fuels, the needed investments in drilling, manpower, and pipeline infrastructure are expected to be made.

Phasing Out MTBE in Gasoline

Methyl tertiary butyl ether (MTBE) is a widely used gasoline blending component. Although it was initially added to gasoline to boost octane, which helps prevent engine knock, the use of MTBE expanded in the 1990s when it was used to meet the 2 percent oxygen requirement in reformulated gasoline (RFG). The Clean Air Act Amendments of 1990 (CAAA90) require RFG to be used year-round in cities with the worst smog problems. In the past few years, the use of MTBE has become a source of debate, because the chemical has made its way from leaking pipelines and storage tanks into water supplies throughout the country. Concerns for water quality have led to a flurry of legislative and regulatory actions at both the State and Federal levels (see “Legislation and Regulations,” page 15).

The Federal proposals are grounded in a set of recommendations made by a “Blue Ribbon Panel” (BRP) of experts convened by the EPA to study the MTBE issue [*34*]. In addition to improving programs to protect against leaking pipelines and storage tanks, the BRP provided a set of recommendations that includes reducing the use of MTBE and amending the Clean Air Act to remove the 2 percent oxygen requirement for RFG while maintaining the current air benefits of reformulated gasoline. The *AEO2001* reference case reflects legislation passed in eight States to restrict the use of MTBE in those States [*35*] but does not assume the implementation of any of the BRP recommendations.

MTBE is an important blending component for RFG because it adds oxygen, extends the volume of the gasoline and boosts octane, all at the same time. In order to meet the 2 percent (by weight) oxygen requirement for Federal RFG, MTBE is blended into RFG at approximately 11 percent by volume, thus extending the volume of the gasoline. When MTBE is added to a gasoline blend stock, it has an important dilution effect, replacing undesirable compounds such as benzene, aromatics, and sulfur. The dilution effect is even more valuable in light of a new ruling by the U.S. Environmental Protection Agency that will require the sulfur content of gasoline to be reduced substantially by 2004 and its recent proposal to maintain benzene at 1998-1999 levels (see “Legislation and Regulations,” page 16). In addition, MTBE is a valuable octane enhancer. Its high octane helps offset the Federal limitations on other high-octane components such as aromatics and benzene [*36*]. If the use of MTBE is reduced or banned, refiners must find other measures to maintain the octane level of gasoline and still meet all Federal requirements.

In the event that the Federal RFG oxygen requirement is waived, replacing the oxygen content in gasoline will not be an issue, but refiners will still need to make up for the loss of volume and octane resulting from banning MTBE. Reliance on other oxygenates, including ethyl tertiary butyl ether (ETBE) and tertiary amyl methyl ether (TAME), is assumed to be limited because of concerns that they have many of the same characteristics as MTBE and may lead to similar problems that affect the water supply. Ethanol, which is now used primarily as an octane booster and volume extender in traditional gasoline, would be the leading candidate to replace MTBE. Ethanol currently receives a Federal excise tax exemption of 54 cents per gallon, which is scheduled to decline to 53 cents in 2001, 52 cents in 2003, and 51 cents in 2005. Legal authority for the Federal tax exemption expires in 2007, but because this exemption has been renewed several times since it was initiated in 1978, the *AEO2001* reference case assumes that the exemption will be extended at the 51-cent (nominal) level through 2020.

Ethanol has some drawbacks that have made it less attractive to refiners than MTBE as an oxygenate. Ethanol results in higher emissions of smog-forming volatile organic compounds (VOCs) than MTBE. Its higher volatility makes it more difficult to meet emissions standards, especially in the summertime when RFG must meet VOC emissions standards. Ethanol’s volatility also limits the use of other gasoline components, such as pentane, which are highly volatile and must be removed from gasoline to balance the addition of ethanol.

In addition to being more volatile than MTBE, ethanol contains more oxygen. As a result, only about half as much ethanol is needed to produce the same oxygen level in gasoline that is provided by MTBE. The result is a volume loss, because the other half of the displaced MTBE volume must come from other petroleum-based gasoline components. The “dilution effect” of ethanol is not as great as that of MTBE, because the use of smaller volumes of ethanol is not as effective in diluting the undesirable qualities of the crude-based blending components [*37*]. Finally, finished fuel-grade ethanol currently contains small amounts of sulfur (between 2 and 8 parts per million), all of which comes from the “denaturant” additive blended with pure ethanol to make it undrinkable [*38*]. The sulfur content of the denaturant could become an issue for gasoline blending as refiners strive to meet a new Federal requirement for low-sulfur gasoline after 2004 (see “Legislation and Regulations,” page 14).

The prospect of increased use of ethanol also poses some logistical problems. Unlike gasoline blended with MTBE and other ethers, gasoline blended with ethanol cannot be shipped in multi-fuel pipelines in the United States. Moisture in pipelines and storage tanks causes ethanol to separate from gasoline. When gasoline is blended with ethanol, the petroleum-based gasoline components are shipped separately to a terminal and then blended with the ethanol when the product is loaded into trucks. Thus, changes in the current fuel distribution infrastructure would be needed to accommodate growth in "terminal blending" of ethanol with gasoline. Alternatively, changes in pipeline and storage procedures would be needed to allow ethanol-blended gasoline to be transported from refineries to distributors.

Ethanol supply is another significant issue, because current ethanol production capacity would not be adequate to replace MTBE nationwide. At present, ethanol supplies come primarily from the Midwest, where most of it is produced from corn feedstocks. Shipments to the West Coast and elsewhere via rail have been estimated to cost an additional 14.6 to 18.7 cents per gallon for transportation [*39*]. If the demand for ethanol increased as a result of a ban on MTBE, ethanol would need to be produced as a fuel on a regular basis; however, higher prices could make new ethanol facilities economically viable, and sufficient capacity could be in place depending on the timing of the MTBE ban.

The *AEO2001* reference case incorporates MTBE bans or reductions in the States where they have passed but does not include any proposed State or Federal actions or the proposed oxygen waiver. Arizona, California, Connecticut, Maine, Minnesota, Nebraska, and New York will ban the use of MTBE within the next several years, and South Dakota will limit the amount of MTBE that can be added to gasoline to 2 percent by volume.

The *AEO2001* projections are developed from a regional model, which captures the effects of limitations on MTBE in individual States through adjustments to assumptions about regional supplies of gasoline. The adjustments are made to reflect shifts in oxygenate selection and gasoline characteristics and changes in average gasoline prices in specific regions. Because the regional price changes are projected only on an annual basis, however, localized price spikes that might occur as a result of State MTBE bans may not be reflected in the model results.

To examine the implications of a possible nationwide ban on MTBE, a sensitivity case was developed using the following assumptions:

- A complete ban on MTBE in gasoline nationwide by 2004
- A waiver of the 2 percent oxygen requirement for Federal RFG
- No renewable standard that would require a specific level of ethanol in RFG
- No loss of air quality benefits from the use of RFG.

Beyond its use as an oxygenate, ethanol is assumed to be used to boost octane and extend volume in gasoline. Given that no renewable standard is assumed, the amount of ethanol use projected in the sensitivity case can be viewed as a floor for ethanol blending.

Despite the assumed removal of the Federal RFG oxygen requirement, the MTBE ban case projects more ethanol blending into gasoline than is projected in the reference case, because additional ethanol would be needed to offset the octane and volume loss that would result from banning MTBE. Ethanol blending in the MTBE ban case is projected to be 194,000 barrels per day in 2004, 55,000 barrels per day higher than projected in the reference case. By comparison, the 1999 level of ethanol use for gasoline blending was about 91,000 barrels per day.

Average U.S. gasoline prices in the MTBE ban case are projected to be 3.5 cents per gallon higher than in the reference case in 2004. (Prices are based on marginal costs.) The higher projected gasoline prices reflect increased costs from blending additional ethanol and other high-octane blendstocks. The MTBE ban case also projects increased imports of petroleum products and reduced imports of crude oil. Net imports of petroleum products are projected to be 150,000 to 200,000 barrels per day higher in the MTBE ban case than in the reference case in the 2004 to 2006 time frame.

A waiver of the Federal oxygen requirement is expected to result in a more cohesive gasoline market in California than assumed in the reference case, because two-thirds of the State currently is bound by Federal requirements and does not use the California Phase III gasoline used elsewhere in the State. As a result, ethanol consumption on the West Coast in 2004 is projected to be 32,000 barrels per day lower in the MTBE ban case than in the reference case.

Distributed Electricity Generation Resources

Distributed electricity generation resources are included in the *AEO2001* projections for three broadly defined sectors: electricity generators, buildings (residential and commercial), and industrial. In the electricity generation sector, the development of new technologies such as microturbines and fuel cells is making distributed generation an increasingly attractive option. Installations of distributed generators by electricity producers are expected to total less than 50 megawatts in size and to be located near load centers. Although electricity supplied by distributed generation in the residential and commercial sectors is projected to increase by more than 50 percent over the forecast period, in 2020 it still is expected to account for less than 1 percent of electricity requirements in those sectors. Distributed generation provided 22 percent of the electricity used in the industrial sector in 1999, and that share is projected to increase to 23 percent by 2020, given the economic incentives in the projections.

Electricity Generation Sector

Distributed generators are relatively small units that can be used to provide electricity when and where it is needed. For example, they can be connected to an electric utility's distribution system to reduce bottlenecks and increase the reliability of electricity supply. Unlike central station generators, which are capital-intensive and may require construction lead times of several years, distributed generators can be put in place quickly. In some cases they can even be moved to different sites as needed.

There is considerable interest among electricity generators in the potential use of distributed generators to cut costs by delaying, reducing, or eliminating investments in transmission and distribution equipment. In addition, the operational flexibility of distributed generators, which can either be connected to the grid or used in remote locations [*40*], may provide new system management options not available with central station units. Technologies used for distributed generation include diesel engines, internal combustion engines, microturbines, fuel cells, and renewable technologies such as wind and photovoltaic generators.

It is not clear how the opening of electricity markets to competition will affect the prospects for distributed generation in the electricity sector. There is considerable uncertainty about prices that would be paid for power from distributed generators when electricity generation services are opened to competition, because the rules have yet to be established in all these markets. There are also questions about the ability of the natural gas industry to supply small generators on a reliable basis and the prices that would be charged. In addition, current planning studies may understate or overstate the potential benefits to utilities and other large power suppliers, because there is little operational experience to draw from. Finally, the future treatment of distributed resources by the regulatory authorities that establish rules and pricing methods for transmission and distribution services is uncertain.

In *AEO2001*, distributed technologies are expected to penetrate in electricity markets when their costs are less than the combined costs of traditional baseload generation and the upgrades or expansions of the transmission and distribution infrastructure that would be needed to meet growth in demand. Two generic distributed technologies are included in the *AEO2001* model: peaking capacity, which has relatively high operating costs and is operated when demand levels are at their highest [*41*], and baseload capacity, which is operated on a continuous basis under a variety of demand levels [*42*]. Table 9 shows the assumed costs for the two generic technologies in 2000 and 2010. The assumed capital costs for the baseload generator are about 27 percent higher than those for the peaking generator in 2010, but its operations and maintenance costs are lower.

Table 9. Cost and performance of generic distributed generators

Characteristic	Generic peaking 2000	Generic peaking 2010	Generic baseload 2000	Generic baseload 2010
Typical size (megawatts)	0.4	0.4	2.5	1.6
Construction lead time (years)	0.2	0.2	0.5	0.5
Overnight costs (1999 dollars per kilowatt)				
Initial versions	—	700	—	2,000
Mature versions	531	440	591	560
Operating and maintenance costs				
Variable (1999 mills per kilowatthour)	23.0	15.5	15.0	10.4
Fixed (1999 dollars per kilowatt per year)	12.5	12.5	4.0	6.3
Heat rate (Btu per kilowatthour)	10,620	10,500	10,991	9,210

In the reference case, electricity producers are projected to add distributed generation capability only to meet peak demands. The first distributed generators are projected to be connected to the grid beginning in 2003, with total capacity reaching about 6 gigawatts in 2010 and 13 gigawatts in 2020. The added capacity is projected to contribute about 3 billion kilowatthours of generation during peak periods in 2010 and about 6 billion kilowatthours in 2020. The modest levels of generation projected represent an average capacity factor of about 5 percent for peaking distributed generators. In contrast, the higher assumed operating costs for generic baseload distributed generators keep them from being competitive with central station generators in the forecast. As a result, no baseload capacity is projected to be built through 2020 in the reference case.

Buildings Sector

In the residential and commercial sectors, distributed generators installed by customers may supply either electricity alone (generation) or electricity as well as heat or steam (cogeneration or combined heat and power). On-site generators can have several advantages for electricity customers:

- If redundant capability is installed, reliability can be much higher than for grid-supplied electricity.
- Although electricity from distributed generation is generally more costly than grid-supplied power, the waste heat from on-site generation can be captured and used to offset energy requirements and costs for other end uses, such as space heating and water heating.
- Distributed generation can reduce the need for energy purchases during periods of peak demand, which can lower both current energy bills and, presumably, future energy bills when peak prices for electricity in competitive markets will be set by the most expensive generator supplying power to the grid.

Currently, very little residential capacity for electricity generation exists. Existing capacity consists primarily of emergency backup generators to provide electricity for minimum basic needs in the event of power outages. There are also a limited number of photovoltaic solar systems in a few niche markets with very high electricity rates and/or subsidies that encourage the use of renewable energy sources. Generating capacity in the commercial sector is also primarily for emergency backup; however, some electricity supply and peak generation is reported. EIA's 1995 Commercial Buildings Energy Consumption Survey (CBECS) estimated that about 0.05 percent of all commercial buildings (0.23 percent of all commercial floorspace) use generators for purposes other than emergency backup.

The *AEO2001* buildings models characterize several distributed generation technologies—either combined heat and power applications or pure generation—including conventional oil or gas engines and combustion turbines as well as such new technologies as photovoltaics, fuel cells, and microturbines. Photovoltaics are the most costly of the distributed technologies for buildings on the basis of installed capital costs; however, once photovoltaic systems are installed, no fuel costs are incurred. Petroleum-based generation is often used for emergency power backup in the commercial sector, but because of potential localized emissions issues it is less appropriate for continuous operation than is natural-gas-based generation. In the projections, the key growth technologies for cogeneration in the buildings sector are photovoltaics and natural-gas-fired generators.

The projected penetration rates of distributed generation technologies in the buildings sector are based either on forecasts of the economic returns from their purchase or on estimated participation in programs aimed at fostering distributed generation. Program-related purchases are based on estimates from the Department of Energy's Million Solar Roofs program and the Department of Defense fuel cell demonstration program [*43*].

Table 10 shows projected equipment costs and electrical conversion efficiencies for several of the distributed generation technologies characterized in the buildings sector models. The greatest cost declines are projected for the emerging technologies—photovoltaics, fuel cells, and microturbines. In addition, conversion efficiencies are projected to show the greatest improvement for fuel cells, reflecting the technical progress expected for this emerging technology. Because technology learning is expected to occur for photovoltaics, fuel cells, and microturbines, the data in Table 10 represent price ceilings for those three technologies; their actual costs could be lower if total cumulative shipments reach sufficiently high levels [*44*].

The reference case projects an increase of 56 percent in electricity supplied by distributed generation in the buildings sector. Distributed generation is estimated to account for approximately 0.3 percent of the sector's total electricity supply in 2000, rising to

Table 10. Projected installed costs (1999 dollars per kilowatt) and electrical conversion efficiencies (percent) for distributed generation technologies by year of introduction and technology, 2000-2020

Year	Photo-voltaics	Fuel cell	Gas tur-bine	Gas en-gine	Gas micro-turbine
2000-2004					
Cost	*7,870*	*3,282*	*1,555*	*1,320*	*1,785*
Efficiency	*14*	*38*	*22*	*29*	*27*
2005-2009					
Cost	*6,700*	*2,834*	*1,503*	*1,240*	*1,574*
Efficiency	*16*	*40*	*24*	*29*	*29*
2010-2014					
Cost	*5,529*	*2,329*	*1,444*	*1,150*	*1,337*
Efficiency	*18*	*43*	*25*	*30*	*31*
2015-2020					
Cost	*4,158*	*1,713*	*1,373*	*990*	*1,047*
Efficiency	*20*	*47*	*27*	*30*	*34*

0.4 percent in 2020. Figure 24 shows the projections for individual technologies.

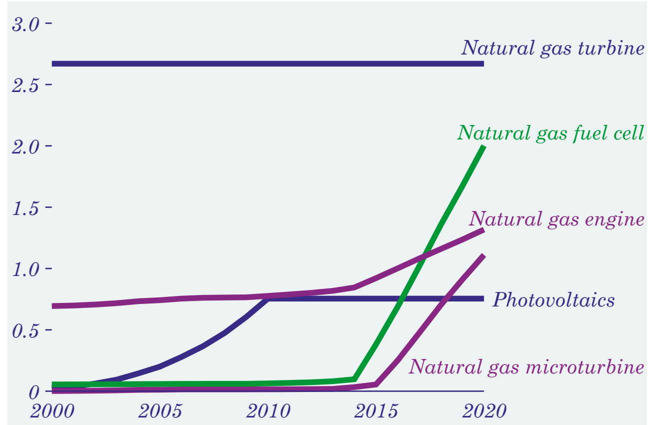
Natural gas turbines are viewed as a "mature" technology that remains static in the forecast. Even so, it maintains the largest share gained by a single technology throughout the period. The shares for other natural-gas-based technologies are projected to grow. This projected growth results from the combined effects of more rapid cost declines than those projected for turbines and increases in generation efficiency increase their market penetration. The combined effect of these two factors is especially important for fuel cell and microturbine technologies, which are currently in the early phases of commercialization for buildings-based applications. By the end of the projection period, fuel cells and microturbines combined are expected to overtake natural gas turbines in terms of total generation. Continued cost declines are also projected for photovoltaics, but the costs are expected to remain significantly higher than those of the other technologies available, and little additional penetration is projected after 2010, when current incentive programs are scheduled to end. Other technologies not shown in Figure 24—including municipal solid waste, hydropower, biomass, coal, and petroleum-based applications—are not widely applicable in the buildings sector or are limited by environmental concerns and therefore do not increase [*45*].

Industrial Sector Cogeneration

Cogeneration systems, also called combined heat and power systems, simultaneously produce electricity or mechanical power and recover waste heat for use in other applications. The degree to which they are used for electricity production versus steam or heat production for other uses varies from facility to facility. Cogeneration systems can substantially reduce the energy losses that occur when electricity and process steam are produced independently. Conventional central station generation averages less than 33 percent delivered efficiency, whereas current cogeneration systems can deliver energy with efficiencies exceeding 80 percent.

The economic incentive to install cogeneration systems is based on the potential reduction in total operating costs. Cogeneration systems typically are most economical where steam loads are large and relatively continuous. Those industries that historically have been large users of cogeneration usually have had access to low-cost fuels, such as byproducts from industrial production processes. About two-thirds of current capacity is concentrated in the pulp and paper, chemical, and refining industries [*46*]. Over the past several years, technology developments have increased the range of sites where cogeneration may be an economical option. The most appropriate technology for a specific site or application depends on many factors: the steam load, fuel and electricity prices, on-site electricity demand, duty cycles, space constraints, emissions regulations, and interconnection issues.

Figure 24. Projected buildings sector electricity generation by selected distributed resources in the reference case, 2000-2020 (billion kilowatthours)



Additions of natural-gas-fired systems and biomass systems are evaluated separately in *AEO2001*. Eight natural-gas-fired cogeneration systems, ranging in size from 800 kilowatts to 100,000 kilowatts, are assumed to be available in the *AEO2001* model. Table 11 summarizes their key cost characteristics and assumed cost improvement over time. Because biomass-based cogeneration is assumed to be added in the industrial sector in response to projected increases in biomass consumption in the sector, installation costs are not explicitly considered. Because most of the expected increase in biomass consumption is concentrated in the pulp and paper

Table 11. Costs of industrial cogeneration systems, 1999 and 2020

System	Size (megawatts)	Installed cost (1999 dollars per kilowatt)		Operating and maintenance costs (1999 cents per kilowatthour)	
		1999	2020	1999	2020
Engine	0.8	975	690	1.07	0.90
	3	850	710	1.03	0.90
Gas turbine	1	1,600	1,340	0.96	0.80
	5	1,075	950	0.59	0.49
	10	965	830	0.55	0.46
	25	770	675	0.49	0.43
	40	700	625	0.42	0.40
Combined cycle	100	690	620	0.36	0.30

industry, which is one of the largest cogeneration industries, it is assumed that 90 percent of the projected increase in biomass consumption will be used to cogenerate electricity.

Figure 25 shows the projected composition of cogeneration capacity by fuel in 2020. Natural gas accounts for most of the projected change in total capacity, followed by biomass. Natural-gas-fired cogeneration capacity in the industrial sector is projected to increase by 18.7 gigawatts from 1999 to 2020, and biomass-fired capacity is projected to increase by 3.5 gigawatts. About 70 percent of the new capacity is expected to be added in the paper and chemical industries. There is assumed to be little growth in cogeneration capacity for other fuels between 1999 and 2020, because coal systems cost significantly more than gas turbine systems and, given their relatively large minimum economical size, are subject to more stringent environmental requirements.

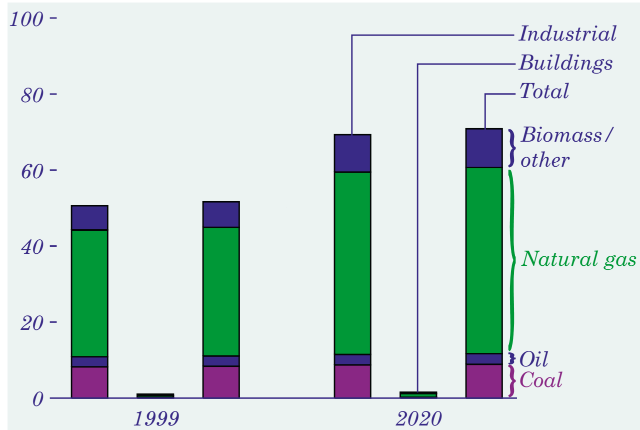
The difference between the delivered prices of electricity and natural gas in the industrial sector is a key component in the economics of cogeneration systems. A larger difference increases the economic incentives for cogeneration, and a smaller difference reduces them. Therefore, in the *AEO2001* reference case, the narrowing difference between electricity and natural gas prices projected over the forecast period reduces the economic incentive to invest in cogeneration systems.

In summary, total distributed generation capacity is projected to grow more rapidly than electricity sales in the forecast, averaging about 2.5 percent annually. When projected additions in the electricity generation sector are excluded, the remainder of the expected capacity growth is slightly less than the projected growth in electricity sales. Given the projections for falling electricity prices and rising natural gas prices, however, this still represents a robust outlook.

Restructuring of State Retail Markets for Electricity

Since May 1996, a number of States have passed legislation mandating the restructuring of their retail electricity industries. Restructuring legislation has focused primarily on deregulating the electricity supply sector to allow retail electricity customers access to competitive energy suppliers. Some States have also granted competitive retail access to components of distribution service, such as billing and meter reading [*47*]. Most of the States that have

Figure 25. Cogeneration capacity by type and fuel, 1999 and 2020 (gigawatts)



authorized competitive retail access to electricity have historically had higher electricity prices than the national average.

As of September 2000, 24 States and the District of Columbia, representing 55 percent of U.S. electricity sales [*48*], have mandated electric industry restructuring. Two States, Alaska and South Carolina, have legislation pending. Virtually all the other States have considered restructuring. Many are waiting to see how deregulated markets will affect electricity prices in the States that have already implemented restructuring legislation before making a decision. Some State utility regulatory bodies have established frameworks for deregulation and are negotiating terms with utilities and potential competitive electricity suppliers that will be implemented in the event that restructuring legislation passes.

Issues of Price Stability and Service Reliability in Deregulated Electricity Markets

In the States that have passed restructuring legislation, settlement negotiations with electricity producers and consumers have raised a number of contentious issues, including market power, stranded cost recovery and securitization, generation asset divestiture, environmental concerns, customer education and attitudes toward restructuring, consumer protection, regulation of affiliate transactions, price stability, and service reliability. Ultimately, the resolution of such issues will determine the rate at which restructured electricity markets become competitive and how customers, utilities and their stockholders, competitive suppliers, and other stakeholders will be affected.

Over the past year, as a result of major regional outages and rising fuel prices, the issues of price stability and service reliability have been of particular concern nationwide. Many observers and participants in restructuring negotiations have raised concerns that electricity customers, especially residents and small businesses, could experience higher prices and less reliable service as a result of deregulation. Fears of higher prices have been fueled by concerns that a competitive market could take a long time to develop. In an underdeveloped market, incumbent utilities or large corporations could gain most of the market share, leaving them free to raise prices at will in the absence of regulation.

In States where competition is underway, it has mostly been the large commercial and industrial consumers who have been courted by competitive energy suppliers. Consequently, all States that have mandated restructuring, or allowed it to proceed, have also mandated price reductions and/or price freezes for residential and small commercial customers for the duration of a negotiated "transition period." The transition period is the estimated number of years that it will take to realize a fully competitive electricity supply market. As discussed below, *AEO2001* incorporates State-mandated price freezes and reductions into its forecasts of energy prices.

Service reliability has also become a concern as utilities have downsized their work forces in preparation for the switch to a competitive marketplace. In addition, although the demand for electricity has been increasing, utilities have been reluctant to make expensive additions to generation and transmission capacity, because their ability to recover the costs remains uncertain as States consider whether and/or how to carry out restructuring of the industry. A recent EIA study [*49*] indicates that constraints on inter- and intraregional electricity transmission capacity could affect the ability of electricity markets to respond quickly and efficiently to changing demand conditions.

Concerns about prices and reliability were heightened when outages and price spikes hit the Midwest region during the summer of 1998, and to a lesser extent, by outages and price spikes around the country during the summer of 1999. More recently, price spikes in New England during the winter of 2000 and outages and price spikes in wholesale and retail electricity markets in California throughout the summer of 2000 have been seen as an indication of potential problems.

The U.S. Department of Energy's Power Outage Study Team [*50*] has studied the major outages and voltage depressions that occurred around the country in the summer of 1999, finding in general that the "necessary operating practices, regulatory policies, and technological tools for assuring an acceptable level of reliability were not yet in place." However, price spikes in the Midwest in 1999 were not as sustained as those in the summer of 1998, and the consequences were not as severe, pointing to a maturing competitive electricity market in that region [*51*]. The 1999 price spikes did not prompt the level of anxiety over the increasingly competitive electricity market as had the Midwest price spikes of the previous year [*52*], and in 2000, with more generating capacity on line and a cooler summer, the Midwest electricity market remained calm.

Separate, independent investigations into the functioning of competitive wholesale electricity markets in New England and California have found market design and operational flaws in both regions [*53*]. Both studies found that market structures may have encouraged traders or generators to bid up prices by "gaming the system" [*54*]. The two regions are now in the process of trying to redesign aspects of their competitive markets. ISO New England investigated the NEPOOL Installed Capacity (ICAP) market after the January 2000 price spikes and found that it was too flawed to be fixed. ISO New England then filed a request with the FERC in May 2000 that the ICAP market be eliminated and that the ISO begin a collaborative effort with NEPOOL participants to develop viable market-driven alternatives to the ICAP market [*55*].

In California, Governor Gray Davis directed the Electricity Oversight Board and the California Public Utilities Commission to investigate the circumstances contributing to the outages and price spikes during the summer of 2000 [*56*]. After the study found serious market flaws, Governor Davis called on FERC to investigate the wholesale markets and intervene to ensure that "a workably competitive market exists before California consumers and California's economy are subjected to unconstrained, market-based electricity prices" [*57*].

Market Effects of High Natural Gas Prices

High natural gas prices in 2000 have also concerned stakeholders in the process of electricity industry deregulation. With new gas turbines increasingly being used as the marginal units of electricity production, higher gas prices will theoretically increase electricity prices more in competitive electricity supply markets with marginal cost pricing than in regulated markets with prices based on average costs.

Although the demand for natural gas has been increasing, low gas prices in 1998 and 1999 curtailed gas drilling in 1999. In 2000, flat production, increased demand, and lower then average stock levels resulted in higher natural gas prices. Still, according to a recent analysis of supply and demand in the gas industry [*58*], although drilling has increased substantially, a 6- to 18-month lag is anticipated before much additional production will be brought on line.

With an expanding economy and an increase in planned construction of new gas turbines, future demand for natural gas is expected to increase regardless of whether the coming winters will be warm or cold. In States with newly deregulated retail electricity markets, mandated price freezes and reductions during the transition to competition are expected to keep electricity prices from increasing excessively with rising gas prices [*59*]. Electricity price increases in other States as a result of higher gas prices may depend on several factors, including the political influence of electricity users and utilities; economic hardships caused by price increases on particular users; the effects of electricity price increases on local economies; and perceptions by some utilities that large increases in electricity prices may cause them to lose support for their positions in restructuring negotiations.

AEO2001 Assumptions

AEO2001 represents 13 electricity supply regions, based on North American Electric Reliability Council (NERC) regions and subregions. When all the electricity sales in a supply region [*60*] come from deregulated States, the region is assumed to be fully competitive. When a majority of electricity sales (but not all) within a region come from deregulated States, the region is assumed to be partially competitive. Within a partially competitive region, *AEO2001* assumes the same percentages of competitive and regulated pricing as the percentages of electricity sales in that region's deregulated and regulated States, respectively. Fully or partially competitive regions include the New England, New York, Mid-Atlantic, East Central (Illinois), Rocky Mountain Power Area, California, and the Southwest Power Pool electricity supply regions.

In *AEO2000*, the Southwest Power Pool was assumed to be a noncompetitive region, with only 32 percent of its sales coming from States that had mandated deregulation. In the past year, however, Entergy, a very large utility supplying about 100 million megawatthours of electricity to 2.5 million customers in several States, left the Southwest Power Pool to join the Southeastern Electric Reliability Council. The huge loss of mostly noncompetitive energy sales increased the share of competitive electricity sales in the Southwest Power Pool to 54 percent, making it a competitive region in *AEO2001*. Electricity prices in the Northwest, Mid-Continent, Southeast, and Florida regions still are assumed to be regulated.

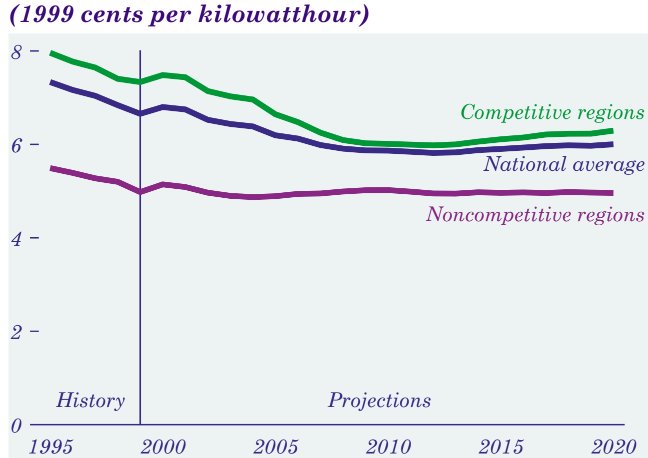
AEO2001 assumes a gradual, 10-year transition to fully competitive pricing from the inception of deregulation in competitive regions, with the 10-year period varying by region. This is the estimated amount of time needed to free the changing industry of the anticompetitive effects of stranded costs, negative customer attitudes toward choosing electricity service providers, and imperfect market structures. It also accounts for the time needed for an adequate number of suppliers to enter the market and learn to be sufficiently cost-efficient to stay in the market and keep it competitive.

AEO2001 Electricity Price Forecasts

AEO2001 forecasts a decline of 1 cent per kilowatthour in the average national electricity price between 2000 and 2012, followed by a slight increase of 0.2 cent per kilowatthour through 2020 (Figure 26). In general, price differences among regions are projected to be greatly reduced—from 7.0 cents per kilowatthour between the highest (New York) and lowest (Northwest) in 1995 to 3.8 cents per kilowatthour between the highest (New York) and lowest (Northwest) in 2020.

Figure 26 shows historical and projected average electricity prices paid by end users in competitive and noncompetitive regions compared with national

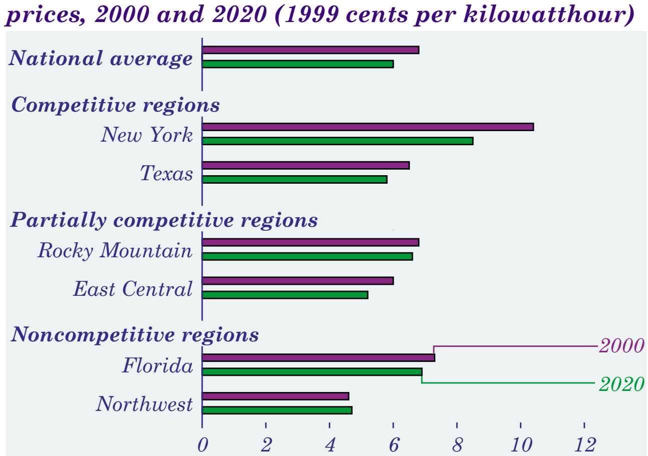
Figure 26. Average annual electricity prices for competitive and noncompetitive regions, 1995-2020 (1999 cents per kilowatthour)



average prices. Most of the States that have authorized competitive retail access to electricity have historically experienced electricity prices that are higher than the national average, mainly as a result of higher than average regional capital costs (the material and labor costs of building power plants). The competitive regions as a group also have a higher concentration of older oil- and gas-fired steam generators that require more maintenance than other types of plants, as well as higher labor costs associated with operations and maintenance, than the noncompetitive regions. For example, in the Southeast and Mid-Continent regions, which are assumed to be noncompetitive, reliance on older coal-fired generators, for which the capital costs have largely been paid, provide a plentiful source of electricity with lower associated maintenance costs, resulting in lower electricity prices. The labor costs associated with plant operation and maintenance are also relatively low in those regions. The Northwest, another noncompetitive area, has access to abundant hydroelectric power sources at very low cost.

Figure 27 shows expected regional price changes between 2000 and 2020 for selected regions with competitive, partially competitive, and noncompetitive electricity supply. By region, the largest declines in electricity prices are projected for the four regions that currently have the highest average electricity prices: California, New England, New York, and the Mid-Atlantic. These were the first regions in which State restructuring laws were implemented, and they have already experienced price drops between 0.5 and 1.5 cents per kilowatthour since 1995. In the reference case, they are expected to see further declines averaging about 2.5 cents per kilowatthour from 2000 to 2010.

Figure 27. Projected average regional electricity prices, 2000 and 2020 (1999 cents per kilowatthour)



Three other regions (East Central, Texas, and Mid-America) are projected to see price declines between 1.5 cents per kilowatthour (in Texas, a fully competitive region) and just over 0.5 cent per kilowatthour (in Mid-America, the least competitive of the three regions) from 2000 to 2010. After the decreases, prices in the East Central and Mid-American regions are expected to increase slightly (about 1 mill per kilowatthour) by 2020. Prices in Texas by 2020 are projected to regain up to half the decrease expected by 2020 as a result of additions of new power plants fueled by increasingly expensive natural gas.

The Mid-Continent, Florida, and Southeast regions are expected to experience very small price declines (from a few mills per kilowatthour in the Southeast to just over 0.5 cent per kilowatthour in Florida) over the next several years, even though they are noncompetitive regions. In Florida, expensive oil plants are being replaced by cheaper coal and gas plants, helping to bring fuel costs down. In the Mid-Continent region, an expected decrease in capital costs is expected to bring prices down as plants are run at higher capacity. In the Southeast region, plant operations and maintenance costs are expected to decline slightly as a result of additions of fossil-fired steam plants in previous years. After 2005, prices in these regions are expected to remain relatively steady through 2020.

The Northwest and Southwest are the two lowest-priced electricity supply regions in the Nation. Prices in the Northwest, a noncompetitive region, are projected to remain relatively steady through 2020. The Southwest is expected to see price increases through 2020 as a result of competition and the costs of expected additions of new generating capacity, most of which are projected to be fueled by natural gas.

Although average electricity prices for the competitive regions are expected to drop to just 1 mill per kilowatthour above the national average by 2010, they remain 1 cent per kilowatthour above the average prices for the noncompetitive regions in the forecast, for the reasons discussed above. Nationally, average electricity prices are expected to fall as the capital costs for some more expensive plants are paid off, newer plants are built with lower associated maintenance costs, and competition (as well as new regulation) forces electricity suppliers to become more efficient. Competitive regions still are expected to have higher resources and labor costs associated with building, maintaining, and fueling generators than are the noncompetitive regions. As a result, after 2010, the expected surge in new additions of natural-gas-fired generators, combined with rising natural gas prices, is expected to increase prices by a little more in the competitive regions than in the noncompetitive regions.

Carbon Dioxide Emissions in *AEO2001*

Reference Case

In the *AEO2001* reference case, carbon dioxide emissions from energy consumption are expected to reach 1,809 million metric tons carbon equivalent in 2010, continuing to rise to 2,041 million metric tons carbon equivalent in 2020 (Figure 28), an average annual growth rate of 1.4 percent between 1999 and 2020. The projections for 2010 and 2020 are 34 percent and 51 percent higher, respectively, than the 1990 level of 1,349 million metric tons carbon equivalent.

Carbon dioxide emissions are projected to increase throughout the forecast, because continued economic growth and moderate increases or even decreases in projected real energy prices are expected to lead to increasing energy consumption. The 1.4-percent growth rate for projected carbon dioxide emissions is slightly faster than the growth rate for total energy consumption, which is expected to increase at an average annual rate of 1.3 percent. The growth in carbon dioxide emissions is projected to be more rapid than the growth in total energy consumption for two primary reasons. First, approximately 27 percent of existing nuclear generating capacity, which emits no carbon dioxide, is expected to be retired by 2020, and no new nuclear plants are projected to be constructed. Second, because prices for both natural gas and coal are expected to remain moderate, growth in the use of renewable energy sources is projected to remain slow.

Through 2020, the demand for energy services, such as travel, household appliances, and commercial equipment, is projected to continue to increase. As a result, projected energy consumption per person and carbon dioxide emissions per person in 2020 are higher than they were in 1999. Between 1999 and 2020, carbon dioxide emissions per person are projected to increase from 5.5 metric tons carbon equivalent to 6.3 metric tons carbon equivalent, an average annual growth rate of 0.6 percent (Figure 29).

Total energy intensity in the U.S. economy, measured as energy consumption per dollar of GDP is expected to show a decrease through 2020, resulting from the penetration of more efficient energy-using equipment into the capital stock. Total energy intensity is projected to fall from 10.8 thousand Btu per dollar of GDP in 1999 to 7.7 thousand Btu per dollar of GDP in 2020, an average decline of 1.6 percent annually. Because carbon dioxide emissions are projected to grow more rapidly than energy consumption, however, carbon dioxide emissions per dollar of GDP are projected to decrease at a slower rate than energy intensity. Between 1999 and 2020, carbon dioxide emissions are estimated to decline from 170 to 124 metric tons carbon equivalent per million dollars of GDP, an average annual decline of 1.5 percent (Figure 30).

Comparisons with AEO2000 Projections

In *AEO2001*, projected carbon dioxide emissions in 2020 are 2,041 million metric tons carbon equivalent, 3.1 percent higher than projected in *AEO2000*.

Figure 28. Projected U.S. carbon dioxide emissions by sector and fuel, 1990-2020 (million metric tons carbon equivalent)

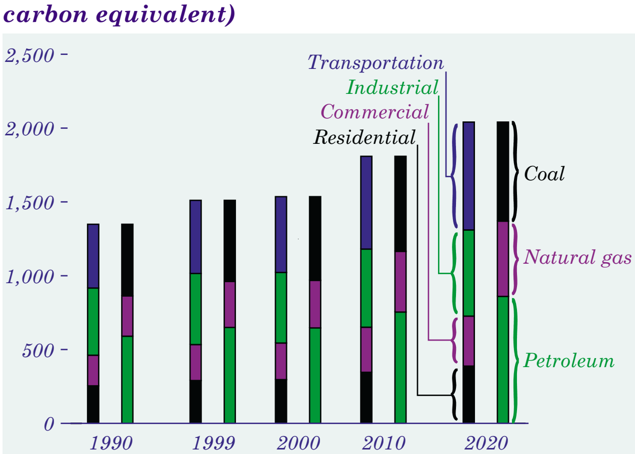


Figure 29. U.S. carbon dioxide emissions per capita, 1990-2020 (metric tons carbon equivalent per person)

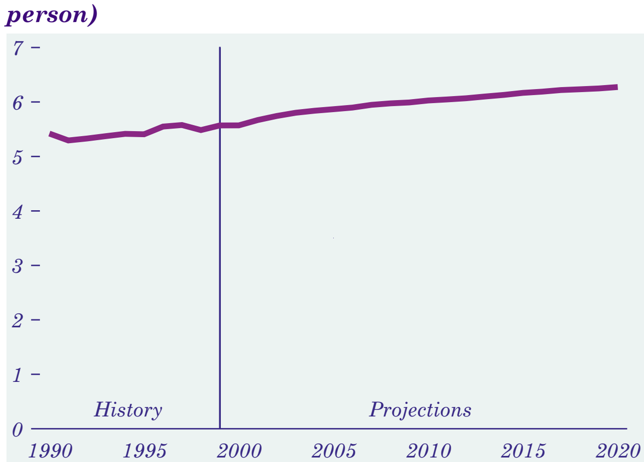
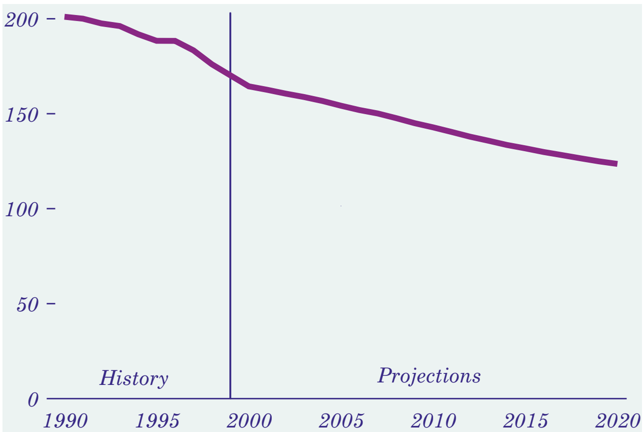


Figure 30. U.S. carbon dioxide emissions per unit of gross domestic product, 1990-2020 (metric tons carbon equivalent per million dollars)



Carbon dioxide emissions are expected to reach a higher level primarily as a result of more rapid projected economic growth in the *AEO2001* reference case. Over the projection period, GDP is expected to increase at an average annual rate of 3.0 percent, compared with the 2.1-percent yearly GDP growth projected in *AEO2000*. The higher economic growth projection in *AEO2001* results in part from statistical and definitional changes in the National Income and Product Accounts, as discussed earlier in "Issues in Focus" (see page 22). In addition, the economic forecast reflects a more optimistic view of long-run economic growth, leading to higher projections for industrial output, housing starts, growth in commercial floorspace, and disposable income, all of which contribute to higher projected growth in the demand for energy services and in energy consumption. As a result, projected energy consumption in 2020 is higher in all end-use sectors in *AEO2001* than in *AEO2000*.

The *AEO2001* projection for the number of U.S. households in 2020 is 1.5 percent higher than was projected in *AEO2000*, with most of the increase being in single-family homes. The total number of U.S. households is expected to increase from 104.1 million in 1999 to 129.4 million in 2020. In addition, *AEO2001* projects that the average size of new homes will increase through 2020, whereas *AEO2000* assumed no growth in the size of new homes. In the commercial sector, the *AEO2001* projection for total floorspace in 2020 is 11.0 percent higher than the *AEO2000* projection as a result of the higher projected economic growth. In addition, *AEO2001* projects more rapid growth in electricity consumption in both the residential and commercial sectors for personal computers, office equipment, and a variety of miscellaneous uses consistent with recent trends.

Overall energy intensity in the residential and commercial sectors is also expected to be higher in *AEO2001* than was projected in *AEO2000*. In the residential sector, total energy consumption per square foot is projected to decrease at an average annual rate of 0.1 percent through 2020, as compared with a projected 0.2-percent decline in *AEO2000*. In addition, because the size of new homes is expected to increase, energy consumption per household is projected to increase by 0.1 percent annually, in contrast to the 0.1-percent annual decrease projected in *AEO2000*. Total residential carbon dioxide emissions, including emissions from the generation of electricity used in the sector, are projected to be 10 million metric tons carbon equivalent (2.8 percent) higher in 2020 than was projected in *AEO2000*. In the commercial sector, total energy consumption per square foot is projected to increase at an average annual rate of 0.1 percent through 2020 in *AEO2001*, as compared with the 0.1-percent decrease projected in *AEO2000*. Higher projected energy intensity combined with higher projected floorspace results in a projection of carbon dioxide emissions in 2020 that is 31 million metric tons carbon equivalent (10.1 percent) higher than the *AEO2000* projection.

Along with higher projected economic growth, industrial output in *AEO2001* is projected to grow at an average annual rate of 2.6 percent through 2020, compared with 1.9 percent in *AEO2000*. Most of the difference, however, is in non-energy-intensive manufacturing, which is expected to grow at a far more rapid pace than energy-intensive manufacturing or nonmanufacturing activity. In addition, the *AEO2001* projections include a more optimistic assessment of the potential for efficiency improvements in the industrial sector consistent with recent trends. Energy intensity in the industrial sector is expected to decline at an average annual rate of 1.5 percent in *AEO2001*, compared with a projected average annual decline of 0.9 percent in *AEO2000*. As a result, with the carbon dioxide emissions associated with industrial electricity use also expected to be lower, the *AEO2001* projection for industrial sector carbon dioxide emissions in 2020 is essentially the same as the *AEO2000* projection.

In the transportation sector, the higher projections for economic growth and disposable income in *AEO2001* lead to higher projections for light-duty vehicle travel and for freight travel by truck, rail, and ship than in *AEO2000*. However, the average efficiency of new light-duty vehicles in 2020 is expected to be higher than was projected in *AEO2000*, due to recent industry developments—28.0 miles per gallon compared with 26.5 miles per gallon in *AEO2000*. Higher efficiency is also projected for freight trucks, based on recent industry data. The potential for growth in air travel was also reevaluated for the *AEO2001* projections. As a result, the *AEO2001* projection for air travel in 2020 is 7.1 percent lower than the *AEO2000* projection. In total, however, transportation energy consumption is expected to increase more rapidly than in *AEO2000* (averaging 1.8 percent as compared with 1.7 percent per year), and carbon dioxide emissions from the transportation sector in 2020 are expected to be higher by 21 million metric tons carbon equivalent, or 2.9 percent.

AEO2000 projected that both electricity sales and carbon dioxide emissions from electricity generation (excluding cogeneration) would increase on average by 1.3 percent per year between 1999 and 2020. The *AEO2001* projections for electricity demand are higher, particularly for the residential and commercial sectors, as noted above. Purchased electricity demand is projected to increase at an average annual rate of 1.8 percent, and carbon dioxide emissions from electricity generation (excluding cogeneration) are projected to increase by an average of 1.6 percent per year. In *AEO2001*, less nuclear capacity is expected to be retired by 2020 than was projected in *AEO2000* as a result of lower assumed costs for extending the operating life of existing nuclear plants and higher projected prices for natural gas. In addition, coal consumption for electricity generation is expected to be slightly lower and natural gas consumption higher than projected in *AEO2000*.

Carbon Dioxide Emissions by Sector

In 2020, electricity generation (excluding cogeneration) is expected to account for 38 percent of all carbon dioxide emissions, up from 37 percent in 1999. The increasing share of carbon dioxide emissions from generation results, in part, from the 1.8-percent annual growth rate in projected electricity consumption. New capacity will be required to meet the expected electricity demand growth and to replace the loss of some nuclear capacity that is expected to be retired. Of that new capacity, about 6 percent is projected to be fueled with coal and 92 percent with natural gas.

The growth of both projected energy consumption and carbon dioxide emissions in the transportation sector is faster than in the other end-use sectors because of projected increases in travel and the relatively slow improvement in fuel efficiency that is expected in the reference case. Between 1999 and 2020, transportation energy demand and carbon dioxide emissions are projected to grow at average annual rates of 1.8 percent, and in 2020 it is estimated that the transportation sector will account for 36 percent of all carbon dioxide emissions from energy use. The average efficiency of the light-duty vehicle fleet—cars, light trucks, vans, and sport utility vehicles—is projected to increase from 20.5 to 21.5 miles per gallon between 1999 and 2020. Over the same period, vehicle-miles traveled by light-duty vehicles are expected to increase by 1.9 percent per year, faster than the expected growth rate for the over-age-16 population (0.9 percent per year). Growth in both air and freight truck travel, at average projected rates of 3.6 percent and 2.6 percent per year, also contributes to the expected growth in carbon dioxide emissions from the transportation sector.

Carbon dioxide emissions from the residential and commercial sectors are expected to grow by 1.4 percent and 1.6 percent per year, respectively, contributing 19 percent and 17 percent of carbon dioxide emissions in 2020, including the emissions from the generation of electricity used in each sector. The projected annual growth rates for energy consumption in the residential and commercial sectors are 1.2 percent and 1.4 percent, respectively. In both sectors, growth in energy consumption and carbon dioxide emissions is expected to result from continued growth in energy service demand from an increasing number of households and commercial establishments, offset somewhat by efficiency improvements in both sectors.

Carbon dioxide emissions from the industrial sector are expected to increase by 0.9 percent per year through 2020, accounting for 29 percent of the total projected carbon dioxide emissions in 2020, including emissions from electricity generation for the sector. Total industrial energy consumption is projected to grow at an average annual rate of 1.0 percent. The relatively low expected growth rate as compared with other sectors results from efficiency improvements, slow growth in coal use for boiler fuel, and a shift to less energy-intensive industries. Energy use per unit of output is expected to decline as additions to the capital stock are made from increasingly efficient equipment and investments are made to improve the efficiency of the existing stock. The use of renewable energy sources in the industrial sector is also projected to increase at a faster rate than is projected for energy markets as a whole. Approximately 90 percent of the projected growth in renewable energy consumption in the industrial sector is for cogeneration and the remainder for boiler fuel.

Carbon Dioxide Emissions by Fuel

By fuel, petroleum products are projected to be the leading source of energy-related carbon dioxide emissions because of the continuing growth expected in the transportation sector, where petroleum products currently account for some 97 percent of total energy use. About 42 percent of all U.S. carbon dioxide emissions—860 million metric tons carbon equivalent of the total of 2,041 million metric tons carbon equivalent in 2020—are projected to be from petroleum products. About 82 percent of the total carbon dioxide emissions from petroleum use are estimated to result from transportation uses in 2020.

Coal is expected to be the second leading source of carbon dioxide emissions in 2020 at 671 million metric tons carbon equivalent, or about 33 percent of total U.S. carbon dioxide emissions. Coal has the highest carbon content of all the fossil fuels and is expected to remain the predominant fuel source for electricity generation through 2020. By 2020, the coal-fired share of generation (excluding cogeneration) is expected to decline from its 1999 level of 54 percent to 47 percent. About 90 percent of carbon dioxide emissions from coal in 2020 are estimated to result from electricity generation.

Natural gas consumption for both electricity generation and direct end uses is expected to grow at the fastest rate of all the fossil fuels—an average of 2.3 percent per year through 2020. Natural gas has a relatively low carbon content relative to other fossil fuels (only about one-half that of coal), and thus carbon dioxide emissions from natural gas use are projected to be just 510 million metric tons carbon equivalent in 2020, about 25 percent of the total.

Macroeconomic Growth

The assumed rate of economic growth has a strong impact on projections of energy consumption and, therefore, carbon dioxide emissions. In *AEO2001* the high economic growth case includes higher projected growth in population, the labor force, and labor productivity than in the reference case, leading to higher industrial output, lower inflation, and lower interest rates. As a result, projected GDP in the high economic growth case increases at an average rate of 3.5 percent per year from 1999 to 2020, compared with a projected growth rate of 3.0 percent per year in the reference case.

With higher projected economic growth, energy consumption is expected to grow at a faster rate, as higher projected manufacturing output and income increase the demand for energy services. Total energy consumption in the high economic growth case is estimated at 135.9 quadrillion Btu in 2020, compared with 127.0 quadrillion Btu in the reference case (Figure 31). As a result of the higher consumption, carbon dioxide emissions are projected to reach a level of 2,193 million metric tons carbon equivalent in 2020, 7 percent higher than the projected reference case level of 2,041 million metric tons carbon equivalent (Figure 32).

In the low economic growth case, assumptions of lower projected growth in population, the labor force, and labor productivity result in a projected average annual growth rate of 2.5 percent through 2020. With lower economic growth, estimated energy consumption in 2020 is reduced from 127.0 quadrillion Btu in the reference case to 119.0 quadrillion Btu, and carbon dioxide emissions in 2020 are estimated at 1,916 million metric tons carbon equivalent, 6 percent lower than in the reference case.

Total energy intensity, measured as primary energy consumption per dollar of GDP, is projected to improve at a more rapid rate in the high economic growth case than in the reference case, partially offsetting the changes in energy consumption caused by the higher growth assumptions. With more rapid projected growth in energy consumption, there is expected to be a greater opportunity to turn over and improve the stock of energy-using technologies, increasing the overall efficiency of the capital stock. Aggregate energy intensity in the high economic growth case is expected to decrease at a rate of 1.8 percent per year from 1999 through 2020, compared

Figure 31. Projected U.S. energy consumption in three economic growth cases, 1990-2020 (quadrillion Btu)

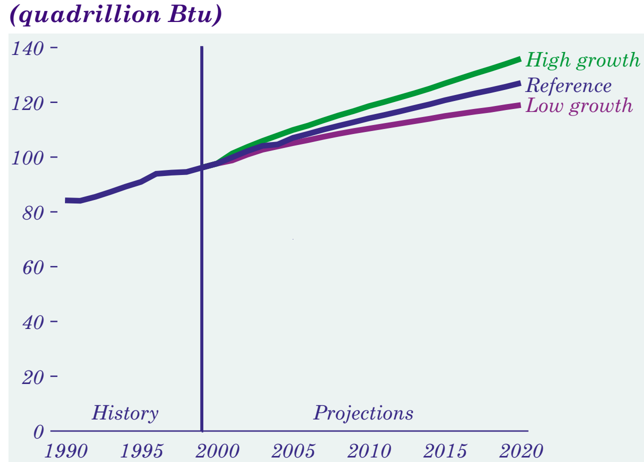


Figure 32. Projected U.S. carbon dioxide emissions in three economic growth cases, 1990-2020 (million metric tons carbon equivalent)

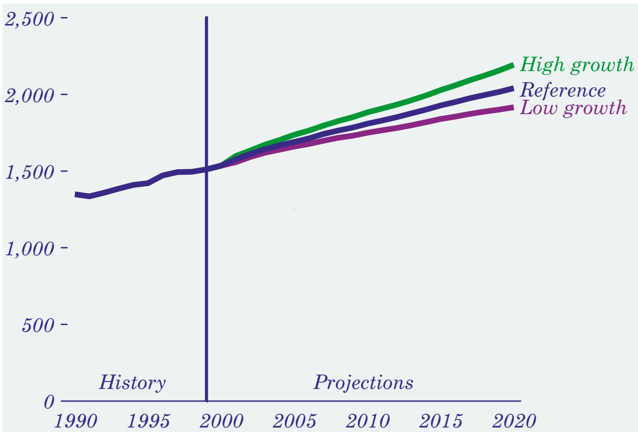
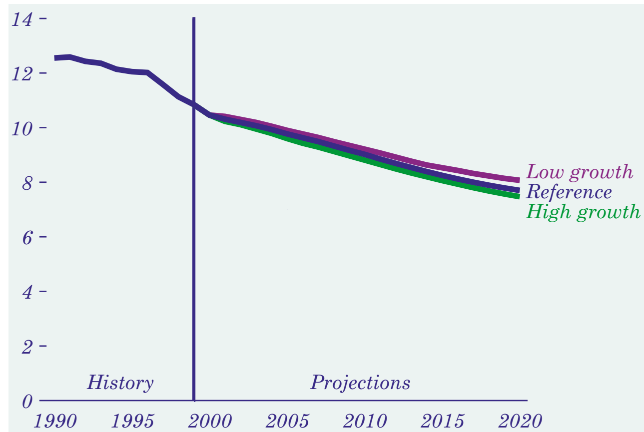


Figure 33. Projected U.S. energy intensity in three economic growth cases, 1990-2020 (thousand Btu per dollar of GDP)



with expected declines of 1.6 percent in the reference case and 1.4 percent in the low economic growth case (Figure 33).

Technology Improvement

The *AEO2001* reference case assumes continued improvements in technology for both energy consumption and production; improvements in building shell efficiencies for both new and existing buildings; efficiency improvements for new appliances, industrial equipment, transportation vehicles, and generating equipment; productivity improvements for coal production; and improvements in the exploration and development costs, finding rates, and success rates for oil and gas production. As a result of the continued improvements in the efficiency of end-use and electricity generation technologies, total energy intensity in the reference case is projected to decline at an average annual rate of 1.6 percent between 1999 and 2020.

The projected decline in energy intensity is considerably less than that experienced during the 1970s and early 1980s, when energy intensity declined, on average, by 2.3 percent per year. Approximately 40 percent of that decline can be attributed to structural shifts in the economy—shifts to service industries and other less energy-intensive industries; however, the rest resulted from the use of more energy-efficient equipment. During those years there were periods of rapid escalation in energy prices, encouraging some of the efficiency improvements. Then, as energy prices moderated, the improvement in energy intensity moderated. Between 1986 and 1999, energy intensity declined at an average annual rate of 1.3 percent.

Regulatory programs have contributed to some of the past improvements in energy efficiency, including the Corporate Average Fuel Economy standards for light-duty vehicles and standards for motors and energy-using equipment in buildings in the Energy Policy Act of 1992 and the National Appliance Energy Conservation Act of 1987. In keeping with the general practice of incorporating only current policy and regulations, the reference case for *AEO2001* assumes no new efficiency standards. Only current standards or approved new standards with specified levels are included (see "Legislation and Regulations," page 18).

AEO2001 presents a range of alternative cases that vary key assumptions about technology improvement and penetration. In the high technology case, a more rapid pace of technology improvements in energy-consuming equipment is projected to reduce energy consumption and energy-related carbon dioxide emissions to levels below those expected in the reference case. Conversely, a slower rate of improvement assumed in the low technology case is projected to result in higher consumption and emissions.

In the end-use demand sectors, experts in technology engineering were consulted to derive high technology assumptions, considering the potential impacts of increased research and development for more advanced technologies. The revised assumptions include earlier years of introduction, lower costs, higher maximum market potential, and higher efficiencies than assumed in the reference case. It is possible that even further technology improvements beyond those assumed in the high technology case could occur if there were a very aggressive research and development effort. For the electricity generation sector, the costs and efficiencies of advanced fossil-fired and new renewable generating technologies were assumed to improve from reference case values, based on assessments from the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy and Office of Fossil Energy and from the Electric Power Research Institute [*61*].

Although more advanced technologies may reduce energy consumption, in general they are more expensive when initially introduced. In order to penetrate into the market, advanced technologies must be purchased by consumers; however, many potential purchasers may not be willing to buy more expensive equipment that has a long period for recovering the additional cost through energy savings, and many may value other attributes over energy efficiency. Penetration can also be slowed by the relative turnover of the capital stock. In order to encourage more rapid penetration of advanced technologies, to reduce energy consumption or carbon dioxide emissions, it is likely that either market policies, such as higher energy prices, or nonmarket policies, such as new standards, may be required.

The 2001 technology case assumes that all future equipment choices will be made from the equipment and vehicles available in 2001, with new building shell and industrial plant efficiencies frozen at 2001 levels. New generating technologies are assumed not to improve over time. Aggregate efficiencies are assumed to improve over the forecast period as new equipment is chosen to replace older stock and the capital stock expands, and building shell efficiencies are assumed to improve as projected energy prices increase in the forecast.

In the high technology case, with the high technology assumptions for all four end-use demand sectors and the electricity generation sector combined, aggregate energy intensity is expected to decline at an average of 1.9 percent per year from 1999 to 2020, compared with 1.6 percent per year in the reference case (Figure 34). In the 2001 technology case, the average decline is expected to be only 1.4 percent per year through 2020. Total energy consumption is projected to increase to 118.9 quadrillion Btu in 2020 in the high technology case, compared with 127.0 quadrillion Btu in the reference case and 133.3 quadrillion Btu in the 2001 technology case (Figure 35).

The lower projected energy consumption in the high technology case lowers the projection for carbon dioxide emissions from 2,041 million metric tons carbon equivalent in the reference case in 2020 to 1,875 million metric tons carbon equivalent (Figure 36). In the 2001 technology case, projected carbon dioxide emissions increase to 2,157 million metric tons carbon equivalent in 2020.

Figure 34. Projected U.S. energy intensity in three technology cases, 1990-2020 (thousand Btu per dollar of GDP)

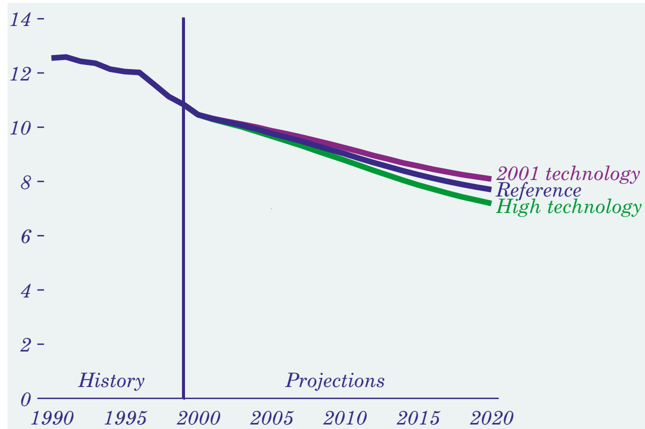
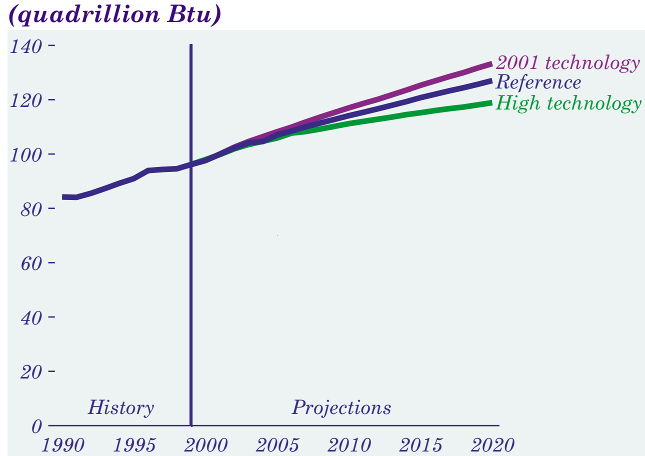


Figure 35. Projected U.S. energy consumption in three technology cases, 1990-2020 (quadrillion Btu)



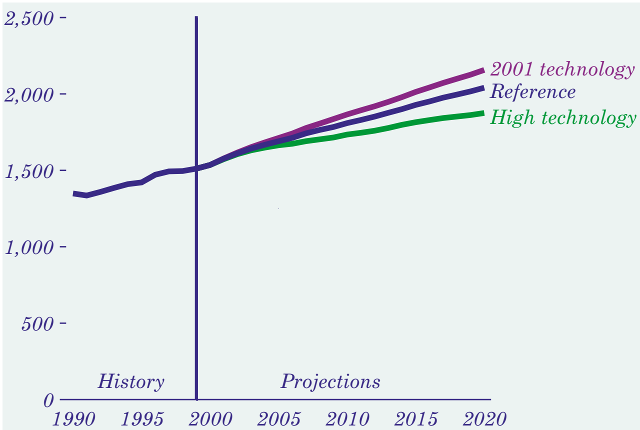
In the high technology case, about 46 percent, or 77 million metric tons carbon equivalent, of the reduction in expected carbon dioxide emissions compared to the reference case results from shifts to more efficient or alternative-fuel vehicles in the transportation sector. An additional 36 percent of the estimated reduction, or 60 million metric tons carbon equivalent, results from lower projections for electricity demand and generation.

International Negotiations on Greenhouse Gas Reductions

The Framework Convention on Climate Change

As a result of increasing warnings by members of the climatological and scientific community about the

Figure 36. Projected U.S. carbon dioxide emissions in three technology cases, 1990-2020 (million metric tons carbon equivalent)



possible harmful effects of rising greenhouse gas concentrations in the Earth's atmosphere, the Intergovernmental Panel on Climate Change was established by the World Meteorological Organization and the United Nations Environment Programme in 1988 to assess the available scientific, technical, and socioeconomic information in the field of climate change. A series of international conferences followed, and in 1990 the United Nations established the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change. After a series of negotiating sessions, the text of the Framework Convention on Climate Change was adopted at the United Nations on May 9, 1992, and opened for signature at Rio de Janeiro on June 4, 1992.

The objective of the Framework Convention was to ". . . achieve . . . stabilization of the greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." All signatories agreed to implement measures to mitigate climate change and prepare periodic emissions inventories. In addition, the developed country signatories agreed to adopt national policies with a goal of returning anthropogenic emissions of greenhouse gases to 1990 levels. The Convention excludes chlorofluorocarbons and hydrochlorofluorocarbons, which are controlled by the 1987 Montreal Protocol on Substances that Deplete the Ozone Layer.

In response to the Framework Convention, the United States issued the Climate Change Action Plan (CCAP) [*62*], published in October 1993, which consists of a series of 44 actions to reduce greenhouse gas emissions. The actions include voluntary programs, industry partnerships, government incentives, research and development, regulatory programs including energy efficiency standards, and forestry actions. Greenhouse gases affected by the CCAP actions include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and perfluorocarbons. At the time CCAP was developed, the Administration estimated that the actions it enumerated would reduce total net emissions [*63*] of these greenhouse gases in the United States to 1990 levels by 2000. Although CCAP no longer stands as a unified program, many of its individual programs remain in effect.

The Conference of the Parties and the Kyoto Protocol

The Framework Convention established the Conference of the Parties to "review the implementation of the Convention and . . . make, within its mandate, the decisions necessary to promote the effective implementation." Moving beyond the 2000 target in the Convention, the first Conference of the Parties met in Berlin in 1995 and issued the Berlin mandate, an agreement to "begin a process to enable it to take appropriate action for the period beyond 2000." The second Conference of the Parties, held in Geneva in July 1996, called for negotiations on quantified limitations and reductions of greenhouse gas emissions and policies and measures for the third Conference of the Parties. From December 1 through 11, 1997, representatives from more than 160 countries met in Kyoto, Japan, at the third session of the Conference of the Parties. In the resulting Kyoto Protocol to the Framework Convention, targets for greenhouse gas emissions were established for the developed nations—the Annex I countries—relative to their emissions levels in 1990 [*64*].

The targets are to be achieved, on average, from 2008 through 2012, the first commitment period in the Protocol. The overall emissions reduction target for the Annex I countries is 5.2 percent below 1990 levels. Relative to 1990, the individual targets range from an 8-percent reduction for the European Union (EU) to a 10-percent increase for Iceland. The reduction target for the United States is 7 percent below 1990 levels. Non-Annex I countries have no targets under the Protocol, although the Protocol reaffirms the commitments of the Framework Convention by all parties to formulate and implement climate change mitigation and adaptation programs.

The Protocol was opened for signature on March 16, 1998, for a 1-year period. It will enter into force 90 days after 55 Parties, including Annex I countries accounting for at least 55 percent of the 1990 carbon dioxide emissions from Annex I nations, have deposited their instruments of ratification, acceptance, approval, or accession. By March 15, 1999, 84 countries had signed the Protocol, including all but two of the Annex I countries, Hungary and Iceland. To date, 30 countries [*65*] have ratified or acceded to the Protocol, but no Annex I nations have done so.

Energy use is a natural focus of greenhouse gas reductions. In 1990, total greenhouse gas emissions in the United States were 1,655 million metric tons carbon equivalent, of which carbon dioxide emissions from the combustion of energy accounted for 1,349 million metric tons carbon equivalent, or 82 percent [*66*]. By 1999, total U.S. greenhouse gas emissions had risen to 1,833 million metric tons carbon equivalent, with 1,511 million metric tons carbon equivalent (82 percent) from energy combustion. Because energy-related carbon dioxide emissions constitute such a large percentage of total greenhouse gas emissions, any action or policy to reduce emissions will affect U.S. energy markets.

The Kyoto Protocol includes a number of flexibility measures for compliance. Reductions in other greenhouse gases—methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride—can offset carbon dioxide emissions [*67*]. "Sinks" that absorb carbon dioxide—forests, other vegetation, and soils—may also be used to offset emissions, but specific guidelines and rules for the accounting of land-use and forestry activities remain to be resolved by the Conference of the Parties.

Emissions trading among the Annex I countries is also permitted under the Protocol, and groups of Annex I countries may jointly meet the total commitment of all the member nations either by allocating a share of the total reduction to each member or by trading emissions rights. Joint implementation projects are also allowed among the Annex I countries, allowing a nation to take emissions credits for projects that reduce emissions or enhance sinks in other Annex I countries. However, it is indicated in the Protocol that trading and joint implementation are supplemental to domestic actions. The Protocol also establishes a Clean Development Mechanism (CDM), a program under which Annex I countries can earn credits for projects that reduce emissions in non-Annex I countries if the projects lead to measurable, long-term emissions benefits.

The targets specified in the Protocol can be achieved on average over the first commitment period of 2008 to 2012 rather than in each individual year. No targets are established for periods after 2012, although the Conference of the Parties will initiate consideration of future commitments at least 7 years before the end of the first commitment period. Banking— carrying over emissions reductions that go beyond the target from one commitment period to some subsequent commitment period—is allowed. The Protocol indicates that each Annex I country must have made demonstrable progress in achieving its commitments by 2005.

At the fourth session of the Conference of the Parties in Buenos Aires, in November 1998, a plan of action was adopted to finalize a number of the implementation issues at the sixth Conference of the Parties (COP 6), held November 13 through 24, 2000, at The Hague, the Netherlands. Negotiations at the fifth Conference of the Parties in Bonn, Germany, from October 25 through November 5, 1999, focused on developing rules and guidelines for emissions trading, joint implementation, and CDM, negotiating the definition and use of forestry activities and additional sinks, and understanding the basics of a compliance system, with an effort to complete this work at COP 6 [*68*].

Negotiations were held before COP 6 on a range of technical issues, including emissions reporting and review, communications by non-Annex I countries, technology transfer, and assessments of capacity needs for developing countries and countries with economies in transition. The United States affirmed its support for the inclusion of a wide range of land and forest management activities under the Protocol, and for an accounting system that would include the total net impact of land management on carbon stocks [*69*]. The goals of COP 6 included developing the concepts in the Protocol in sufficient detail that it could be ratified by enough Annex I countries to be put into force, and encouraging significant action by the non-Annex I countries to meet the objectives of the Framework Convention [*70*].

EIA's Analyses of Emissions Reductions

In 1998, at the request of the U.S. House of Representatives Committee on Science, EIA analyzed the likely impacts of the Kyoto Protocol on U.S. energy prices, energy use, and the economy in the 2008 to 2012 period. The analysis was published in *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* [*71*], with an accompanying briefing report, *What Does the Kyoto Protocol Mean to U.S. Energy Markets and the U.S. Economy?* [*72*].

In 1999, the Committee on Science made an additional request for EIA to analyze the impacts of an earlier, phased-in start date for U.S. carbon dioxide emissions reductions. Earlier carbon dioxide reductions could lead to the purchase of more efficient or less carbon-dioxide-intensive equipment at an earlier date, making it easier and less expensive to meet greenhouse gas emissions targets. The resulting analysis, *Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol*, was published in July 1999 [*73*].

In both 1999 and 2000, EIA received requests from the U.S. House of Representatives for analyses of the Administration's Climate Change Technology Initiative (CCTI)—from the Committee on Science in 1999 and from the Committee on Government Reform, Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs in 2000. The two resulting studies examined the impacts of the fiscal year 2000 and 2001 budget requests for tax incentives, research and development, and other spending in CCTI, primarily focusing on the tax incentives. Both studies analyzed the potential of CCTI to reduce energy consumption and carbon dioxide emissions. The results were published in *Analysis of the Climate Change Technology Initiative* (April 1999), and *Analysis of the Climate Change Technology Initiative: Fiscal Year 2001* (April 2000) [*74*].

Most recently, EIA was requested by the Committee on Government Reform, Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs to undertake a two-part study on reducing emissions from electricity generating plants. The first report, scheduled for release in December 2000, will analyze the potential costs of various strategies to achieve simultaneous reductions in emissions of sulfur dioxide, nitrogen oxide, and carbon dioxide by electricity generators. The strategies are based on bills that have been proposed in the House of Representatives and the Senate. The second report, to be released early in 2001, will analyze the costs of reducing mercury emissions and the impacts of renewable portfolio standards. The two reports, taken together, will give a sense as to the costs of reducing multiple emissions and the potential cost savings from doing so in a coordinated fashion.

Market Trends

The projections in *AEO2001* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. Thus, they provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as currently enacted; however, the impacts of emerging regulatory changes, when defined, are reflected.

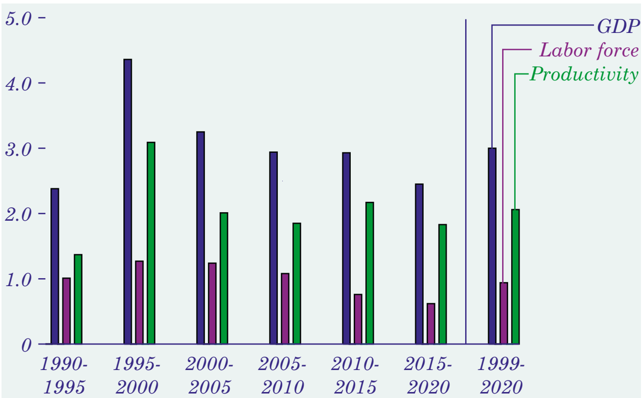
Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated, including severe weather, political disruptions, strikes, and technological breakthroughs. In addition, future developments in technologies, demographics, and resources cannot be foreseen with any degree of certainty. Many key uncertainties in the *AEO2001* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, analytical processes in the examination of policy initiatives.

Strong Economic Growth Is Expected To Continue

Figure 37. Projected average annual real growth rates of economic factors, 1999-2020 (percent)

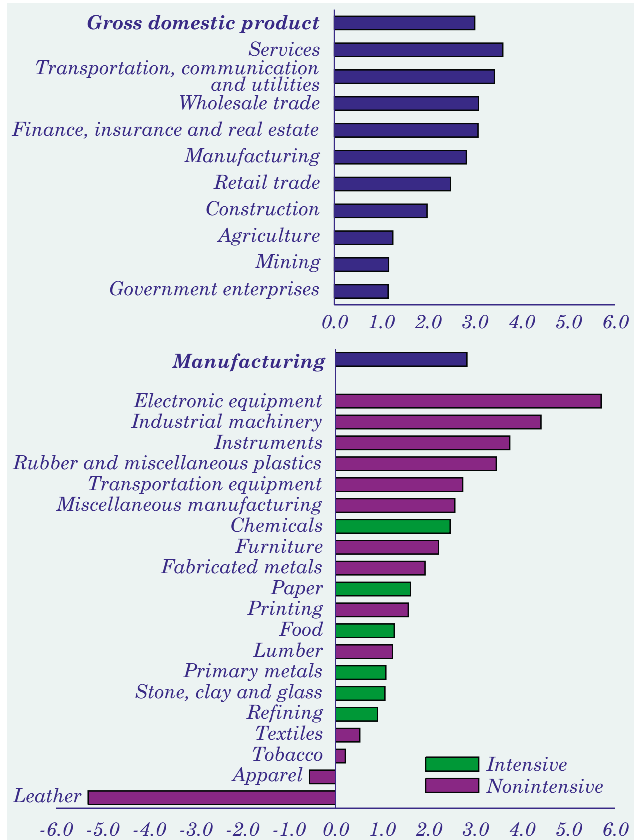


The output of the Nation's economy, measured by gross domestic product (GDP), is projected to increase by 3.0 percent per year between 1999 and 2020 (with GDP based on 1996 chain-weighted dollars) (Figure 37), higher than the 2.1-percent growth projected in *AEO2000* for the same period. The projected growth rate for the labor force is similar to last year's forecast through 2020; however, in the *AEO2001* projection, productivity growth (GDP growth minus labor force growth) is 2.1 percent per year, up from 1.2 percent per year in *AEO2000* (see "Issues in Focus," page 22).

The projected rate of growth in GDP slows in the latter half of the forecast period as the expansion of the labor force slows, but sustained levels of labor productivity growth moderate the effects of lower labor force growth. Total population growth is expected to remain fairly constant after 2000; the slowing growth in the size of the labor force results instead from the increasing size of the population over the age of 65 years after 2000. As more people retire from the work force, and as life expectancy rises, the labor force participation rate—the percentage of the population over 16 years of age actually holding or looking for employment—is expected to peak in 2011 and then to begin declining as "baby boom" cohorts begin to retire. From 2010 to 2015, labor force growth is projected to slow to 0.8 percent, and from 2015 to 2020 it is expected to fall to 0.6 percent per year. Labor force productivity growth, however, is expected to remain near 2 percent per year throughout each of the 5-year periods.

Electronic, Industrial Equipment Lead Manufacturing Growth

Figure 38. Projected sectoral composition of GDP growth, 1999-2020 (percent per year)

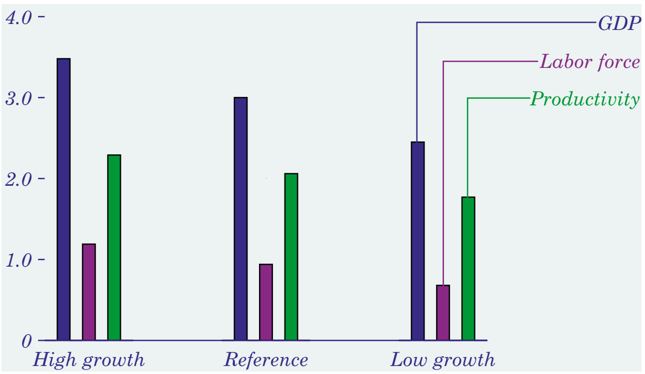


The projected growth rate for manufacturing production is 2.8 percent per year, slightly lower than the 3.0-percent annual growth projected for the aggregate economy (Figure 38). Energy-intensive manufacturing sectors are projected to grow more slowly than non-energy-intensive manufacturing sectors (1.2 percent and 3.3 percent annual growth, respectively).

The electronic equipment and industrial machinery sectors lead the expected growth in manufacturing, as semiconductors and computers find broader applications. The rubber and miscellaneous plastic products sector is expected to grow faster than manufacturing as a whole, with plastics continuing to penetrate new markets as well. Higher growth is expected for the services sector than for the manufacturing sector, as in last year's forecast.

High and Low Growth Cases Reflect Uncertainty of Economic Growth

Figure 39. Projected average annual real growth rates of economic factors in three cases, 1999-2020 (percent)



To reflect the uncertainty in forecasts of economic growth, *AEO2001* includes high and low economic growth cases in addition to the reference case (Figure 39). The high and low growth cases show the projected effects of alternative growth assumptions on energy markets. The three economic growth cases are based on macroeconomic forecasts prepared by Standard & Poor's DRI (DRI) [*75*]. The DRI forecast used in generating the *AEO2001* reference case is the February 2000 trend growth scenario, adjusted to incorporate the world oil price assumptions used in the *AEO2001* reference case. The *AEO2001* high and low economic growth cases are based on the spread between the optimistic and pessimistic growth projections prepared by DRI in February 1999.

The high economic growth case incorporates higher projected growth rates for population, labor force, and labor productivity. With higher productivity gains, inflation and interest rates are projected to be lower than in the reference case, and economic output is projected to grow by 3.5 percent per year. GDP per capita is expected to grow by 2.4 percent per year, compared with 2.1 percent in the reference case. The low economic growth case assumes lower growth rates for population, labor force, and productivity, resulting in higher projections for prices and higher interest rates and lower projections for industrial output growth. In the low growth case, economic output is projected to increase by 2.5 percent per year from 1999 through 2020, and growth in GDP per capita is projected to slow to 1.8 percent per year.

Long-Run Trend Shows Slowing of the U.S. Economic Growth Rate

Figure 40. Annual GDP growth rate for the preceding 21 years, 1970-2020 (percent)

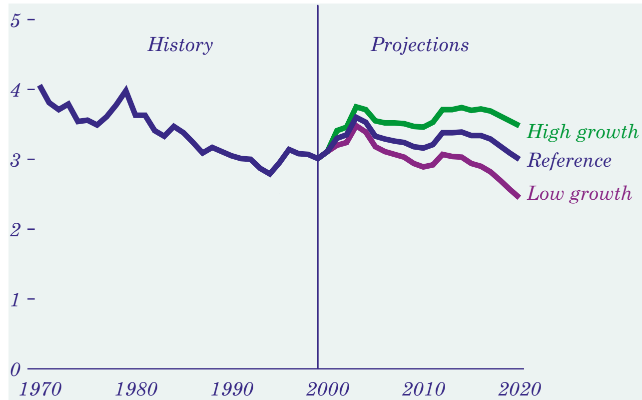
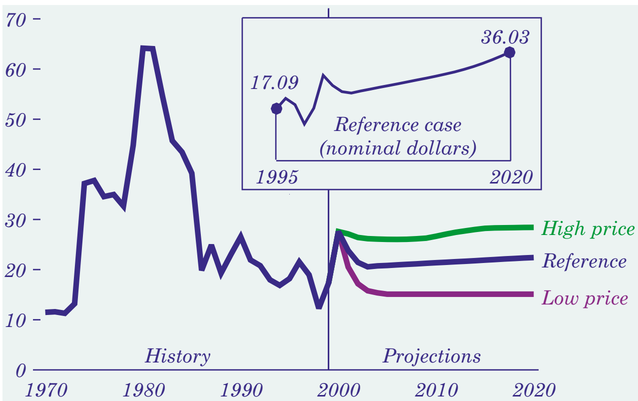


Figure 40 shows the trend in the moving 21-year annual growth rate for GDP, including projections for the three *AEO2001* cases. The value for each year is calculated as the annual growth rate over the preceding 21 years. The 21-year average shows major long-term trends in GDP growth by smoothing more volatile year-to-year changes (although the increase shown for 2000-2002 reflects the slow and negative growth of 1980-1982). Annual GDP growth has fluctuated considerably around the trend. The high and low growth cases capture the potential for different paths of long-term output growth.

One reason for the variability of the forecasts is the composition of economic output, reflected by growth rates of consumption and investment relative to the overall GDP growth for the aggregate economy. In the reference case, consumption is projected to grow by 3.1 percent per year, while investment grows at a 4.7-percent annual rate. In the high growth case, growth in investment is projected to increase to 5.5 percent per year. Higher investment rates lead to faster capital accumulation and higher productivity gains, which, coupled with higher labor force growth, yield faster aggregate economic growth than projected in the reference case. In the low growth case, annual growth in investment expenditures is projected to slow to 3.6 percent. With the labor force also growing more slowly, aggregate economic growth is expected to slow considerably.

Projections Vary in Cases With Different Oil Price Assumptions

Figure 41. World oil prices in three cases, 1970-2020 (1999 dollars per barrel)



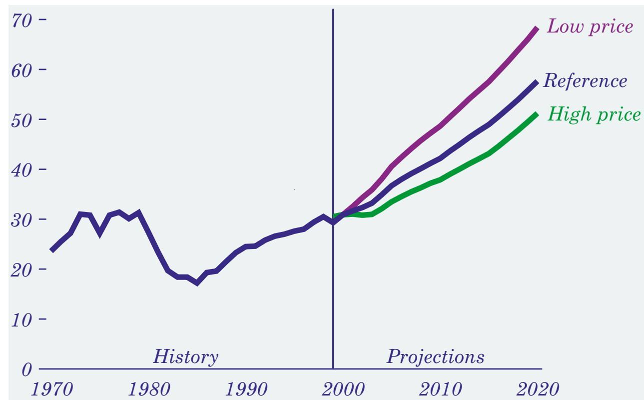
Just as the historical record shows substantial variability in world oil prices, there is considerable uncertainty about future prices. Three *AEO2001* cases with different price paths allow an assessment of alternative views on the course of future oil prices (Figure 41). In the reference case, prices are projected to rise by about 1.2 percent per year, reaching $22.41 in 2020 (all prices in 1999 dollars unless otherwise noted). In nominal dollars, the reference case price is expected to exceed $36 in 2020. In the low price case, prices are projected to decline after the current price rise, to $15.10 by 2005, and to remain at about that level out to 2020. The high price case projects a price rise of about 3.1 percent per year out to 2015, with prices remaining at about $28 out to 2020. The projected leveling off in the high price case is due to the market penetration of alternative energy supplies that could become economically viable at that price.

All three price cases are similar to the price projections in *AEO2000* beyond 2005, reflecting considerable optimism about the potential for worldwide petroleum supply, even in the face of the substantial expected increase in demand. Production from countries outside OPEC is expected to show a steady increase, exceeding 45 million barrels per day in 2000 and increasing gradually thereafter to 59 million barrels per day by 2020.

Total worldwide demand for oil is expected to reach 117 million barrels per day by 2020. Developing countries in Asia show the largest projected growth in demand, averaging 3.9 percent per year.

Uncertain Prospects for Persian Gulf Production Shape Oil Price Cases

Figure 42. OPEC oil production in three cases, 1970-2020 (million barrels per day)



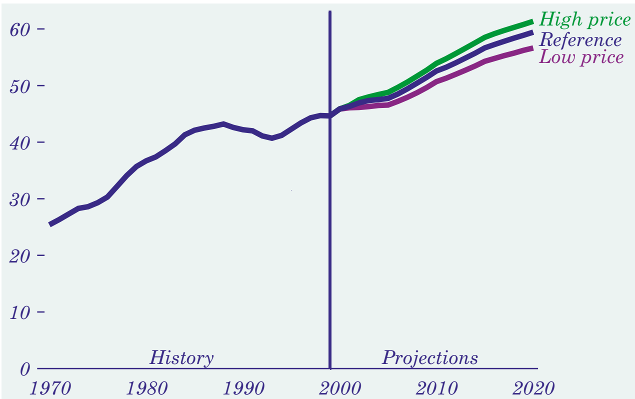
The three price cases are based on alternative assumptions about oil production levels in OPEC nations: higher production in the low price case and lower production in the high price case. With its vast store of readily accessible oil reserves, OPEC—primarily the Persian Gulf nations—is expected to be the principal source of marginal supply to meet future incremental demand.

The projected increase in OPEC production capacity in the reference case is consistent with announced plans for OPEC capacity expansion [*76*]. By 2020, OPEC production is projected to be 58 million barrels per day (almost twice its 1999 production) in the reference case, 51 million in the high case, and 68 million in the low case (Figure 42). Worldwide demand for oil varies across the price cases in response to the price paths. The forecasts of total world demand for oil range from about 125 million barrels per day in the low price case to about 113 million barrels per day in the high price case.

The variation in oil production forecasts reflects uncertainty about the prospects for future production from the Persian Gulf region. The expansion of productive capacity will require major capital investments, which could depend on the availability and acceptability of foreign investments. Iraq is assumed to continue selling oil only at sanction-allowed volumes through 2001. Recent discoveries offshore of Nigeria, as well as Venezuela's aggressive capacity expansion plans, will more than accommodate increasing demand in the absence of Iraq's full return to the oil market.

Production Increases Are Expected for Non-OPEC Oil Producers

Figure 43. Non-OPEC oil production in three cases, 1970-2020 (million barrels per day)

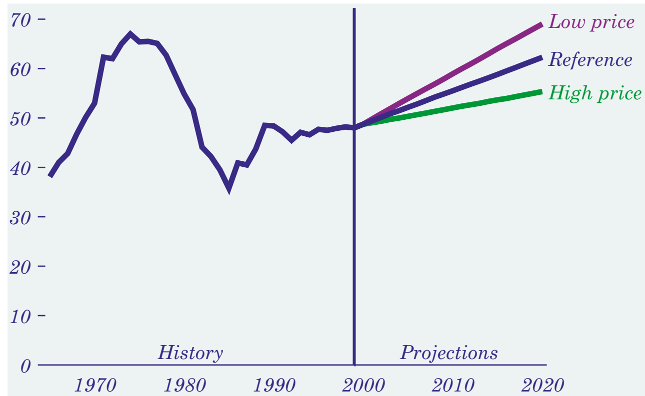


The growth and diversity in non-OPEC oil supply have shown surprising resilience even in the low price environment of the late 1990s. Although OPEC producers will certainly benefit from the projected growth in oil demand, significant competition is expected from non-OPEC suppliers. Countries in the Organization for Economic Cooperation and Development (OECD) that are expected to register production increases over the next decade include North Sea producers, Australia, Canada, and Mexico. In Latin America, Colombia, Brazil, and Argentina are showing accelerated growth in oil production, due in part to privatization efforts. Deepwater projects off the coast of western Africa and in the South China Sea will start producing significant volumes of oil early in this decade. In addition, much of the increase in non-OPEC supply over the next decade is expected to come from the former Soviet Union, and political uncertainty appears to be the only potential barrier to the development of vast oil resources in the Caspian Basin.

In the *AEO2001* reference case, non-OPEC supply is projected to reach 59 million barrels per day by 2020 (Figure 43). In the low oil price case, non-OPEC supply is projected to grow to 57 million barrels per day by 2020, whereas in the high oil price case it is projected to reach 61 million barrels per day by the end of the forecast period.

Persian Gulf Producers Could Take More Than Half of World Oil Trade

Figure 44. Persian Gulf share of worldwide oil exports in three cases, 1965-2020 (percent)

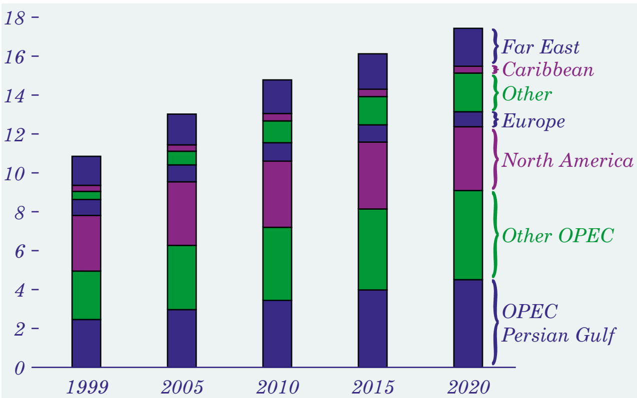


Considering the world market in oil exports, the historical peak for Persian Gulf exports (as a percent of world oil exports) occurred in 1974, when they made up more than two-thirds of the oil traded in world markets (Figure 44). The most recent historical low for Persian Gulf oil exports came in 1985 as a result of more than a decade of high oil prices, which led to significant reductions in worldwide petroleum consumption. Less than 40 percent of the oil traded in 1985 came from Persian Gulf suppliers. Following the 1985 oil price collapse, the Persian Gulf export percentage has been steadily increasing.

In the *AEO2001* reference case, Persian Gulf producers are expected to account for more than 50 percent of worldwide trade by 2002—for the first time since the early 1980s. After 2002, the Persian Gulf share of worldwide petroleum exports is projected to increase gradually to more than 62 percent by 2020. In the low oil price case, the Persian Gulf share of total exports is projected to exceed 69 percent by 2020. All Persian Gulf producers are expected to increase oil production capacity significantly over the forecast period, and both Saudi Arabia and Iraq are expected to more than double their current production capacity.

OPEC Accounts for More Than Half of Projected U.S. Oil Imports

Figure 45. Projected U.S. gross petroleum imports by source, 1999-2020 (million barrels per day)



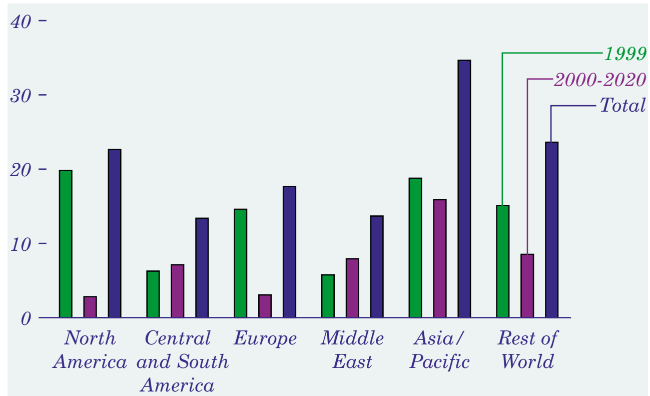
In the reference case, total U.S. gross oil imports are projected to increase from 10.9 million barrels per day in 1999 to 17.4 million in 2020 (Figure 45). Crude oil accounts for most of the expected increase in imports through 2005, whereas imports of petroleum products make up a larger share of the increase after 2005. Product imports are projected to increase more rapidly as U.S. production stabilizes, because U.S. refineries lack the capacity to process larger quantities of imported crude oil.

Not until 2014 is OPEC expected to account for more than 50 percent of total projected U.S. petroleum imports. The OPEC share is expected to increase gradually to 52 percent in 2020, and the Persian Gulf share of U.S. imports from OPEC is projected to range between 47 percent and 50 percent consistently throughout the forecast. Crude oil imports from the North Sea are projected to increase slightly through 2010, then to decline gradually as North Sea production ebbs. Significant imports of petroleum from Canada and Mexico are expected to continue, and West Coast refiners are expected to import crude oil from the Far East to replace the declining production of Alaskan crude oil.

Imports of light products are expected to nearly triple by 2020, to 4.1 million barrels per day. Most of the projected increase is from refiners in the Caribbean Basin and the Middle East, where refining capacity is expected to expand significantly. Vigorous growth in demand for lighter petroleum products in developing countries means that U.S. refiners are likely to import smaller volumes of light, low-sulfur crude oils.

Asia/Pacific Region Is Expected To Surpass U.S. Refining Capacity

Figure 46. Projected worldwide refining capacity by region, 1999 and 2020 (million barrels per day)



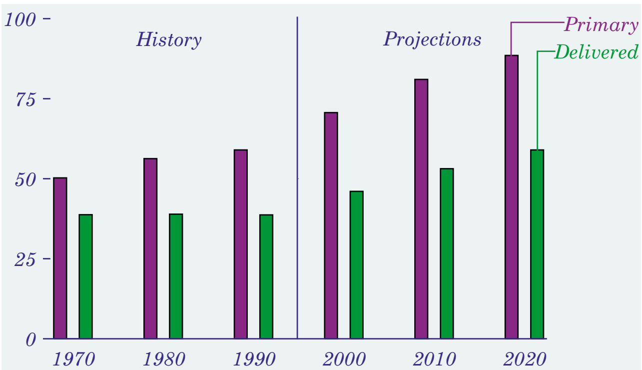
Worldwide crude oil distillation capacity was 80.3 million barrels per day at the beginning of 1999. To meet the growth in international oil demand in the reference case, worldwide refining capacity is expected to increase by about 55 percent—to more than 125 million barrels per day—by 2020. Substantial growth in distillation capacity is expected in the Middle East, Central and South America, and the Asia/Pacific region (Figure 46).

The Asia/Pacific region was the fastest growing refining center in the 1990s. It passed Western Europe as the world's second largest refining center and, in terms of distillation capacity, is expected to surpass North America by 2005. While not adding significantly to their distillation capacity, refiners in the United States and Europe have tended to improve product quality and enhance the usefulness of heavier oils through investment in downstream capacity.

Future investments in the refinery operations of developing countries must include configurations that are more advanced than those currently in operation. Their refineries will be called upon to meet increased worldwide demand for lighter products, to upgrade residual fuel, to supply transportation fuels with reduced lead, and to supply both distillate and residual fuels with decreased sulfur levels. An additional burden on new refineries will be the need to supply lighter products from crude oils whose quality is expected to deteriorate over the forecast period.

Annual Growth in Energy Use Is Projected To Continue

Figure 47. Primary and delivered energy consumption, excluding transportation use, 1970-2020 (quadrillion Btu)



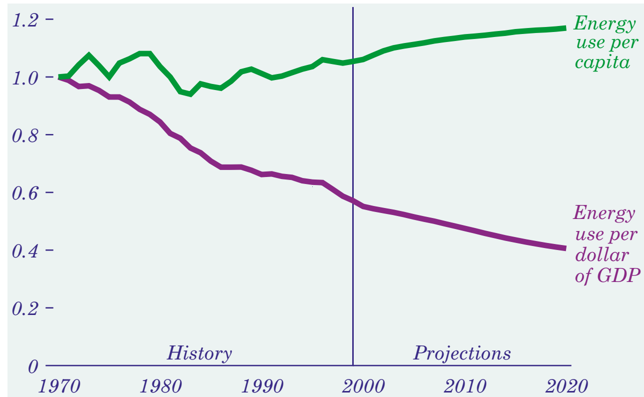
Net energy delivered to consumers represents only a part of total primary energy consumption. Primary consumption includes energy losses associated with the generation, transmission, and distribution of electricity, which are allocated to the end-use sectors (residential, commercial, and industrial) in proportion to each sector's share of electricity use [*77*].

How energy consumption is measured has become more important over time, as reliance on electricity has expanded. In 1970 electricity accounted for only 12 percent of energy delivered to the end-use sectors, excluding transportation. Since then, the growth in electricity use for applications such as space conditioning, consumer appliances, telecommunication equipment, and industrial machinery has resulted in greater divergence between primary and delivered energy consumption (Figure 47). This trend is expected to stabilize in the forecast, as more efficient generating technologies offset increased demand for electricity. Projected primary energy consumption and delivered energy consumption grow by 1.1 percent and 1.3 percent per year, respectively, excluding transportation use.

At the end-use sectoral level, tracking of primary energy consumption is necessary to link specific policies with overall goals. Carbon dioxide emissions, for example, are closely correlated with total energy consumption. In the development of carbon dioxide stabilization policies, growth rates for primary energy consumption may be more important than those for delivered energy.

Average Energy Use per Person Increases Slightly in the Forecast

Figure 48. Energy use per capita and per dollar of gross domestic product, 1970-2020 (index, 1970 = 1)

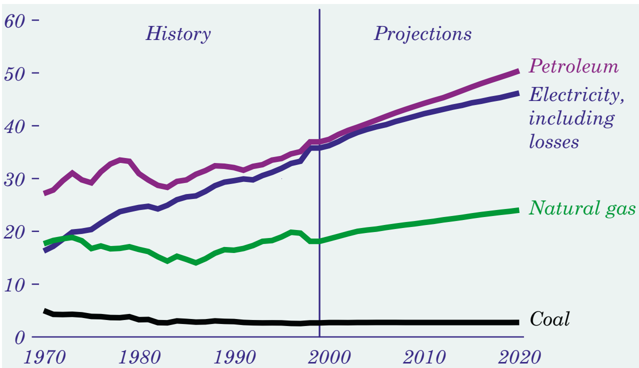


Energy intensity, both as measured by primary energy consumption per dollar of GDP and as measured on a per capita basis, declined between 1970 and the mid-1980s (Figure 48). Although the overall GDP-based energy intensity of the economy is projected to continue declining between 1999 and 2020, the decline is not expected to be as rapid as it was in the earlier period. GDP is estimated to increase by 86 percent between 1999 and 2020, compared with a 32-percent increase in primary energy use. Relatively stable energy prices are expected to slow the decline in energy intensity, as is increased use of electricity-based energy services. When electricity claims a greater share of energy use, consumption of primary energy per dollar of GDP declines at a slower rate, because electricity use contributes both end-use consumption and energy losses to total energy consumption.

In the *AEO2001* forecast, the demand for energy services is projected to increase markedly over 1999 levels. The average home in 2020 is expected to be 5 percent larger and to rely more heavily on electricity-based technologies. Annual highway travel and air travel per capita in 2020 are expected to be 27 percent and 77 percent higher, respectively, than in 1999. With the growth in demand for energy services, primary energy intensity on a per capita basis is projected to increase by 0.5 percent per year through 2020, with efficiency improvements in many end-use energy applications making it possible to provide higher levels of service without significant increases in total energy use per capita.

Petroleum Products Lead Growth in Energy Consumption

Figure 49. Delivered energy use by fossil fuel and primary energy use for electricity generation, 1970-2020 (quadrillion Btu)



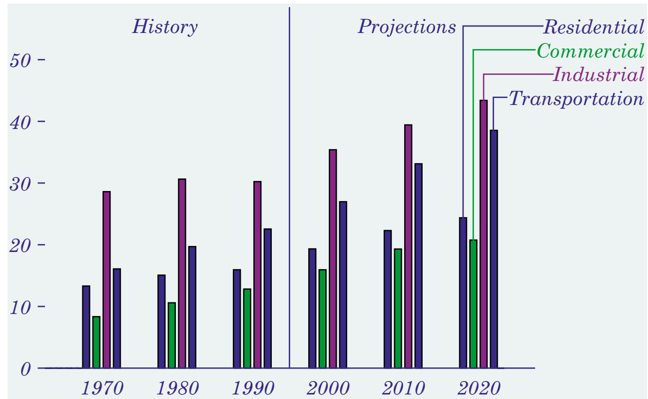
Consumption of petroleum products, mainly for transportation, is expected to claim the largest share of primary energy use in the *AEO2001* forecast (Figure 49). Energy demand growth in the transportation sector averaged 2.0 percent per year during the 1970s but was slowed in the 1980s by rising fuel prices and new Federal efficiency standards, leading to a 2.1-percent annual increase in average vehicle fuel economy. In the forecast, fuel economy gains are projected to slow as a result of expected stable fuel prices and the absence of new legislative mandates. Projected growth in population and in travel per capita are expected to result in increases in demand for gasoline throughout the forecast.

Increased competition and technological advances in electricity generation and distribution are expected to reduce the real cost of electricity. Despite low projected prices, however, growth in electricity use is expected to be slower than the rapid growth of the 1970s. Excluding consumption for electricity generation, demand for natural gas is projected to grow at a slightly slower rate than overall end-use energy demand, in contrast to the recent trend of more rapid growth in the use of gas as the industry was deregulated. Natural gas is projected to meet 24.7 percent of end-use energy requirements in 2020.

End-use demand for renewable energy from sources such as wood, wood wastes, and ethanol is projected to increase by 1.5 percent per year. Geothermal and solar energy use in buildings is expected to increase by about 2.7 percent per year but is not expected to exceed 1 percent of energy use for space and water heating.

U.S. Primary Energy Use Reaches 127 Quadrillion Btu per Year by 2020

Figure 50. Primary energy consumption by sector, 1970-2020 (quadrillion Btu)



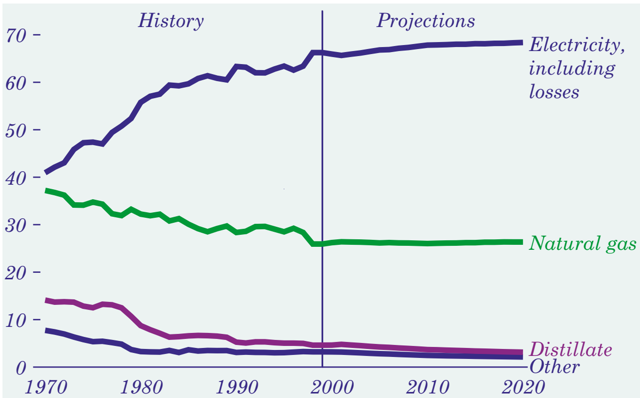
Primary energy use in the reference case is projected to reach 127 quadrillion Btu by 2020, 32 percent higher than the 1999 level. In the early 1980s, as energy prices rose, sectoral energy consumption grew relatively little (Figure 50). Between 1985 and 1999, however, stable energy prices contributed to a marked increase in sectoral energy consumption.

In the forecast, energy demand in the residential and commercial sectors is projected to grow at a faster rate than population but at less than half the expected growth rate for GDP. Demand for energy is expected to grow more rapidly in the transportation sector than in the buildings sectors as a result of increased per capita travel and slower fuel efficiency gains. Assumed efficiency gains in the industrial sector are projected to cause the demand for primary energy to grow more slowly than GDP.

To bracket the uncertainty inherent in any long-term forecast, alternative cases were used to highlight the sensitivity of the forecast to different oil price and economic growth paths. At the consumer level, oil prices primarily affect the demand for transportation fuels. Projected oil use for transportation in the high world oil price case is 3.0 percent lower than in the low world oil price case in 2020, as consumer choices favor more fuel-efficient vehicles and the demand for travel services is reduced slightly. In contrast, variations in economic growth assumptions lead to larger changes in the projections of overall energy demand in each of the end-use sectors [*78*]. For 2020, the projection of total annual energy use in the high economic growth case is 14 percent higher than in the low economic growth case.

Residential Energy Use Grows by 28 Percent From 1999 to 2020

Figure 51. Residential primary energy consumption by fuel, 1970-2020 (percent of total)



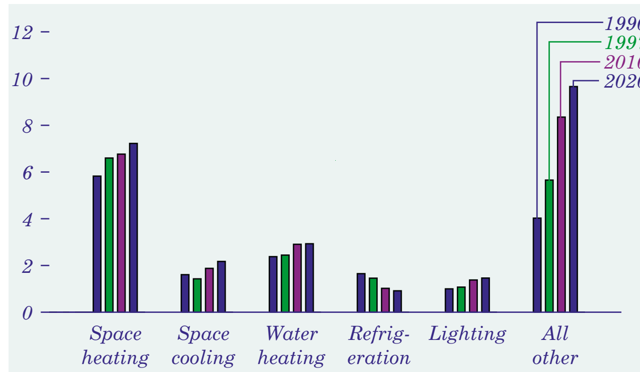
Residential energy consumption is projected to increase by 28 percent overall between 1999 and 2020. Most (75 percent) of the growth in total energy use is related to increased use of electricity. Sustained growth in housing in the South, where almost all new homes use central air conditioning, is an important component of the national trend, along with the penetration of consumer electronics, such as home office equipment and security systems (Figure 51).

While its share increases slightly, natural gas use in the residential sector is projected to grow by 1.3 percent per year through 2020. Natural gas prices to residential customers are projected to decline in the forecast and to be lower than the prices of other fuels, such as heating oil. The number of homes heated by natural gas is projected to increase more than the number heated by electricity and oil. Petroleum use is projected to fall, with the number of homes using petroleum-based fuels for space heating applications expected to decrease over time.

Newly built homes are, on average, larger than the existing stock, with correspondingly greater needs for heating, cooling, and lighting. Under current building codes and appliance standards, however, energy use per square foot is typically lower for new construction than for the existing stock. Further reductions in residential energy use per square foot could result from additional gains in equipment efficiency and more stringent building codes, requiring more insulation, better windows, and more efficient building designs.

Efficiency Standards Should Moderate Residential Energy Use

Figure 52. Residential primary energy consumption by end use, 1990, 1997, 2010, and 2020 (quadrillion Btu)



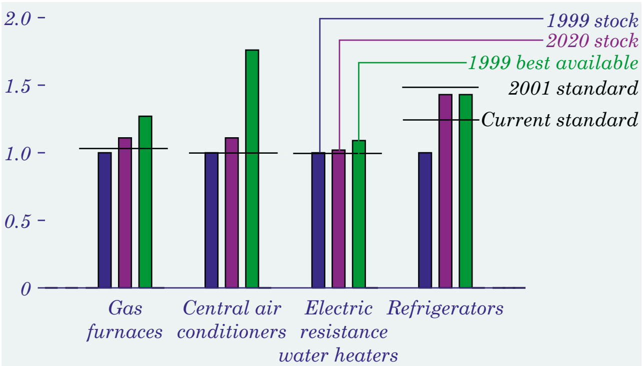
Energy use for space heating, the most energy-intensive end use in the residential sector, grew by 1.8 percent per year from 1990 to 1997 (Figure 52). Future growth is expected to be slowed by higher equipment efficiency and tighter building codes. Building shell efficiency gains are projected to cut space heating demand by nearly 10 percent per household in 2020 relative to the demand in 1997.

A variety of appliances are now subject to minimum efficiency standards, including heat pumps, air conditioners, furnaces, refrigerators, and water heaters. Current standards for a typical residential refrigerator limit electricity use to 690 kilowatthours per year, and revised standards are expected to reduce consumption by another 30 percent by 2002. Energy use for refrigeration has declined by 1.8 percent per year from 1990 to 1997 and is expected to decline by about 2.0 percent per year through 2020, as older, less efficient refrigerators are replaced with newer models.

The "all other" category, which includes smaller appliances such as personal computers, dishwashers, clothes washers, and dryers, has grown by 5 percent per year from 1990 to 1997 (Figure 52) and now accounts for 30 percent of residential primary energy use. It is projected to account for 40 percent in 2020, as small electric appliances continue to penetrate the market. The promotion of voluntary standards, both within and outside the appliance industry, is expected to forestall even larger increases. Even so, the "all other" category is projected to exceed other components of residential demand by 2020.

Available Technologies Can Slow Future Residential Energy Demand

Figure 53. Efficiency indicators for selected residential appliances, 1999 and 2020 (index, 1999 stock efficiency =1)

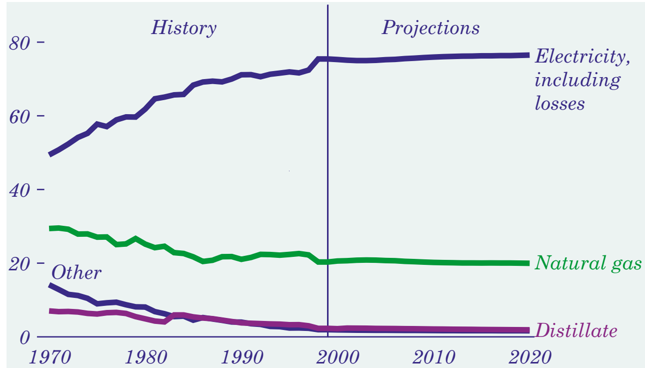


The *AEO2001* reference case projects an increase in the stock efficiency of residential appliances, as stock turnover and technology advances in most end-use services combine to reduce residential energy intensity over time. For most appliances covered by the National Appliance Energy Conservation Act of 1987, the most recent Federal efficiency standards are higher than the 1998 stock, ensuring an increase in stock efficiency (Figure 53) without any additional new standards. Future updates to the Federal standards could have a significant effect on residential energy consumption, but they are not included in the reference case. Proposed rules for new efficiency standards for clothes washers, central air conditioners, and heat pumps were announced in October 2000.

For almost all end-use services, technologies now exist that can significantly curtail future energy demand if they are purchased by consumers. The most efficient technologies can provide significant long-run savings in energy bills, but their higher purchase costs tend to restrict their market penetration. For example, condensing technology for natural gas furnaces, which reclaims heat from exhaust gases, can raise efficiency by more than 20 percent over the current standard; and variable-speed scroll compressors for air conditioners and refrigerators can increase their efficiency by 50 percent or more. In contrast, there is little room for efficiency improvements in electric resistance water heaters, because the technology is approaching its thermal limit.

Energy Fuel Shares for Commercial Users Are Expected To Remain Stable

Figure 54. Commercial nonrenewable primary energy consumption by fuel, 1970-2020 (percent of total)

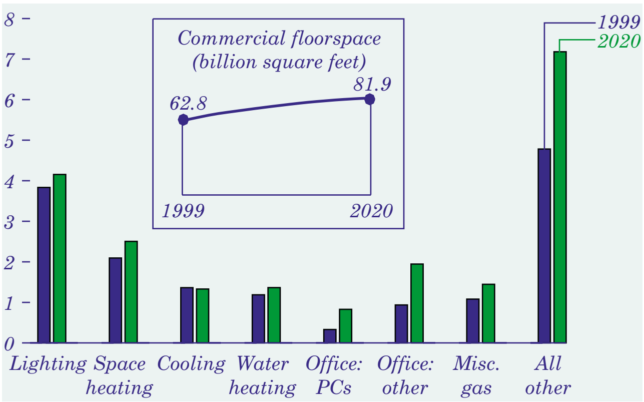


Projected energy use trends in the commercial sector show stable shares for all fuels, with growth in overall consumption slowing from its pace over the past three decades (Figure 54). Moderate growth (1.4 percent per year) is expected in the commercial sector, for two reasons. First, commercial floorspace is projected to grow by 1.3 percent per year between 1999 and 2020, compared with an average of 1.8 percent per year over the past 30 years, reflecting the slowing labor force growth expected later in the forecast. Second, energy consumption per square foot is projected to increase by a modest 0.1 percent per year, with efficiency standards, voluntary government programs aimed at improving efficiency, and other technology improvements expected to balance the effects of a projected increase in demand for electricity-based services and stable or declining fuel prices.

Electricity is projected to account for three-fourths of commercial primary energy consumption throughout the forecast. Expected efficiency gains in electric equipment are expected to be offset by the continuing penetration of new technologies and greater use of office equipment. Natural gas, which accounted for 20 percent of commercial energy consumption in 1999, is projected to maintain that share throughout the forecast. Distillate fuel oil made up only 2 percent of commercial demand in 1999, down from 6 percent in the years before deregulation of the natural gas industry. The fuel share projected for distillate remains at 2 percent in 2020, as natural gas continues to compete for space and water heating uses. With stable prices projected for conventional fuels, no appreciable growth in the share of renewable energy in the commercial sector is anticipated.

Commercial Lighting Is the Sector's Most Important Energy Application

Figure 55. Commercial primary energy consumption by end use, 1999 and 2020 (quadrillion Btu)

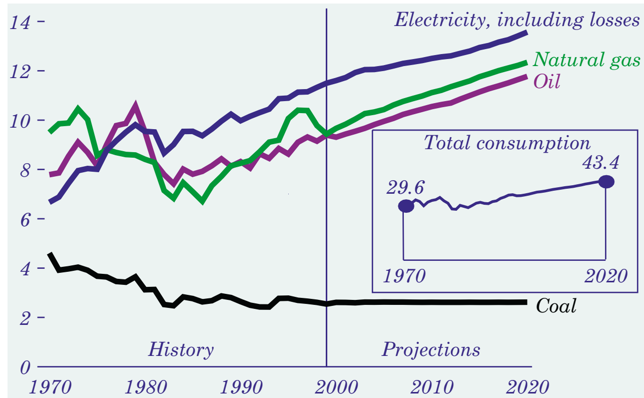


Through 2020, lighting is projected to remain the most important individual end use in the commercial sector [*79*]. Energy use for lighting is projected to increase slightly, as growth in lighting requirements is expected to outpace the adoption of more energy-efficient lighting equipment. Efficiency of space heating, space cooling, and water heating is also expected to improve, moderating growth in overall commercial energy demand. A projected increase in building shell efficiency, which affects the energy required for space heating and cooling, contributes to the trend (Figure 55).

The highest growth rates are expected for end uses that have not yet saturated the commercial market. Energy use for personal computers is projected to grow by 4.5 percent per year and for other office equipment, such as fax machines and copiers, by about 3.5 percent per year. The projected growth in electricity use for office equipment reflects a trend toward more powerful equipment, the response to projected declines in real electricity prices and increases in the market for commercial electronic equipment. Natural gas use for such miscellaneous uses as cooking and self-generated electricity is expected to grow by 1.4 percent per year. New telecommunications technologies and medical imaging equipment are projected to increase electricity demand in the "all other" end use category, which also includes ventilation, refrigeration, minor fuel consumption, service station equipment, and vending machines. Growth in the "all other" category is expected to slow somewhat in later years of the forecast as emerging technologies achieve greater market penetration.

Industrial Energy Use Could Grow by 24 Percent by 2020

Figure 56. Industrial primary energy consumption by fuel, 1970-2020 (quadrillion Btu)

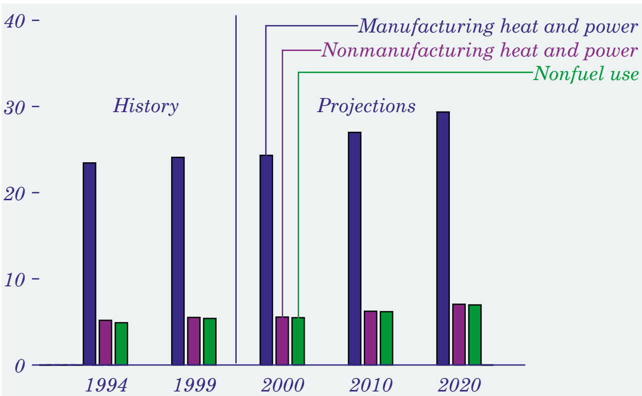


From 1970 to 1986, with demand for coking coal reduced by declines in steel production and natural gas use falling as a result of end-use restrictions and curtailments, electricity's share of industrial energy use increased from 23 percent to 33 percent. The natural gas share fell from 32 percent to 24 percent, and coal's share fell from 16 percent to 9 percent. After 1986, natural gas began to recover its share as end-use regulations were lifted and supplies became more certain and less costly. In the *AEO2001* forecast, natural gas is projected to account for a larger share and electricity for a smaller share of industrial delivered energy consumption by 2020. Industrial output is projected to grow by 2.6 percent per year from 1999 to 2020.

Primary energy use in the industrial sector—which includes the agriculture, mining, and construction industries in addition to traditional manufacturing—is projected to increase by 1.0 percent per year (Figure 56). Electricity (for machine drive and some production processes) and natural gas (given its ease of handling) are the major energy sources for the industrial sector. Industrial delivered electricity use is projected to increase by 32.5 percent, with competition in the generation market keeping electricity prices low. Despite a projected increase in natural gas prices, its use for energy in the industrial sector is expected to increase by 30.9 percent by 2020. Industrial petroleum use is also projected to grow by 25.3 percent. Coal use is expected to increase slowly, by 0.1 percent per year, as new steelmaking technologies continue to reduce demand for metallurgical coal, offsetting modest growth in coal use for boiler fuel and as a substitute for coke in steelmaking.

Industrial Energy Use Grows Steadily in the Projections

Figure 57. Industrial primary energy consumption by industry category, 1994-2020 (quadrillion Btu)



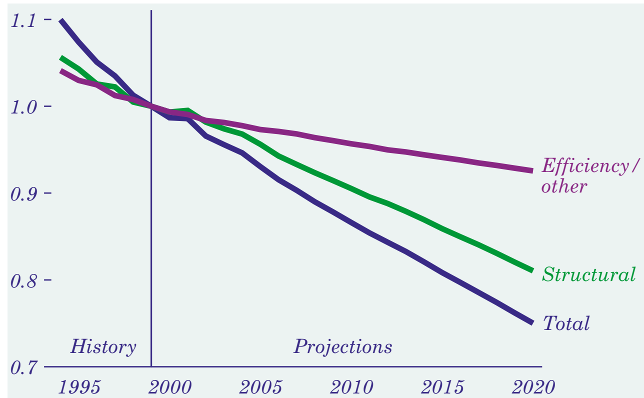
Two-thirds of all the energy consumed in the industrial sector is used to provide heat and power for manufacturing. The remainder is approximately equally distributed between nonmanufacturing heat and power and consumption for nonfuel purposes, such as raw materials and asphalt (Figure 57).

Nonfuel use of energy in the industrial sector is projected to grow more rapidly (1.2 percent annually) than heat and power consumption (1.0 percent annually). The feedstock portion of nonfuel use is projected to grow at a slightly lower rate than the output of the bulk chemical industry (1.3 percent annually) due to limited substitution possibilities. In 2020, feedstock consumption is projected to be 5.1 quadrillion Btu. Asphalt, the other component of nonfuel use, is projected to grow by 1.6 percent per year, to 1.9 quadrillion Btu in 2020. The growth rate for asphalt use is less than the projected annual growth rate for the construction industry (2.0 percent), which is the principal consumer of asphalt for paving and roofing, because other parts of the construction industry do not use asphalt.

Petroleum refining, chemicals, and pulp and paper are the largest end-use consumers of energy for heat and power in the manufacturing sector. These three energy-intensive industries used 8.7 quadrillion Btu in 1999. The major fuels used in petroleum refineries are still gas, natural gas, and petroleum coke. In the chemical industry, natural gas accounts for 60 percent of the energy consumed for heat and power. The pulp and paper industry uses the most renewables, in the form of wood and spent liquor.

Output From U.S. Industries Grows Faster Than Energy Use

Figure 58. Industrial delivered energy intensity by component, 1994-2020 (index, 1999 = 1)

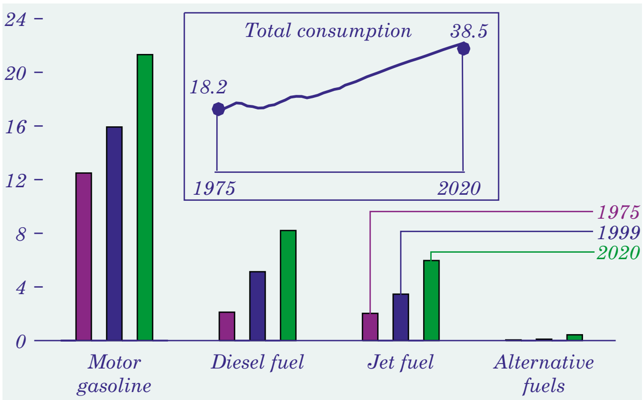


Changes in industrial energy intensity (consumption per unit of output) can be separated into two effects. One component reflects underlying increases in equipment and production efficiencies; the other arises from structural changes in the composition of manufacturing output. Since 1970, the use of more energy-efficient technologies, combined with relatively low growth in the energy-intensive industries, has dampened growth in industrial energy consumption. Thus, despite a 43-percent increase in industrial output, total energy use in the sector grew by only 7 percent between 1978 and 1999. These basic trends are expected to continue.

The share of total industrial output attributed to the energy-intensive industries is projected to fall from 23 percent in 1999 to 17 percent in 2020. Consequently, even if no specific industry experienced a decline in intensity, aggregate industrial intensity would decline. Figure 58 shows projected changes in energy intensity due to structural effects and efficiency effects separately [*80*]. Over the forecast period, industrial delivered energy intensity is projected to drop by 26 percent, and the changing composition of industrial output alone is projected to result in approximately a 19-percent drop. Thus, two-thirds of the expected change in delivered energy intensity for the sector is attributable to structural shifts and the remainder to changes in energy intensity associated with projected increases in equipment and production efficiencies.

Alternative Fuels Make Up 2 Percent of Light-Duty Vehicle Fuel Use in 2020

Figure 59. Transportation energy consumption by fuel, 1975, 1999, and 2020 (quadrillion Btu)



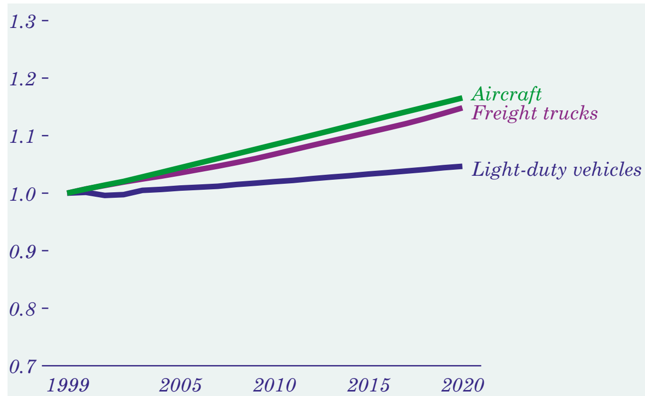
By 2020, total energy demand for transportation is expected to be 38.5 quadrillion Btu, compared with 26.4 quadrillion Btu in 1999 (Figure 59). Petroleum products dominate energy use in the sector. Motor gasoline use is projected to increase by 1.4 percent per year in the reference case, making up 55 percent of transportation energy demand. Alternative fuels are projected to displace about 203,000 barrels of oil equivalent per day [*81*] by 2020 (2.1 percent of light-duty vehicle fuel consumption), in response to current environmental and energy legislation intended to reduce oil use. Gasoline's share of demand is expected to be sustained, however, by low gasoline prices and slower fuel efficiency gains for conventional light-duty vehicles (cars, vans, pickup trucks, and sport utility vehicles) than were achieved during the 1980s.

Assumed industrial output growth of 2.6 percent per year through 2020 leads to an increase in freight transport, with a corresponding 2.3-percent annual increase in diesel fuel use. Economic growth and low projected jet fuel prices yield a 3.6-percent projected annual increase in air travel, causing jet fuel use to increase by 2.6 percent per year.

In the forecast, energy prices directly affect the level of oil use through travel costs and average vehicle fuel efficiency. Most of the price sensitivity is seen as variations in motor gasoline use in light-duty vehicles, because the stock of light-duty vehicles turns over more rapidly than the stock for other modes of travel. In the high oil price case, gasoline use increases by only 1.3 percent per year, compared with 1.5 percent per year in the low oil price case.

Average Horsepower for New Cars Is Projected To Grow by 55 Percent

Figure 60. Projected transportation stock fuel efficiency by mode, 1999-2020 (index, 1999 = 1)



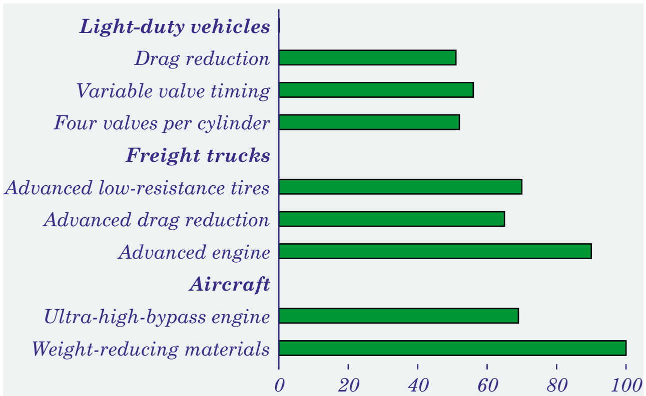
Fuel efficiency is projected to improve at a slower rate through 2020 than it did in the 1980s (Figure 60), with fuel efficiency standards for light-duty vehicles assumed to stay at current levels and projected low fuel prices and higher personal income expected to increase the demand for larger, more powerful vehicles. Average horsepower for new cars in 2020 is projected to be about 55 percent above the 1999 average (Table 12), but advanced technologies and materials are expected to keep new vehicle fuel economy from declining [*82*]. Advanced technologies such as gasoline fuel cells and direct fuel injection as well as electric hybrids for both gasoline and diesel engines, are projected to boost the average fuel economy of new light-duty vehicles by about 4 miles per gallon, to 28.0 miles per gallon in 2020. Larger percentage gains in efficiency are expected for freight trucks (from 6.0 miles per gallon in 1999 to 6.9 in 2020) and for aircraft (a 17-percent increase over the forecast period).

Table 12. New car and light truck horsepower ratings and market shares, 1990-2020

	Cars			Light trucks		
Year	Small	Medium	Large	Small	Medium	Large
1990						
Horsepower	118	141	164	132	158	176
Sales share	0.60	0.28	0.12	0.32	0.50	0.18
1999						
Horsepower	144	173	220	164	197	227
Sales share	0.49	0.38	0.12	0.36	0.52	0.12
2010						
Horsepower	197	223	285	204	234	256
Sales share	0.51	0.36	0.13	0.31	0.49	0.20
2020						
Horsepower	233	257	335	239	270	295
Sales share	0.50	0.36	0.14	0.30	0.49	0.21

New Technologies Promise Better Vehicle Fuel Efficiency

Figure 61. Projected technology penetration by mode of travel, 2020 (percent)



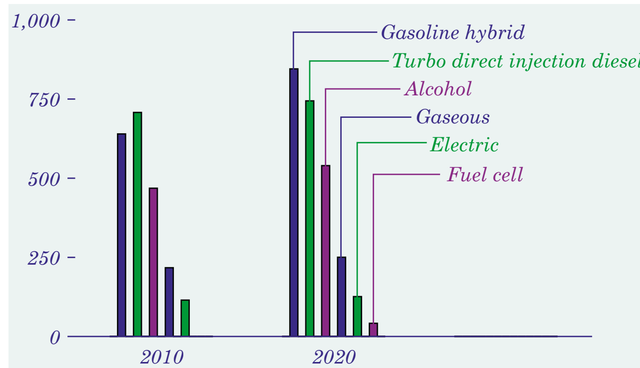
New automobile fuel economy is projected to reach approximately 32.5 miles per gallon by 2020, as a result of advances in fuel-saving technologies (Figure 61). Three of the most promising are advanced drag reduction, variable valve timing, and extension of four valve per cylinder technology to six-cylinder engines, each of which would provide between 7 and 10 percent higher fuel economy. Advanced drag reduction reduces air resistance over the vehicle; variable valve timing optimizes the timing of air intake into the cylinder with the spark ignition during combustion; and increasing the number of valves on the cylinder improves efficiency through more complete combustion of fuel in the engine.

Due to concerns about economic payback, the trucking industry is more sensitive to the marginal cost of fuel-efficient technologies; however, several technologies can increase fuel economy significantly, including advanced low-resistance tires (3 percent), advanced drag reduction (10 percent), and advanced low-emission high-efficiency diesel engines (10 percent). These technologies are anticipated to penetrate the heavy-duty truck market by 2020. Advanced technology penetration is projected to increase new freight truck fuel efficiency from 6.4 miles per gallon to 7.4 miles per gallon between 1999 and 2020.

New aircraft fuel efficiencies are projected to increase by 17 percent from 1999 levels by 2020. Ultra-high-bypass engine technology can potentially increase fuel efficiency by 10 percent, and increased use of weight-reducing materials may contribute up to a 15-percent improvement.

Advanced Technologies Could Reach Nearly 17 Percent of Sales by 2020

Figure 62. Projected sales of advanced technology light-duty vehicles by fuel type, 2010 and 2020 (thousand vehicles sold)



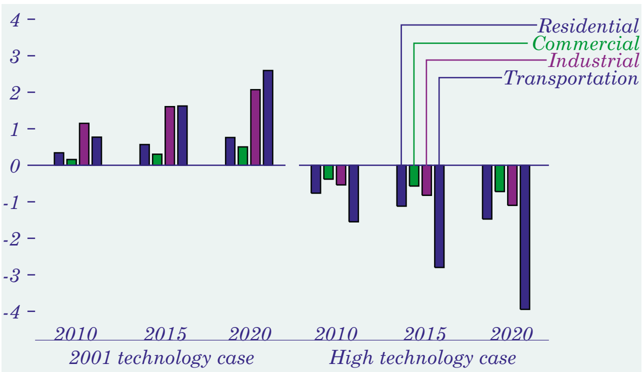
Advanced technology vehicles, representing automotive technologies that use alternative fuels or require advanced engine technology, are projected to near 2.7 million vehicle sales (16.7 percent of total projected light-duty vehicle sales) by 2020 (Figure 62).

Gasoline hybrid electric vehicles, introduced into the U.S. market by two manufacturers in 2000, are anticipated to lead advanced technology vehicle sales with about 845,000 units by 2020. Both turbo direct injection diesels and alcohol flexible-fueled vehicles are expected to sell well in the personal vehicle market, reaching approximately 744,000 and 540,000 vehicle sales, respectively, by 2020. All three of these advanced technologies will initially sell for less than $3,000 above an equivalent gasoline vehicle, but only the gasoline hybrid and the turbo direct injection diesel can achieve vehicle ranges that exceed 600 miles while delivering 35 to 45 percent better fuel economy than a comparable gasoline vehicle.

About 41 percent of advanced technology sales are a result of Federal and State mandates for either fuel economy standards, emissions programs, or other energy regulations. Alcohol flexible-fueled vehicles are currently sold by manufacturers who receive fuel economy credits to comply with corporate average fuel economy regulations. The majority of projected gasoline hybrid and electric vehicle sales result from compliance with low-emission vehicle programs in California, New York, Maine, Vermont, and Massachusetts, which currently permit zero-emission vehicle credits for advanced technologies.

Alternative Cases Analyze Effects of Advances in Technology

Figure 63. Projected variation from reference case primary energy use by sector in two alternative cases, 2010, 2015, and 2020 (quadrillion Btu)



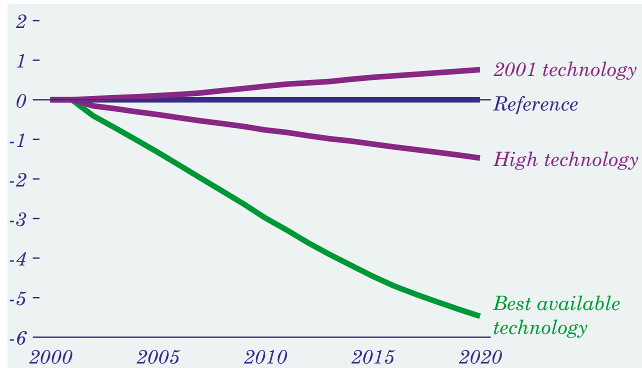
The availability and market penetration of new, more efficient technologies are uncertain. Alternative cases for each sector, based on a range of assumptions about technological progress, show the effects of these assumptions (Figure 63). The alternative cases assume that current equipment and building standards are met but do not include feedback effects on energy prices or on economic growth.

For the residential and commercial sectors, the 2001 technology case holds equipment and building shell efficiencies at 2001 levels. The best available technology case assumes that the most energy-efficient equipment and best residential building shells available are chosen for new construction each year regardless of cost, and that efficiencies of existing residential and all commercial building shells improve from their reference case levels. The high technology case assumes earlier availability, lower costs, and higher efficiencies for more advanced technologies than in the reference case.

The 2001 technology cases for the industrial and transportation sectors and the high technology case for the industrial sector use the same assumptions as the buildings sector cases. The high transportation technology case includes lower costs for advanced technologies and improved efficiencies, comparable to those assumed in a Department of Energy (DOE) interlaboratory study for air, rail, and marine travel and provided by the DOE Office of Energy Efficiency and Renewable Energy and American Council for an Energy-Efficient Economy for light-duty vehicles and by Argonne National Laboratory for freight trucks [*83*].

Advanced Technologies Could Reduce Residential Energy Use by 22 Percent

Figure 64. Projected variation from reference case primary residential energy use in three alternative cases, 2000-2020 (quadrillion Btu)



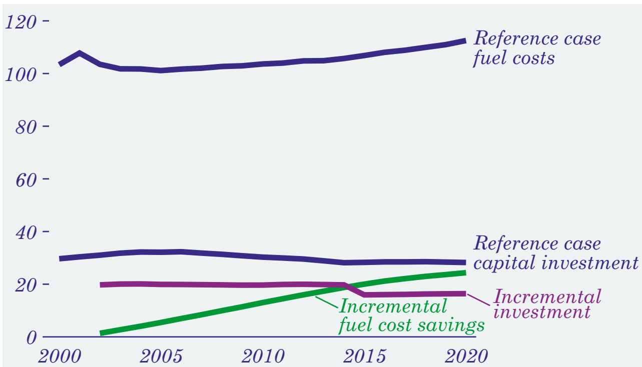
The *AEO2001* reference case forecast includes the projected effects of several different policies aimed at increasing residential end-use efficiency. Examples include minimum efficiency standards and voluntary energy savings programs designed to promote energy efficiency through innovations in manufacturing, building, and mortgage financing. In the 2001 technology case, which assumes no further increases in the efficiency of equipment or building shells beyond that available in 2001, 3.1 percent more energy would be required in 2020 (Figure 64).

In the best available technology case, assuming that the most energy-efficient technology considered is always chosen regardless of cost, projected energy use is 22.5 percent lower than in the reference case in 2020, and projected household primary energy use is 24.8 percent lower than in the 2001 technology case in 2020.

The high technology case does not constrain consumer choices. Instead, the most energy-efficient technologies are assumed to be available earlier, with lower costs and higher efficiencies. The consumer discount rates used to determine the purchased efficiency of all residential appliances in the high technology case do not vary from those used in the reference case; that is, consumers value efficiency equally across the two cases. Energy savings in this case relative to the reference case are projected to reach 6.0 percent in 2020; however, the savings are not as great as those projected in the best available technology case.

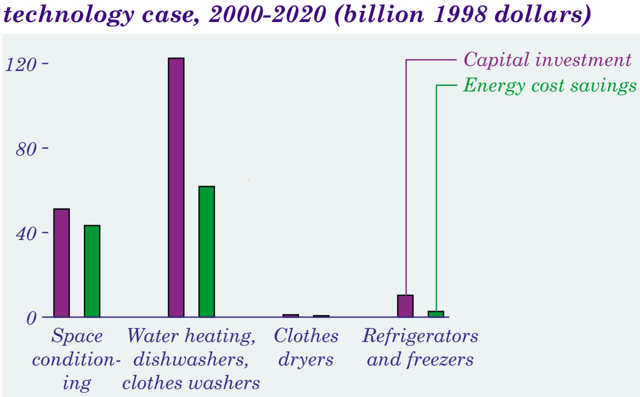
High Residential Energy Savings Would Require High Investment

Figure 65. Projected cost and investment for selected residential appliances in the best available technology case, 2000-2020 (billion 1998 dollars)



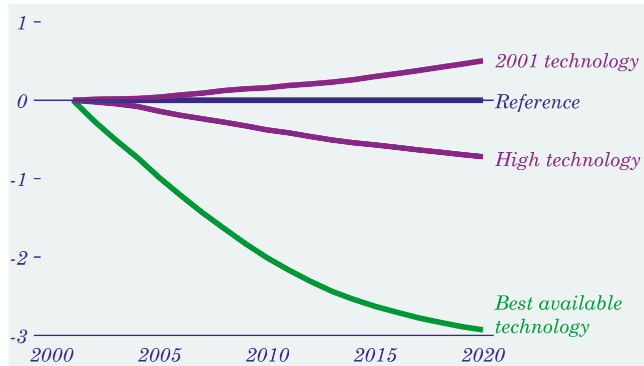
In the best available technology case, which assumes the purchase of the most efficient equipment available, projected residential energy expenditures are lower but capital investment costs are higher than projected in the reference case (Figures 65 and 66). This case captures the effects of installing the most efficient (usually the most expensive) equipment at reference case turnover rates. A total incremental investment of $185 billion [*84*] is projected to reduce residential delivered energy use by 24 quadrillion Btu through 2020, saving consumers $108 billion in energy expenditures. Water heating and space conditioning show the greatest potential for savings, but at a substantial investment cost. In place of conventional technologies (such as electric resistance water heaters), natural gas and electric heat pump water heaters and horizontal-axis washing machines can substantially cut the amount of energy needed to provide hot water services.

Figure 66. Present value of investment and savings for residential appliances in the best available technology case, 2000-2020 (billion 1998 dollars)



Advanced Technologies Could Reduce Commercial Energy Use by 14 Percent

Figure 67. Projected variation from reference case primary commercial energy use in three alternative cases, 2000-2020 (quadrillion Btu)

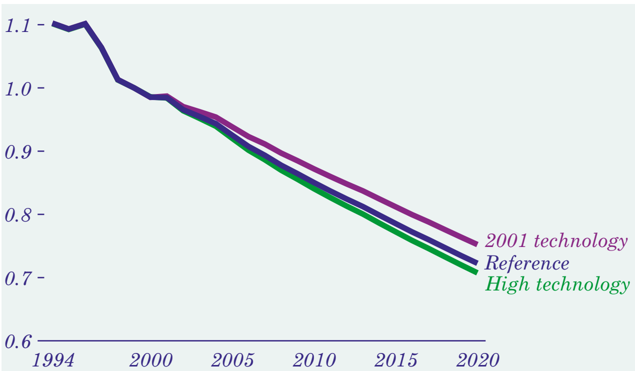


The *AEO2001* reference case incorporates efficiency improvements for commercial equipment and building shells, holding commercial energy intensity to a 0.1-percent annual increase over the forecast. The 2001 technology case assumes that future equipment and building shells will be no more efficient than those available in 2001. The high technology case assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment than in the reference case and more rapid improvement in building shells. The best available technology case assumes that only the most efficient technologies will be chosen, regardless of cost, and that building shells will improve at the rate assumed in the high technology case.

Energy use in the 2001 technology case is projected to be 2.4 percent higher than in the reference case by 2020 (Figure 67) as the result of a 0.2-percent annual increase in commercial primary energy intensity. The high technology case projects an additional 3.5-percent energy savings in 2020, with primary energy intensity falling by 0.1 percent per year from 1999 to 2020. Assuming the purchase of only the most efficient equipment in the best available technology case yields energy use that is 14.1 percent lower than in the reference case by 2020. Commercial primary energy intensity in this case is projected to decline more rapidly than in the high technology case, by 0.6 percent per year. More optimistic assumptions result in additional projected energy savings from both renewable and conventional fuel-using technologies. Solar photovoltaic systems are projected to generate 2 percent more electricity in the best technology case than in the reference case.

Alternative Technology Cases Show Range of Industrial Efficiency Gains

Figure 68. Projected industrial primary energy intensity in two alternative cases, 1994-2020 (index, 1999 = 1)



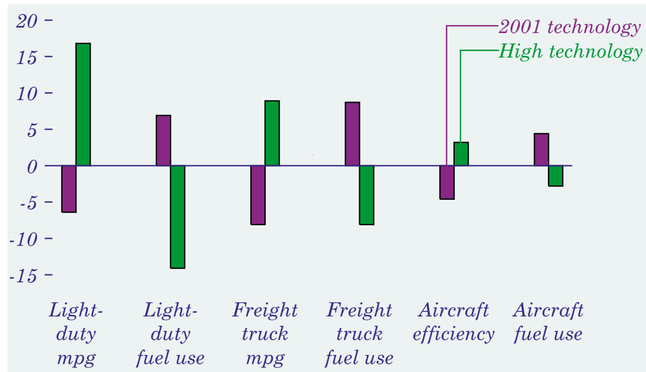
Efficiency gains in both energy-intensive and non-energy-intensive industries are projected to reduce overall energy intensity in the industrial sector. Expected growth in machinery and equipment production, driven primarily by investment and export-related demand, is a key factor: in the reference case, these less energy-intensive industries are projected to grow 56 percent faster than the industrial average (4.1 percent and 2.6 percent per year, respectively).

In the high technology case, 1.1 quadrillion Btu less energy is projected to be used in 2020 than for the same level of output in the reference case. Industrial primary energy intensity is projected to decline by 1.7 percent per year through 2020 in this case, compared with a 1.5-percent annual decline in the reference case (Figure 68). While some individual industry intensities are projected to decline almost twice as rapidly in the high technology case as in the reference case, the aggregate intensity is not as strongly affected, because the composition of industrial output is the same in the two cases.

In the 2001 technology case, industry is projected to use 2.1 quadrillion Btu more energy in 2020 than in the reference case. Energy efficiency remains at the level achieved by new plants in 2001, but average efficiency still improves as old plants are retired. Aggregate industrial energy intensity is projected to decline by 1.3 percent per year because of reduced efficiency gains and changes in industrial structure. The composition of industrial output accounts for 87 percent of the projected change in aggregate industrial energy intensity in the 2001 technology case, compared with 73 percent in the reference case.

Vehicle Technology Advances Could Lower Carbon Dioxide Emissions

Figure 69. Projected changes in key components of the transportation sector in two alternative cases, 2020 (percent change from reference case)



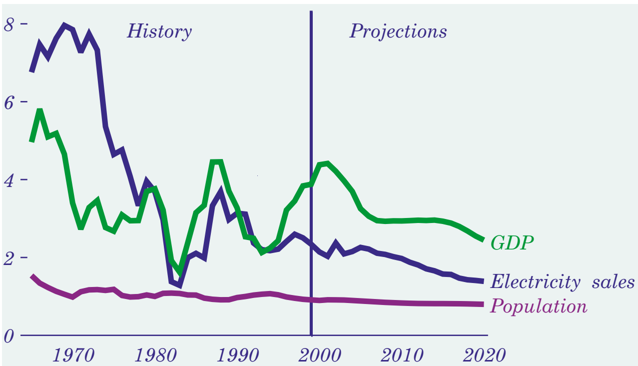
The transportation high technology case assumes lower costs, higher efficiencies, and earlier introduction for new technologies. Projected energy demand is 3.9 quadrillion Btu (10 percent) lower in 2020 than in the reference case, reducing projected carbon dioxide emissions by 76 million metric tons carbon equivalent. About 76 percent (3.0 quadrillion Btu) of the relative reduction is attributed to light-duty vehicles as a result of advances in conventional technologies and in vehicle attributes for advanced technologies that are projected to raise the average efficiency of the light-duty vehicle fleet to 25.1 miles per gallon (compared with a projected increase to 21.5 miles per gallon in the reference case) (Figure 69).

Projected fuel demand for freight trucks in 2020 is 0.5 quadrillion Btu lower in the high technology case than in the reference case, and the projected stock efficiency is 9.0 percent higher. Advanced aircraft technologies are also projected to improve aircraft efficiency by 3.2 percent above the reference case projection, reducing the projected fuel use for air travel in 2020 by 0.2 quadrillion Btu.

In the 2001 technology case, with new technology efficiencies fixed at 2001 levels, efficiency improvements can result only from stock turnover. In 2020, the total projected energy demand for transportation is 2.6 quadrillion Btu (7 percent) higher than in the reference case, and projected carbon dioxide emissions are higher by 50 million metric tons carbon equivalent. The average fuel economy of new light-duty vehicles is projected to be 25.3 miles per gallon in 2020 in the 2001 technology case, 2.7 miles per gallon lower than projected in the reference case.

Electricity Use Is Expected To Grow More Slowly Than GDP

Figure 70. Population, gross domestic product, and electricity sales, 1965-2020 (5-year moving average annual percent growth)



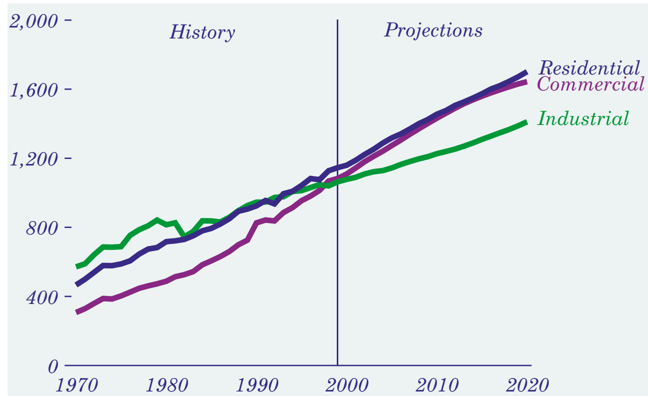
As generators and cogenerators try to adjust to the evolving structure of the electricity market, they also face slower growth in demand than in the past. Historically, the demand for electricity has been related to economic growth. That positive relationship is expected to continue, but the ratio is uncertain.

During the 1960s, electricity demand grew by more than 7 percent per year, nearly twice the rate of economic growth (Figure 70). In the 1970s and 1980s, however, the ratio of electricity demand growth to economic growth declined to 1.5 and 1.0, respectively. Several factors have contributed to this trend, including increased market saturation of electric appliances, improvements in equipment efficiency and utility investments in demand-side management programs, and more stringent equipment efficiency standards. Throughout the forecast, growth in demand for office equipment and personal computers, among other equipment, is dampened by slowing growth or reductions in demand for space heating and cooling, refrigeration, water heating, and lighting. The continuing saturation of electricity appliances, the availability and adoption of more efficient equipment, and efficiency standards are expected to hold the growth in electricity sales to an average of 1.8 percent per year between 1999 and 2020, compared with 3.0-percent annual growth in GDP.

Changing consumer markets could mitigate the slowing of electricity demand growth seen in these projections. New electric appliances are introduced frequently. If new uses of electricity are more substantial than currently expected, they could offset future efficiency gains to some extent.

Continued Growth in Electricity Use Is Expected in All Sectors

Figure 71. Annual electricity sales by sector, 1970-2020 (billion kilowatthours)



With the number of U.S. households projected to rise by 1.0 percent per year between 1999 and 2020, residential demand for electricity is expected to grow by 1.9 percent annually (Figure 71). Residential electricity demand changes as a function of the time of day, week, or year. During summer, residential demand peaks in the late afternoon and evening, when household cooling and lighting needs are highest. This periodicity increases the peak-to-average load ratio for local utilities, which rely on quick-starting gas turbines or internal combustion engines to satisfy peak demand. Although many regions currently have surplus baseload capacity, strong growth in the residential sector is expected to result in a need for more "peaking" capacity. Between 1999 and 2020, generating capacity from gas turbines and internal combustion engines is projected to increase from 75 gigawatts to 211 gigawatts.

Electricity demand in the commercial and industrial sectors is projected to grow by 2.0 and 1.4 percent per year, respectively, between 1999 and 2020. Projected growth in commercial floorspace of 1.3 percent per year and growth in industrial output of 2.6 percent per year contribute to the expected increase.

In addition to sectoral sales, cogenerators in 1999 produced 156 billion kilowatthours for their own use in industrial and commercial processes, such as petroleum refining and paper manufacturing. By 2020, cogenerators are expected to see only a slight decline in their share of total generation, increasing their own-use generation to 227 billion kilowatthours as the demand for manufactured products increases.

Retirements and Rising Demand Are Expected To Require New Capacity

Figure 72. Projected new generating capacity and retirements, 2000-2020 (gigawatts)

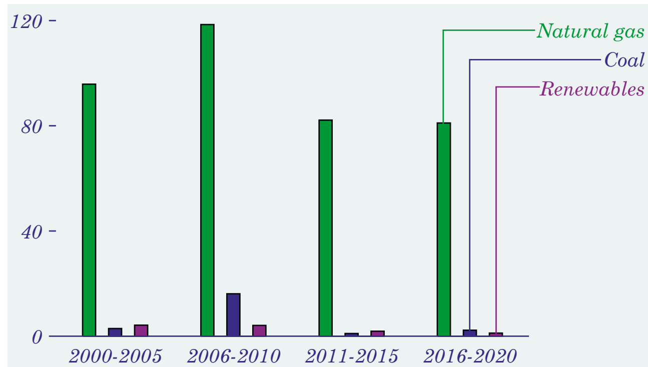
Although growth in electricity demand from 1999 to 2020 is projected to be slower than in the past, 393 gigawatts of new generating capacity (excluding cogenerators) is expected to be needed by 2020 to meet growing demand and to replace retiring units. Between 1999 and 2020, 26 gigawatts (27 percent) of current nuclear capacity and 43 gigawatts (8 percent) of current fossil-fueled capacity [*85*] are expected to be retired. Of the 162 gigawatts of new capacity expected after 2010 (Figure 72), 16 percent will replace retired nuclear capacity.

The projected reduction in baseload nuclear capacity has a modest impact on the electricity outlook after 2010: 51 percent of the new combined-cycle and 15 percent of the new coal-fired capacity projected in the entire forecast are expected to be brought on line between 2010 and 2020. Before the advent of natural gas combined-cycle plants, fossil-fired baseload capacity additions were limited primarily to pulverized-coal steam units; however, efficiencies for combined-cycle units are expected to approach 54 percent by 2010, compared with 49 percent for coal-steam units, and the expected construction costs for combined-cycle units are only about 41 percent of those for coal-steam plants.

As older nuclear power plants age and their operating costs rise, 27 percent of currently operating nuclear capacity is expected to be retired by 2020. More optimistic assumptions about operating lives and costs for nuclear units would reduce the projected need for new fossil-based capacity and reduce fossil fuel prices.

About 1,300 New Power Plants Could Be Needed by 2020

Figure 73. Projected electricity generation capacity additions by fuel type, including cogeneration, 2000-2020 (gigawatts)



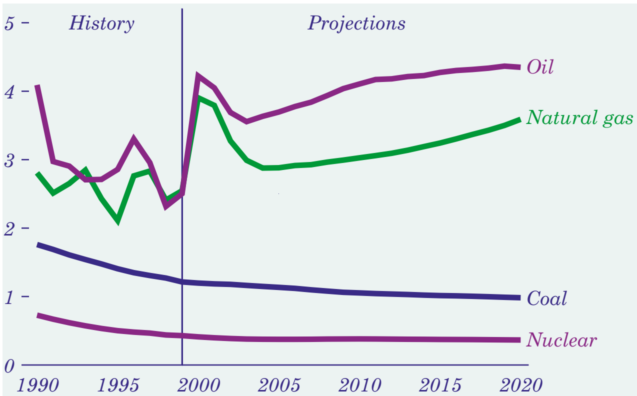
Before building new capacity, utilities are expected to use other options to meet demand growth—maintenance of existing plants, power imports from Canada and Mexico, and purchases from cogenerators. Even so, assuming an average plant capacity of 300 megawatts, 1,310 new plants with a total of 393 gigawatts of capacity (excluding cogenerators) are projected to be needed by 2020 to meet growing demand and to offset retirements. Of this new capacity, 92 percent is projected to be combined-cycle or combustion turbine technology, including distributed generation capacity, fueled by natural gas (Figure 73). Both technologies are designed primarily to supply peak and intermediate capacity, but combined-cycle technology can also be used to meet baseload requirements.

Nearly 22 gigawatts of new coal-fired capacity is projected to come on line between 1999 and 2020, accounting for almost 6 percent of all the capacity expansion expected. Competition with low-cost gas-turbine-based technologies and the development of more efficient coal gasification systems have compelled vendors to standardize designs for coal-fired plants in efforts to reduce capital and operating costs in order to maintain a share of the market. Renewable technologies account for 2 percent of expected capacity expansion by 2020—primarily wind, biomass gasification, and municipal solid waste units. Nearly 13 gigawatts of distributed generation capacity is projected to be added by 2020, as well as a small amount (less than 1 gigawatt) of fuel cell capacity. Oil-fired steam plants, with higher fuel costs and lower efficiencies, are expected to account for very little of the new capacity in the forecast.

Electricity Prices

Rising Natural Gas Prices, Falling Coal Prices Are Projected

Figure 74. Fuel prices to electricity generators, 1990-2020 (1999 dollars per million Btu)

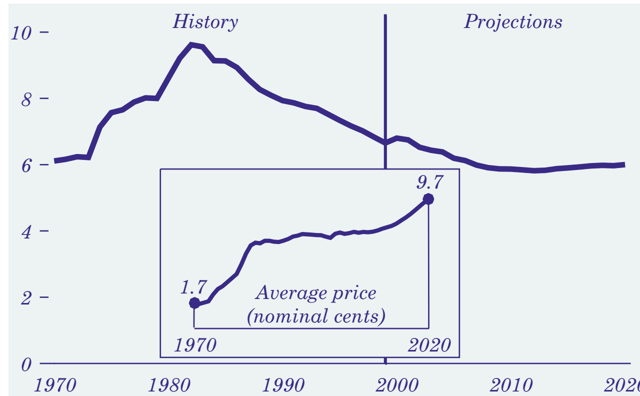


The cost of producing electricity is a function of fuel costs, operating and maintenance costs, and the cost of capital. In 1999, fuel costs typically represented $25 million annually—or 79 percent of the total operational costs (fuel and variable operating and maintenance)—for a 300-megawatt coal-fired plant, and $40 million annually—or 98 percent of the total operational costs—for a gas-fired combined-cycle plant of the same size. For nuclear plants, fuel costs are typically a much smaller portion of total production costs. Nonfuel operations and maintenance costs are a larger component of the operating costs for nuclear power plants than for fossil plants.

Over the projection period, the impact of rising gas prices is expected to be more than offset by the combination of falling coal prices and stable nuclear fuel costs. Natural gas prices to electricity suppliers are projected to rise by 1.6 percent per year in the forecast, from $2.59 per thousand cubic feet in 1999 to $3.66 in 2020 (Figure 74). The projected increases are offset by forecasts of declining coal prices, declining capital expenditures, and improved efficiencies for new plants. Sufficient supplies of uranium and fuel processing services are expected to keep nuclear fuel costs around $0.40 per million Btu (roughly 4 mills per kilowatthour) through 2020. Oil prices to utilities are expected to increase by 2.7 percent per year, leading to a decline in oil-fired generation of 81 percent (excluding cogeneration) between 1999 and 2020. Oil currently accounts for only 3.0 percent of total generation, however, and that share is expected to decline to 0.4 percent by 2020 as oil-fired steam generators are replaced by gas turbine technologies.

Average U.S. Electricity Prices Are Expected To Decline

Figure 75. Average U.S. retail electricity prices, 1970-2020 (1999 cents per kilowatthour)



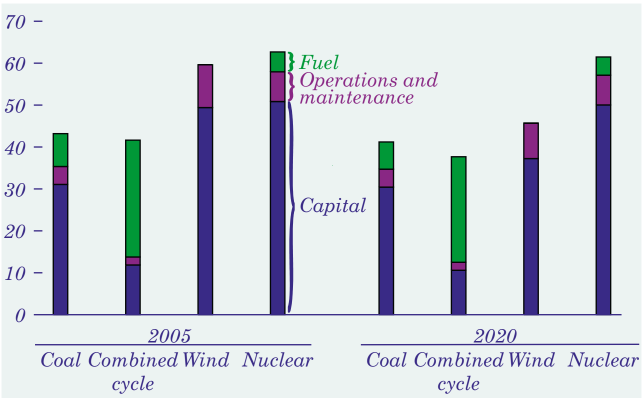
Between 1999 and 2020, the average price of electricity in real 1999 dollars is projected to decline by an average of 0.5 percent per year as a result of competition among electricity suppliers (Figure 75). By sector, projected prices in 2020 are 6, 16, and 11 percent lower than 1999 prices for residential, commercial, and industrial customers, respectively.

The reference case assumes a transition to competitive pricing in five regions—California, New York, New England, the Mid-Atlantic Area Council (consisting of Pennsylvania, Delaware, New Jersey and Maryland), and Texas. In addition, prices in the Rocky Mountain Power Area/Arizona, the Mid-America Interconnected Network (consisting of Illinois and parts of Wisconsin and Missouri), the Southwest Power Pool, and the East Central Area Reliability Council are treated as partially competitive, because some of the States in those regions have begun to deregulate their markets.

Specific restructuring plans differ from State to State and utility to utility, but most call for a transition period during which customer access will be phased in. The transition period reflects the time needed for the establishment of competitive market institutions and the recovery of stranded costs as permitted by regulators. It is assumed that competition will be phased in over 10 years, starting from the inception of restructuring in each region. In all the competitively priced regions, the generation price is set by the marginal cost of generation. Transmission and distribution prices are assumed to remain regulated.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 76. Projected electricity generation costs, 2005 and 2020 (1999 mills per kilowatthour)



Technology choices for new generating capacity are made to minimize cost while meeting local and Federal emissions constraints. The choice of technology for capacity additions is based on the least expensive option available (Figure 76). The reference case assumes a capital recovery period of 20 years. In addition, the cost of capital is based on competitive market rates, to account for the competitive risk of siting new units.

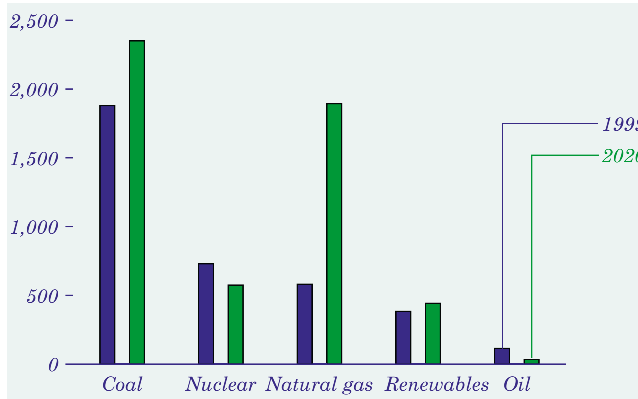
In the *AEO2001* projections, the costs and performance characteristics for new plants are expected to improve over time, at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, the costs are assumed to decline. The decline continues at a slower rate as more units are built. The performance (efficiency) of new plants is also assumed to improve, with heat rates declining by 4 to 14 percent between 1999 and 2010, depending on the technology (Table 13).

Table 13. Costs of producing electricity from new plants, 2005 and 2020

	2005		2020	
Item	Advanced coal	Advanced combined cycle	Advanced coal	Advanced combined cycle
	1999 mills per kilowatthour			
Capital	31.08	11.87	30.44	10.60
O&M	4.28	1.90	4.28	1.90
Fuel	7.84	27.86	6.49	25.18
Total	**43.20**	**41.63**	**41.22**	**37.68**
	Btu per kilowatthour			
Heat rate	9,253	6,639	9,087	6,350

Gas- and Coal-Fired Generation Grows as Nuclear Plants Are Retired

Figure 77. Projected electricity generation by fuel, 1999 and 2020 (billion kilowatthours)



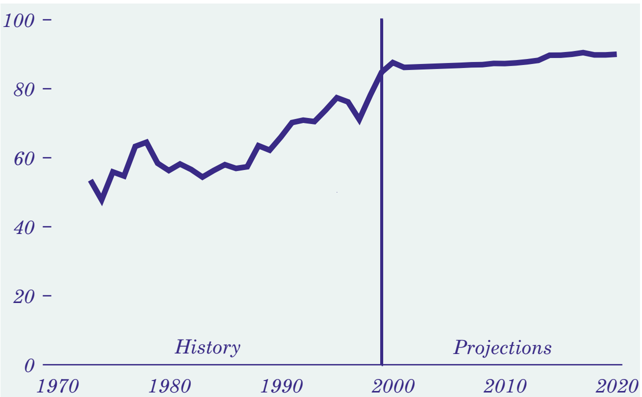
As they have since early in this century, coal-fired power plants are expected to remain the key source of electricity through 2020 (Figure 77). In 1999, coal accounted for 1,880 billion kilowatthours or 51 percent of total generation. Although coal-fired generation is projected to increase to 2,350 billion kilowatthours in 2020, increasing gas-fired generation is expected to reduce coal's share to 44 percent. Concerns about the environmental impacts of coal plants, their relatively long construction lead times, and the availability of economical natural gas make it unlikely that many new coal plants will be built before about 2005. Nevertheless, slow growth in other generating capacity, the huge investment in existing plants, and increasing utilization of those plants are expected to keep coal in its dominant position. By 2020, it is projected that 11 gigawatts of coal-fired capacity will be retrofitted with scrubbers to meet the requirements of the Clean Air Act Amendments of 1990 (CAAA90).

The large investment in existing plants is expected to make nuclear power a growing source of electricity at least through 2000. With substantial recent improvements in the performance of nuclear power plants, nuclear generation is projected to increase until 2000, then decline as older units are retired.

In percentage terms, gas-fired generation is projected to show the largest increase, from 16 percent of the 1999 total to 36 percent in 2020. As a result, by 2004, natural gas is expected to overtake nuclear power as the Nation's second-largest source of electricity. Generation from oil-fired plants is projected to remain fairly small throughout the forecast.

Nuclear Power Plant Operating Performance Is Expected To Improve

Figure 78. Nuclear power plant capacity factors, 1973-2020 (percent)

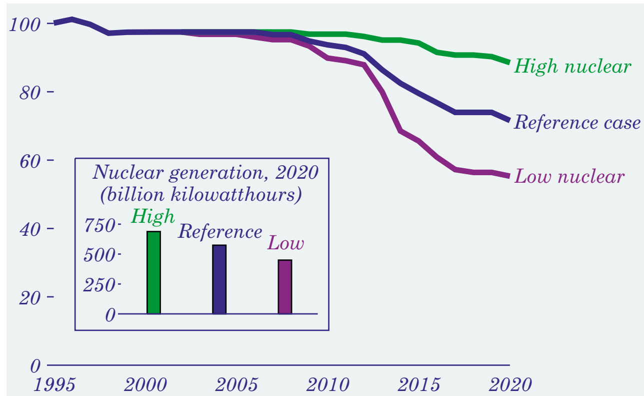


The United States currently has 104 operable nuclear units, which provided 20 percent of total electricity generation in 1999. The performance of U.S. nuclear units has improved in recent years, to a national average capacity factor of 85 percent in 1999 (Figure 78). It is assumed that performance improvements will continue, to an expected average capacity factor of 90 percent by 2015. In the reference case, 27 percent of current nuclear capacity is projected to be taken out of service by 2020, primarily as a result of operating license expirations. No new nuclear units are expected to become operable by 2020, because natural gas and coal-fired plants are projected to be more economical.

Nuclear units are projected to be retired when their operation is no longer economical relative to the cost of building replacement capacity. As a result, their operational lifetimes could be either shorter or longer than their current operating licenses. In the reference case, only one nuclear unit is projected to be retired before its current license expires, while 27 are projected to continue operating after their original 40-year licenses expire. In 2000, license renewals for two nuclear plants have been approved by the U.S. Nuclear Regulatory Commission. Three other applications are currently under review. As many as 17 other owners of nuclear power plants have announced intentions to apply for license renewals over the next 5 years, indicating a strong interest in maintaining the existing stock of nuclear plants. In addition, a nuclear industry task force has been developed to determine the key factors needed to prompt new orders of nuclear plants in the changing electricity market [*86*].

Nuclear Power Could Be Key to Reducing Carbon Dioxide Emissions

Figure 79. Projected operable nuclear capacity in three cases, 1995-2020 (gigawatts)

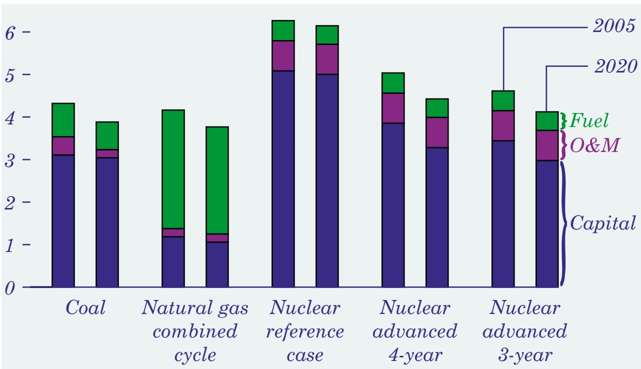


Two alternative cases—the high and low nuclear cases—show how nuclear plant retirement decisions affect the projections for capacity (Figure 79). In the high nuclear case, which assumes that the capital expenditures required after 40 years will be lower than in the reference case, more license renewals are projected to be obtained by 2020. Conditions favoring license renewal could include performance improvements, a solution to the waste disposal problem, and stricter limits on emissions from fossil-fired generating facilities. The low nuclear case assumes that the capital expenditures required for continued operation are higher than assumed in the reference case, leading to the projected retirements of 18 additional units by 2020. Higher costs could result from more severe degradation of the units or from waste disposal problems.

In the high nuclear case it is projected that 14 gigawatts of new fossil-fired capacity would not be needed, as compared with the reference case, and carbon dioxide emissions are projected to be 16 million metric tons carbon equivalent (2 percent of total emissions by electricity generators) lower in 2020 than projected in the reference case. In the low nuclear case, nearly 60 new fossil-fired units (assuming an average size of 300 megawatts) are projected be built to replace additional retiring nuclear units beyond those projected to be retired in the reference case. The additional new capacity is projected to be made up predominantly of gas-fired combined-cycle units (72 percent) and combustion turbines (24 percent). The additional fossil-fueled capacity is projected to increase carbon dioxide emissions in 2020 by 2 percent above the reference case projection.

Sensitivity Cases Look at Possible Reductions in Nuclear Power Costs

Figure 80. Projected electricity generation costs by fuel type in two advanced nuclear cost cases, 2005 and 2020 (1999 cents per kilowatthour)

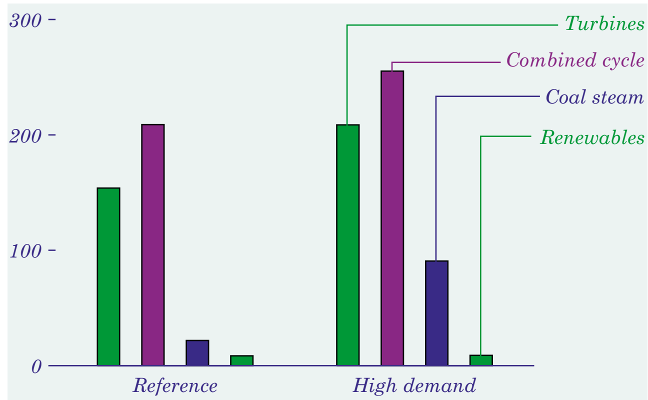


The *AEO2001* reference case assumptions for the cost and performance characteristics of new technologies are based on current estimates by government and industry analysts, allowing for uncertainties about new, unproven designs. For nuclear power plants, a pair of advanced nuclear cost cases were used 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, 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 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.

Projected nuclear generating costs in the two sensitivity cases are lower than in the reference case in 2005 and 2020 (Figure 80). A larger reduction is projected when a 3-year construction time is assumed to reduce financing costs, and nuclear generating costs in that case are projected to approach those for new coal- and gas-fired units. One new 460-megawatt advanced nuclear unit is projected to come on line in 2020 in the most optimistic nuclear cost case. The projections in Figure 80 are average generating costs; the costs and relative competitiveness of the generating technologies could vary across regions.

High Demand Assumption Leads to Higher Fuel Prices for Generators

Figure 81. Projected cumulative new generating capacity by type in two cases, 1999-2020 (gigawatts)

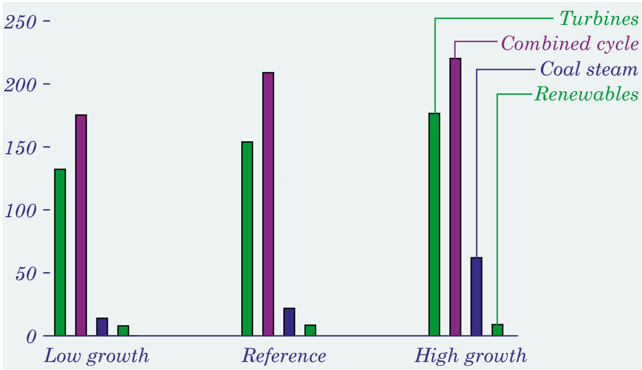


Electricity consumption grows in the forecast, but the projected rate of increase is less than historical levels as a result of assumptions about improvements in end-use efficiency, demand-side management programs, and population and economic growth. Different assumptions result in substantial changes in the projections. In a high demand case, electricity demand is assumed to grow by 2.5 percent per year between 1999 and 2020, as compared with the growth rate of 2.2 percent per year between 1990 and 1998. In the reference case, electricity demand is projected to grow by 1.8 percent per year.

In the high demand case, an additional 171 gigawatts of new generating capacity—equivalent to 569 new 300-megawatt generating plants—is projected to be built between 1999 and 2020 as compared with the reference case (Figure 81). The shares of coal- and gas-fired (including non-coal steam, combustion turbine, combined cycle, distributed generation, and fuel cell) capacity additions are projected to change from 6 percent and 92 percent, respectively, in the reference case to 16 percent and 82 percent in the high demand case. Relative to the reference case, there is a 17-percent increase in projected coal consumption and a 9-percent increase in natural gas consumption in the high demand case, and carbon dioxide emissions are projected to be higher by 123 million metric tons carbon equivalent (16 percent). More rapid assumed growth in electricity demand also leads to higher projected prices in 2020—6.4 cents per kilowatthour in the high demand case, compared with 6.0 cents in the reference case. Higher projected fuel prices, especially for natural gas, are the primary reason for the difference.

Rapid Economic Growth Would Boost Advanced Coal-Fired Capacity

Figure 82. Projected cumulative new generating capacity by technology type in three economic growth cases, 1999-2020 (gigawatts)



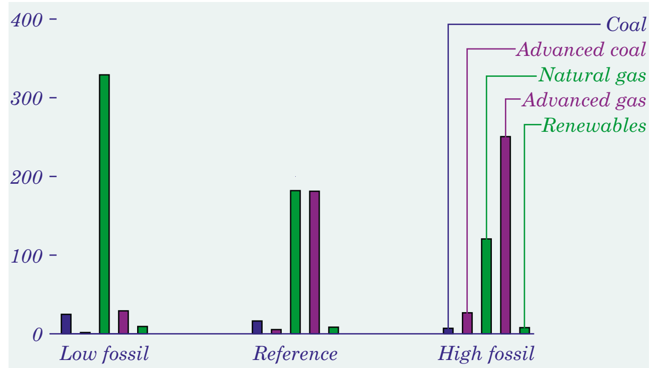
The projected annual average growth rate for GDP from 1999 to 2020 ranges from 3.5 percent in the high economic growth case to 2.5 percent in the low economic growth case. The difference leads to a 14-percent change in projected electricity demand in 2020, with a corresponding difference of 138 gigawatts (excluding cogenerators) in the amount of new capacity projected to be built in the high and low economic growth cases. Utilities are expected to retire about 9 percent of their current generating capacity (equivalent to 231 300-megawatt generating plants) by 2020 as the result of increased operating costs for aging plants.

Much of the new capacity projected to be needed in the high economic growth case beyond that added in the reference case is expected to consist of new advanced coal-fired plants, which make up 50 percent of the projected new capacity in the high growth case. The stronger assumed growth also is projected to stimulate additions of gas-fired plants, accounting for 45 percent of the projected capacity increase in the high economic growth case over that projected in the reference case (Figure 82).

Current construction costs for a typical plant range from $450 per kilowatt for combined-cycle technologies to $1,100 per kilowatt for coal-steam technologies. Those costs, along with the difficulty of obtaining permits and developing new generating sites, make refurbishment of existing power plants a profitable option in some cases. Between 1999 and 2020, utilities are expected to maintain most of their older coal-fired plants while retiring many of their older, higher cost oil- and gas-fired generating plants.

Gas-Fired Technologies Lead New Additions of Generating Capacity

Figure 83. Projected cumulative new generating capacity by technology type in three fossil fuel technology cases, 1999-2020 (gigawatts)

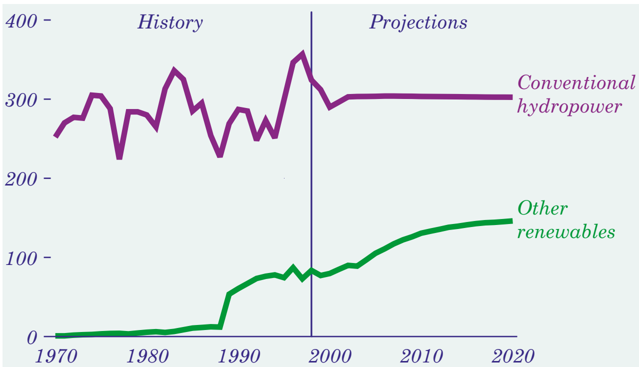


The *AEO2001* reference case uses the cost and performance characteristics of generating technologies to select the mix and amounts of new generating capacity for each year in the forecast. Numerical values for the characteristics of different technologies are determined in consultation with industry and government specialists. In the high fossil fuel case, capital costs and/or heat rates for advanced fossil-fired generating technologies (integrated coal gasification combined cycle, advanced combined cycle, advanced combustion turbine, and molten carbonate fuel cell) were revised to reflect potential improvements in costs and efficiencies as a result of accelerated research and development. The low fossil fuel case assumes that capital costs and heat rates for advanced technologies will remain flat throughout the forecast.

The basic story is the same in each of the three cases—gas technologies are projected to dominate new generating capacity additions (Figure 83). Across the cases the projected share of additions accounted for by gas technologies varies only from 90 percent to 92 percent, but the projected mix between current and advanced gas technologies varies more significantly across the cases. In the low fossil fuel case only 8 percent (29 gigawatts) of the gas plants projected to be added are advanced technology facilities, as compared with a projected 68-percent share (251 gigawatts) in the high fossil fuel case. The projection for additions of coal-fired capacity is somewhat higher in the high fossil fuel case, whereas the projections for additions of new renewable plants do not vary significantly across the cases.

Small Increases Are Expected for Renewable Electricity Generation

Figure 84. Grid-connected electricity generation from renewable energy sources, 1970-2020 (billion kilowatthours)

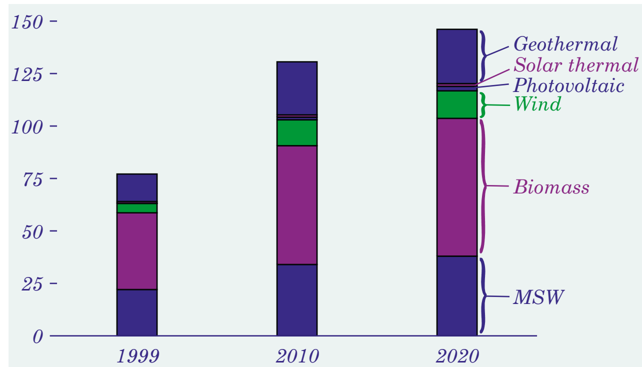


In the *AEO2001* reference case, projections are mixed for renewables in central station grid-connected U.S. electricity supply. Federal and State incentives are projected to produce substantial near-term growth for some renewable energy technologies, but generally higher projected costs are a disadvantage for renewables relative to fossil-fueled technologies over the forecast period as a whole. Total U.S. grid-connected electricity generation from renewable energy sources is projected to increase from 389 billion kilowatthours in 1999 to 448 billion kilowatthours in 2020, and generation from renewables other than hydroelectricity is projected to increase from 77 billion kilowatthours to 146 billion kilowatthours (Figure 84). Overall, renewables are projected to make up a smaller share of U.S. electricity generation, declining from 10.5 percent in 1999 to 8.5 percent in 2020.

Conventional hydroelectricity, which in 1999 provided 80 percent of the electricity supply from renewables, is projected to decline slightly in the forecast. The expected net addition of 600 megawatts of new hydropower capacity does not offset the projected decline in generation from existing hydroelectric facilities, as increasing environmental and other competing needs reduce their average productivity. Hydroelectric generation is projected to slip from 8.4 percent of the U.S. total in 1999 to 5.7 percent in 2020. The economic value of hydroelectric capacity is also likely to decline as environmental and other preferences shift generation to off-peak hours and seasons.

Biomass and Landfill Gas Lead Renewable Fuel Use for Electricity

Figure 85. Projected nonhydroelectric renewable electricity generation by energy source, 2010 and 2020 (billion kilowatthours)

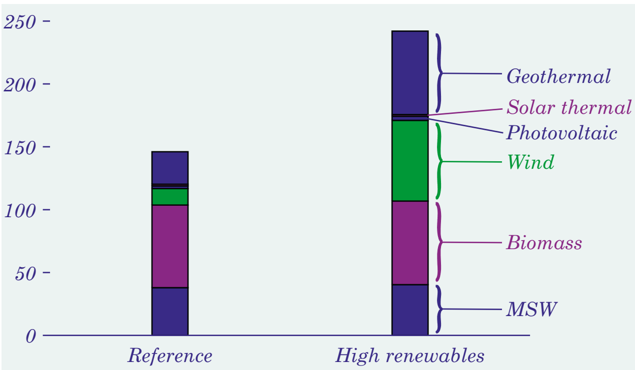


Most of the projected growth in renewable electricity generation is expected from biomass, landfill gas, geothermal energy, and wind power (Figure 85). The largest increase is projected for biomass, from 36.6 billion kilowatthours in 1999 to 65.7 billion in 2020. Cogeneration accounts for more than one-half of the expected growth in biomass generation; dedicated biomass plants and co-firing in coal plants account for the remainder. Electricity generation from municipal solid waste, including both direct firing with solid waste and the use of landfill gas, is projected to increase by 15.9 billion kilowatthours from 1999 to 2020. No new capacity additions are projected for plants that burn solid waste, but landfill gas capacity is projected to grow by 2.1 gigawatts.

Geothermal energy capacity is projected to increase by 1.5 gigawatts in the forecast, adding 12.8 billion kilowatthours of baseload generation by 2020. Intermittent generation from wind power is expected to increase in the near term as a result of the extension of the Federal production tax credit through 2001 (at 1.7 cents per kilowatthour) and by additional State incentives. Total wind capacity is projected to grow by 36 percent by 2001 and to more than double by 2010, but capacity additions are expected to slow after 2010 without additional incentives. High capital costs, lower output per kilowatt, and intermittent availability are expected to continue to disadvantage wind power relative to conventional generating technologies. Grid-connected photovoltaics are projected to add nearly 900 megawatts but remain small contributors to overall electric power supply. Off-grid photovoltaics, which are not included in the projections, are expected to continue to increase rapidly.

Wind Energy Use Could Gain Most From Cost Reductions

Figure 86. Projected nonhydroelectric renewable electricity generation by energy source in two cases, 2020 (billion kilowatthours)

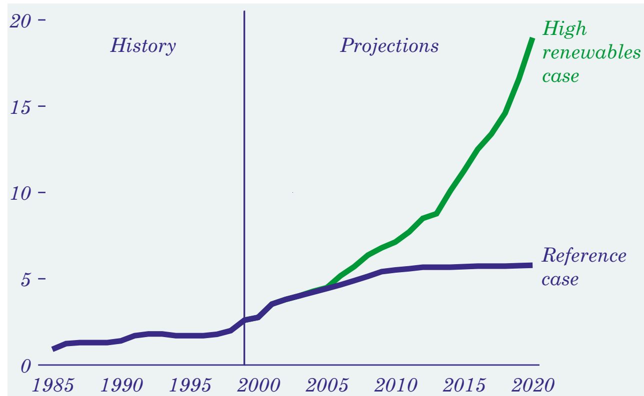


The high renewables case assumes more favorable characteristics for nonhydroelectric renewable energy technologies than in the reference case, including a 24-percent average reduction in capital costs by 2020 relative to the reference case, lower operations and maintenance costs, increased biomass fuel supplies, and higher capacity factors for solar and wind power plants. The assumptions in the high renewables case approximate the renewable energy technology goals of the U.S. Department of Energy. Fossil and nuclear technology assumptions are not changed from those in the reference case.

More rapid technology improvements are projected to increase renewable energy use, but the overall lead of fossil-fueled technologies in U.S. electricity supply is not expected to change. Total generation from nonhydroelectric renewables is projected to reach 242 billion kilowatthours in 2020, compared with 146 billion in the reference case (Figure 86), increasing from 2.8 percent of total generation to 4.6 percent. About 51 billion kilowatthours of the projected difference is from 13.2 gigawatts of additional intermittent wind capacity (Figure 87) and 41 billion kilowatthours is from 5.2 gigawatts of additional baseload geothermal capacity. Solar central station technologies are projected to remain too expensive, but small-scale photovoltaics are expected to grow more rapidly. The projected increase in renewable energy use in the high renewables case reduces fossil fuel use relative to the reference case projection, lowering projected carbon dioxide emissions by 14 million metric tons carbon equivalent (1.8 percent). Retail electricity prices are not projected to change significantly from the reference case.

State Mandates Call for More Generation From Renewable Energy

Figure 87. Wind-powered electricity generating capacity in two cases, 1985-2020 (gigawatts)

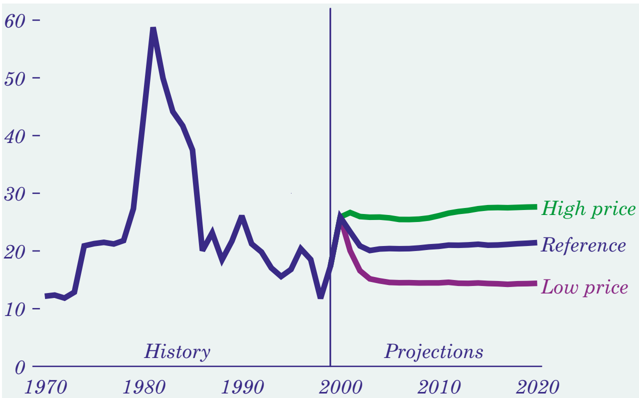


AEO2001 assumes rapidly increasing State requirements for investments in renewable energy technologies. The requirements, reflecting both energy and environmental interests, ensure investment in renewables despite increasingly competitive electricity markets. Renewable portfolio standards, which require increasing percentages of electricity supplies from renewables, are the most common, although other mandates also exist. Requirements differ from State to State, reflecting varying renewable resources, supporting industries, and supply alternatives. In *AEO98,* no quantifiable State mandates existed. *AEO99* projected 2,010 megawatts of renewable capacity additions as a result of State mandates through 2020.

The implementation plans for most State renewable energy mandates are uncertain, and it is difficult to project their effects on new capacity additions in some States. For *AEO2001* it is assumed that State mandates will require total additions of 5,065 megawatts of central station renewable generating capacity from 2000 through 2020, including 4,377 megawatts as a result of renewable portfolio standards. Mandated additions are expected to include 2,900 megawatts of wind capacity, 1,145 megawatts of landfill gas capacity, 840 megawatts of biomass capacity, 117 megawatts of geothermal capacity, and 64 megawatts of central station solar (photovoltaic and thermal) capacity—averaging a few hundred megawatts of total new renewable capacity in each year through 2012. After 2012, the current State mandates are estimated by EIA to result in about 330 megawatts of new renewable capacity additions.

Oil Prices Are Expected To Remain Above Low 1998 Levels

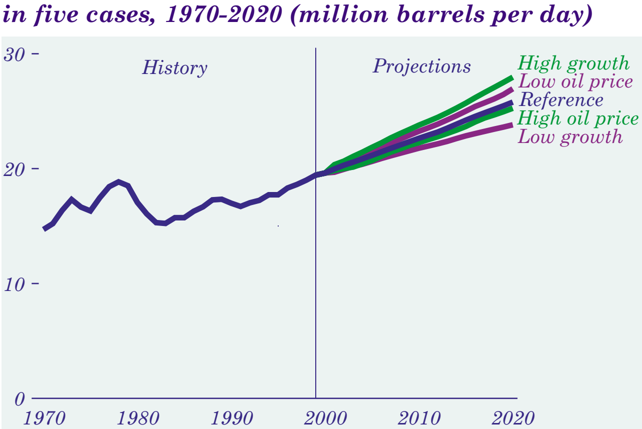
Figure 88. Lower 48 crude oil wellhead prices in three cases, 1970-2020 (1999 dollars per barrel)



Because domestic prices for crude oil are determined largely by the international market, recovery from the 1998 decline in world oil prices led to a steep increase in wellhead prices for crude oil in the lower 48 States in 1999 and 2000. After 2000, prices are projected to decline initially, then increase through the rest of the forecast. Prices are expected to remain above 1998 levels in all cases, with wellhead prices projected to decrease by 0.6 percent per year on average from 1999 to 2020 in the low world oil price case and to increase by 1.3 and 2.5 percent per year on average in the reference and high world oil price cases, respectively (Figure 88).

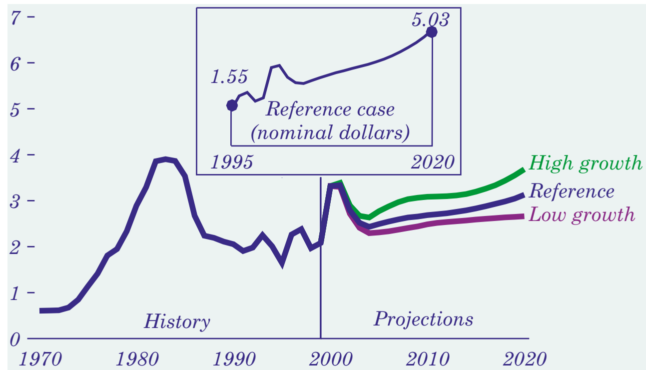
U.S. petroleum consumption is projected to rise in all the *AEO2001* cases (Figure 89). Total petroleum product supplied is projected to range from 23.8 million barrels per day in the low economic growth case to 28.0 million in the high growth case, as compared with 19.5 million barrels per day in 1999.

Figure 89. U.S. petroleum consumption in five cases, 1970-2020 (million barrels per day)



Rising Demand Increases Natural Gas Prices in All Economic Growth Cases

Figure 90. Lower 48 natural gas wellhead prices in three cases, 1970-2020 (1999 dollars per thousand cubic feet)



Wellhead prices for natural gas in the lower 48 States are projected to increase on average by 1.2, 2.0, and 2.8 percent per year in the low economic growth, reference, and high economic growth cases, respectively (Figure 90). In the reference case, gas prices are projected to increase from $2.08 per thousand cubic feet in 1999 to $3.13 in 2020. The increases reflect the rising demand projected for natural gas and its expected impact on the natural progression of the discovery process from larger and more profitable fields to smaller, less economical ones. The projected price increases also reflect more production expected from higher cost sources, such as unconventional gas recovery. Growth in lower 48 unconventional gas production is projected to range from 2.5 to 3.5 percent per year across cases, compared with a projected range of 2.3 to 2.7 percent per year for conventional sources. Technically recoverable resources (Table 14) are expected to remain more than adequate overall to meet the projected production increases.

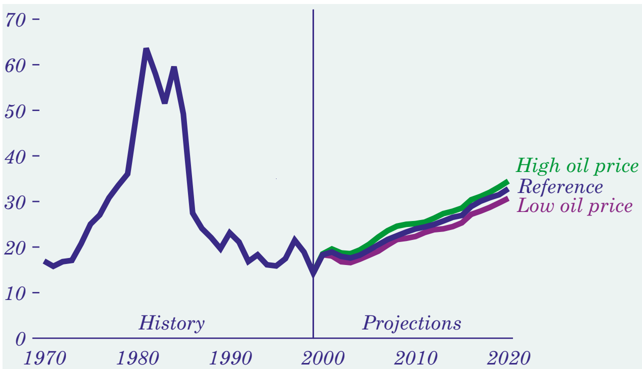
Although natural gas consumption (and thus production and prices) is projected to rise in all three cases, the price increases are expected to be tempered by the beneficial impacts of technological progress on both the discovery process and production operations.

Table 14. Technically recoverable U.S. oil and gas resources as of January 1, 1999

Total U.S. resources	Crude oil (billion barrels)	Natural gas (trillion cubic feet)
Proved	22	164
Unproved	121	1,117
Total	**144**	**1,281**

Rising Prices and Lower Drilling Costs Increase Well Completions

Figure 91. Successful new lower 48 natural gas and oil wells in three cases, 1970-2020 (thousand successful wells)



Both exploratory drilling and developmental drilling are projected to increase in the forecast (Table 15). With rising prices and declining drilling costs, crude oil and natural gas well completions are projected to increase on average by 3.7 and 4.3 percent per year in the low and high oil price cases, respectively, compared with 4.0 percent in the reference case (Figure 91). The high growth rates projected for oil and gas drilling reflect, in part, the low level of drilling activity in 1999.

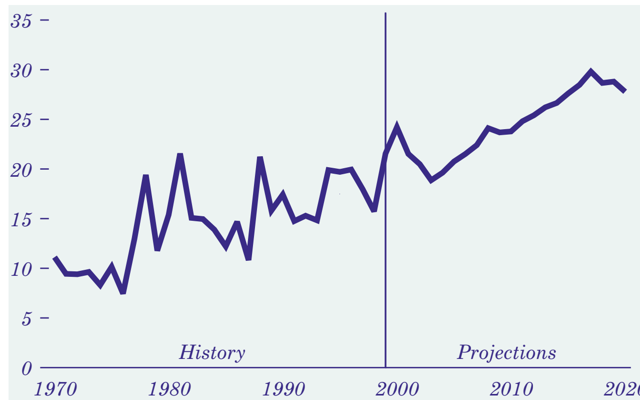
The productivity of natural gas drilling is not expected to decline as much as that of oil drilling, in part because total recoverable gas resources are more abundant than oil resources. At the projected production levels, however, undiscovered recoverable resources of conventional natural gas would decline rapidly in some areas, particularly in the onshore Gulf Coast and offshore Gulf of Mexico regions. The future overall productivity of both oil and gas drilling is necessarily uncertain, given the uncertainty associated with such factors as the extent of the Nation's oil and gas resources [*87*].

Table 15. Natural gas and crude oil drilling in three cases, 1999-2020 (thousand successful wells)

	1999	2000	2010	2020
Natural gas				
Low oil price case		12.8	16.5	22.2
Reference case	10.3	12.8	17.5	23.4
High oil price case		13.0	18.1	24.3
Crude oil				
Low oil price case		5.5	5.8	8.5
Reference case	4.1	5.5	6.5	9.4
High oil price case		5.5	7.0	10.2

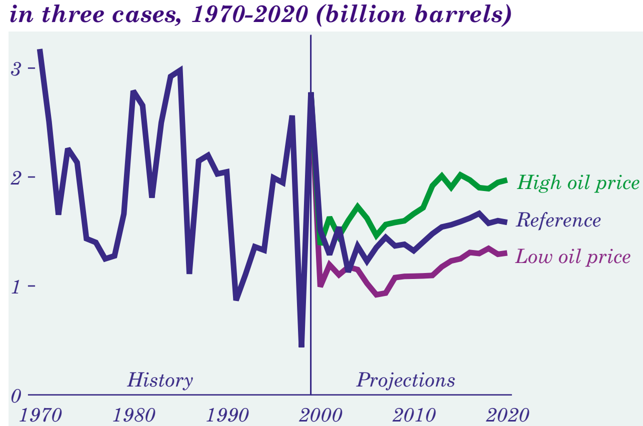
High Levels of Gas Reserve Additions Are Projected Through 2020

Figure 92. Lower 48 natural gas reserve additions in the reference case, 1970-2020 (trillion cubic feet)



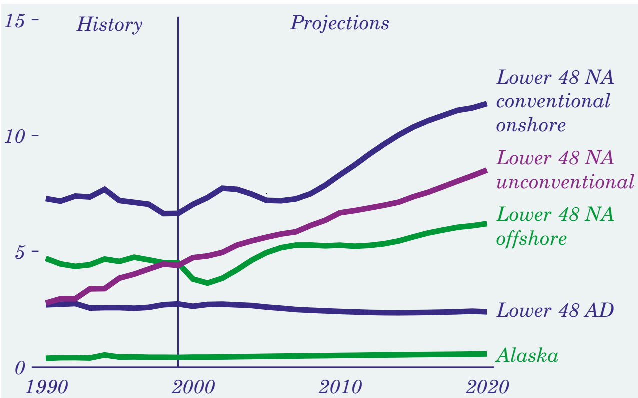
For most of the past two decades lower 48 production of both oil and natural gas has exceeded reserve additions, but the pattern for natural gas reversed from 1994 through 1997. Although reserve additions fell below production in 1998 with the decline in prices, they exceeded production again in 1999. After 2004, rising prices are projected to result in natural gas reserve additions that generally exceed production through 2020 (Figure 92), even with expected increases in demand. The relatively high projected levels of annual gas reserve additions through 2020 reflect an expected increase in exploratory and developmental drilling as a result of higher prices, as well as expected productivity gains from technology improvements comparable to those of recent years. For the most part, total lower 48 crude oil production is projected to continue to exceed total reserve additions (Figure 93), except in the later years in the high world oil price case.

Figure 93. Lower 48 crude oil reserve additions in three cases, 1970-2020 (billion barrels)



Significant New Finds Are Likely To Continue Increases in Gas Production

Figure 94. Natural gas production by source, 1990-2020 (trillion cubic feet)



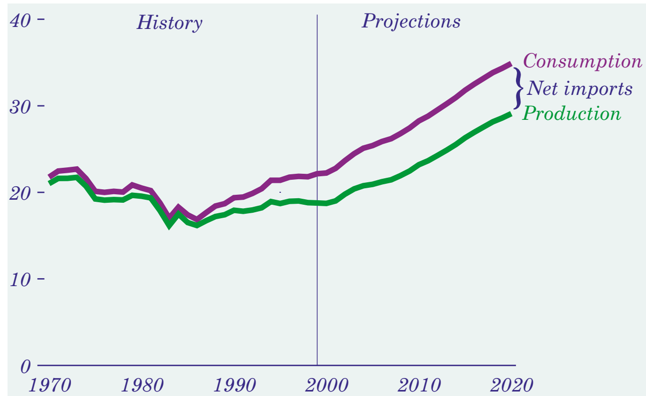
The continuing increase in domestic natural gas production in the forecast is expected to come primarily from lower 48 onshore nonassociated (NA) sources (Figure 94). Conventional onshore production is projected to grow rapidly from 2006 through 2020, increasing in share from 35.5 percent of total U.S. domestic production in 1999 to 39.2 percent of the total in 2020. Gas production from unconventional sources is projected to increase steadily over the forecast as a result of technology advances, playing a key role in meeting projected demand. Offshore production is projected to increase less rapidly but to remain a major source of domestic supply. Innovative use of cost-saving technology in recent years and the expected mid-term continuation of recent huge finds, particularly in the deep waters of the Gulf of Mexico, support the projections.

Natural gas production from Alaska is projected to grow by 1.5 percent per year through 2020, not including gas from the North Slope. The future of North Slope gas is uncertain, however. Current options under consideration include transporting the gas through a pipeline, converting it to liquefied natural gas, and converting it to synthetic petroleum products [*88*].

Production of associated-dissolved (AD) natural gas from lower 48 crude oil reservoirs generally declines in the projections, following the expected pattern of domestic crude oil production. AD gas is projected to account for 8.2 percent of total production in 2020, compared with 14.6 percent in 1999.

Net Imports of Natural Gas Grow in the Projections

Figure 95. Natural gas production, consumption, and imports, 1970-2020 (trillion cubic feet)



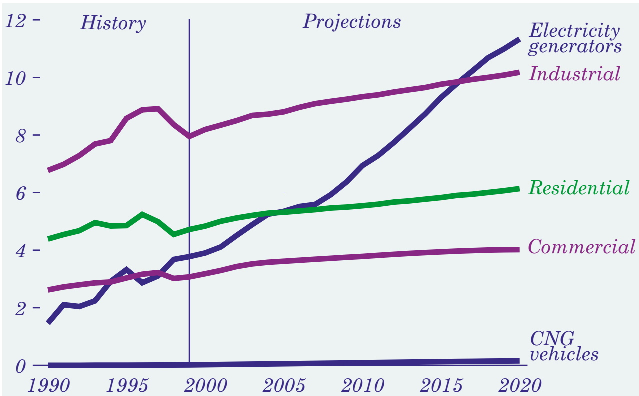
Net natural gas imports are expected to grow in the forecast (Figure 95) from 15.8 percent of total gas consumption in 1999 to 16.7 percent in 2020. Most of the increase is attributable to imports from Canada, which are projected to grow substantially. Most of the additional imports are expected to come from western Canada. In addition, new pipeline capacity is now providing access to eastern supplies. Natural gas from Sable Island, in the offshore Atlantic, began flowing on January 1, 2000.

Mexico has a considerable natural gas resource base, but its indigenous production is unlikely to increase sufficiently to satisfy rising demand. Since 1984, U.S. natural gas trade with Mexico has consisted primarily of exports. That trend is expected to continue throughout the forecast, especially in light of continuing additions to cross-border pipeline capacity. U.S. exports to Mexico are projected to grow from 60 billion cubic feet in 1999 to 520 billion cubic feet in 2020.

Imports of liquefied natural gas (LNG) are projected to increase by 8.0 percent per year on average, resulting in part from the expected reactivation of both the Elba Island terminal in Georgia and the Cove Point terminal in Maryland in 2003. LNG is not expected to grow beyond a regionally significant source of U.S. supply, however. LNG imports are projected to reach a level of 0.81 trillion cubic feet in 2020, compared with 0.16 trillion cubic feet in 1999.

Projected Increases in Natural Gas Use Are Led by Electricity Generators

Figure 96. Natural gas consumption by sector, 1990-2020 (trillion cubic feet)

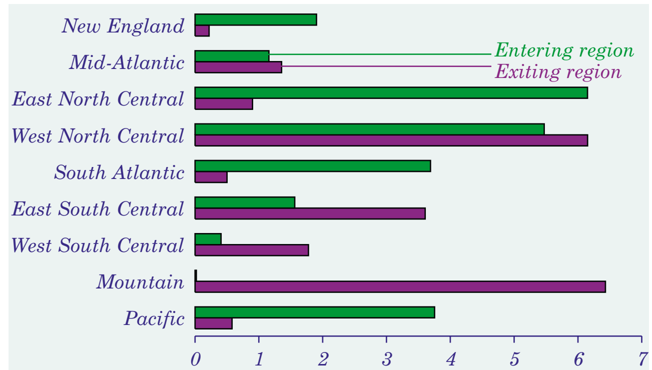


In all the *AEO2001* cases, total natural gas consumption is projected to increase from 1999 to 2020. The projections for domestic consumption in 2020 range from 32.2 trillion cubic feet per year in the low economic growth case to 36.1 trillion cubic feet in the high growth case, as compared with an estimated 21.4 trillion cubic feet in 1999. Although rising demand by electricity generators accounts for 57 percent of the increase in the reference case, growth is also expected in the residential, commercial, industrial, and transportation sectors (Figure 96). Natural gas consumption in the electricity generation sector is projected to grow steadily throughout the forecast as demand for electricity increases and retiring nuclear and older oil and gas steam plants are replaced by gas turbines and combined-cycle facilities.

In the reference case, natural gas consumption for electricity generation (excluding cogeneration) is projected to increase from 3.8 trillion cubic feet in 1999 to 11.3 trillion cubic feet in 2020. In 2017 electricity generation is projected to surpass the industrial sector as the largest consumer of natural gas. Although coal prices to the electricity generation sector are projected to fall throughout the forecast, lower capital costs, shorter construction lead times, higher efficiencies, and lower emissions are expected to give gas-fired generators an advantage over coal-fired plants for new capacity additions in most regions of the United States. Natural-gas-fired facilities are less capital-intensive than coal, nuclear, or renewable electricity generation plants. In addition, the environmental advantages of natural gas are expected to favor increased utilization of existing gas-fired power plants.

Gas Pipeline Capacity Expansion Is Needed To Serve New Markets

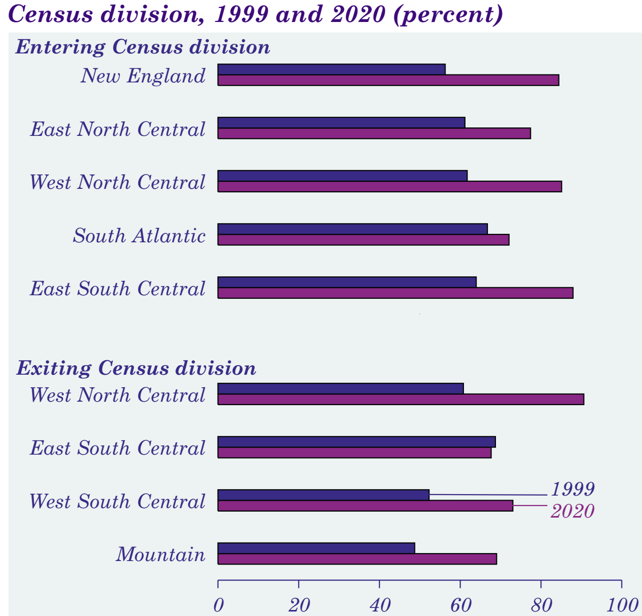
Figure 97. Projected pipeline capacity expansion by Census division, 1999-2020 (billion cubic feet per day)



Projected growth in natural gas consumption will require additional pipeline capacity. Expansion of interstate capacity (Figure 97) will be needed to provide access to new supplies and to serve expanding markets. Expansion is projected to proceed at an average rate of 1.0 percent per year in the forecast.

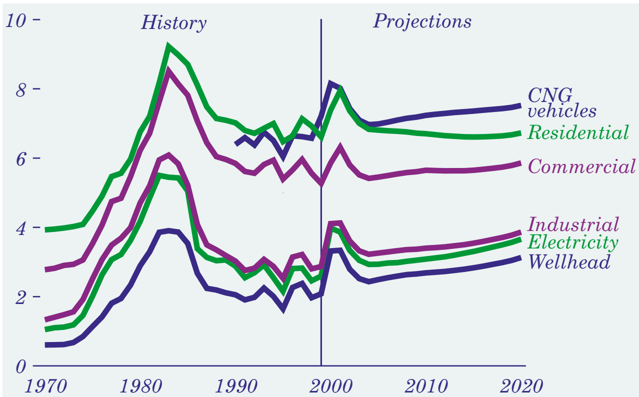
The greatest increases in capacity are expected along the corridors that provide access to Canadian, Gulf Coast, and Mountain region supplies and deliver them to the South Atlantic, Pacific, and Northeast regions. In all regions, growth in new pipeline construction is expected to be tempered by higher utilization of existing pipeline capacity (Figure 98).

Figure 98. Projected pipeline capacity utilization by Census division, 1999 and 2020 (percent)



Competitive Markets Keep Residential Gas Prices in Check

Figure 99. Natural gas end-use prices by sector, 1970-2020 (1999 dollars per thousand cubic feet)



Consumer prices for natural gas in all the end-use sectors are projected to be higher in 2020 that they were in 1999 (Figure 99), but prices in the residential and transportation sectors are expected to remain within 5 percent of 1999 levels. The limited price increases in the forecast reflect expectations for declining distribution margins, due in part to anticipated efficiency improvements in an increasingly competitive market. Margins in the industrial sector are projected to remain relatively constant, and growth in end-use prices is expected to result mainly from wellhead price increases. In the electricity generation sector, expected increases in both pipeline margins and wellhead prices combine to yield a projected 1.6-percent average annual increase in end-use prices.

Compared with their rise and decline over the 1970 to 1999 period, transmission and distribution revenues in the natural gas industry are projected to grow relatively steadily from 2000 forward, increasing overall at an average rate of 1.1 percent per year (Table 16). Declines in margins are expected to be balanced by higher volumes.

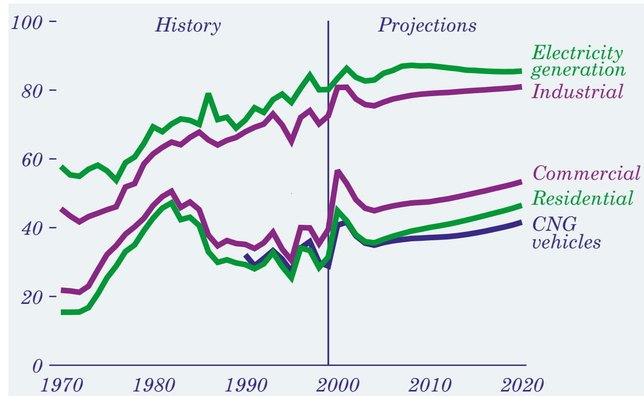
Table 16. Transmission and distribution revenues and margins, 1970-2020

	1970	1985	1999	2010	2015	2020
T&D revenues (billion 1999 dollars)	30.73	49.62	39.86	44.59	47.01	49.82
End-use consumption (trillion cubic feet)	19.21	15.97	21.41	28.05	31.61	34.73
Average margin* (1999 dollars per thousand cubic feet)	1.62	3.14	2.04	1.74	1.63	1.57

*Revenue divided by end-use consumption.

Distribution Costs Claim a Smaller Share of Residential Gas Prices

Figure 100. Wellhead share of natural gas end-use prices by sector, 1970-2020 (percent)



With distribution margins projected to decline, the wellhead shares of end-use prices generally increase in the forecast (Figure 100). The greatest impact is expected in the residential and commercial markets, where most customers purchase gas through local distribution companies (LDCs). In the electricity generation sector, the majority of customers do not purchase from distributors.

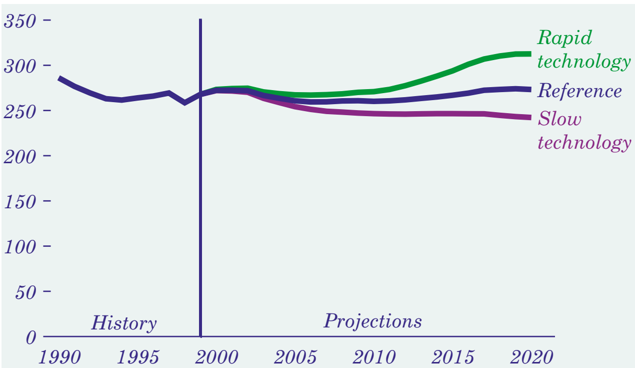
Changes have been seen historically in all components of end-use prices (Table 17). Pipeline margins dropped significantly between 1985 and 1999 with industry restructuring, and the decline is projected to continue through 2010. From 2010 to 2020, pipeline margins are projected to remain relatively flat. LDC margins in the residential and commercial sectors were above 1985 levels in 1999, but efficiency improvements and other impacts of restructuring are expected to exert downward pressure on distribution costs, and lower margins are projected for both the residential and commercial sectors in 2010 and 2020.

Table 17. Components of residential and commercial natural gas end-use prices, 1985-2020 (1999 dollars per thousand cubic feet)

Price Component	1985	1999	2010	2020
Wellhead price	3.38	2.08	2.69	3.13
Citygate price	5.05	3.10	3.60	4.04
Pipeline margin	1.67	1.02	0.91	0.91
LDC margin				
Residential	3.19	3.59	3.10	2.69
Commercial	2.36	2.39	2.05	1.82
End-use price				
Residential	8.24	6.69	6.70	6.73
Commercial	7.41	5.49	5.65	5.86

Technology Advances Could Improve Finding and Drilling Success Rates

Figure 101. Lower 48 crude oil and natural gas end-of-year reserves in three technology cases, 1990-2020 (quadrillion Btu)



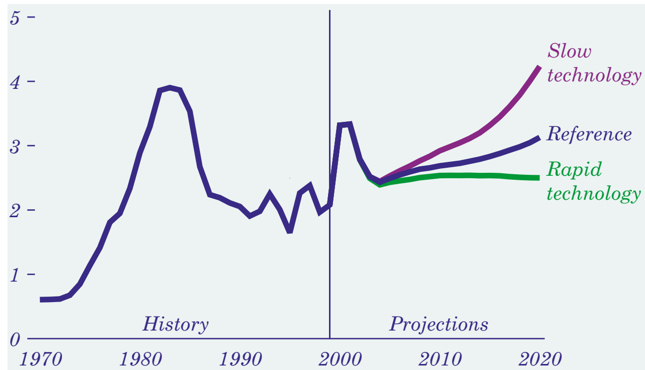
In the forecast, major advances in data acquisition, data processing, and the display and integration of seismic data with other geologic data—combined with lower cost computer power and experience gained with new techniques—are projected to continue putting downward pressure on costs while significantly improving finding and success rates. Effective use of improved exploration and production technologies to aid in the discovery and development of resources—particularly, unconventional gas and offshore deepwater fields—will be needed if new reserves are to replace those depleted by production.

Alternative cases assess the sensitivity of the projections to changes in success rates, exploration and development costs, and finding rates as a result of technological progress. The assumed technology improvement rates increase and decrease by 25 percent in the rapid and slow technology cases, which are analyzed as fully integrated model runs. All other parameters in the model are at their reference case values, including technology parameters in other energy markets, parameters affecting foreign oil supply, and assumptions about foreign natural gas trade, excluding Canada.

Although gas reserves are projected to make up a slightly larger share of the total in the reference case, total hydrocarbon reserve additions are expected to offset production, keeping total reserves essentially constant throughout the forecast (Figure 101). By 2020, reserves are projected to be 14.4 percent higher in the rapid technology case than in the reference case and 11.3 percent lower in the slow technology case.

Gas Price Projections Change With Technology Assumptions

Figure 102. Lower 48 natural gas wellhead prices in three technology cases, 1970-2020 (1999 dollars per thousand cubic feet)



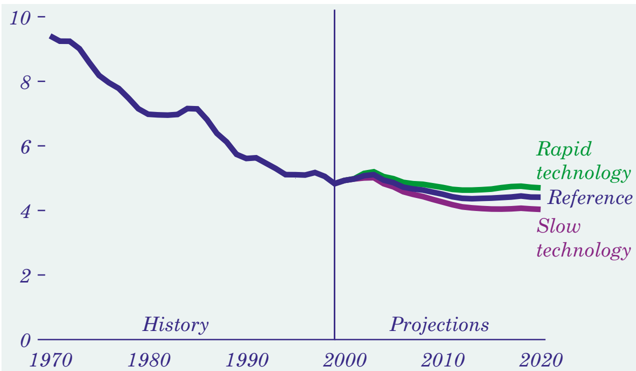
The natural gas price projections are highly sensitive to changes in assumptions about technological progress (Figure 102). Lower 48 wellhead prices are projected to increase at an average annual rate of 3.4 percent in the slow technology case, compared with only 2.0 percent in the reference case, over the projection period. In the rapid technology case, average natural gas wellhead prices are projected to remain relatively flat through 2020 at about $2.50 per thousand cubic feet.

Through 2003, the projections of both price and production levels for lower 48 oil and natural gas are almost identical in the reference case and the two technological progress cases. By 2020, however, natural gas prices are projected to be 35.1 percent higher (at $4.23 per thousand cubic feet) in the slow technology case and 20.1 percent lower (at $2.50 per thousand cubic feet) in the rapid technology case than the reference case level of $3.13 per thousand cubic feet.

Unlike the projections for natural gas prices, those for lower 48 average wellhead prices for crude oil do not vary significantly across the technology cases. In both the rapid and slow technology cases, the projections for crude oil prices vary from the reference case projections by at most $0.14 per barrel. Domestic oil prices are determined largely by the international market; changes in U.S. oil production do not constitute a significant volume relative to the global market.

More Rapid Technology Advances Could Raise Oil Production Slightly

Figure 103. Lower 48 crude oil production in three technology cases, 1970-2020 (million barrels per day)



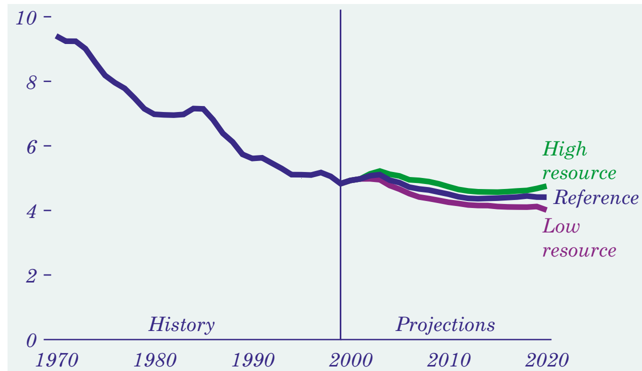
Projections for domestic oil production also are sensitive to changes in technological progress assumptions (Figure 103). In comparison with the projected lower 48 production level of 4.4 million barrels per day in 2020 in the reference case, oil production is projected to increase to 4.7 million barrels per day in the rapid technology case and to decrease to 4.0 million barrels per day in the slow technology case.

Given the assumption that changes in the levels of technology affect only U.S. oil producers, total oil supply adjusts to the variations in technological progress assumptions primarily through changes in imports of crude oil and other petroleum products. Net imports in 2020 are projected to range from a low of 16.1 million barrels per day in the rapid technology case to a high of 17.4 million barrels per day in the slow technology case.

Offshore oil production in the lower 48 States shows more sensitivity than onshore production to changes in technological progress assumptions, because large deepwater fields that are not economically feasible in the slow technology case are projected to become profitable in the rapid technology case. Cumulative offshore production from 1999 through 2020 is projected to be about 745 million barrels (4.9 percent) higher in the rapid technology case than in the reference case and 922 million barrels (6.0 percent) lower in the slow technology case than in the reference case. For onshore production, in contrast, the projected differences are only 3.5 percent and 3.6 percent. The projections for Alaskan oil production vary by about 3.9 percent from the reference case in both the rapid and slow technology cases.

Oil Production Forecasts Vary, Depending on Resource Estimates

Figure 104. Lower 48 crude oil production in three oil and gas resource cases, 1970-2020 (million barrels per day)



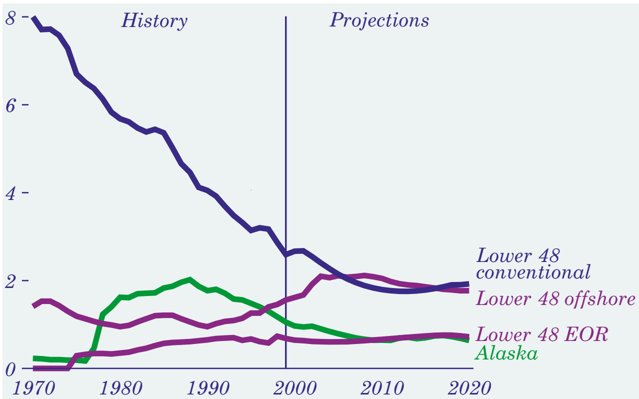
Another important assumption for the projections of domestic oil and gas resources is the size of the domestic resource base. Two alternative cases were used to evaluate the impacts of uncertainty in the resource estimates. In the high and low resource sensitivity cases, the estimates for both undiscovered technically recoverable resources and inferred reserves for conventional onshore and offshore production were increased and decreased, respectively, by 20 percent. As in the other *AEO2001* cases, resources in areas currently restricted from exploration and development were excluded from the resource assumption.

In the high resource case, both oil production levels and industry profits are projected to increase over those projected in the reference case. Lower 48 crude oil production is projected to reach 4.8 million barrels per day in 2020, as compared with 4.4 million barrels per day projected in the reference case (Figure 104). The corresponding projection in the low resource case is 4.0 million barrels per day.

The variations in oil production projections in the two resource sensitivity cases lead to similar variations in the projections of oil import dependence. In the high resource case, with higher projected production levels, net petroleum imports are projected to make up 62 percent of domestic supply in 2020, compared with 64 percent in the reference case. In the low resource case, with lower projected domestic production, imports are projected to make up 68 percent of domestic supply.

Domestic Crude Oil Production Continues To Decline

Figure 105. Crude oil production by source, 1970-2020 (million barrels per day)

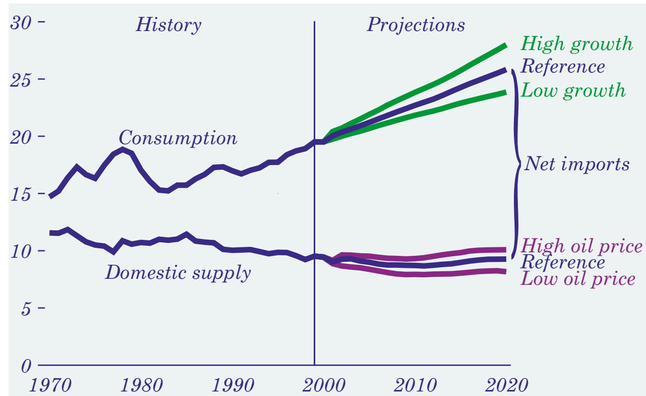


Domestic crude oil production is projected to remain relatively stable from 1999 through 2003 as a result of a favorable price environment and increased success of offshore drilling (Figure 105). A decline in production is projected from 2004 through 2010, followed by another period of projected stable production levels through 2020 as a result of rising prices and continuing improvements in technology [*89*]. In 2020, the projected domestic production level of 5.1 million barrels per day is 0.8 million barrels per day less than the 1999 level.

Conventional onshore production in the lower 48 States, accounting for 44 percent of total U.S. crude oil production in 1999, is projected to decrease to 38 percent in 2020, with production from mature areas expected to decline. Offshore production is projected to range from 1.6 to 2.1 million barrels per day throughout the forecast, surpassing the projected level of lower 48 conventional onshore production from 2006 to 2016. Crude oil production from Alaska is expected to decline at an average annual rate of 2.4 percent between 1999 and 2020. Projected drops in production from most of Alaska's oil fields—particularly Prudhoe Bay, the State's largest producing field—are expected to be offset by production from the National Petroleum Reserve–Alaska (NPRA), which is projected to commence in 2010. Production from the Alaska National Wildlife Refuge (ANWR) is not included, because drilling in the area is currently prohibited. Production from enhanced oil recovery (EOR) [*90*] is expected to slow as it becomes less profitable when oil prices fall in the forecast through 2003, and then to increase along with the world oil price projections until close to the end of the forecast.

Imports Fill the Gap Between Domestic Supply and Demand

Figure 106. Petroleum supply, consumption, and imports, 1970-2020 (million barrels per day)



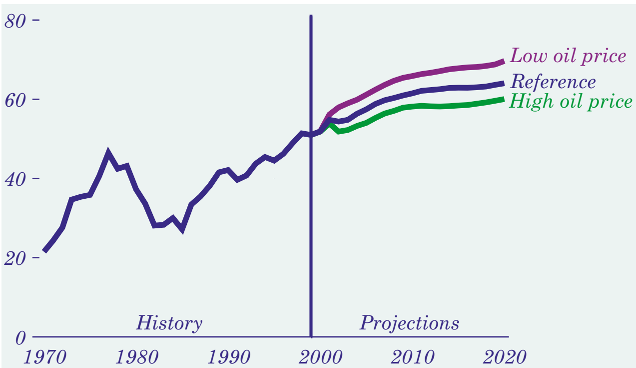
In the reference case, domestic petroleum supply is projected to decline slightly from its 1999 level of 9.5 million barrels per day to 9.3 million barrels per day in 2020 (Figure 106). As U.S. crude oil production falls off, refinery gain and production of natural gas plant liquids are projected to increase. Domestic supply in 2020 is projected to drop to 8.2 million barrels per day in the low oil price case and to rise to 10.1 million barrels per day in the high oil price case.

The greatest variation in petroleum consumption levels is seen across the economic growth cases, with a projected increase of 8.5 million barrels per day over the 1999 level in the high growth case, compared with a projected increase of only 4.4 million barrels per day in the low growth case.

Additional petroleum imports would be needed to fill the projected widening gap between supply and consumption. The greatest gap between supply and consumption is projected in the low world oil price case and the smallest in the low economic growth case. The projections for net petroleum imports in 2020 range from a high of 18.8 million barrels per day in the low oil price case to a low of 15.0 million barrels per day in the low growth case, compared with the 1999 level of 10.0 million barrels per day. The expected value of petroleum imports in 2020 ranges from $115.8 billion in the low price case to $170.8 billion in the high economic growth case. Total annual U.S. expenditures for petroleum imports, which reached a historical peak of $138.9 billion (in 1999 dollars) in 1980 [*91*], were $60.2 billion in 1999.

Growing Dependence on Petroleum Imports Is Projected

Figure 107. Share of U.S. petroleum consumption supplied by net imports in three oil price cases, 1970-2020 (percent)



In 1999, net imports of petroleum accounted for 51 percent of domestic petroleum consumption. Continued dependence on petroleum imports is projected, reaching 64 percent in 2020 in the reference case (Figure 107). The corresponding import shares of total consumption in 2020 are projected to be 60 percent in the high oil price case and 70 percent in the low price case.

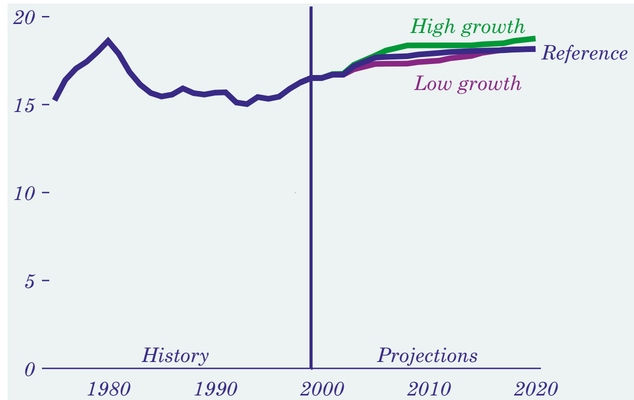
Although crude oil is expected to continue as the major component of petroleum imports, refined products are projected to represent a growing share. More imports would be needed as the projected growth in demand for refined products exceeds the expansion of domestic refining capacity. Refined products are projected to make up 19 percent of net petroleum imports in 2020 in the low economic growth case and 32 percent in the high growth case, as compared with their 13-percent share in 1999 (Table 18).

Table 18. Petroleum consumption and net imports in five cases, 1999 and 2020 (million barrels per day)

Year and projection	Product supplied	Net imports	Net crude imports	Net product imports
1999	19.5	9.9	8.6	1.3
2020				
Reference	25.8	16.5	12.1	4.4
Low oil price	27.0	18.8	13.3	5.5
High oil price	25.3	15.2	11.5	3.7
Low growth	23.9	15.0	12.1	2.9
High growth	28.0	18.2	12.5	5.8

New U.S. Oil Refining Capacity Is Likely To Be at Existing Refineries

Figure 108. Domestic refining capacity in three cases, 1975-2020 (million barrels per day)



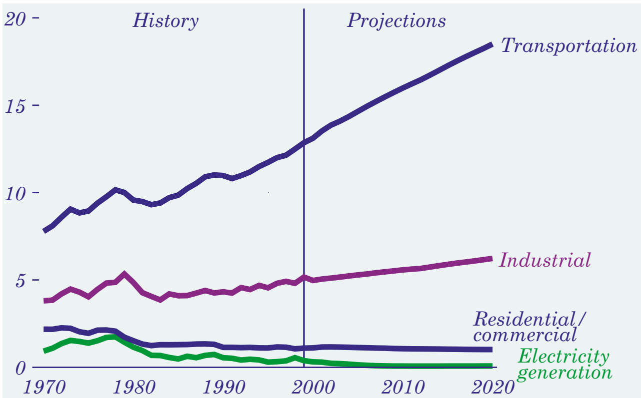
Falling demand for petroleum and the deregulation of the domestic refining industry in the 1980s led to 13 years of decline in U.S. refinery capacity. That trend was reversed in 1995, and 1.2 million barrels per day of distillation capacity had been added by 2000. Financial and legal considerations make it unlikely that new refineries will be built in the United States, but additions at existing refineries are expected to increase total U.S. refining capacity in all the *AEO2001* cases (Figure 108).

Distillation capacity is projected to grow from the 1999 year-end level of 16.5 million barrels per day to 18.2 million in 2020 in the low economic growth case and 18.8 million in the high growth case, compared with the 1981 peak of 18.6 million barrels per day. Almost all the capacity additions are projected to occur on the Gulf Coast. Existing refineries are expected to continue to be utilized intensively throughout the forecast, in a range from 91 percent to 95 percent of design capacity. In comparison, the 1999 utilization rate was 93 percent, well above the rates of the 1980s and early 1990s.

Additional "downstream" processing units are expected to allow domestic refineries to produce less residual fuel, which has a shrinking market, and more higher value "light product" such as gasoline, distillate, jet fuel, and liquefied petroleum gases.

Petroleum Use Increases Mainly in the Transportation Sector

Figure 109. Petroleum consumption by sector, 1970-2020 (million barrels per day)



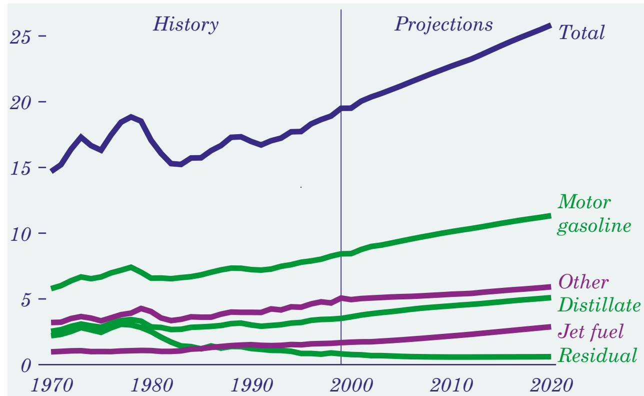
U.S. petroleum consumption is projected to increase by 6.3 million barrels per day between 1999 and 2020. Most of the increase is expected in the transportation sector, which accounted for two-thirds of U.S. petroleum use in 1999 (Figure 109). Petroleum use for transportation is projected to increase by 5.6 million barrels per day in the reference case, 4.3 million in the low economic growth case, and 7.0 million in the high economic growth case.

In the industrial sector, which currently accounts for 26 percent of U.S. petroleum use, consumption in 2020 is projected to be higher than the 1999 level by 1.1 million barrels per day in the reference case, by 0.4 million in the low economic growth case, and by 1.9 million in the high economic growth case. About 84 percent of the growth is expected in the petrochemical, construction, and refining sectors.

In the reference case, petroleum use for heating and for electricity generation is expected to decline as oil loses market share to natural gas. Increased oil use for heating and electricity generation is projected, however, in the low oil price case. Natural gas use for home heating is growing in New England, the last stronghold of heating oil. Compared with 1999, heating oil use is projected to be 150,000 barrels per day lower in 2020 in the high price case and 90,000 barrels per day higher in the low price case. For electricity generation, oil-fired steam plants are being retired in favor of natural gas combined-cycle units. Oil use for electricity generation (excluding cogeneration) is projected to be 320,000 barrels per day lower in 2020 than in 1999 in the high price case and 110,000 barrels per day higher in the low price case.

Light Products Account for Most of the Increase in Demand for Petroleum

Figure 110. Consumption of petroleum products, 1970-2020 (million barrels per day)

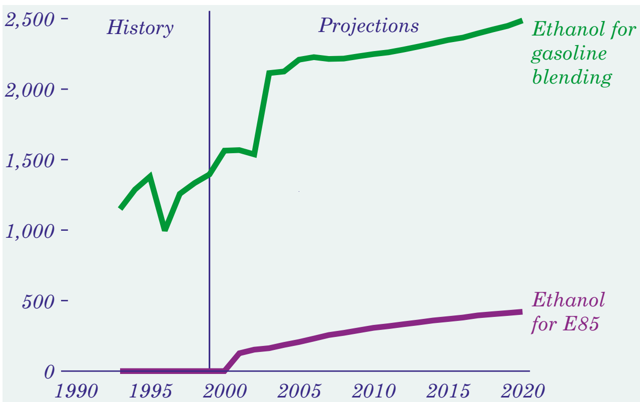


About 96 percent of the projected growth in petroleum consumption stems from increased consumption of "light products," including gasoline, diesel, heating oil, jet fuel, and liquefied petroleum gases, which are more difficult and costly to produce than heavy products (Figure 110). Although refinery investments and enhancements are expected to increase the ability of domestic refineries to produce light products, imports of light products are expected to more than triple by 2020.

In the forecast, gasoline continues to account for almost 45 percent of all the petroleum used in the United States. Between 1999 and 2020, U.S. gasoline consumption is projected to rise from 8.4 million barrels per day to 11.3 million barrels per day. Consumption of distillate fuel is projected to be 1.6 million barrels per day higher in 2020 than it was in 1999, with diesel fuel accounting for 92 percent of the projected increase as demand for freight transportation grows. With air travel also expected to increase, jet fuel consumption is projected to be 1.2 million barrels per day higher in 2020 than in 1999. Consumption of liquefied petroleum gas (LPG), included in "other" petroleum, is projected to increase by about 360,000 barrels per day between 1999 and 2020. Consumption of "other" petroleum products—including petrochemical feedstocks, still gas used to fuel refineries, asphalt and road oil, and other miscellaneous products—is projected to grow by 490,000 barrels per day. Residual fuel use, mainly for electricity generation, is projected to decline from 820,000 barrels per day in 1999 to 600,000 barrels per day in 2020.

State Bans on MTBE Are Expected To Result in Increased Use of Ethanol

Figure 111. U.S. ethanol consumption, 1993-2020 (million gallons)



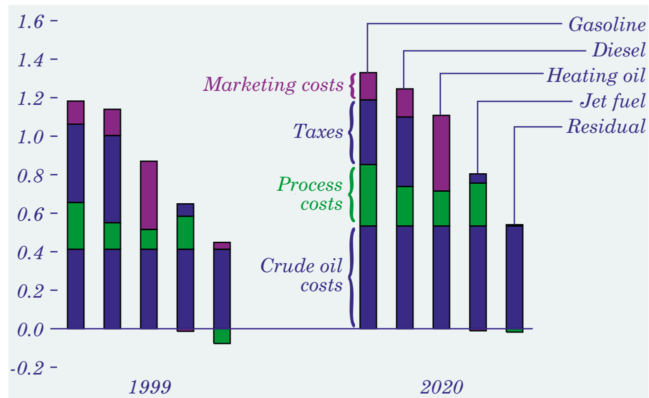
U.S. ethanol production, with corn as the primary feedstock, reached 1.5 billion gallons in 1999. Production is projected to increase to 2.9 billion gallons by 2020, with most of the growth coming from the conversion of cellulosic biomass to ethanol. Ethanol is used primarily in the Midwest as a gasoline volume extender and octane enhancer in a blend of 10 percent ethanol and 90 percent gasoline. It also serves as an oxygenate in areas that are required to use oxygenated fuels (with a minimum 2.7 percent oxygen content by volume) during the winter months to reduce carbon monoxide emissions.

AEO2001 projects an expanded role for ethanol, replacing MTBE as the oxygenate for reformulated gasoline (RFG) in the eight States that have passed legislation limiting the use of MTBE because of concerns about groundwater contamination. The reference case assumes that the Federal requirement for a 2-percent oxygen content in RFG will continue in all States. Ethanol consumption in E85 vehicles is also projected to increase, from the national total of 2.0 million gallons in 1999 to 421 million gallons in 2020 (Figure 111). E85 vehicles are currently in use as government fleet vehicles, flexible-fuel passenger vehicles (which run on either E85 or gasoline), and urban transit buses.

The Federal Highway Bill of 1998 extended the current excise tax exemption for ethanol through 2007 but stipulated reductions from 54 cents per gallon to 53 cents in 2001, 52 cents in 2003, and 51 cents in 2005. *AEO2001* assumes that the exemption will be extended at 51 cents per gallon (nominal) through 2020.

Processing Costs for Most Petroleum Products Rise in the Forecast

Figure 112. Components of refined product costs, 1999 and 2020 (1999 dollars per gallon)



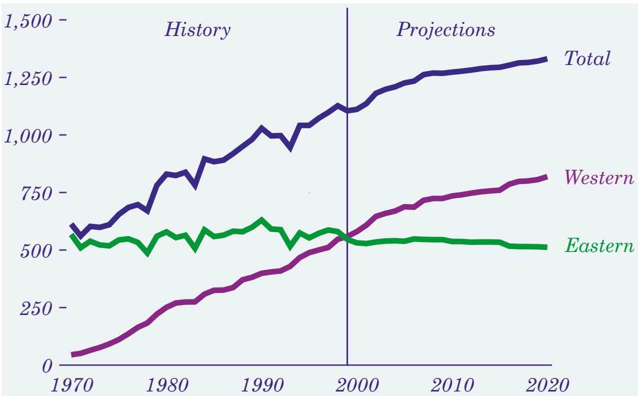
Refined product prices are determined by crude oil costs, refining process costs (including refiner profits), marketing costs, and taxes (Figure 112). In the *AEO2001* projections, crude oil costs are projected to continue making the greatest contribution to product prices and marketing costs are projected to remain stable, but the contributions of processing costs and taxes are expected to change considerably.

The processing costs for light products, including gasoline, diesel fuel, heating oil, and jet fuel, are projected to increase by 6 to 7 cents per gallon between 1999 and 2020. The expected increases are attributed primarily to the projected growth in demand for those products, investment needed to meet new Federal requirements for low-sulfur gasoline between 2004 and 2007, and investments related to compliance with refinery emissions, health, and safety regulations.

Whereas processing costs tend to increase refined product prices in the forecast, assumptions about Federal taxes tend to slow the growth of motor fuels prices. In keeping with the *AEO2001* assumption of current laws and legislation, Federal motor fuels taxes are assumed to remain at nominal 1999 levels throughout the forecast, although Federal taxes have actually been raised sporadically in the past. State motor fuels taxes are assumed to keep up with inflation, as they have in the past. The net impact of the assumptions is an expected decrease in Federal taxes (in 1999 dollars) between 1999 and 2020—7 cents per gallon for gasoline, 9 cents for diesel fuel, and 1 cent for jet fuel.

Emissions Caps Lead to More Use of Low-Sulfur Coal From Western Mines

Figure 113. Coal production by region, 1970-2020 (million short tons)



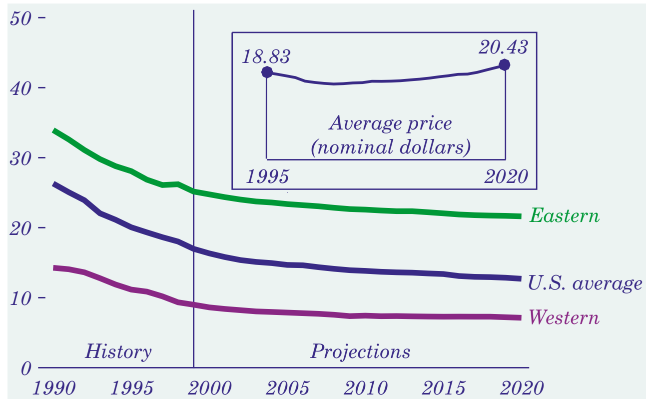
Continued improvements in mine productivity (which have averaged 6.7 percent per year since 1979) are projected to cause falling real minemouth prices throughout the forecast. Higher electricity demand and lower prices, in turn, are projected to yield increasing coal demand, but the demand is subject to an overall sulfur emissions cap from CAAA90, which encourages progressively greater reliance on the lowest sulfur coals (from Wyoming, Montana, Colorado, and Utah).

The use of western coals can result in up to 85 percent lower sulfur dioxide emissions than the use of many types of higher sulfur eastern coal. As coal demand grows in the forecast, however, new coal-fired generating capacity is required to use the best available control technology: scrubbers or advanced coal technologies that can reduce sulfur emissions by 90 percent or more. Thus, even as the demand for low-sulfur coal is projected to grow, there are still expected to be market opportunities for low-cost higher sulfur coal throughout the forecast.

From 1999 to 2020, high- and medium-sulfur coal production is projected to decline from 616 to 592 million tons (0.2 percent per year), and low-sulfur coal production is projected to rise from 490 to 740 million tons (2.0 percent per year). As a result of the competition between low-sulfur coal and post-combustion sulfur removal, western coal production is expected to continue its historical growth, reaching 819 million tons in 2020 (Figure 113), but its annual growth rate is projected to fall from the 9.3 percent achieved between 1970 and 1999 to 1.8 percent in the forecast period.

Minemouth Coal Prices Continue To Fall in the Projections

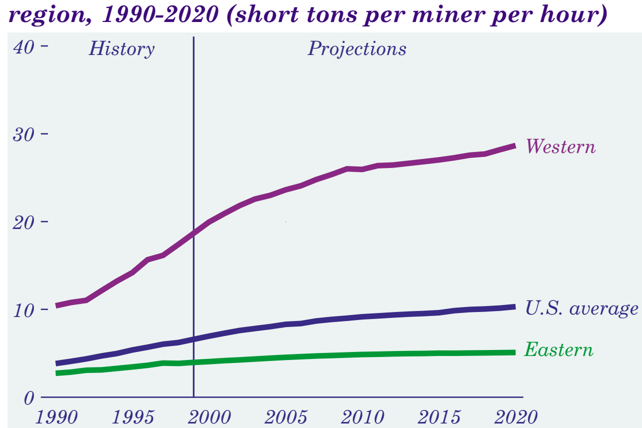
Figure 114. Average minemouth price of coal by region, 1990-2020 (1999 dollars per short ton)



Minemouth coal prices declined by $5.80 per ton (in 1999 dollars) between 1970 and 1999, and they are projected to decline by 1.4 percent per year, or $4.28 per ton, between 1999 and 2020 (Figure 114). The price of coal delivered to electricity generators, which declined by approximately 95 cents per ton between 1970 and 1999, is projected to fall to $19.45 per ton in 2020—a 1.1-percent annual decline.

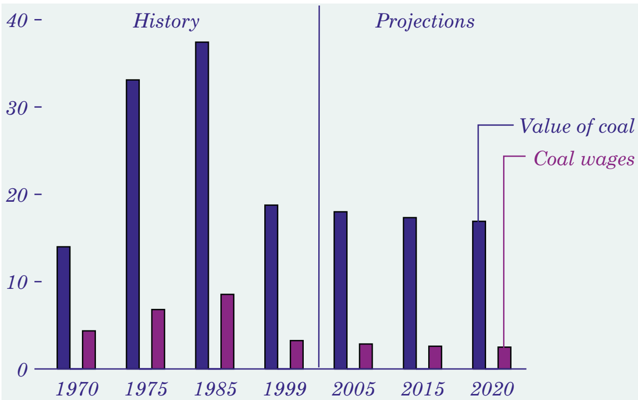
The mines of the Northern Great Plains, with thick seams and low overburden ratios, have had higher labor productivity than other coalfields, and their advantage is expected to be maintained throughout the forecast. Average U.S. labor productivity (Figure 115) is projected to follow the trend for eastern mines most closely, because eastern mining is more labor-intensive than western mining.

Figure 115. Coal mining labor productivity by region, 1990-2020 (short tons per miner per hour)



Labor Cost Contribution to Total Coal Prices Continues To Decline

Figure 116. Labor cost component of minemouth coal prices, 1970-2020 (billion 1999 dollars)



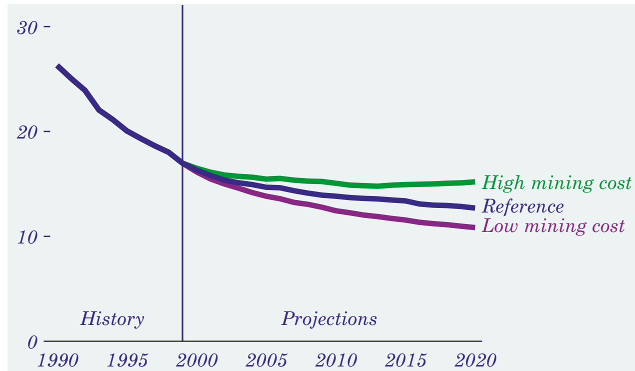
Gains in coal mine labor productivity result from technology improvements, economies of scale, and better mine design. At the national level, however, average labor productivity is also expected to be influenced by changing regional production shares. Competition from very low sulfur, low-cost western and imported coals is projected to limit the growth of eastern low-sulfur coal mining. The boiler performance of western low-sulfur coal has been successfully tested in all U.S. Census divisions except New England and the Mid-Atlantic, and its use in eastern markets is projected to increase.

Eastern coalfields contain extensive reserves of higher sulfur coal in moderately thick seams suited to longwall mining. Continued penetration of technologies for extracting and hauling large volumes of coal in both surface and underground mining suggests that further reductions in mining cost are likely. Improvements in labor productivity have been, and are expected to remain, the key to lower coal mining costs.

As labor productivity improved between 1970 and 1999, the average number of miners working daily fell by 2.2 percent per year. With improvements expected to continue through 2020, a further decline of 1.2 percent per year in the number of miners is projected. The share of wages (excluding irregular bonuses, welfare benefits, and payroll taxes paid by employers) in minemouth coal prices [*92*], which fell from 31 percent to 17 percent between 1970 and 1999, is projected to decline to 15 percent by 2020 (Figure 116).

High Labor Cost Assumption Leads to Lower Production in the East

Figure 117. Average minemouth coal prices in three mining cost cases, 1990-2020 (1999 dollars per short ton)



Alternative assumptions about future regional mining costs affect the projections for market shares of eastern and western mines and the national average minemouth price of coal. In two alternative mining cost cases, projected minemouth prices, delivered prices, and the resulting regional coal production levels vary with changes in projected mining costs.

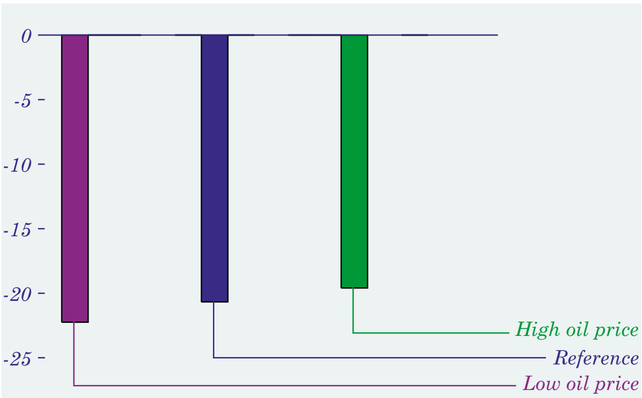
Productivity is assumed to increase by 2.2 percent per year through 2020 in the reference case, while wage rates and equipment costs are constant in 1999 dollars. The national minemouth coal price is projected to decline by 1.4 percent per year to $12.70 per ton in 2020 (Figure 117).

In the low mining cost case, productivity is assumed to increase by 3.7 percent per year, and real wages and equipment costs are assumed to decline by 0.5 percent per year [*93*]. As a result, the average minemouth price is projected to fall by 2.1 percent per year to $10.84 per ton in 2020 (14.6 percent less than projected in the reference case). Eastern coal production is projected to be 4 million tons higher in the low mining cost case than in the reference case in 2020, reflecting the higher labor intensity of mining in eastern coalfields. In the high mining cost case, productivity is assumed to increase by only 0.6 percent per year, and real wages and equipment costs are assumed to increase by 0.5 percent per year. Consequently, the average minemouth price of coal is projected to fall by 0.5 percent per year to $15.18 per ton in 2020 (19.5 percent higher than in the reference case). Eastern production in 2020 is projected to be 13 million tons lower in the high mining cost case than in the reference case.

Coal Transportation Costs

Transportation Costs Are a Key Factor for Coal Markets

Figure 118. Projected change in coal transportation costs in three cases, 1999-2020 (percent)

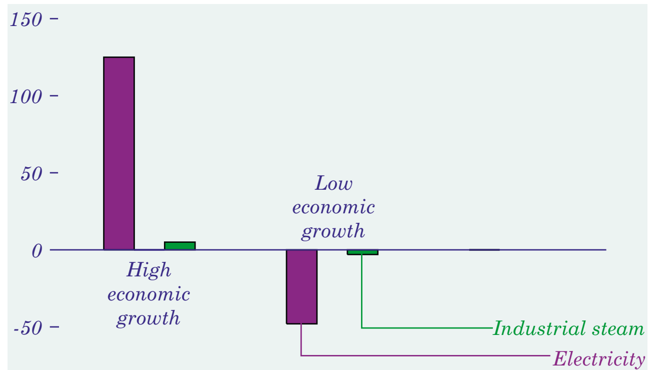


The competition between coal and other fuels, and among coalfields, is influenced by coal transportation costs. Changes in fuel costs affect transportation costs (Figure 118), but transportation fuel efficiency also grows with other productivity improvements in the forecast. As a result, in the reference case, average coal transportation rates are projected to decline by 1.1 percent per year between 1999 and 2020. Historically, the most rapid declines in coal transportation costs have occurred on routes originating in coalfields that have had the greatest declines in real minemouth prices. Railroads are likely to reinvest profits from increasing coal traffic to reduce transportation costs and, thus, expand the market for such coal. Therefore, coalfields that are most successful at improving productivity and lowering minemouth prices are likely to obtain the lowest transportation rates and, consequently, the largest markets at competitive delivered prices.

Assuming that mines in the Powder River Basin will complete needed expansions of their train-loading capacities, western coal is expected to be able to meet the increase in demand expected with the advent of Phase 2 of CAAA90, which became effective on January 1, 2000. The transition will require more low-sulfur coal than was projected in *AEO2000*, because scrubber retrofits are expected to be made at a slower pace in *AEO2001*. Any coal transportation problems associated with the increased shift to low-sulfur coal are expected to be temporary.

Higher Economic Growth Would Favor Coal for Electricity Generation

Figure 119. Projected variation from reference case projections of coal demand in two economic growth cases, 2020 (million short tons)

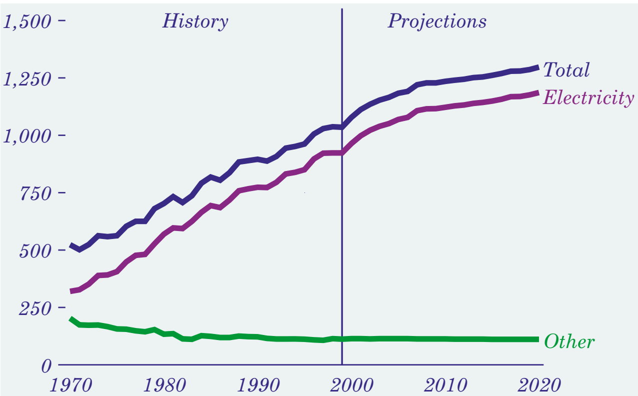


A strong correlation between economic growth and electricity use accounts for the variation in coal demand projections across the economic growth cases (Figure 119), with domestic coal consumption in 2020 projected to range from 1,245 to 1,426 million tons in the low and high economic growth cases, respectively. Of the difference, coal use for electricity generation is projected to make up 173 million tons. The difference in total projected coal production between the two economic growth cases is 182 million tons, of which 148 million tons (81 percent) is projected to be western production. Although western coal must travel up to 2,000 miles to reach some of its markets, it is expected to remain competitively priced in all regions except the Northeast when its transportation costs are added to its low minemouth price and low sulfur allowance cost.

Changes in world oil prices affect the costs of energy (both diesel fuel and electricity) for coal mining. In the low and high oil price cases, the average prices of coal delivered to electricity generators are projected to be 0.8 percent lower and 0.2 percent higher, respectively, in 2020 than projected in the reference case. The low world oil price case projects 79 million tons less coal use in 2020 than the high world oil price case. Low oil prices encourage electricity generation from oil, whereas high oil prices encourage coal consumption. The higher projection for coal consumption in the high oil price case is attributable to the electricity generation sector, which is projected to account for virtually all of the increase.

Coal Consumption for Electricity Continues To Rise in the Forecast

Figure 120. Electricity and other coal consumption, 1970-2020 (million short tons)



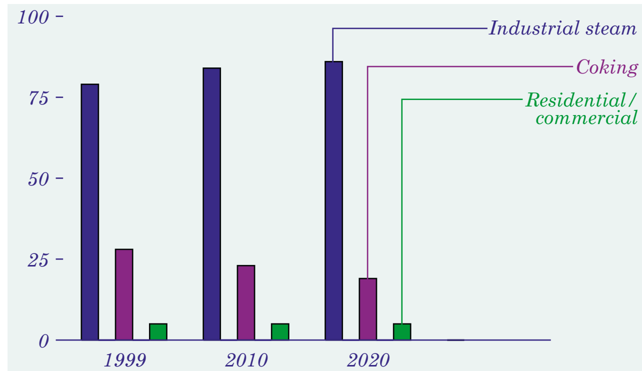
Domestic coal demand is projected to increase by 262 million tons in the reference case forecast, from 1,035 million tons in 1999 to 1,297 million tons in 2020 (Figure 120), because of projected growth in coal use for electricity generation. Coal demand in other domestic end-use sectors is projected to decline.

Coal consumption for electricity generation (excluding cogeneration) is projected to increase from 923 million tons in 1999 to 1,186 million tons in 2020 as the utilization of existing coal-fired generation capacity increases and, in later years, new capacity is added. The average utilization rate is projected to increase from 68 percent in 1999 to 83 percent in 2020. Because coal consumption (in tons) per kilowatthour generated is higher for subbituminous and lignite than for bituminous coals, the shift to western coal is projected to increase the tonnage per kilowatthour of generation in the midwestern and southeastern regions. In the East, generators are expected to shift to lower sulfur Appalachian bituminous coals that contain more energy (Btu) per ton.

Although coal is projected to maintain its fuel cost advantage over both oil and natural gas, gas-fired generation is expected to be the most economical choice for construction of new power generation units in most situations, when capital, operating, and fuel costs are considered. Between 2005 and 2020, rising natural gas costs and nuclear retirements are projected to cause increasing demand for coal-fired baseload capacity.

Industrial Steam Coal Use Rises, But Demand for Coking Coal Declines

Figure 121. Projected coal consumption in the industrial and buildings sectors, 2010 and 2020 (million short tons)



In the non-electricity sectors, a projected increase of 7 million tons in industrial steam coal consumption between 1999 and 2020 (0.5-percent annual growth) is expected to be offset by a decrease of 9 million tons in coking coal consumption (Figure 121). Increasing consumption of industrial steam coal is projected to result primarily from greater use of existing coal-fired boilers in energy-intensive industries.

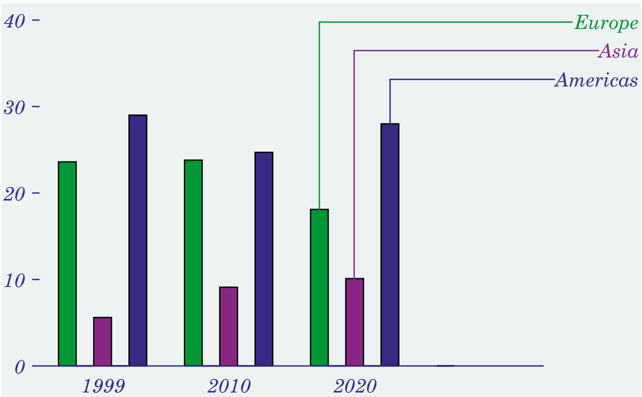
The projected decline in domestic consumption of coking coal results from the expected displacement of raw steel production from integrated steel mills (which use coal coke for energy and as a material input) by increased production from minimills (which use electric arc furnaces that require no coal coke) and by increased imports of semi-finished steels. The amount of coke required per ton of pig iron produced is also declining, as process efficiency improves and injection of pulverized steam coal is used increasingly in blast furnaces. Domestic consumption of coking coal is projected to fall by 1.9 percent per year through 2020, but domestic production of coking coal is expected to be stabilized, in part, by sustained levels of export demand.

Although total energy consumption in the combined residential and commercial sectors is projected to grow by 1.3 percent per year, most of the growth is expected to be captured by electricity and natural gas. Coal consumption in the residential and commercial sectors is projected to remain constant, accounting for less than 1 percent of total U.S. coal demand in the forecast.

Coal Exports

U.S. Coal Exports to Europe and Asia Are Projected To Remain Stable

Figure 122. Projected U.S. coal exports by destination, 2010 and 2020 (million short tons)



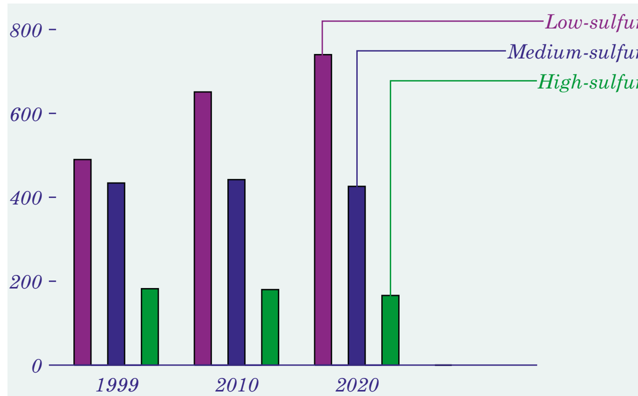
U.S. coal exports declined sharply between 1998 and 1999, from 78 million tons to 58 million tons, but are projected to remain relatively stable over the forecast horizon, settling at 56 million tons by 2020 (Figure 122). Australian and South African coal export prices dropped substantially in 1999, displacing U.S. coal exports to Europe and Asia. Price cuts by Australia, the world's leading coal exporter, were attributed to both strong productivity growth and a favorable exchange rate against the U.S. dollar.

The U.S. share of total world coal trade is projected to decline from 11 percent in 1999 to 8 percent by 2020 as international competition intensifies and demand for coal imports in Europe and the Americas grows more slowly or declines. From 1999 to 2020, U.S. steam coal exports are projected to decline slightly, from 26 million tons to 22 million tons, despite substantial projected growth in world steam coal trade. Steam coal exports from Australia, South Africa, China, and Indonesia are expected to increase in response to growing import demand in Asian countries, and increasing exports from South Africa are expected to displace some U.S. exports to Europe.

U.S. coking coal exports are projected to increase slightly, from 32 million tons in 1999 to 34 million tons in 2020. A small increase in the world trade in coking coal is expected, primarily in Asia. Australia is expected to capture an increasing share of the international market for coking coal because of its proximity to Asian importers and its ample reserves of coking coal.

Low-Sulfur Coal Continues To Gain Share in the Generation Market

Figure 123. Projected coal production by sulfur content, 2010 and 2020 (million short tons)



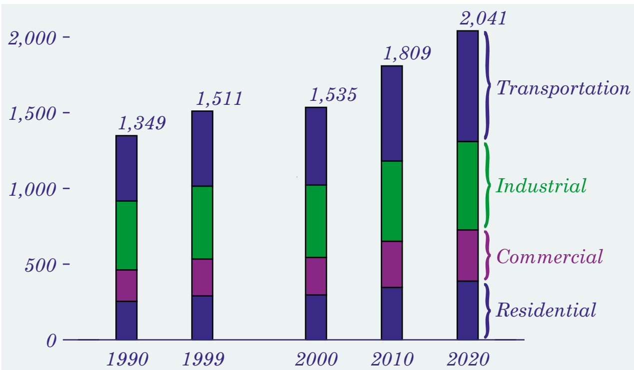
Phase 1 of CAAA90 required 261 coal-fired generating units to reduce sulfur dioxide emissions to about 2.5 pounds per million Btu of fuel. Phase 2, which took effect on January 1, 2000, tightens the annual emissions limits imposed on these large, higher emitting plants and also sets restrictions on smaller, cleaner plants fired with coal, oil, and gas. The program affects existing utility units serving generators over 25 megawatts capacity and all new utility units [*94*].

With relatively modest capital investments many generators can blend very low sulfur subbituminous and bituminous coal in Phase 1 affected boilers. Such fuel switching often generates sulfur dioxide allowances beyond those needed for Phase 1 compliance, and the excess allowances generated during Phase 1 were banked for use in Phase 2 or sold to other generators. (The proceeds of such sales can be seen as further reducing fuel costs for the seller.) In the forecast, fuel switching for regulatory compliance and for cost savings is projected to reduce the composite sulfur content of all coal produced (Figure 123). The main sources of low-sulfur coal are the Central Appalachian, Powder River Basin, and Rocky Mountain regions, as well as coal imports.

Coal users may incur additional costs in the future if environmental problems associated with nitrogen oxides, particulate emissions, and possibly carbon dioxide emissions from coal combustion are monetized and added to the costs of coal combustion.

Higher Energy Consumption Forecast Increases Carbon Dioxide Emissions

Figure 124. Projected carbon dioxide emissions by sector, 2000, 2010, and 2020 (million metric tons carbon equivalent)



Carbon dioxide emissions from energy use are projected to increase on average by 1.4 percent per year from 1999 to 2020, to 2,041 million metric tons carbon equivalent (Figure 124), and emissions per capita are projected to grow by 0.6 percent per year.

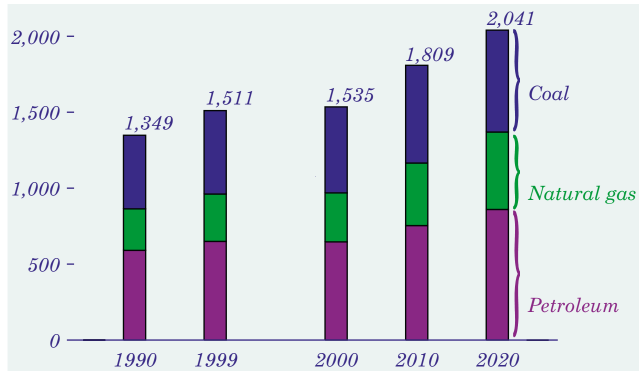
Carbon dioxide emissions in the residential sector, including emissions from the generation of electricity used in the sector, are projected to increase by an average of 1.4 percent per year, reflecting the ongoing trends of electrification and penetration of new appliances and services. Significant growth in office equipment and other uses is also projected in the commercial sector, but growth in consumption—and in carbon dioxide emissions, which are projected to increase by 1.6 percent per year—is expected to be moderated by slowing growth in floorspace.

In the transportation sector, carbon dioxide emissions are projected to grow at an average annual rate of 1.8 percent as a result of projected increases in vehicle-miles traveled and freight and air travel, combined with small increases in average light-duty fleet efficiency. Industrial emissions are projected to grow by only 0.9 percent per year, as shifts to less energy-intensive industries and efficiency gains are projected to moderate growth in energy use.

In all sectors, potential growth in carbon dioxide emissions is expected to be moderated by efficiency standards, voluntary efficiency programs, and improvements in technology. Carbon dioxide mitigation programs, further improvements in technology, or more rapid adoption of voluntary programs could result in lower emissions levels than projected here.

Petroleum Products Lead Carbon Dioxide Emissions From Energy Use

Figure 125. Projected carbon dioxide emissions by fuel, 2000, 2010, and 2020 (million metric tons carbon equivalent)



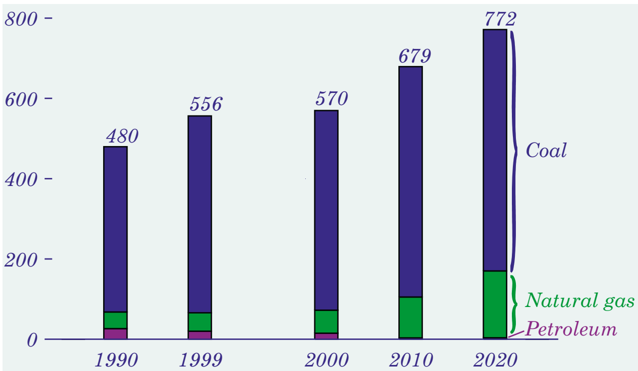
Petroleum products are the leading source of carbon dioxide emissions from energy use. In 2020, petroleum is projected to account for 860 million metric tons carbon equivalent, a 42-percent share of the projected total (Figure 125). About 82 percent (705 million metric tons carbon equivalent) of the emissions from petroleum use are expected to result from transportation fuel use, which could be lower with less travel or more rapid development and adoption of higher efficiency or alternative-fuel vehicles.

Coal is the second leading source of carbon dioxide emissions, projected to produce 671 million metric tons carbon equivalent in 2020, or 33 percent of the total. The coal share is projected to decline from 36 percent in 1999, because coal consumption is expected to increase at a slower rate through 2020 than consumption of petroleum and natural gas, the sources of virtually all other energy-related carbon dioxide emissions. Most of the increases in emissions from coal use result from electricity generation.

In 2020, natural gas use is projected to produce a 25-percent share of total carbon dioxide emissions, 510 million metric tons carbon equivalent. Of the fossil fuels, natural gas consumption and emissions increase most rapidly through 2020, at average annual rates of 2.3 and 2.4 percent; however, natural gas produces only half the carbon dioxide emissions of coal per unit of input. Average emissions from petroleum use are between those for coal and natural gas. Electricity generation from renewable fuels and nuclear power, which emit little or no carbon dioxide, is expected to mitigate the projected increase in carbon dioxide emissions.

Electricity Use Is Another Major Cause of Carbon Dioxide Emissions

Figure 126. Projected carbon dioxide emissions from electricity generation by fuel, 2000, 2010, and 2020 (million metric tons carbon equivalent)



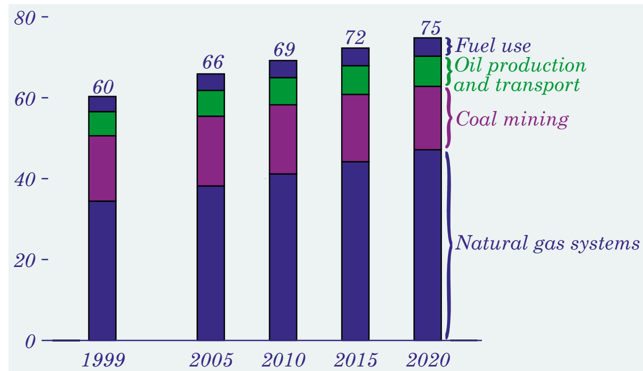
Electricity generation is a major source of carbon dioxide emissions. Although electricity produces no emissions at the point of use, generation (excluding cogeneration) accounted for 37 percent of total carbon dioxide emissions in 1999, and its share is expected to increase to 38 percent in 2020. Coal is projected to account for 47 percent of electricity generation in 2020 (excluding cogeneration) and to produce 78 percent of electricity-related carbon dioxide emissions (Figure 126). In 2020, natural gas is projected to account for 33 percent of electricity generation (excluding cogeneration) but only 22 percent of electricity-related carbon dioxide emissions.

Between 1999 and 2020, 26 gigawatts of nuclear capacity is projected to be retired, resulting in a 21-percent decline in nuclear generation. To make up for the loss of nuclear capacity and meet rising demand, 385 gigawatts of new fossil-fueled capacity (excluding cogeneration) is projected to be needed. Increased generation from fossil fuels is expected to raise carbon dioxide emissions from electricity generation (excluding cogeneration) by 215 million metric tons carbon equivalent, or 39 percent, from 1999 levels. Generation from renewable technologies (excluding cogeneration) is projected to increase by 43 billion kilowatthours, or 12 percent, between 1999 and 2020 but is not expected to be sufficient to offset the projected increase in generation from fossil fuels.

The projections include announced activities under the Climate Challenge program, such as fuel switching, repowering, life extension, and demand-side management, but they do not include offset activities, such as reforestation.

Moderate Growth in Methane Emissions Is Expected

Figure 127. Projected methane emissions from energy use, 2005-2020 (million metric tons carbon equivalent)



Methane emissions from energy use are projected to increase at an average rate of 1.0 percent per year from 1999 to 2020, somewhat slower than the 1.4-percent projected growth rate for carbon dioxide emissions. Based on global warming potential, methane is the second largest component of U.S. man-made greenhouse gas emissions after carbon dioxide, and it is one of the six gases covered in the Kyoto Protocol. In 1999, methane accounted for 9 percent of total U.S. greenhouse gas emissions of 1,833 million metric tons carbon equivalent. About a third of U.S. methane emissions are related to energy activities, mostly from energy production and transportation and to a much smaller extent from fuel combustion. Other sources of methane emissions include waste management, agriculture, and industrial processes.

Much of the projected increase in energy-related methane emissions is tied to increases in oil and gas use (Figure 127). The fugitive methane emissions that occur during natural gas production, processing, and distribution are expected to increase, despite declines in the average rate of emissions per unit of production. Emissions related to oil production and, to a lesser extent, refining and transport are also expected to increase. Coal-related methane emissions are expected to decline, with coal production from methane-intensive underground mining projected to remain flat over the forecast period while progress in the recovery of vented gas continues. About 6 percent of methane emissions in 1999 resulted from wood and fossil fuel combustion. A 20-percent increase is projected by 2020, with residential use of wood as a fuel expected to remain at about its 1999 level.

Scrubber Retrofits Will Be Needed To Meet Sulfur Emissions Caps

Figure 128. Projected sulfur dioxide emissions from electricity generation, 2000-2020 (million tons)

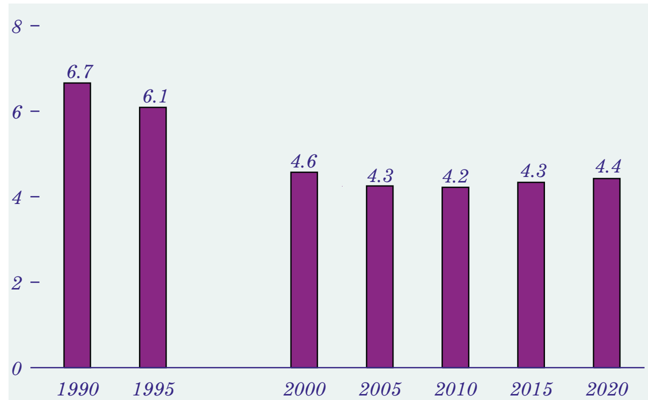
CAAA90 called for annual emissions of sulfur dioxide (SO_2) by electricity generators to be reduced to approximately 12 million tons in 1996, 9.48 million tons between 2000 and 2009, and 8.95 million tons per year thereafter. Because companies can bank allowances for future use, however, the long-term cap of 8.95 million tons per year may not be reached until after 2010. About 97 percent of the SO_2 produced by generators results from coal combustion and the rest from residual oil.

CAAA90 called for the reductions to occur in two phases, with larger (more than 100 megawatts) and higher emitting (more than 2.5 pounds per million Btu) plants making reductions first. In Phase 1, 261 generating units at 110 plants were issued tradable emissions allowances permitting SO_2 emissions to reach a fixed amount per year—generally less than the plant's historical emissions. Allowances may also be banked for use in future years. Switching to lower sulfur subbituminous coal was the option chosen by most generators, as only about 12 gigawatts of capacity had been retrofitted by 1995.

In Phase 2, beginning in 2000, emissions constraints on Phase 1 plants are tightened, and limits are set for the remaining 2,500 boilers at 1,000 plants. With allowance banking, emissions are projected to decline from 11.9 million tons in 1995 to 11.5 million in 2000 (Figure 128). With the SO_2 emissions cap tightened in 2000 and after, the price of allowances is projected to rise, reaching $215 per ton by 2005. As the price rises, 11 gigawatts of capacity—about 37 300-megawatt plants—is expected to be retrofitted with scrubbers to meet the Phase 2 goal.

A Significant Drop in Nitrogen Oxide Emissions Is Expected in 2000

Figure 129. Projected nitrogen oxide emissions from electricity generation, 2000-2020 (million tons)



Nitrogen oxide (NO_x) emissions from electricity generation in the United States are projected to fall significantly over the next 5 years as new legislation takes effect (Figure 129). The required reductions are intended to reduce the formation of ground-level ozone, for which NO_x emissions are a major precursor. Together with volatile organic compounds and hot weather, NO_x emissions contribute to unhealthy air quality in many areas during the summer months. The CAAA90 NO_x reduction program called for reductions at electric power plants in two phases, the first in 1995 and the second in 2000. The second phase of CAAA90 is expected to result in NO_x reductions of 0.8 million tons between 1999 and 2000.

Even after the CAAA90 regulations take effect, further effort may be needed in some areas. For several years the EPA and the States have studied the movement of ozone from State to State. The States in the Northeast have argued that emissions from coal plants in the Midwest make it difficult for them to meet national air quality standards for ground-level ozone, and they have petitioned the EPA to force the coal plant operators to reduce their emissions more than required under current rules.

The interpretation of ozone transport studies has been controversial. In September 1998 the EPA issued a rule, referred to as the Ozone Transport Rule (OTR), to address the problem. The OTR calls for capping NO_x emissions in 22 midwestern and eastern States during the 5-month summer season, beginning in 2003. After an initial court challenge the rules have been upheld, and emissions limits have been finalized for 19 States.

Forecast Comparisons

Forecast Comparisons

Three other organizations—Standard & Poor's DRI (DRI), the WEFA Group (WEFA), and the Gas Research Institute (GRI) [*95*]—also produce comprehensive energy projections with a time horizon similar to that of *AEO2001*. The most recent projections from those organizations (DRI, Spring/Summer 2000; WEFA, 1st Quarter 2000; GRI, January 2000), as well as other forecasts that concentrate on petroleum, natural gas, and international oil markets, are compared here with the *AEO2001* projections.

Economic Growth

Differences in long-run economic forecasts can be traced primarily to different views of the major supply-side determinants of growth in gross domestic product (GDP): labor force and productivity change (Table 19). In comparison with the *AEO2001* and DRI reference cases, the WEFA forecast shows the highest economic growth, including a higher growth rate for the labor force. The *AEO2001* long-run forecast of average annual economic growth from 1999 to 2020 in the reference case is 3.0 percent—0.9 percent higher than the *AEO2000* forecast.

The June 26, 2000, mid-session review by the Office of Management and Budget projected real GDP growth of 3.1 percent per year between 1999 and 2010. *AEO2001* projects annual growth of 3.3 percent over the same period.

World Oil Prices

Comparisons with other oil price forecasts—including the International Energy Agency (IEA), Petroleum Economics Ltd. (PEL), Petroleum Industry Research Associates, Inc. (PIRA), Natural Resources Canada (NRCan), and Deutsche Banc Alex. Brown (DBAB)—are shown in Table 20 (IEA, 1998; PEL, February 2000; PIRA, October 2000; NRCan, April 1997; DBAB, June 2000). With the exception of IEA and PEL, the range between the *AEO2001* low and high world oil price cases spans the range of other published forecasts.

Total Energy Consumption

The *AEO2001* forecast of end-use sector energy consumption over the next two decades shows far less volatility than has occurred historically. Between 1974 and 1984, volatile world oil markets dampened domestic oil consumption. Consumers switched to electricity-based technologies in the buildings sector, while in the transportation sector new car fuel efficiency nearly doubled. Natural gas use declined as a result of high prices and limitations on new gas hookups. Between 1984 and 1995, however, both petroleum and natural gas consumption rebounded, bolstered by plentiful supplies and declining real energy prices. As a consequence, new car fuel efficiency in 1995 was less than 2 miles per gallon higher than in 1984, and natural gas use (residential, commercial, and industrial) was almost 25 percent higher than it was in 1984.

Given potentially different assumptions about, for example, technological developments over the next 20 years, the forecasts from DRI, GRI, and WEFA have remarkable similarities with the *AEO2001* projections. Electricity is expected to remain the fastest growing source of delivered energy (Table 21), although its projected rate of growth is down sharply from historical rates in each of the forecasts, because many traditional uses of electricity (such as for air conditioning) approach saturation while

Table 19. Forecasts of economic growth, 1999-2020

Forecast	Average annual percentage growth: Real GDP	Labor force	Productivity
AEO2001			
Low growth	*2.5*	*0.7*	*1.8*
Reference	*3.0*	*0.9*	*2.1*
High growth	*3.5*	*1.2*	*2.3*
DRI			
Low	*2.3*	*0.7*	*1.6*
Reference	*2.9*	*0.9*	*2.0*
High	*3.6*	*1.0*	*2.6*
WEFA			
Low	*2.8*	*0.9*	*1.8*
Reference	*3.2*	*1.1*	*2.1*
High	*3.5*	*1.3*	*2.3*

Note: Totals may not equal sum of components due to independent rounding.

Table 20. Forecasts of world oil prices, 2000-2020

Forecast	1999 dollars per barrel: 2000	2005	2010	2015	2020
AEO2001 reference	*27.59*	*20.83*	*21.37*	*21.89*	*22.41*
AEO2001 high price	*27.59*	*26.04*	*26.66*	*28.23*	*28.42*
AEO2001 low price	*27.59*	*15.10*	*15.10*	*15.10*	*15.10*
DRI	*26.65*	*19.47*	*18.65*	*19.87*	*21.16*
IEA	*20.43*	*20.43*	*20.43*	*30.04*	*30.04*
PEL	*17.69*	*15.63*	*13.77*	*11.75*	*NA*
PIRA	*30.04*	*22.56*	*23.58*	*NA*	*NA*
WEFA	*23.76*	*18.39*	*18.48*	*19.42*	*20.41*
GRI	*18.17*	*18.17*	*18.17*	*18.17*	*NA*
NRCan	*21.24*	*21.24*	*21.24*	*21.24*	*21.24*
DBAB	*23.67*	*17.08*	*17.36*	*17.34*	*17.68*

NA = not available.

average equipment efficiencies rise. Petroleum use and natural gas consumption are projected to grow at rates similar to those of recent years. For other fuels, future growth in consumption is expected to slow as a result of moderating economic growth, fuel switching, and increased end-use efficiency.

Residential and Commercial Sectors

Growth rates for energy demand in the residential and commercial sectors are expected to decrease by more than 25 percent from the rates between 1984 and 1998, largely because of projected lower growth in population, housing starts, and commercial floorspace additions. Other contributing factors include increasing energy efficiency due to technical innovations and legislated standards; voluntary government efficiency programs; and reduced opportunities for additional market penetration of such end uses as air conditioning.

Differing views on the growth of new uses for energy contribute to variations among the forecasts. By fuel, electricity (excluding generation and transmission losses) remains the fastest growing energy source for both sectors across all forecasts (Table 22). All the forecasts project substantial growth in electricity use, with the *AEO2001*, DRI, and WEFA projections showing slower growth toward the end of the forecast. Natural gas use also is projected to grow but at lower rates, and projected petroleum use either is stable or continues to fall. GRI projects a more rapid decline in oil use, particularly for commercial space and water heating, than the other forecasts.

Industrial Sector

The projected growth rates for delivered energy consumption in the industrial sector range from 1.0 percent to 1.4 percent per year (Table 23). The *AEO2001* forecast is in the middle, at 1.2 percent. Generally, the projected growth rates are somewhat lower than the actual rates from 1984 to 1998. The decline is attributable to lower growth for GDP and manufacturing output. In addition, there has been a continuing shift in the industrial output mix toward less energy-intensive products.

The growth rates for different fuels in the industrial sector between 1984 and 1998 reflect a shift from petroleum products and coal to greater reliance on natural gas and electricity. In all the forecasts, natural gas use is expected to grow more slowly than in

Table 21. Forecasts of average annual growth rates for energy consumption (percent)

	History		Projections			
Energy use	1974-1984	1984-1998	AEO2001 (1999-2020)	DRI (1999-2020)	GRI (1998-2015)	WEFA (1999-2020)
Petroleum*	-0.1	1.3	1.5	1.6	1.2	1.1
Natural gas*	-1.7	1.4	1.4	1.2	1.8	1.0
Coal*	-3.0	-1.8	0.2	0.0	-0.8	-0.2
Electricity	3.0	2.5	1.8	1.4	2.0	1.6
Delivered energy	-0.2	1.4	1.5	1.4	1.4	1.1
Electricity losses	2.5	1.8	0.9	0.3	1.1	0.2
Primary energy	0.4	1.5	1.3	1.1	1.3	0.8

*Excludes consumption by electric utilities.

Table 22. Forecasts of average annual growth in residential and commercial energy demand (percent)

	History	Projections			
Forecast	1984-1998	AEO2001 (1999-2020)	DRI (1999-2020)	GRI (1998-2015)	WEFA (1999-2020)
Residential					
Petroleum	-0.1	-0.7	0.2	-0.3	-0.6
Natural gas	0.0	1.3	1.1	1.4	1.1
Electricity	2.7	1.9	1.3	2.0	1.7
Delivered energy	1.1	1.3	1.0	1.3	1.1
Electricity losses	2.2	1.0	0.2	1.2	0.3
Primary energy	1.6	1.2	0.7	1.2	0.7
Commercial					
Petroleum	-4.3	0.5	-0.5	-1.3	-0.5
Natural gas	1.3	1.3	0.5	1.8	1.3
Electricity	3.4	2.0	1.0	1.9	1.8
Delivered energy	1.4	1.6	0.9	1.6	1.4
Electricity losses	3.0	1.2	0.0	1.0	0.4
Primary energy	2.2	1.4	0.4	1.3	0.8

Table 23. Forecasts of average annual growth in industrial energy demand (percent)

	History	Projections			
Forecast	1984-1998	AEO2001 (1999-2020)	DRI (1999-2020)	GRI (1998-2015)	WEFA (1999-2020)
Petroleum	1.0	1.1	1.1	1.6	1.2
Natural gas	2.2	1.3	1.3	1.7	0.7
Coal	-1.6	0.1	0.0	-0.8	-0.4
Electricity	1.6	1.4	1.8	2.0	1.2
Delivered energy	1.4	1.2	1.1	1.4	1.0
Electricity losses	0.8	0.5	0.6	1.4	-0.2
Primary energy	1.3	1.0	0.9	1.4	0.7

recent history, because much of the potential for fuel switching was realized during the 1980s. A key uncertainty in industrial coal forecasts is the environmental acceptability of coal as a boiler fuel.

Transportation Sector

Overall fuel consumption in the transportation sector is expected to grow slightly more slowly than in the recent past in each of the forecasts (Table 24). All the forecasts anticipate continued rapid growth in air travel and considerably slower growth in light-duty vehicle travel. Demand for diesel fuel is expected to grow more slowly in all the forecasts than it has in the past.

GRI and WEFA project slower growth in gasoline demand as a result of slower growth in light-duty vehicle travel, and GRI projects more rapid efficiency improvements. GRI also projects the slowest growth in air travel of all the forecasts, leading to slower growth in jet fuel demand. For diesel fuel, however, GRI projects rapid growth in demand comparable to the *AEO2001* forecast, because it projects similar annual growth in freight travel.

Electricity

Comparison across forecasts shows slight variation in projected electricity sales (Table 25). Sales projections for 2020 range from 1,485 billion kilowatthours (DRI) to 1,610 billion kilowatthours (WEFA) for the residential sector, as compared with the *AEO2001* reference case value of 1,701 billion kilowatthours. The forecasts for total electricity sales in 2020 range from 4,450 billion kilowatthours (DRI) to 4,503 billion kilowatthours (WEFA), compared with the *AEO2001* reference case value of 4,804 billion kilowatthours. All the projections for total electricity sales in 2020 fall below the range of the *AEO2001* low and high economic growth cases (4,516 and 5,135 billion kilowatthours, respectively). Different assumptions related to expected economic activity, coupled with diversity in the estimation of penetration rates for energy-efficient technologies, are the primary reasons for variation among the forecasts. All the forecasts compared here agree that stable fuel prices and slow growth in electricity demand relative to GDP growth will tend to keep the price of electricity stable—or declining in real terms—until 2020.

Table 24. Forecasts of average annual growth in transportation energy demand (percent)

Forecast	History 1975-1985	History 1985-1997	Projections AEO2001 (1999-2020)	Projections DRI (1999-2020)	Projections GRI (1998-2015)	Projections WEFA (1999-2020)
Consumption						
Motor gasoline	0.2	1.4	1.4	1.7	1.1	0.7
Diesel fuel	4.2	3.3	2.3	1.2	1.9	1.2
Jet fuel	2.1	2.4	2.6	3.1	2.5	3.0
Residual fuel	1.0	-0.7	0.8	2.2	3.2	2.5
All energy	1.0	2.7	1.8	1.9	1.2	1.1
Key indicators						
Car and light truck travel	2.9	3.1	1.9	1.9	1.5	1.6
Air travel (revenue passenger-miles)	7.3	4.9	3.6	4.3	3.0	3.7
Average new car fuel efficiency	5.5	0.4	0.7	0.4	2.1	0.5
Gasoline prices	0.5	-2.7	0.6	0.3	0.9	0.2

NA = not available.

Both the DRI and GRI forecasts assume that the electric power industry will be fully restructured, resulting in average electricity prices that approach long-run marginal costs. *AEO2001* also assumes that competitive pressures will grow and continue to push prices down until the later years of the projections. *AEO2001* also assumes that increased competition in the electric power industry will lead to lower operating and maintenance costs, lower general and administrative costs, early retirement of inefficient generating units, and other cost reductions. Further, in the DRI forecast, it is assumed that time-of-use electricity rates will cause some flattening of electricity demand (lower peak period sales relative to average sales), resulting in better utilization of capacity and capital cost savings.

The distribution of sales among sectors affects the mix of capacity types needed to satisfy sectoral demand. Although the *AEO2001* mix of capacity among fuels is similar to those in the other forecasts, small differences in sectoral demands across the forecasts could lead to significant differences in the expected mix of capacity types. In general, recent growth in the residential sector, coupled with an oversupply of baseload capacity, results in a need for more peaking and intermediate capacity than baseload capacity. Consequently, generators are expected to plan for more combustion turbine and combined-cycle technology than coal, oil, or gas steam capacity.

Table 25. Comparison of electricity forecasts (billion kilowatthours, except where noted)

Projection	AEO2001			Other forecasts		
	Reference	Low economic growth	High economic growth	WEFA	GRI	DRI
2015						
Average end-use price (1999 cents per kilowatthour)	**5.9**	**5.7**	**6.1**	**5.8**	**6.0**	**5.4**
Residential	7.5	7.2	7.8	7.1	7.6	6.7
Commercial	6.0	5.7	6.4	6.3	6.9	5.7
Industrial	3.8	3.6	4.1	3.9	3.4	3.8
Net energy for load	**4,771**	**4,564**	**5,011**	**4,842**	**4,812**	**4,783**
Coal	2,246	2,176	2,362	2,026	2,337	2,267
Oil	17	17	18	51	85	174
Natural gas	1,266	1,145	1,373	1,764	1,158	1,257
Nuclear	639	632	650	508	531	640
Hydroelectric/other [a]	395	390	398	448	472	411
Nonutility sales to grid [b]	187	184	190	NA	185	NA
Net imports	21	21	21	44	44	34
Electricity sales	**4,484**	**4,286**	**4,715**	**4,210**	**4,489**	**4,173**
Residential	1,573	1,540	1,600	1,494	1,573	1,388
Commercial/other [c]	1,602	1,532	1,673	1,419	1,448	1,365
Industrial	1,309	1,214	1,442	1,296	1,469	1,421
Capability (gigawatts) [d,e]	**1,061**	**1,020**	**1,112**	**961**	**962**	**1,084**
Coal	324	319	337	302	327	355
Oil and gas	541	500	569	461	411	516
Nuclear	80	78	81	64	78	95
Hydroelectric/other [a]	117	123	126	134	146	118
2020						
Average end-use price (1999 cents per kilowatthour)	**6.0**	**5.6**	**6.4**	**5.6**	**NA**	**5.8**
Residential	7.6	7.2	8.0	6.8	NA	6.5
Commercial	6.2	5.7	6.7	6.0	NA	5.6
Industrial	4.0	3.6	4.3	3.8	NA	3.6
Net energy for load	**5,094**	**4,792**	**5,437**	**5,180**	**NA**	**5,090**
Coal	2,298	2,205	2,614	2,177	NA	2,395
Oil	19	17	22	48	NA	189
Natural gas	1,587	1,409	1,584	2,005	NA	1,462
Nuclear	574	554	591	433	NA	604
Hydroelectric/other [a]	396	392	399	472	NA	409
Nonutility sales to grid [b]	200	195	207	NA	NA	NA
Net imports	21	21	21	44	NA	31
Electricity sales	**4,804**	**4,516**	**5,135**	**4,503**	**NA**	**4,450**
Residential	1,701	1,645	1,736	1,610	NA	1,485
Commercial/other [c]	1,692	1,595	1,794	1,528	NA	1,427
Industrial	1,411	1,276	1,604	1,365	NA	1,538
Capability (gigawatts) [d,e]	**1,132**	**1,068**	**1,201**	**1,021**	**NA**	**1,139**
Coal	325	317	366	317	NA	373
Oil and gas	609	558	635	511	NA	560
Nuclear	72	69	74	54	NA	89
Hydroelectric/other [a]	126	124	127	139	NA	118

[a]"Other" includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power, plus a small quantity of petroleum coke. For nonutility generators, "other" also includes waste heat, blast furnace gas, and coke oven gas.

[b]For *AEO2001*, includes only net sales from cogeneration; for the other forecasts, also includes nonutility sales to the grid.

[c]"Other" includes sales of electricity to government, railways, and street lighting authorities.

[d]For DRI, "capability" represents nameplate capacity; for the others, "capability" represents net summer capability.

[e]GRI generating capability includes only central utility and independent power producer capacity. It does not include cogeneration capacity in the commercial and industrial sectors, which would add another 107 gigawatts.

Sources: ***AEO2001:*** AEO2001 National Energy Modeling System, runs AEO2001.D101600A (reference case), LM2001.D101600A (low economic growth case), and HM2001.D101600A (high economic growth case). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (2000). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 2000 Edition (January 2000). **DRI:** Standard & Poor's DRI, *U.S. Energy Outlook* (Spring/Summer 2000).

Natural Gas

The differences among published forecasts of natural gas prices, production, consumption, and imports (Table 26) indicate the uncertainty of future market trends. Because the forecasts depend heavily on the underlying assumptions that shape them, the assumptions should be considered when different projections are compared. For instance, the forecast from GRI incorporates a cyclical price trend based on exploration and production cycles, which can be deceptive when isolated years are considered. In both 2015 and 2020, the forecast with the highest natural gas consumption is the *AEO2001* high economic growth forecast (33.36 and 36.09 trillion cubic feet, respectively); and the forecast with the lowest level is the DRI forecast (29.46 and 28.58 trillion cubic feet, respectively).

The National Petroleum Council (NPC) forecast shows the greatest expected growth in natural gas consumption between 1999 and 2015 in the residential and commercial sectors. The DRI forecast shows the lowest growth between 1999 and 2015 and also between 1999 and 2020. For residential consumption in 2015, the expected percentage increase over 1999 is 10 percentage points higher in the NPC forecast than in the DRI forecast; for commercial consumption the difference is 23 percentage points. The DRI forecast for commercial consumption is significantly lower than the other forecasts, due in part to definitional differences, and is even lower for 2020 than for 2015. Both the *AEO2001* reference and high economic growth forecasts for residential and commercial consumption exceed the other forecasts for 2020.

For industrial sector consumption of natural gas, the WEFA and DRI forecasts are not strictly comparable with the others because of differences in definitions. Among the remaining forecasts, the *AEO2001* reference, low economic growth, and high economic growth cases all project lower consumption in 2015 than do the GRI, AGA, and NPC reference cases. All the forecasts project the strongest growth in natural gas consumption for the electricity generation sector.

Domestic natural gas consumption is met by domestic production and imports. DRI projects the highest level of net imports, as well as the highest share of imports relative to total supply, in both 2015 and 2020. GRI's projection for 2015 is 1.7 trillion cubic feet lower than DRI's, corresponding to projected import shares of total supply at 12 percent and 19 percent, respectively. The forecasts available for 2020 are much more closely aligned. In general the projections for domestic production levels among the forecasts correspond to their projections for domestic consumption. GRI projects the highest production level in 2015, as well as relatively low import levels.

Even with production levels closer to the mid-range, the NPC forecast projects the highest wellhead price in 2015. At the other extreme, GRI projects the lowest wellhead price and the highest production levels. By 2020 the wellhead price forecasts from WEFA and DRI fall within the range of the *AEO2001* low and high economic growth cases, but both the WEFA and DRI forecasts for domestic production are lower than that in the *AEO2001* low economic growth case. With one exception, all the forecasts for end-use prices follow the same ranking from highest to lowest as do the wellhead price forecasts for both 2015 and 2020.

For the residential and commercial sectors in 2015, WEFA projects the highest end-use margins relative to the wellhead. The lowest projections for residential (GRI) and commercial (AGA) margins are $1.10 and $1.02 per thousand cubic feet lower than WEFA's, respectively, a noticeable difference. The GRI forecast, projecting relatively low residential and commercial margins, projects the highest margin to electricity generators in 2015, at $0.23 above the lowest (AGA). AGA generally projects the lowest margins, but they do not include some State and local taxes. Because of definitional differences industrial prices are not as readily comparable, although on-system sale prices would generally be expected to be higher than an estimate of the average price to all industrial customers. With the exception of the *AEO2001* high economic growth case, margins to the industrial sector are expected to decline through 2015 in all the forecasts. The *AEO2001* and NPC forecasts project declines of less than 10 percent in the industrial margin from 1998 to 2015, whereas the projected decline in the GRI and AGA forecasts is over 20 percent.

Table 26. Comparison of natural gas forecasts (trillion cubic feet, except where noted)

Projection	AEO2001			Other forecasts				
	Reference	Low economic growth	High economic growth	WEFA	GRI[a]	DRI	AGA	NPC
2015								
Lower 48 wellhead price (1999 dollars per thousand cubic feet)	**2.83**	**2.59**	**3.20**	**2.64**	**1.89**	**2.79**	**2.56**	**3.67**
Dry gas production[b]	**26.24**	**24.63**	**27.86**	**24.43**	**28.58**	**24.00**	**26.71**	**26.50**
Net imports	**5.50**	**5.35**	**5.62**	**5.35**	**4.01**	**5.70**	**4.15**	**4.70**
Consumption	**31.61**	**29.85**	**33.36**	**30.13**	**32.78**	**29.46**	**30.86**	**31.84**
Residential	5.83	5.70	5.90	5.67	5.67	5.57	5.93	6.07
Commercial[c]	3.94	3.79	4.07	3.93[d]	4.14	3.46[d]	3.95	4.09
Industrial[c]	9.76	9.18	10.50	6.33[d]	10.98	8.43[e]	10.72	10.76
Electricity generators[f]	9.30	8.54	9.97	11.63[c]	8.72	9.25[g]	7.06	7.76
Other[h]	2.78	2.63	2.92	2.57	3.27	2.75	3.20	3.16[i]
End-use prices (1999 dollars per thousand cubic feet)								
Residential	6.61	6.37	6.95	7.36	5.51	7.02	6.31[j]	7.65
Commercial[c]	5.65	5.41	6.00	6.16[d]	4.62	6.03	5.07[j]	6.76
Industrial[c]	3.54	3.29	3.91	3.70[d,k]	2.91[k]	3.98[k]	3.09[j,l]	4.86[k]
Electricity generators[f]	3.30	3.05	3.67	3.12[c]	2.55	3.24	2.99[j]	4.21
2020								
Lower 48 wellhead price (1999 dollars per thousand cubic feet)	**3.13**	**2.66**	**3.68**	**2.72**	**NA**	**3.07**	**NA**	**NA**
Dry gas production[b]	**29.04**	**26.74**	**30.38**	**25.72**	**NA**	**25.13**	**NA**	**NA**
Net imports	**5.80**	**5.58**	**5.82**	**5.72**	**NA**	**6.00**	**NA**	**NA**
Consumption	**34.73**	**32.22**	**36.09**	**31.82**	**NA**	**28.58**	**NA**	**NA**
Residential	6.14	5.95	6.21	5.88	NA	5.84	NA	NA
Commercial[c]	4.02	3.83	4.19	4.05[d]	NA	3.43[d]	NA	NA
Industrial[c]	10.18	9.36	11.20	6.45[d]	NA	8.82[e]	NA	NA
Electricity generators[f]	11.34	10.23	11.29	12.72[c]	NA	9.89[g]	NA	NA
Other[h]	3.06	2.85	3.20	2.71	NA	2.88	NA	NA
End-use prices (1999 dollars per thousand cubic feet)								
Residential	6.73	6.32	7.24	7.44	NA	7.25	NA	NA
Commercial[c]	5.86	5.42	6.38	6.25[d]	NA	6.26	NA	NA
Industrial[c]	3.86	3.38	4.43	3.78[d,k]	NA	4.25[k]	NA	NA
Electricity generators[f]	3.66	3.17	4.17	3.20[c]	NA	3.52	NA	NA

[a]The baseline projection includes a cyclical price trend based on exploration and production cycles; therefore, forecast values for an isolated year may be misleading.
[b]Does not include supplemental fuels.
[c]Includes gas consumed in cogeneration.
[d]Excludes gas used for cogenerators and other nonutility generation.
[e]Excludes cogenerators' energy attributed to generating electricity
[f]Includes independent power producers and excludes cogenerators.
[g]Includes portion of cogeneration attributed to electricity generation
[h]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.
[i]Includes balancing item.
[j]Does not include certain State and local taxes levied on customers.
[k]On system sales or system gas (i.e., does not include gas delivered for the account of others).
[l]Volume-weighted average of "system" gas and "transportation" gas.
NA = Not available.

Note: Assumed conversion factors: electricity generators, 1,022 Btu per cubic foot; other end-use sectors, 1,029 Btu per cubic foot; net imports, 1,022 Btu per cubic foot; production and other consumption, 1,028 Btu per cubic foot.

Sources: ***AEO2001*:** AEO2001 National Energy Modeling System, runs AEO2001.D101600A (reference case), LM2001.D101600A (low economic growth case), and HM2001.D101600A (high economic growth case). **WEFA:** The WEFA Group, *Natural Gas Outlook* (2000). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 2000 Edition (January 2000). **DRI:** Standard & Poor's DRI, *U.S. Energy Outlook* (Spring/Summer 2000). **AGA:** American Gas Association, *1999 AGA-TERA Base Case* (December 1999). **NPC:** National Petroleum Council, *Natural Gas, Meeting the Challenges of the Nation's Growing Natural Gas Demand* (December 1999).

Petroleum

Projected prices for crude oil in the *AEO2001* low and high oil price cases (Table 27) bound the 2010 and 2020 projections in five other petroleum forecasts: the *AEO2001* reference case, WEFA, GRI, DRI, and the Independent Petroleum Association of America (IPAA). Comparisons with GRI and IPAA forecasts, which do not extend to 2020, apply only to 2010. *AEO2001* shows the highest reference case price path of the five forecasts. The *AEO2001* reference case projection for the world oil price in 2010 is $2.89 per barrel above the WEFA projection, $3.20 above GRI, and $2.72 above DRI. In 2020, however, the *AEO2001* reference case projection is only $2.00 per barrel above the WEFA projection and $1.25 above the DRI projection.

Crude oil price forecasts are influenced by differing views of the projected composition of world oil production, such as the expansion of OPEC oil production and the timing of an expected recovery in East Europe/former Soviet Union oil production. Differences may also arise on the basis of different views of the strength of the U.S. economy and the timing and strength of economic recovery in southeast Asia.

All the forecasts except GRI project a significant decline in domestic oil production between 2000 and 2010, reflecting assumed declines in proved reserves. GRI projects a milder decline before 2005, followed by an upturn in production between 2005 and 2015. Both WEFA and DRI continue their downward production projections to 2020, at slower rates. *AEO2001* projects a sharper decline before 2010 than do the other four projections, resulting in a 2010 reference case projection for crude oil production that is at least 280,000 barrels per day below the other reference case forecasts.

The *AEO2001* reference case projects relatively little change in annual domestic oil production between 2010 and 2020, whereas the high world oil price case projects a slight recovery after 2010, leading to more production in 2020 than in 2010. As a result, projected production in 2020 in the *AEO2001* high oil price case is above the WEFA and DRI projections, whereas the *AEO2001* reference case projection is essentially the same as the WEFA projection. The *AEO2001* projections for production of natural gas liquids are within the range of the other forecasts. GRI projects the highest level of natural gas liquids production in 2010 at 2.69 million barrels per day and IPAA the lowest at 2.03 million barrels per day.

The three *AEO2001* cases, along with DRI and IPAA, project relatively high levels of petroleum consumption, mostly as a result of higher projections for gasoline consumption. WEFA and GRI project the lowest petroleum consumption in 2010 at around 21.5 million barrels per day. DRI projects the highest consumption in 2010, followed by IPAA, the *AEO2001* low oil price case, and the *AEO2001* reference case. DRI has the highest 2020 consumption projection, followed closely by the *AEO2001* low oil price case. The WEFA consumption projection is significantly lower than all other forecasts for 2020, mainly because WEFA expects lower consumption of transportation fuels. Despite a wide range of oil price assumptions, the three *AEO2001* cases show limited variation in their projections for gasoline consumption. The three *AEO2001* cases show significantly more distillate fuel consumption than do WEFA and DRI, mainly attributable to a higher projected rate of increase in freight travel.

The projections of net petroleum imports in the *AEO2001* low oil price case are well above those in the other forecasts, reflecting low production and high consumption projections. The projected percentage of petroleum consumption from imports, which is an indicator of the relative direction of production, net imports, and consumption, is also highest in the *AEO2001* low oil price case, followed by the DRI forecast. For 2010 the projected import share of consumption ranges from 52 percent (WEFA and IPAA) to 66 percent (*AEO2001* low oil price case). In 2020 all the forecasts show increased reliance on imports, with the highest projection being 70 percent in the *AEO2001* low oil price case. WEFA projects the lowest share of imports in 2020 at 56 percent, because it projects significantly lower petroleum consumption than in the other forecasts. WEFA actually projects lower import shares than were projected in its own forecast last year for both 2010 and 2020 and is the only forecast with lower projected import shares than last year.

Table 27. Comparison of petroleum forecasts (million barrels per day, except where noted)

Projection	AEO2001			Other forecasts			
	Reference	Low world oil price	High world oil price	WEFA	GRI	DRI	IPAA
2010							
World oil price (1999 dollars per barrel)	**21.37**	**15.10**	**26.66**	**18.48**	**18.17**	**18.65**[a]	**NA**
Crude oil and NGL production	**7.50**	**6.85**	**7.93**	**7.55**	**8.50**	**7.71**	**7.52**
Crude oil	5.15	4.51	5.54	5.43	5.81	5.49[b]	5.49
Natural gas liquids	2.35	2.34	2.39	2.12	2.69	2.22	2.03
Total net imports	**13.92**	**15.31**	**12.95**	**11.11**	**NA**	**14.68**	**12.37**
Crude oil	11.54	11.89	11.16	10.23	NA	10.94	NA
Petroleum products	2.38	3.42	1.79	0.88	NA	3.74	NA
Petroleum demand	**22.70**	**23.30**	**22.29**	**21.57**	**21.39**	**23.86**	**23.65**
Motor gasoline	10.11	10.31	10.03	9.10	8.51	10.61	NA
Jet fuel	2.18	2.20	2.16	1.92	2.20	2.37	NA
Distillate fuel	4.47	4.57	4.44	4.09	4.15	4.33	NA
Residual fuel	0.58	0.77	0.55	0.76	1.12	0.91	NA
Other	5.36	5.46	5.11	5.70	5.41	5.64	NA
Import share of product supplied (percent)	**61**	**66**	**58**	**52**	**NA**	**62**	**52**
2020							
World oil price (1999 dollars per barrel)	**22.41**	**15.10**	**28.42**	**20.41**	**NA**	**21.16**[a]	**NA**
Crude oil and NGL production	**7.94**	**7.16**	**8.67**	**7.49**	**NA**	**7.38**	**NA**
Crude oil	5.05	4.35	5.78	5.07	NA	4.95[b]	NA
Natural gas liquids	2.89	2.81	2.89	2.42	NA	2.43	NA
Total net imports	**16.51**	**18.77**	**15.17**	**13.26**	**NA**	**18.17**	**NA**
Crude oil	12.14	13.31	11.45	11.39	NA	11.33	NA
Petroleum products	4.37	5.46	3.72	1.87	NA	6.84	NA
Petroleum demand	**25.83**	**27.00**	**25.28**	**23.81**	**NA**	**27.11**	**NA**
Motor gasoline	11.33	11.67	11.11	9.68	NA	12.05	NA
Jet fuel	2.88	2.91	2.84	2.58	NA	3.16	NA
Distillate fuel	5.10	5.47	5.06	4.45	NA	4.73	NA
Residual fuel	0.60	0.80	0.58	0.84	NA	0.88	NA
Other	5.92	6.15	5.69	6.27	NA	6.29	NA
Import share of product supplied (percent)	**64**	**70**	**60**	**56**	**NA**	**67**	**NA**

[a]Composite of U.S. refiners' acquisition cost.
[b]Includes shale and other.
NA = Not available.
Sources: ***AEO2001*:** AEO2001 National Energy Modeling System, runs AEO2001.D101600A (reference case), LW2001.D101600A (low world oil price case), and HW2001.D101600A (high world oil price case). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (2000). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 2000 Edition (January 2000). **DRI:** Standard & Poor's DRI, *U.S. Energy Outlook* (Spring/Summer 2000). **IPAA:** Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Run Report* (April 2000).

Coal

The coal forecast by DRI is the most similar to the *AEO2001* coal forecasts; however, the coal forecasts by DRI, WEFA and GRI/Hill [*96*] all project lower production and overall consumption than does *AEO2001* (Table 28). The differences stem from differences in assumptions related to expected economic activity and sectoral growth in electricity demand and whether the forecast includes the effects of emissions limits proposed by the U.S. Environmental Protection Agency, which could force the retirement of many older coal plants. *AEO2001* represents the provisions of the State implementation plan (SIP) call for 19 States where NO_x caps were finalized but does not incorporate revised limits on emissions of particulate matter. The DRI forecast projects substantial gains in efficiency for coal-fired generators.

EIA projects growing domestic consumption over the forecast horizon in combination with shrinking real coal prices. DRI expects some expansion of electricity and industrial sector coal consumption followed by declines beginning after 2010. Similarly, GRI/Hill predicts increases in coal consumption until 2013 followed by a decline. WEFA is the most pessimistic about coal consumption in the electricity generation and industrial sectors.

The differences among the forecasts for coal exports are significant. U.S. coal exports declined from 90 million tons in 1996 to 58 million tons in 1999, and net coal exports in 1999 (after adjustment for imports) were 49 million tons. EIA expects net exports to decline to 35 million tons in 2015 and remain approximately at that level through 2020. GRI/Hill projects an even more dramatic decline in net exports to 4 million tons in 2015 and 2 million tons in 2020, reflecting declining coal demands by importing countries and strong competition from other producers such as Australia, South Africa, and Colombia. The projections for a long-term decline in exports are based primarily on the inability of the U.S. mining industry to keep pace with strong price competition by other exporters and the loss of markets as Europe moves away from coal for environmental reasons. Both DRI and WEFA, however, project relative stability in U.S. net coal exports, at 57 million tons in 2015 and 55 million tons in 2020 (DRI) and 51 million tons in 2015 and 52 million tons in 2020 (WEFA).

The *AEO2001* and WEFA price forecasts for national average minemouth coal prices (all shown in 1999 dollars) are fairly close. The GRI/Hill minemouth price projections are somewhat lower than the other forecasts because they exclude exported and metallurgical coal in the calculation. (Exported and metallurgical coal tend to be more expensive.) In dollars per million Btu, WEFA's slightly lower projected prices at $0.62 in 2015 and $0.59 in 2020 indicate a slightly higher average Btu per ton conversion factor, which in turn indicates a higher proportion of bituminous (over subbituminous) coal in the WEFA forecast.

The coal forecasts reviewed provide a broad range of views, reflecting the great uncertainties facing the U.S. coal industry as it must simultaneously adapt to the financial pressures arising from increasing environmental restrictions on coal use (both here and in Europe), deregulation of the U.S. electricity generation industry, and increasing competition from the younger coal fields of international competitors. The uncertainties are, and will continue to be, passed on to U.S. coal producers in the form of demands for higher quality products at ever lower prices.

Table 28. Comparison of coal forecasts (million short tons, except where noted)

Projection	AEO2001			Other forecasts		
	Reference	Low economic growth	High economic growth	WEFA	GRI/Hill	DRI
2015						
Production	**1,294**	**1,259**	**1,352**	**1,078**	**1,123**	**1,210**
Consumption by sector						
Electricity generation[a]	1,149	1,117	1,203	971	1,070	1,057
Coking plants	21	21	21	25	20	22
Industrial/other[a]	90	88	94	34	71	75
Total	**1,261**	**1,226**	**1,318**	**1,030**	**1,162**	**1,154**
Net coal exports	**35**	**35**	**35**	**51**	**4**	**57**
Minemouth price						
(1999 dollars per short ton)	13.38	13.23	13.28	13.39	12.81[c]	NA
(1999 dollars per million Btu)	0.66	0.65	0.65	0.62	0.58[c]	NA
Average delivered price, electricity						
(1999 dollars per short ton)	20.25	19.96	20.65	22.13[b]	22.41	20.73
(1999 dollars per million Btu)	1.01	1.00	1.04	1.08	1.06	0.99
2020						
Production	**1,331**	**1,279**	**1,461**	**1,124**	**1,101**	**1,196**
Consumption by sector						
Electricity generation[a]	1,186	1,138	1,311	1,015	1,050	1,044
Coking plants	19	19	19	24	19	21
Industrial/other[a]	91	88	97	34	61	76
Total	**1,297**	**1,245**	**1,426**	**1,073**	**1,130**	**1,141**
Net coal exports	**36**	**36**	**36**	**52**	**2**	**55**
Minemouth price						
(1999 dollars per short ton)	12.70	12.79	12.80	12.73	12.62[c]	NA
(1999 dollars per million Btu)	0.63	0.63	0.64	0.59	0.57[c]	NA
Average delivered price, electricity						
(1999 dollars per short ton)	19.45	19.11	19.83	21.31[b]	22.01	19.76
(1999 dollars per million Btu)	0.98	0.96	1.01	1.04	1.04	0.94

[a]WEFA includes cogeneration in the electricity generation category, whereas the other forecasts include it under industrial/ other.
[b]Computed using a conversion factor of 20.495 million Btu per short ton from the Technical Appendix.
[c]GRI's minemouth prices represent an average for domestic steam coal only. Exports and coking coal are not included in the average.
NA = Not available.
Btu = British thermal unit.
Sources: ***AEO2001***: AEO2001 National Energy Modeling System, runs AEO2001.D101600A (reference case), LM2001.D101600A (low economic growth case), and HM2001.D101600A (high economic growth case). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (2000). **GRI/Hill:** Gas Research Institute, *Final Report, Coal Outlook and Price Projection*, Vol. I, GRI-00/0019.1, and Vol. II, GRI/0019.2 (April 2000). **DRI:** Standard & Poor's DRI, *U.S. Energy Outlook* (Spring/Summer 2000).

List of Acronyms

AD	Associated-dissolved (natural gas)
AEO	*Annual Energy Outlook*
AGA	American Gas Association
ANWR	Arctic National Wildlife Refuge
BEA	Bureau of Economic Analysis (U.S. Department of Commerce)
BRP	Blue Ribbon Panel
Btu	British thermal unit
CAAA90	Clean Air Act Amendments of 1990
CARB	California Air Resources Board
CBECS	EIA's 1995 Commercial Buildings Energy Consumption Survey
CCAP	Climate Change Action Plan
CCTI	Climate Change Technology Initiative
CDM	Clean Development Mechanism
CO	Carbon monoxide
DBAB	Deutsche Banc Alex. Brown
DOE	U.S. Department of Energy
DRI	Standard & Poor's DRI
E85	Motor fuel containing 85 percent ethanol
EIA	Energy Information Administration
EOR	Enhanced oil recovery
EPACT	Energy Policy Act of 1992
ETBE	Ethyl tertiary butyl ether
EU	European Union
FERC	Federal Energy Regulatory Commission
GDP	Gross domestic product
GRI	Gas Research Institute
HERS	Home energy rating system
ICAP	NEPOOL Installed Capacity market
IEA	International Energy Agency
IPAA	Independent Petroleum Association of America
ISO	Independent system operator
LDC	Local distribution company
LEV	Low-emission vehicle
LEVP	Low-Emission Vehicle Program
LNG	Liquefied natural gas
LPGs	Liquefied petroleum gases
M85	Motor fuel containing 85 percent methanol
MMS	Minerals Management Service
MSATs	Mobile source air toxics
MSW	Municipal solid waste
MTBE	Methyl tertiary butyl ether
NA	Nonassociated (natural gas)
NAAQS	National Ambient Air Quality Standards
NAECA	National Appliance Energy Conservation Act
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Council
NGPA	Natural Gas Policy Act of 1978
NIPA	National Income and Product Accounts
NLEV	National Low Emission Vehicles Program
NO_x	Nitrogen oxides
NPC	National Petroleum Council
NPRM	Notice of Proposed Rulemaking
NRCan	Natural Resources Canada
OBD	On-board diagnostics
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of Petroleum Exporting Countries
OTR	Ozone Transport Rule
PEL	Petroleum Economics Ltd.
PIRA	Petroleum Industry Research Associates, Inc.
ppm	Parts per million
RFG	Reformulated gasoline
RPS	Renewable Portfolio Standard
RTO	Regional transmission organization
SO_2	Sulfur dioxide
SPR	Strategic Petroleum Reserve
SULEV	Super-ultra-low-emission vehicle
SUV	Sport utility vehicle
ULEV	Ultra-low-emission vehicle
USGS	U.S. Geological Survey
VMT	Vehicle-miles traveled
VOCs	Volatile organic compounds
WEFA	The WEFA Group
ZEV	Zero-emission vehicle

Notes and Sources

Text Notes

Legislation and Regulations

[*1*] The tax of 4.3 cents per gallon is in nominal terms.

[*2*] Federal Energy Regulatory Commission, Order 2000, "Regional Transmission Organizations," Docket No. RM99-2-000 (December 20, 1999).

[*3*] Federal Energy Regulatory Commission, Order 2000, "Regional Transmission Organizations," Docket No. RM99-2-000 (December 20, 1999), p. 3.

[*4*] R. Wiser, K. Porter, and M. Bolinger, *Comparing State Portfolio Standards and Systems-Benefits Charges Under Restructuring* (Berkeley, CA: Lawrence Berkeley National Laboratory, August 2000).

[*5*] *Federal Register*, Vol. 65, No. 51 (March 15, 2000), p. 14074.

[*6*] U.S. Environmental Protection Agency, *Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Control Requirements*, 40 CFR Parts 80, 85, and 86 (Washington, DC, February 10, 2000).

[*7*] U.S. Environmental Protection Agency, web site www.epa.gov/oms/regs/hd-hwy/2000frm/f00026.htm.

[*8*] U.S. Environmental Protection Agency, web site www.epa.gov/oms/regs/hd-hwy/2000frm/2004frm.pdf.

[*9*] U.S. Environmental Protection Agency, "Proposed Rules," *Federal Register*, Vol. 65, No. 107, p. 35546 (June 2, 2000).

[*10*] U.S. Environmental Protection Agency, *Proposal for Cleaner Heavy-Duty Trucks and Buses and Cleaner Diesel Fuel: Fact Sheet* (Washington, DC, May 17, 2000).

[*11*] EIA will be conducting a study of the proposed diesel fuel standards at the request of the Committee on Science of the U.S. House of Representatives. The study is expected to be released in spring 2001.

[*12*] Figure quoted by Dr. James R. Katzer, ExxonMobil Research & Engineering Company, at the Hart 2000 World Fuels Conference (Washington, DC, September 21, 2000).

[*13*] "RFG Watch: With No Minimum Oxygen Standard, Ethanol in RFG Widens," *Octane Week* (August 14, 2000).

[*14*] U.S. Environmental Protection Agency, *Regulatory Announcement: Control of Emissions of Hazardous Air Pollutants from Mobile Sources*, EPA-420-F-00-025 (Washington, DC, July 2000).

[*15*] State of California Air Resources Board, *Staff Report: Proposed Regulations for Low Emission Vehicles and Clean Fuels* (Sacramento, CA, August 13, 1990).

[*16*] State of California Air Resources Board, Mobile Source Control Division, *Staff Report: Initial Statement of Reasons, Proposed Amendments to California Exhaust and Evaporative Emissions Standards and Test Procedures for Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicles—"LEV II" and Proposed Amendments to California Motor Vehicle Certification, Assembly-Line and In-Use Test Requirements—"CAP 2000"* (El Monte, CA, September 18, 1998).

Issues in Focus

[*17*] See web site www.bea.doc.gov/bea/dn1.htm for a listing and access to BEA national accounts.

[*18*] J.S. Landefeld and R.P. Parker, "BEA's Chain Indexes, Time Series, and Measures of Long-Term Economic Growth," *Survey of Current Business* (May 1997), pp. 58-68, web site www.bea.doc.gov/bea/an1.htm.

[*19*] The fixed-weighed, or Laspeyres, measure of real GDP specified a single base-period set of prices and then value the output in all periods in those prices. As explained in the May 1997 BEA article, this resulted in significant changes in perceived growth rates when the base year was periodically updated. Chain-weighted, or Fisher, indexes overcome this problem by using weights of adjacent years. The annual changes are "chained" together to form a time series that allows for the effects of changes in relative prices and in the composition of output over time.

[*20*] E.P. Seskin, "Improved Estimates of the National Income and Product Accounts for 1959-98: Results of the Comprehensive Revision," *Survey of Current Business* (December 1999), pp. 15-43, web site www.bea.doc.gov/bea/an1.htm.

[*21*] As part of any comprehensive revision of the NIPA's, BEA will designate a more recent year as a benchmark year to express the real value of the output of the economy. The update presented in the December BEA article changed the base year from 1992 to 1996. However, as explained in the previous note, this revaluation does not affect historical growth rates because of the chain-weighting procedure introduced by BEA (BEA, May 1997).

[*22*] D. Wyss, "Rewriting History," in *The U.S. Economy* (Standard & Poor's DRI, November 1999).

[*23*] D. Wyss, "Growing Faster," in *The U.S. Economy* (Standard & Poor's DRI, April 2000); and A. Hodge, "Productivity and the New Age Economy," *U.S. Macro Special Study* (May 8, 2000). For a summary of the debate about recent productivity trends, see "United States: Adjusting the Lens," *The Economist* (November, 20, 1999), pp. 29-30; "Productivity on Stilts," *The Economist* (June 10, 2000), p. 86; and "Performing Miracles," *The Economist* (June 17, 2000), p. 78. The latter two articles highlight the work of Robert Gordon of Northwestern University (web site http://faculty-web.at.northwestern.edu/economics/gordon/351_text.pdf); Stephen Oliner and Daniel Sichel of the Federal Reserve Board in Washington, DC (web site www.federalreserve.gov/pubs/feds/2000/200020/200020pap.pdf); and Dale Jorgenson of Harvard University and Kevin Stiroh of the Federal Reserve Bank of New York (web site www.economics.harvard.edu/faculty/jorgenson/papers/dj_ks5.pdf).

[*24*] A 21-year period was selected to match the 21-year forecast period (from 1999 to 2020) for *AEO2001*.

[*25*] U.S. Geological Survey, *Worldwide Petroleum Assessment 2000* (Reston, VA, June 2000).

[*26*] Energy Information Administration, Office of Oil and Gas.

[*27*] "Upstream Digging Its Way Back, But Production Hole a Deep One," *Natural Gas Week*, Vol. 16, No. 29 (July 17, 2000), p. 1.

[*28*] U.S. Department of Energy, Office of Fossil Energy, *Natural Gas Imports and Exports, Fourth Quarter Report 1999*, DOE/FE-0414 (Washington, DC, 1999), p. xi.

[*29*] T.A. Stokes and M.R. Rodriguez, "44th Annual Reed Rig Census," *World Oil* (October 1996).

[*30*] "Simmons: Offshore Rig Shortage Looms," *Oil and Gas Journal* (April 27, 1998), p. 24.

[*31*] Adjustments were made to unconventional resources with data from Advanced Resources International and to offshore resources with data from the National Petroleum Council.

[*32*] 3-D seismic technology provides data to create a multidimensional picture of the subsurface by bouncing acoustic or electrical vibrations off subsurface structures, enabling the oil and gas deposits to be better targeted. 4-D seismic technology goes one step further by allowing the scientist to see the flow pattern of hydrocarbon changes in the formation over time.

[*33*] As of November 13, 2000, the Alliance Pipeline was scheduled to open on December 1, 2000.

[*34*] U.S. Environmental Protection Agency, *Achieving Clean Air and Clean Water: The Report of the Blue Ribbon Panel on Oxygenates in Gasoline*, EPA-420-R-99-021 (Washington, DC, September 15, 1999).

[*35*] States that have passed legislation limiting MTBE are Arizona, California, Connecticut, Maine, Minnesota, Nebraska, New York, and South Dakota.

[*36*] At least one bill banning MTBE—S. 2962, as amended—would also put new limits on high-octane aromatics, which would make octane replacement even more difficult for refiners.

[*37*] J. Vaiutrain, "California Refiners Anticipate Broad Effects of Possible State MTBE Ban," *Oil and Gas Journal* (January 18, 1999).

[*38*] S. Shaffer, "Ethanol Sulfur: Not a Serious Concern", *Oxy-Fuel News* (June 5, 2000).

[*39*] Downstream Alternatives, Inc., *The Use of Ethanol in California Clean Burning Gasoline: Ethanol Supply and Demand* (Bremen, IN, February 5, 1999).

[*40*] Remote applications are not addressed in this analysis.

[*41*] This includes a generic representation of microturbines, frame type combustion turbines operating on natural gas, and three types of reciprocating engines. The cost of the generic technology is the sum of an assumed share of each of the technologies mentioned above multiplied by its respective costs. The lowest costs are for the diesel cycle/compression ignition engines operated with natural gas. This technology represents 40 percent of the generic technology for peaking distributed generators.

[*42*] The technologies in the generic include heavy-duty microturbines, combustion turbines, compression ignition engines, and fuel cells. The cost of the base-load generic is calculated in the same fashion as is done for the peaking generic. Combustion turbines and engines make up about one-half of the generic for baseload distributed generators.

[*43*] For further information on DOE's Million Solar Roofs program see the program web site at www.eren.doe.gov/millionroofs/background.html. For the Department of Defense fuel cell demonstration program see http://energy.nfesc.navy.mil/enews/96b/fuelcell.htm.

[*44*] For photovoltaic and fuel cell technologies, a doubling of cumulative shipments yields an assumed 13 percent reduction in installed capital costs. For microturbines, a doubling results in an assumed 7 percent reduction in costs.

[*45*] For a more detailed discussion of modeling distributed generation and several sensitivity cases see E. Boedecker, J. Cymbalsky, and S. Wade, "Modeling Distributed Electricity Generation in the NEMS Buildings Models," Energy Information Administration, web site www.eia.doe.gov/oiaf/analysispaper/electricity_generation.html.

[*46*] ONSITE SYCOM Energy Corporation, *The Market and Technical Potential for Combined Heat and Power in the Industrial Sector* (January 2000), p. 17.

[*47*] Arkansas, Arizona, California, Illinois, Maine, Maryland, Nevada, New Hampshire, New York, and Pennsylvania allow some form of competitive metering and/or billing services. Delaware, Massachusetts, Michigan, Montana , New Jersey, Ohio, Oregon, Rhode Island, Virginia, and West Virginia are studying or have not made final determinations on whether or not to allow competitive metering and/or billing services. Louisiana is considering allowing these services to be competitive as part of a restructuring package.

[*48*] Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, Virginia, and West Virginia have legislation mandating competition of electricity supply. New York passed a comprehensive regulatory order mandating electric restructuring which is considered legally binding.

[*49*] R.T. Eynon, T.J. Leckey, and D.R. Hale, "The Electric Transmission Network: A Multi-Region Analysis," Energy Information Administration, web site www.eia.doe.gov/oiaf/analysispaper/transmiss.html.

[*50*] U.S. Department of Energy, *Report of the U.S. Department of Energy's Power Outage Study Team: Findings and Recommendations to Enhance Reliability From the Summer of 1999*, Final Report, March 2000, web site www.policy.energy.gov/electricity/postfinal.pdf.

[*51*] Office of the Chief Accountant, Office of Economic Policy, Office of Electric Power Regulation, Office of the General Counsel, *Staff Report to the Federal Energy Regulatory Commission on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998* (Washington, DC, September 22, 1998), pp. 4-15 to 4-17, web site www.ferc.fed.us/electric/mastback.pdf. Immediately after the June 1998 Midwest price spikes, wholesale market participants told the staff investigating team that they were actively reviewing the creditworthiness of their counterparts and asking for increased assurances of performance in

appropriate cases. The team also found some evidence that power purchasers had, immediately after the June price spikes, begun to change their short-term buying strategy to anticipate large price swings without disrupting service to native load retail customers.

[*52*] *Power Markets Week* (September 6, 1999).

[*53*] "ISO New England Files to Eliminate ICAP Market in June," ISO New England Press Advisory (May 8, 2000), web site www.iso-ne.com/iso_news/newsnews.html; M. Kahn and L. Lynch, *California's Electricity Options and Challenges: Report to Governor Gray Davis* (August 2, 2000).

[*54*] Gaming the system is when traders or generators use their knowledge of market procedures and regulations to buy up or withhold large amounts of power, bid up the price, then dump the power in the spot market at a much higher rate.

[*55*] "ISO New England Files to Eliminate ICAP Market in June," ISO New England Press Advisory (May 8, 2000), web site www.iso-ne.com/iso_news/newsnews.html.

[*56*] M. Kahn and L. Lynch, *California's Electricity Options and Challenges: Report to Governor Gray Davis* (August 2, 2000).

[*57*] "Governor Davis Presses FERC for Action on Wholesale Power Rates: Calls on Federal Regulators To Reduce Prices, Issue Refunds," Office of the Governor press release (September 12, 2000).

[*58*] A. de Rouffignac, "Supply vs. Demand: The Gas Industry's Catch-22," *Financial Times Energy* (September 14, 2000). Can be accessed by registering with Energy Insight Today at web site www.einsight.com.

[*59*] Based on the most recently completed survey of electricity sales data from the 1998 Form EIA-861, "Annual Electric Utility Report."

[*60*] Some of the regulations mandating price freezes and reductions have a fuel clause allowing prices to increase or further decrease within a certain range with a substantial increase or decrease in fuel costs.

[*61*] **Buildings:** Energy Information Administration (EIA), *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Arthur D. Little, Inc., September 1998). **Industrial:** EIA, *Aggressive Technology Strategy for the NEMS Model* (Arthur D. Little, Inc., September 1998). **Transportation:** 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* (November 1998); 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); and 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). **Fossil-fired generating technologies:** U.S. Department of Energy, Office of Fossil Energy. **Renewable Generating Technologies:** 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).

[*62*] President William J. Clinton and Vice President Albert Gore, Jr., *The Climate Change Action Plan* (Washington, DC, October 1993).

[*63*] Carbon dioxide is absorbed by growing vegetation and soils. Defining the total impacts of CCAP as net reductions accounts for the increased sequestration of carbon dioxide as a result of the forestry and land-use actions in the program.

[*64*] Australia, Austria, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, Estonia, European Community, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, United Kingdom of Great Britain and Northern Ireland, and United States of America. Turkey and Belarus are Annex I nations that have not ratified the Framework Convention and did not commit to quantifiable emissions targets.

[*65*] Antigua and Barbuda, Azerbaijan, Bahamas, Barbados, Bolivia, Cyprus, Ecuador, El Salvador, Equatorial Guinea, Fiji, Georgia, Guatemala, Guinea, Honduras, Jamaica, Kiribati, Lesotho, the Maldives, Mexico, Micronesia, Mongolia, Nicaragua, Niue, Palau, Panama, Paraguay, Trinidad and Tobago, Turkmenistan, Tuvalu, and Uzbekistan.

[*66*] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1999*, DOE/EIA-0573(99) (Washington, DC, October 2000), web site www.eia.doe.gov/oiaf/1605/ggrpt/.

[*67*] Hydrofluorocarbons are a non-ozone-depleting substitute for CFCs; perfluorocarbons are byproducts of aluminum production and are also used in semiconductor manufacturing; and sulfur hexafluoride is used as an insulator in electrical equipment and in semiconductor manufacturing.

[*68*] Web site www.state.gov/www/global/global_issues/climate/fs-9911_bonn_climate_conf.html.

[*69*] Web site www.state.gov/www/global/global_issues/climate/fs-000801_unfccc1_subm.html.

[*70*] Web site http://cop6.unfccc.int/media/press.html.

[*71*] Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998), web site www.eia.doe.gov/oiaf/kyoto/kyotorpt.html.

[*72*] Energy Information Administration, *What Does the Kyoto Protocol Mean to U.S. Energy Markets and the U.S. Economy?*, SR/OIAF/98-03(S) (Washington, DC, October 1998), web site www.eia.doe.gov/oiaf/kyoto/kyotobrf.html.

[*73*] Energy Information Administration, *Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol*, SR/OIAF/99-02 (Washington, DC, July 1999), web site www.eia.doe.gov/oiaf/kyoto3/kyoto3rpt.html.

[*74*] Energy Information Administration (EIA), *Analysis of the Climate Change Technology Initiative*, SR/OIAF/99-01 (Washington, DC, April 1999), web site www.eia.doe.gov/oiaf/climate99/climaterpt.html, and EIA, *Analysis of the Climate Change Technology Initiative: Fiscal Year 2001*, SR/OIAF/2000-01 (Washington, DC, April 2000), web site www.eia.doe.gov/oiaf/climate/index.html.

Market Trends

[*75*] Standard & Poor's DRI, Simulation T250200 (February 2000).

[*76*] I. Ismail, "Future Growth in OPEC Oil Production Capacity and the Impact of Environmental Measures," presented to the Sixth Meeting of the International Energy Workshop (Vienna, Austria, June 1993).

[*77*] The transportation sector has been left out of these calculations because levels of transportation sector electricity use have historically been far less than 1 percent of delivered electricity. In the transportation sector, the difference between total and delivered energy consumption is also less than 1 percent.

[*78*] The high and low macroeconomic growth cases are linked to higher and lower population growth, respectively, which affects energy use in all sectors.

[*79*] The definition of the commercial sector for *AEO2001* is based on data from the 1995 Commercial Buildings Energy Consumption Survey (CBECS). See Energy Information Administration, 1995 CBECS Micro-Data Files (February 17, 1998), web site www.eia.doe.gov/emeu/cbecs/. Nonsampling and sampling errors (found in any statistical sample survey) and a change in the target building population resulted in a lower commercial floorspace estimate than found with the previous CBECS. In addition, 1995 CBECS energy intensities for specific end uses varied from earlier estimates, providing a different composition of end-use consumption. These factors contribute to the pattern of commercial energy use projected for *AEO2001*. Further discussion is provided in Appendix G.

[*80*] The intensities shown were disaggregated using the divisia index. The divisia index is a weighted sum of growth rates and is separated into a sectoral shift or "output" effect and an energy efficiency or "substitution" effect. It has at least two properties that make it superior to other indexes. First, it is not sensitive to where in the time period or in which direction the index is computed. Second, when the effects are separated, the individual components have the same magnitude, regardless of which is calculated first. See Energy Information Administration, "Structural Shift and Aggregate Energy Efficiency in Manufacturing" (unpublished working paper in support of the National Energy Strategy, May 1990); and Boyd et al., "Separating the Changing Effects of U.S. Manufacturing Production from Energy Efficiency Improvements," *Energy Journal*, Vol. 8, No. 2 (1987).

[*81*] Estimated as consumption of alternative transportation fuels in crude oil Btu equivalence.

[*82*] Small light trucks (compact pickup trucks and compact vans) are used primarily as passenger vehicles, whereas medium light trucks (compact utility trucks and standard vans) and large light trucks (standard utility trucks and standard pickup trucks) are used more heavily for commercial purposes.

[*83*] 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* (November 1998); 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); and F. Stodolsky, A. Vyas, and R. Cuenca, *Heavy-Duty and Medium-Duty Truck Fuel Economy and Market Penetration Analysis*, Draft Report (Chicago, IL: Argonne National Laboratory, August 1999).

[*84*] Values for incremental investments and energy expenditure savings are discounted back to 2000 at a 7-percent real discount rate.

[*85*] Unless otherwise noted, the term "capacity" in the discussion of electricity generation indicates utility, nonutility, and cogenerator capacity.

[*86*] D. Stellfox, "Colvin Tells UI That U.S. Utility May Order New Unit Before 2006," *Nucleonics Week*, Vol. 41, No. 36 (September 7, 2000).

[*87*] For example, according to the latest USGS estimates, the size of the Nation's technically recoverable undiscovered conventional crude oil resources (in onshore areas and State waters) is most likely to be 30.3 billion barrels—with a 19 in 20 chance of being at least 23.5 billion barrels and a 1 in 20 chance of being at least 39.6 billion barrels. The corresponding USGS estimate for the Nation's natural gas resources is 258.7 trillion cubic feet—with a 19 in 20 chance of being at least 207.1 trillion cubic feet and a 1 in 20 chance of being at least 329.1 trillion cubic feet. *AEO2001* does not examine the implications of geological resource uncertainty. The figures cited above are taken from U.S. Geological Survey, National Oil and Gas Resource Assessment Team, *1995 National Assessment of United States Oil and Gas Resources*, U.S. Geological Survey Circular 1118 (Washington, DC, 1995), p. 2. The cited numbers exclude natural gas liquids resources, for which the corresponding USGS estimates are 7.2, 5.8, and 8.9 billion barrels.

[*88*] Currently, all production in Alaska is either consumed in the State, reinjected, or exported to Japan as liquefied natural gas (LNG). Projected Alaskan natural gas production does not include gas from the North Slope, which primarily is being reinjected to support oil production. In the future, North Slope gas may be transported to the lower 48 market through a pipeline, converted into LNG and marketed to the Pacific Rim, and/or converted into synthetic petroleum products and marketed to California.

[*89*] Greater technological advances can markedly increase the quantity of economically recoverable resources by driving down costs, increasing success rates, and increasing recovery from producing wells. Expected production rate declines could be slowed or

even reversed within the forecast period if faster implementation of advanced technologies is realized.

[*90*] Enhanced oil recovery (EOR) is the extraction of the oil that can be economically produced from a petroleum reservoir greater than that which can be economically recovered by conventional primary and secondary methods. EOR methods usually involve injecting heated fluids, pressurized gases, or special chemicals into an oil reservoir in order to produce additional oil.

[*91*] Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000).

[*92*] Total labor costs are estimated by multiplying the average hourly earnings of coal mine production workers by total annual labor hours worked. Average hourly earnings do not represent total labor costs per hour for the employer, because they exclude retroactive payments and irregular bonuses, employee benefits, and the employer's share of payroll taxes. Labor hours of office workers are excluded from the calculation.

[*93*] Variations in mining costs are not necessarily limited to changes in labor productivity and wage rates. Other factors that affect mining costs and, subsequently, the price of coal include such items as severance taxes, royalties, fuel costs, and the costs of parts and supplies.

[*94*] U.S. Environmental Protection Agency, web site www.epa.gov/acidrain/overview.html (September 1997).

Forecast Comparisons

[*95*] In April 2000, the Gas Research Institute and the Institute of Gas Technology combined to form the Gas Technology Institute.

[*96*] The source used is a forecast prepared for GRI by Hill & Associates, Inc., containing coal projection detail that is comparable with the other forecasts reviewed.

Table Notes

Note: Tables indicated as sources in these notes refer to the tables in Appendixes A, B, and C of this report.

Table 1. Summary of results for five cases: Tables A1, A19, A20, B1, B19, B20, C1, C19, and C20.

Table 2. Summer season NO_x emissions budgets for 2003 and beyond: U.S. Environmental Protection Agency, *Federal Register*, Vol. 65, No. 207 (October 27, 1998).

Table 3. Effective dates of appliance efficiency standards, 1988-2005: U.S. Department of Energy, Office of Codes and Standards; and Electric Power Research Institute, "Energy Conservation Standards for Consumer Products."

Table 4. Historical revisions to growth rates of GDP and its major components, 1959-1998: E.P. Seskin, "Improved Estimates of the National Income and Product Accounts for 1959-98: Results of the Comprehensive Revision," *Survey of Current Business* (December 1999), pp. 15-43, web site www.bea.doc.gov/bea/an1.htm.

Table 5. Revisions to nominal GDP, 1959-1998: E.P. Seskin, "Improved Estimates of the National Income and Product Accounts for 1959-98: Results of the Comprehensive Revision," *Survey of Current Business* (December 1999), pp. 15-43, web site www.bea.doc.gov/bea/an1.htm.

Table 6. Revisions to nominal GDP for 1998: E.P. Seskin, "Improved Estimates of the National Income and Product Accounts for 1959-98: Results of the Comprehensive Revision," *Survey of Current Business* (December 1999), pp. 15-43, web site www.bea.doc.gov/bea/an1.htm.

Table 7. Historical growth in GDP, the labor force, productivity and energy intensity: Real GDP: Data from BEA web site www.bea.doc.gov/bea/dn1.htm. **Labor force:** Data from BLS web site stats.bls.gov/datahome.htm. **Productivity:** Calculated as real GDP growth minus labor force growth. **Energy intensity:** Calculated with energy data from Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000).

Table 8. Forecast comparison of key macroeconomic variables: National Energy Modeling System, runs AEO2K.D100199A and AEO2001.D101600A.

Table 9. Cost and performance of generic distributed generators: Distributed Utility Associates, *Assessing Market Acceptance and Penetration for Distributed Generation in the United States*, June 7, 1999.

Table 10. Projected installed costs and electrical conversion efficiencies for distributed generation technologies by year of introduction and technology, 2000-2020: 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); and ONSITE SYCOM Energy Corporation, *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector* (Washington, DC, January 2000).

Table 11. Costs of industrial cogeneration systems, 1999 and 2020: ONSITE SYCOM Energy Corporation, *The Market and Technical Potential for Combined Heat and Power in the Industrial Sector* (Washington, DC, January 2000).

Table 12. New car and light truck horsepower ratings and market shares, 1990-2020: History: U.S. Department of Transportation, National Highway Traffic Safety Administration. **Projections:** AEO2001 National Energy Modeling System, run AEO2001.D101600A.

Table 13. Costs of producing electricity from new plants, 2005 and 2020: AEO2001 National Energy Modeling System, run AEO2001.D101600A.

Table 14. Technically recoverable U.S. oil and gas resources as of January 1, 1999: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 15. Natural gas and crude oil drilling in three cases, 1999-2020: AEO2001 National Energy Modeling System, runs AEO2001.D101600A, LW2001. D101600A, and HW2001.D101600A.

Table 16. Transmission and distribution revenues and margins, 1970-2020: History: Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-

0384(99) (Washington, DC, July 2000). **Projections:** AEO2001 National Energy Modeling System, run AEO2001.D101600A. End-use consumption is net of pipeline and lease and plant fuels.

Table 17. Components of residential and commercial natural gas end-use prices, 1985-2020: History: Energy Information Administration, *Annual Energy Review 1987*, DOE/EIA-0384(87) (Washington, DC, July 1988). **1999 and projections:** AEO2001 National Energy Modeling System, run AEO2001.D101600A. **Note:** End-use prices may not equal the sum of citygate prices and LDC margins due to independent rounding.

Table 18. Petroleum consumption and net imports in five cases, 1999 and 2020: 1999: Energy Information Administration, *Petroleum Supply Annual 1999*, Vol. 1, DOE/EIA-0340(99)/1 (Washington, DC, June 2000). **Projections:** Tables A11, B11, and C11.

Table 19. Forecasts of economic growth, 1999-2020: AEO2001: Table B20. **DRI:** Standard and Poor's DRI, *The U.S. Economy 25-Year Outlook*, Winter 2000. **WEFA:** The WEFA Group, *U.S. Long Term Economic Outlook*, Second Quarter 2000.

Table 20. Forecasts of world oil prices, 2000-2020: AEO2001: Tables A1 and C1. **DRI:** Standard and Poor's DRI, *U.S. Energy Outlook* (Spring/Summer 2000). **IEA:** International Energy Agency, *World Energy Outlook 1998*. **PEL:** Petroleum Economics, Ltd., *Oil and Energy Outlook to 2015* (February 2000). **PIRA:** PIRA Energy Group, "Retainer Client Seminar" (October 2000). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (2000). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 2000 Edition (January 2000). **NRCan:** Natural Resources Canada, *Canada's Energy Outlook 1996-2020* (April 1997). **DBAB:** Deutsche Banc Alex. Brown, World Oil Supply and Demand Estimates (June 2000).

Table 21. Forecasts of average annual growth rates for energy consumption: History: Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA--0384(99) (Washington, DC, July 2000). **AEO2001:** Table A2. **DRI:** Standard & Poor's DRI, *U.S. Energy Outlook* (Spring/Summer 2000). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 2000 Edition (January 2000). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (2000). **Note:** Delivered energy includes petroleum, natural gas, coal, and electricity (excluding generation and transmission losses) consumed in the residential, commercial, industrial, and transportation sectors.

Table 22. Forecasts of average annual growth in residential and commercial energy demand: History: Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **AEO2001:** Table A2. **DRI:** Standard & Poor's DRI, *U.S. Energy Outlook* (Spring/Summer 2000). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 2000 Edition (January 2000). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (2000).

Table 23. Forecasts of average annual growth in industrial energy demand: History: Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **AEO2001:** Table A2. **DRI:** Standard & Poor's DRI, *U.S. Energy Outlook* (Spring/Summer 2000). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 2000 Edition (January 2000). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (2000).

Table 24. Forecasts of average annual growth in transportation energy demand: History: Energy Information Administration (EIA), *State Energy Data Report 1997*, DOE/EIA-0214(97) (Washington, DC, September 1999); EIA, *State Energy Price and Expenditures Report 1997*, DOE/EIA-0376(97) (Washington, DC, July 2000); Federal Highway Administration, *Highway Statistics*, various issues, Table VM-1; U.S. Department of Energy, Oak Ridge National Laboratory, *Transportation Energy Data Book #19*, ORNL-6958 (Oak Ridge, TN, September 1999); and National Highway Transportation Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000). **AEO2001:** Table A2. **DRI:** Standard & Poor's DRI, *U.S. Energy Outlook* (Spring/Summer 2000). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 2000 Edition (January 2000). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (2000).

Table 25. Comparison of electricity forecasts: AEO2001: AEO2001 National Energy Modeling System, runs AEO2001.D101600A, LM2001.D101600A, and HM2001.D101600A. **WEFA:** The WEFA Group, *U.S. Energy Outlook* (2000). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 2000 Edition (January 2000). **DRI:** Standard & Poor's DRI, *U.S. Energy Outlook* (Spring/Summer 2000).

Table 26. Comparison of natural gas forecasts: AEO2001: AEO2001 National Energy Modeling System, runs AEO2001.D101600A, LM2001.D101600A, and HM2001.D101600A. **WEFA:** The WEFA Group, *Natural Gas Outlook* (2000). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 2000 Edition (January 2000). **DRI:** Standard & Poor's DRI, *U.S. Energy Outlook* (Spring/Summer 2000). **AGA:** American Gas Association, *1999 AGA-TERA Base Case* (December 1999). **NPC:** National Petroleum Council, *Meeting the Challenges of the Nation's Growing Natural Gas Demand* (December 1999).

Table 27. Comparison of petroleum forecasts: AEO2001: AEO2001 National Energy Modeling System, runs AEO2001.D101600A, LW2001.D101600A, and HW2001.D101600A. **WEFA:** The WEFA Group, *U.S. Energy Outlook* (2000). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 2000 Edition (January 2000). **DRI:** Standard & Poor's DRI, *U.S. Energy Outlook* (Spring/Summer 2000). **IPAA:** Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Run Report* (April 2000).

Table 28. Comparison of coal forecasts: AEO2001: AEO2001 National Energy Modeling System, runs AEO2001.D101600A, LM2001.D101600A, and HM2001.D101600A. **WEFA**: The WEFA Group, *U.S. Energy Outlook* (2000). **GRI/Hill**: Gas Research Institute, Final Report, *Coal Outlook and Price Projection*, Vol. I, GRI-00/0019.1, and Vol. II, GRI/0019.2 (April 2000). **DRI:** Standard & Poor's DRI, *U.S. Energy Outlook* (Spring/Summer 2000).

Figure Notes

Note: Tables indicated as sources in these notes refer to the tables in Appendixes A, B, C, and F of this report.

Figure 1. Fuel price projections, 1999-2020: *AEO2000* and *AEO2001* compared: *AEO2000* projections: Energy Information Administration, *Annual Energy Outlook 2000*, DOE/EIA-0383(2000) (Washington, DC, December 1999). ***AEO2001* projections:** Table A1.

Figure 2. Energy consumption by fuel, 1970-2020: History: Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** Tables A1 and A18.

Figure 3. Energy use per capita and per dollar of gross domestic product, 1970-2020: History: Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** Table A20.

Figure 4. Electricity generation by fuel, 1970-2020: History: Energy Information Administration (EIA), Form EIA-860B, "Annual Electric Generator Report - Nonutility;" EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000); and Edison Electric Institute. **Projections:** Table A8.

Figure 5. Energy production by fuel, 1970-2020: History: Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** Tables A1 and A18.

Figure 6. Net energy imports by fuel, 1970-2020: History: Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** Table A1.

Figure 7. Projected U.S. carbon dioxide emissions by sector and fuel, 1990-2020: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1999*, DOE/EIA-0573(99) (Washington, DC, October 2000). **Projections:** Table A19.

Figure 8. Index of energy use per dollar of gross domestic product, 1960-1998: Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, July 2000) and U.S. Department of Commerce, Bureau of Economic Analysis.

Figure 9. Annual growth in real gross domestic product: 21-year moving average, 1980-2020: History: U.S. Department of Commerce, Bureau of Economic Analysis. **Projections:** AEO2001 National Energy Modeling System, run AEO2001.D101600A.

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Appendixes

Reference Case Forecast

Table A1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Production							
Crude Oil and Lease Condensate	13.19	12.45	11.96	10.90	10.76	10.69	-0.7%
Natural Gas Plant Liquids	2.49	2.62	3.03	3.33	3.73	4.10	2.2%
Dry Natural Gas	19.19	19.16	21.35	23.74	26.92	29.79	2.1%
Coal	23.76	23.09	25.21	26.06	26.42	26.95	0.7%
Nuclear Power	7.19	7.79	7.90	7.69	6.82	6.13	-1.1%
Renewable Energy[1]	6.62	6.58	7.13	7.82	8.12	8.31	1.1%
Other[2]	0.65	1.65	0.57	0.30	0.32	0.34	-7.3%
Total	**73.10**	**73.35**	**77.16**	**79.85**	**83.10**	**86.30**	**0.8%**
Imports							
Crude Oil[3]	18.90	18.96	23.13	25.15	25.94	26.44	1.6%
Petroleum Products[4]	3.99	4.14	4.81	6.49	8.46	10.69	4.6%
Natural Gas	3.22	3.63	4.91	5.61	6.17	6.58	2.9%
Other Imports[5]	0.58	0.62	1.06	0.89	0.88	0.94	2.0%
Total	**26.69**	**27.35**	**33.91**	**38.14**	**41.44**	**44.64**	**2.4%**
Exports							
Petroleum[6]	1.94	1.98	1.81	1.78	1.83	1.91	-0.2%
Natural Gas	0.16	0.17	0.33	0.43	0.53	0.63	6.5%
Coal	1.99	1.48	1.51	1.46	1.35	1.41	-0.2%
Total	**4.09**	**3.62**	**3.64**	**3.67**	**3.72**	**3.95**	**0.4%**
Discrepancy[7]	**0.86**	**0.94**	**0.39**	**0.18**	**0.07**	**-0.04**	**N/A**
Consumption							
Petroleum Products[8]	37.16	38.03	41.41	44.41	47.50	50.59	1.4%
Natural Gas	21.96	21.95	25.88	28.75	32.39	35.57	2.3%
Coal	21.61	21.43	24.15	25.15	25.68	26.20	1.0%
Nuclear Power	7.19	7.79	7.90	7.69	6.82	6.13	-1.1%
Renewable Energy[1]	6.63	6.59	7.14	7.83	8.13	8.31	1.1%
Other[9]	0.29	0.34	0.55	0.31	0.23	0.23	-1.9%
Total	**94.84**	**96.14**	**107.03**	**114.14**	**120.75**	**127.03**	**1.3%**
Net Imports - Petroleum	**20.95**	**21.12**	**26.13**	**29.86**	**32.57**	**35.22**	**2.5%**
Prices (1999 dollars per unit)							
World Oil Price (dollars per barrel)[10]	12.02	17.35	20.83	21.37	21.89	22.41	1.2%
Gas Wellhead Price (dollars per Mcf)[11]	2.02	2.08	2.49	2.69	2.83	3.13	2.0%
Coal Minemouth Price (dollars per ton)	18.02	16.98	14.68	13.83	13.38	12.70	-1.4%
Average Electric Price (cents per kilowatthour)	6.8	6.7	6.2	5.9	5.9	6.0	-0.5%

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Mcf = Thousand cubic feet.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1998 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1998*, DOE/EIA-0131(98) (Washington, DC, October 1999). 1998 coal minemouth prices: EIA, *Coal Industry Annual 1998*, DOE/EIA-0584(98) (Washington, DC, June 2000). Other 1998 values: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). 1999 natural gas values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 petroleum values: EIA, *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). Other 1999 values: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000). **Projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case 1998	1999	2005	2010	2015	2020	Annual Growth 1999-2020 (percent)
Energy Consumption							
Residential							
Distillate Fuel	0.78	0.86	0.88	0.81	0.77	0.75	-0.7%
Kerosene	0.11	0.10	0.08	0.07	0.07	0.07	-1.7%
Liquefied Petroleum Gas	0.42	0.46	0.45	0.41	0.40	0.39	-0.7%
Petroleum Subtotal	1.31	1.42	1.42	1.29	1.24	1.21	-0.7%
Natural Gas	4.67	4.85	5.46	5.69	5.99	6.30	1.3%
Coal	0.04	0.04	0.05	0.05	0.05	0.05	0.5%
Renewable Energy[1]	0.39	0.41	0.43	0.43	0.43	0.44	0.4%
Electricity	3.85	3.91	4.50	4.96	5.37	5.80	1.9%
Delivered Energy	**10.26**	**10.62**	**11.86**	**12.43**	**13.08**	**13.81**	**1.3%**
Electricity Related Losses	8.43	8.48	9.45	9.87	10.19	10.55	1.0%
Total	**18.70**	**19.10**	**21.31**	**22.30**	**23.27**	**24.36**	**1.2%**
Commercial							
Distillate Fuel	0.42	0.36	0.41	0.41	0.40	0.39	0.4%
Residual Fuel	0.09	0.10	0.10	0.11	0.11	0.11	0.4%
Kerosene	0.03	0.03	0.03	0.03	0.03	0.03	0.6%
Liquefied Petroleum Gas	0.07	0.08	0.09	0.09	0.10	0.10	1.0%
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.03	-0.5%
Petroleum Subtotal	0.65	0.59	0.66	0.67	0.67	0.66	0.5%
Natural Gas	3.10	3.15	3.71	3.88	4.05	4.13	1.3%
Coal	0.07	0.07	0.07	0.07	0.07	0.08	0.7%
Renewable Energy[3]	0.08	0.08	0.08	0.08	0.08	0.08	0.0%
Electricity	3.64	3.70	4.35	4.89	5.32	5.61	2.0%
Delivered Energy	**7.54**	**7.59**	**8.87**	**9.59**	**10.19**	**10.55**	**1.6%**
Electricity Related Losses	7.99	8.01	9.14	9.71	10.10	10.20	1.2%
Total	**15.52**	**15.61**	**18.00**	**19.30**	**20.29**	**20.75**	**1.4%**
Industrial[4]							
Distillate Fuel	1.15	1.07	1.13	1.27	1.35	1.44	1.5%
Liquefied Petroleum Gas	2.07	2.32	2.45	2.50	2.65	2.83	1.0%
Petrochemical Feedstock	1.39	1.29	1.42	1.53	1.61	1.70	1.3%
Residual Fuel	0.26	0.22	0.22	0.25	0.26	0.27	1.1%
Motor Gasoline[2]	0.20	0.21	0.23	0.25	0.26	0.28	1.4%
Other Petroleum[5]	4.08	4.29	4.50	4.76	5.01	5.24	1.0%
Petroleum Subtotal	9.15	9.39	9.95	10.55	11.14	11.77	1.1%
Natural Gas[6]	9.78	9.43	10.43	11.11	11.76	12.34	1.3%
Metallurgical Coal	0.76	0.75	0.69	0.61	0.55	0.50	-1.9%
Steam Coal	1.79	1.73	1.82	1.85	1.87	1.90	0.4%
Net Coal Coke Imports	0.07	0.06	0.12	0.16	0.19	0.22	6.6%
Coal Subtotal	2.61	2.54	2.62	2.62	2.61	2.62	0.1%
Renewable Energy[7]	2.10	2.15	2.42	2.64	2.86	3.08	1.7%
Electricity	3.55	3.63	3.90	4.18	4.47	4.81	1.4%
Delivered Energy	**27.19**	**27.15**	**29.32**	**31.10**	**32.84**	**34.63**	**1.2%**
Electricity Related Losses	7.78	7.87	8.21	8.32	8.48	8.76	0.5%
Total	**34.96**	**35.02**	**37.53**	**39.42**	**41.31**	**43.39**	**1.0%**

Table A2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Transportation							
Distillate Fuel	4.97	5.13	6.28	6.99	7.60	8.21	2.3%
Jet Fuel[8]	3.36	3.46	3.90	4.51	5.22	5.97	2.6%
Motor Gasoline[2]	15.59	15.92	17.70	19.04	20.23	21.32	1.4%
Residual Fuel	0.65	0.74	0.85	0.85	0.86	0.87	0.8%
Liquefied Petroleum Gas	0.02	0.02	0.03	0.04	0.05	0.06	4.8%
Other Petroleum[9]	0.22	0.26	0.29	0.31	0.33	0.35	1.4%
Petroleum Subtotal	24.80	25.54	29.06	31.74	34.28	36.77	1.8%
Pipeline Fuel Natural Gas	0.65	0.66	0.77	0.90	0.99	1.09	2.4%
Compressed Natural Gas	0.01	0.02	0.06	0.09	0.13	0.16	11.7%
Renewable Energy (E85)[10]	0.01	0.01	0.02	0.03	0.04	0.04	7.5%
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	6.4%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	0.06	0.06	0.09	0.12	0.15	0.17	5.0%
Delivered Energy	**25.53**	**26.28**	**30.00**	**32.89**	**35.60**	**38.23**	**1.8%**
Electricity Related Losses	0.13	0.13	0.19	0.23	0.28	0.30	4.2%
Total	**25.66**	**26.41**	**30.18**	**33.12**	**35.87**	**38.54**	**1.8%**
Delivered Energy Consumption for All Sectors							
Distillate Fuel	7.32	7.42	8.70	9.47	10.12	10.80	1.8%
Kerosene	0.16	0.15	0.14	0.13	0.13	0.12	-1.0%
Jet Fuel[8]	3.36	3.46	3.90	4.51	5.22	5.97	2.6%
Liquefied Petroleum Gas	2.58	2.88	3.03	3.05	3.20	3.38	0.8%
Motor Gasoline[2]	15.82	16.17	17.96	19.31	20.52	21.63	1.4%
Petrochemical Feedstock	1.39	1.29	1.42	1.53	1.61	1.70	1.3%
Residual Fuel	1.00	1.05	1.17	1.21	1.22	1.25	0.8%
Other Petroleum[12]	4.27	4.53	4.77	5.04	5.31	5.57	1.0%
Petroleum Subtotal	35.90	36.95	41.09	44.25	47.33	50.41	1.5%
Natural Gas[6]	18.21	18.11	20.43	21.68	22.91	24.02	1.4%
Metallurgical Coal	0.76	0.75	0.69	0.61	0.55	0.50	-1.9%
Steam Coal	1.90	1.84	1.94	1.98	1.99	2.02	0.4%
Net Coal Coke Imports	0.07	0.06	0.12	0.16	0.19	0.22	6.6%
Coal Subtotal	2.72	2.65	2.74	2.74	2.74	2.74	0.2%
Renewable Energy[13]	2.58	2.65	2.95	3.19	3.42	3.65	1.5%
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	6.4%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	11.10	11.29	12.83	14.15	15.30	16.39	1.8%
Delivered Energy	**70.51**	**71.65**	**80.05**	**86.01**	**91.71**	**97.22**	**1.5%**
Electricity Related Losses	24.33	24.49	26.98	28.13	29.04	29.81	0.9%
Total	**94.84**	**96.14**	**107.03**	**114.14**	**120.75**	**127.03**	**1.3%**
Electric Generators[14]							
Distillate Fuel	0.12	0.06	0.05	0.04	0.04	0.04	-1.4%
Residual Fuel	1.14	1.03	0.27	0.12	0.12	0.14	-9.2%
Petroleum Subtotal	1.26	1.08	0.32	0.16	0.16	0.18	-8.2%
Natural Gas	3.75	3.85	5.45	7.07	9.48	11.55	5.4%
Steam Coal	18.89	18.78	21.40	22.41	22.94	23.46	1.1%
Nuclear Power	7.19	7.79	7.90	7.69	6.82	6.13	-1.1%
Renewable Energy[15]	4.05	3.94	4.19	4.64	4.71	4.66	0.8%
Electricity Imports[16]	0.29	0.34	0.55	0.31	0.22	0.22	-2.0%
Total	**35.43**	**35.78**	**39.81**	**42.28**	**44.34**	**46.20**	**1.2%**

Table A2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Total Energy Consumption							
Distillate Fuel	7.44	7.48	8.75	9.51	10.17	10.84	1.8%
Kerosene	0.16	0.15	0.14	0.13	0.13	0.12	-1.0%
Jet Fuel[8]	3.36	3.46	3.90	4.51	5.22	5.97	2.6%
Liquefied Petroleum Gas	2.58	2.88	3.03	3.05	3.20	3.38	0.8%
Motor Gasoline[2]	15.82	16.17	17.96	19.31	20.52	21.63	1.4%
Petrochemical Feedstock	1.39	1.29	1.42	1.53	1.61	1.70	1.3%
Residual Fuel	2.14	2.08	1.44	1.33	1.35	1.38	-1.9%
Other Petroleum[12]	4.27	4.53	4.77	5.04	5.31	5.57	1.0%
Petroleum Subtotal	37.16	38.03	41.41	44.41	47.50	50.59	1.4%
Natural Gas	21.96	21.95	25.88	28.75	32.39	35.57	2.3%
Metallurgical Coal	0.76	0.75	0.69	0.61	0.55	0.50	-1.9%
Steam Coal	20.79	20.62	23.34	24.39	24.93	25.48	1.0%
Net Coal Coke Imports	0.07	0.06	0.12	0.16	0.19	0.22	6.6%
Coal Subtotal	21.61	21.43	24.15	25.15	25.68	26.20	1.0%
Nuclear Power	7.19	7.79	7.90	7.69	6.82	6.13	-1.1%
Renewable Energy[17]	6.63	6.59	7.14	7.83	8.13	8.31	1.1%
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	6.4%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity Imports[16]	0.29	0.34	0.55	0.31	0.22	0.22	-2.0%
Total	**94.84**	**96.14**	**107.03**	**114.14**	**120.75**	**127.04**	**1.3%**
Energy Use and Related Statistics							
Delivered Energy Use	70.51	71.65	80.05	86.01	91.71	97.22	1.5%
Total Energy Use	94.84	96.14	107.03	114.14	120.75	127.04	1.3%
Population (millions)	270.61	273.13	288.02	300.17	312.58	325.24	0.8%
Gross Domestic Product (billion 1996 dollars)	8,516	8,876	10,960	12,667	14,635	16,515	3.0%
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1,495.4	1,510.8	1,690.2	1,809.1	1,928.1	2,040.6	1.4%

[1]Includes wood used for residential heating. See Table A18 estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector electricity cogenerated by using wood and wood waste, landfill gas, municipal solid waste, and other biomass. See Table A18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Fuel consumption includes consumption for cogeneration, which produces electricity and other useful thermal energy.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Includes lease and plant fuel and consumption by cogenerators; excludes consumption by nonutility generators.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass; includes cogeneration, both for sale to the grid and for own use.
[8]Includes only kerosene type.
[9]Includes aviation gas and lubricants.
[10]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[11]M85 is 85 percent methanol and 15 percent motor gasoline.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes cogeneration. Excludes net electricity imports.
[16]In 1998 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[17]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1998 natural gas lease, plant, and pipeline fuel values: Energy Information Administration (EIA), *Natural Gas Annual 1998*, DOE/EIA-0131(98) (Washington, DC, October 1999). 1998 and 1999 electric utility fuel consumption: EIA, *Electric Power Annual 1998, Volume 1,* DOE/EIA-0348(98)/1 (Washington, DC, April 1999). 1998 and 1999 nonutility consumption estimates: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 1998 values: EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A. Other 1999 values: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A3. Energy Prices by Sector and Source
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Residential	**13.64**	**13.17**	**12.93**	**13.16**	**13.33**	**13.59**	**0.1%**
Primary Energy[1]	6.87	6.72	7.12	7.01	6.92	7.01	0.2%
Petroleum Products[2]	7.53	7.55	9.18	9.37	9.49	9.64	1.2%
Distillate Fuel	6.25	6.27	7.33	7.51	7.80	7.98	1.2%
Liquefied Petroleum Gas	10.45	10.36	12.83	13.07	12.83	12.87	1.0%
Natural Gas	6.74	6.52	6.63	6.53	6.44	6.55	0.0%
Electricity	24.24	23.60	21.90	21.88	22.01	22.17	-0.3%
Commercial	**13.53**	**13.25**	**12.39**	**11.75**	**11.96**	**12.37**	**-0.3%**
Primary Energy[1]	5.26	5.22	5.35	5.53	5.55	5.74	0.5%
Petroleum Products[2]	4.66	5.00	6.01	6.17	6.34	6.50	1.3%
Distillate Fuel	4.01	4.37	5.12	5.28	5.55	5.75	1.3%
Residual Fuel	2.42	2.63	3.64	3.69	3.77	3.85	1.8%
Natural Gas[3]	5.47	5.34	5.31	5.50	5.50	5.71	0.3%
Electricity	22.17	21.54	19.58	17.63	17.72	18.12	-0.8%
Industrial[4]	**4.97**	**5.33**	**5.49**	**5.45**	**5.56**	**5.85**	**0.4%**
Primary Energy	3.51	3.92	4.25	4.38	4.48	4.72	0.9%
Petroleum Products[2]	4.79	5.55	5.95	6.05	6.10	6.27	0.6%
Distillate Fuel	4.11	4.65	5.29	5.45	5.73	5.94	1.2%
Liquefied Petroleum Gas	7.27	8.50	7.94	8.01	7.75	7.83	-0.4%
Residual Fuel	2.56	2.78	3.36	3.42	3.50	3.58	1.2%
Natural Gas[5]	2.73	2.79	3.17	3.31	3.45	3.76	1.4%
Metallurgical Coal	1.73	1.65	1.59	1.54	1.49	1.44	-0.7%
Steam Coal	1.45	1.43	1.35	1.29	1.25	1.21	-0.8%
Electricity	13.34	13.09	12.34	11.24	11.27	11.62	-0.6%
Transportation	**7.70**	**8.30**	**9.27**	**9.46**	**9.38**	**9.31**	**0.5%**
Primary Energy	7.68	8.29	9.25	9.45	9.36	9.29	0.5%
Petroleum Products[2]	7.68	8.28	9.25	9.44	9.36	9.29	0.5%
Distillate Fuel[6]	7.66	8.22	8.89	8.94	9.05	8.98	0.4%
Jet Fuel[7]	4.13	4.70	5.25	5.47	5.75	5.88	1.1%
Motor Gasoline[8]	8.74	9.45	10.64	10.93	10.75	10.68	0.6%
Residual Fuel	2.29	2.46	3.10	3.18	3.25	3.33	1.5%
Liquefied Petroleum Gas[9]	11.23	12.87	14.19	14.26	13.96	13.84	0.3%
Natural Gas[10]	6.40	7.02	6.80	7.04	7.17	7.32	0.2%
Ethanol (E85)[11]	14.25	14.42	19.12	19.00	19.24	19.36	1.4%
Methanol (M85)[12]	8.93	10.38	13.12	13.74	14.33	14.43	1.6%
Electricity	15.86	15.57	14.33	13.47	13.21	13.06	-0.8%
Average End-Use Energy	**8.26**	**8.55**	**8.91**	**8.95**	**9.01**	**9.17**	**0.3%**
Primary Energy	5.89	6.33	7.00	7.18	7.21	7.30	0.7%
Electricity	20.03	19.50	18.15	17.20	17.30	17.59	-0.5%
Electric Generators[13]							
Fossil Fuel Average	1.50	1.49	1.52	1.54	1.68	1.86	1.1%
Petroleum Products	2.32	2.50	3.70	4.11	4.27	4.35	2.7%
Distillate Fuel	3.25	4.05	4.65	4.84	5.10	5.28	1.3%
Residual Fuel	2.22	2.42	3.52	3.88	4.00	4.07	2.5%
Natural Gas	2.41	2.55	2.88	3.03	3.24	3.59	1.6%
Steam Coal	1.27	1.21	1.13	1.05	1.01	0.98	-1.0%

Table A3. Energy Prices by Sector and Source (Continued)
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case 1998	1999	2005	2010	2015	2020	Annual Growth 1999-2020 (percent)
Average Price to All Users[14]							
Petroleum Products[2]	6.81	7.44	8.43	8.64	8.61	8.61	0.7%
Distillate Fuel	6.68	7.27	8.06	8.18	8.36	8.38	0.7%
Jet Fuel	4.13	4.70	5.25	5.47	5.75	5.88	1.1%
Liquefied Petroleum Gas	7.87	8.84	8.84	8.88	8.58	8.62	-0.1%
Motor Gasoline[8]	8.74	9.45	10.64	10.93	10.75	10.68	0.6%
Residual Fuel	2.29	2.48	3.26	3.33	3.41	3.49	1.6%
Natural Gas	4.02	4.05	4.24	4.27	4.28	4.50	0.5%
Coal	1.29	1.23	1.15	1.07	1.03	1.00	-1.0%
Ethanol (E85)[11]	14.25	14.42	19.12	19.00	19.24	19.36	1.4%
Methanol (M85)[12]	8.93	10.38	13.12	13.74	14.33	14.43	1.6%
Electricity	20.03	19.50	18.15	17.20	17.30	17.59	-0.5%
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)							
Residential	134.68	134.60	147.79	157.93	168.52	181.70	1.4%
Commercial	100.85	99.50	108.85	111.72	120.89	129.51	1.3%
Industrial	104.61	110.90	121.44	126.53	135.93	150.97	1.5%
Transportation	191.50	212.63	270.48	302.06	323.87	344.96	2.3%
Total Non-Renewable Expenditures	531.64	557.64	648.57	698.23	749.21	807.14	1.8%
Transportation Renewable Expenditures	0.09	0.14	0.42	0.61	0.75	0.86	9.0%
Total Expenditures	**531.73**	**557.78**	**648.99**	**698.85**	**749.96**	**808.00**	**1.8%**

[1]Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Excludes independent power producers.
[4]Includes cogenerators.
[5]Excludes uses for lease and plant fuel.
[6] Low sulfur diesel fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[8]Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[9]Includes Federal and State taxes while excluding county and local taxes.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]M85 is 85 percent methanol and 15 percent motor gasoline.
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[14]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1998 prices for gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1998*, ftp://ftp.eia.doe.gov/pub/ oil_gas/petroleum/data_publications/petroleum_marketing_annual/historical/1998/pdf/pmaall.pdf (October 1999). 1999 prices for gasoline, distillate, and jet fuel are based on prices in various issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380 (99/03-2000/04) (Washington, DC, 1999-2000). 1998 and 1999 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1997*, DOE/EIA-0376(97) (Washington, DC, July 2000). 1998 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Annual 1998*, DOE/EIA-0131(98) (Washington, DC, October 1999). 1998 electric generators natural gas delivered prices: Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 1998 and 1999 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1994*. 1999 residential and commercial natural gas delivered prices: EIA,, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1998 and 1999 coal prices based on EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000) and EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A. 1998 residential electricity prices derived from EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. 1998 and 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A. **Projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A4. Residential Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Key Indicators							
Households (millions)							
Single-Family	74.69	75.70	81.38	85.51	89.93	94.36	1.1%
Multifamily	21.61	21.79	23.12	24.25	25.69	27.09	1.0%
Mobile Homes	6.47	6.59	6.94	7.20	7.57	7.96	0.9%
Total	**102.77**	**104.08**	**111.45**	**116.97**	**123.20**	**129.41**	**1.0%**
Average House Square Footage	**1667**	**1673**	**1702**	**1724**	**1744**	**1763**	**0.3%**
Energy Intensity							
(million Btu per household)							
Delivered Energy Consumption	99.9	102.1	106.4	106.3	106.2	106.7	0.2%
Total Energy Consumption	181.9	183.5	191.2	190.6	188.9	188.3	0.1%
(thousand Btu per square foot)							
Delivered Energy Consumption	59.9	61.0	62.5	61.7	60.9	60.5	-0.0%
Total Energy Consumption	109.1	109.7	112.3	110.6	108.3	106.8	-0.1%
Delivered Energy Consumption by Fuel							
Electricity							
Space Heating	0.37	0.38	0.44	0.47	0.49	0.51	1.4%
Space Cooling	0.56	0.52	0.56	0.63	0.69	0.77	1.9%
Water Heating	0.40	0.39	0.41	0.43	0.43	0.43	0.4%
Refrigeration	0.44	0.43	0.37	0.34	0.32	0.33	-1.3%
Cooking	0.10	0.10	0.11	0.12	0.13	0.13	1.2%
Clothes Dryers	0.21	0.22	0.24	0.26	0.27	0.29	1.4%
Freezers	0.12	0.12	0.10	0.09	0.09	0.09	-1.4%
Lighting	0.33	0.34	0.41	0.46	0.49	0.52	2.0%
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.04	0.04	1.3%
Dishwashers[1]	0.02	0.02	0.02	0.02	0.03	0.03	1.2%
Color Televisions	0.12	0.12	0.16	0.19	0.21	0.24	3.3%
Personal Computers	0.05	0.06	0.09	0.09	0.10	0.11	2.8%
Furnace Fans	0.07	0.07	0.09	0.10	0.11	0.12	2.1%
Other Uses[2]	1.02	1.10	1.46	1.73	1.97	2.20	3.3%
Delivered Energy	**3.85**	**3.91**	**4.50**	**4.96**	**5.37**	**5.80**	**1.9%**
Natural Gas							
Space Heating	3.05	3.22	3.70	3.85	4.06	4.31	1.4%
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	11.4%
Water Heating	1.25	1.26	1.35	1.41	1.47	1.52	0.9%
Cooking	0.19	0.19	0.21	0.23	0.24	0.25	1.5%
Clothes Dryers	0.06	0.07	0.08	0.09	0.10	0.11	2.4%
Other Uses[3]	0.11	0.11	0.12	0.11	0.11	0.11	-0.2%
Delivered Energy	**4.67**	**4.85**	**5.46**	**5.69**	**5.99**	**6.30**	**1.3%**
Distillate							
Space Heating	0.66	0.73	0.76	0.69	0.66	0.65	-0.6%
Water Heating	0.13	0.13	0.13	0.12	0.11	0.10	-1.2%
Other Uses[4]	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Delivered Energy	**0.78**	**0.86**	**0.88**	**0.81**	**0.77**	**0.75**	**-0.7%**
Liquefied Petroleum Gas							
Space Heating	0.28	0.31	0.31	0.28	0.27	0.27	-0.7%
Water Heating	0.10	0.11	0.10	0.09	0.09	0.09	-1.0%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	-0.2%
Other Uses[3]	0.01	0.01	0.01	0.01	0.01	0.01	-0.5%
Delivered Energy	**0.42**	**0.46**	**0.45**	**0.41**	**0.40**	**0.39**	**-0.7%**
Marketed Renewables (wood)[5]	0.39	0.41	0.43	0.43	0.43	0.44	0.4%
Other Fuels[6]	0.15	0.14	0.13	0.12	0.12	0.12	-0.9%

Table A4. Residential Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Delivered Energy Consumption by End-Use							
Space Heating	4.90	5.18	5.77	5.84	6.03	6.29	0.9%
Space Cooling	0.56	0.52	0.57	0.63	0.70	0.77	1.9%
Water Heating	1.87	1.89	1.99	2.05	2.10	2.14	0.6%
Refrigeration	0.44	0.43	0.37	0.34	0.32	0.33	-1.3%
Cooking	0.32	0.32	0.35	0.38	0.40	0.42	1.2%
Clothes Dryers	0.28	0.28	0.32	0.35	0.37	0.40	1.7%
Freezers	0.12	0.12	0.10	0.09	0.09	0.09	-1.4%
Lighting	0.33	0.34	0.41	0.46	0.49	0.52	2.0%
Clothes Washers	0.03	0.03	0.03	0.03	0.04	0.04	1.3%
Dishwashers	0.02	0.02	0.02	0.02	0.03	0.03	1.2%
Color Televisions	0.12	0.12	0.16	0.19	0.21	0.24	3.3%
Personal Computers	0.05	0.06	0.09	0.09	0.10	0.11	2.8%
Furnace Fans	0.07	0.07	0.09	0.10	0.11	0.12	2.1%
Other Uses[7]	1.14	1.23	1.58	1.86	2.09	2.32	3.1%
Delivered Energy	**10.26**	**10.62**	**11.86**	**12.43**	**13.08**	**13.81**	**1.3%**
Electricity Related Losses	**8.43**	**8.48**	**9.45**	**9.87**	**10.19**	**10.55**	**1.0%**
Total Energy Consumption by End-Use							
Space Heating	5.71	6.01	6.69	6.76	6.96	7.22	0.9%
Space Cooling	1.79	1.64	1.75	1.87	2.01	2.17	1.3%
Water Heating	2.74	2.75	2.86	2.90	2.92	2.93	0.3%
Refrigeration	1.41	1.35	1.15	1.02	0.94	0.92	-1.8%
Cooking	0.54	0.54	0.59	0.61	0.63	0.66	0.9%
Clothes Dryers	0.75	0.75	0.82	0.86	0.89	0.93	1.0%
Freezers	0.39	0.37	0.30	0.27	0.25	0.25	-2.0%
Lighting	1.06	1.08	1.26	1.38	1.42	1.46	1.5%
Clothes Washers	0.09	0.09	0.10	0.10	0.11	0.11	0.7%
Dishwashers	0.07	0.07	0.07	0.07	0.08	0.08	0.7%
Color Televisions	0.37	0.38	0.51	0.57	0.62	0.67	2.7%
Personal Computers	0.17	0.20	0.29	0.28	0.29	0.32	2.2%
Furnace Fans	0.23	0.24	0.27	0.29	0.31	0.33	1.5%
Other Uses[7]	3.37	3.62	4.65	5.30	5.84	6.32	2.7%
Total	**18.70**	**19.10**	**21.31**	**22.30**	**23.27**	**24.36**	**1.2%**
Non-Marketed Renewables							
Geothermal[8]	0.02	0.02	0.02	0.03	0.03	0.03	2.9%
Solar[9]	0.01	0.01	0.01	0.01	0.01	0.01	0.5%
Total	**0.02**	**0.02**	**0.03**	**0.03**	**0.03**	**0.04**	**2.4%**

[1]Does not include electric water heating portion of load.
[2]Includes small electric devices, heating elements, and motors.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as swimming pool and hot tub heaters.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1997*.
[6]Includes kerosene and coal.
[7]Includes all other uses listed above.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1998 and 1999: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A5. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Key Indicators							
Total Floor Space (billion square feet)							
Surviving	59.8	60.8	69.0	74.0	78.1	80.7	1.4%
New Additions	1.8	2.0	1.8	1.8	1.5	1.3	-2.1%
Total	**61.5**	**62.8**	**70.9**	**75.8**	**79.6**	**81.9**	**1.3%**
Energy Consumption Intensity (thousand Btu per square foot)							
Delivered Energy Consumption	122.5	120.9	125.2	126.6	128.0	128.8	0.3%
Electricity Related Losses	129.8	127.6	129.0	128.2	126.8	124.5	-0.1%
Total Energy Consumption	252.2	248.5	254.1	254.8	254.9	253.2	0.1%
Delivered Energy Consumption by Fuel							
Purchased Electricity							
Space Heating[1]	0.13	0.14	0.16	0.16	0.16	0.16	0.6%
Space Cooling[1]	0.46	0.43	0.44	0.46	0.46	0.46	0.4%
Water Heating[1]	0.14	0.14	0.15	0.16	0.16	0.16	0.4%
Ventilation	0.17	0.17	0.19	0.21	0.21	0.21	0.9%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	-0.5%
Lighting	1.19	1.21	1.33	1.42	1.48	1.47	0.9%
Refrigeration	0.18	0.18	0.20	0.21	0.22	0.22	1.0%
Office Equipment (PC)	0.09	0.10	0.18	0.24	0.28	0.29	5.1%
Office Equipment (non-PC)	0.28	0.30	0.41	0.51	0.60	0.69	4.1%
Other Uses[2]	0.97	0.99	1.25	1.48	1.71	1.91	3.2%
Delivered Energy	**3.64**	**3.70**	**4.35**	**4.89**	**5.32**	**5.61**	**2.0%**
Natural Gas[3]							
Space Heating[1]	1.34	1.42	1.67	1.74	1.80	1.81	1.2%
Space Cooling[1]	0.01	0.02	0.02	0.02	0.03	0.03	2.9%
Water Heating[1]	0.63	0.64	0.72	0.77	0.82	0.84	1.3%
Cooking	0.20	0.21	0.23	0.25	0.26	0.27	1.3%
Other Uses[4]	0.92	0.87	1.07	1.11	1.14	1.18	1.4%
Delivered Energy	**3.10**	**3.15**	**3.71**	**3.88**	**4.05**	**4.13**	**1.3%**
Distillate							
Space Heating[1]	0.22	0.23	0.25	0.25	0.25	0.24	0.2%
Water Heating[1]	0.09	0.09	0.09	0.09	0.08	0.08	-0.2%
Other Uses[5]	0.12	0.04	0.07	0.07	0.07	0.07	2.7%
Delivered Energy	**0.42**	**0.36**	**0.41**	**0.41**	**0.40**	**0.39**	**0.4%**
Other Fuels[6]	**0.29**	**0.30**	**0.32**	**0.33**	**0.34**	**0.34**	**0.6%**
Marketed Renewable Fuels							
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.0%
Delivered Energy	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.0%**
Delivered Energy Consumption by End-Use							
Space Heating[1]	1.69	1.79	2.08	2.15	2.21	2.21	1.0%
Space Cooling[1]	0.47	0.44	0.46	0.48	0.49	0.49	0.5%
Water Heating[1]	0.86	0.87	0.96	1.01	1.06	1.08	1.0%
Ventilation	0.17	0.17	0.19	0.21	0.21	0.21	0.9%
Cooking	0.23	0.24	0.26	0.28	0.29	0.30	1.1%
Lighting	1.19	1.21	1.33	1.42	1.48	1.47	0.9%
Refrigeration	0.18	0.18	0.20	0.21	0.22	0.22	1.0%
Office Equipment (PC)	0.09	0.10	0.18	0.24	0.28	0.29	5.1%
Office Equipment (non-PC)	0.28	0.30	0.41	0.51	0.60	0.69	4.1%
Other Uses[7]	2.38	2.29	2.79	3.07	3.35	3.58	2.2%
Delivered Energy	**7.54**	**7.59**	**8.87**	**9.59**	**10.19**	**10.55**	**1.6%**

Table A5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Electricity Related Losses	**7.99**	**8.01**	**9.14**	**9.71**	**10.10**	**10.20**	**1.2%**
Total Energy Consumption by End-Use							
Space Heating[1]	1.98	2.09	2.42	2.48	2.52	2.50	0.9%
Space Cooling[1]	1.47	1.36	1.38	1.39	1.37	1.33	-0.1%
Water Heating[1]	1.17	1.19	1.28	1.33	1.37	1.37	0.7%
Ventilation	0.55	0.55	0.60	0.61	0.61	0.59	0.3%
Cooking	0.30	0.31	0.33	0.34	0.35	0.35	0.6%
Lighting	3.79	3.83	4.11	4.26	4.29	4.15	0.4%
Refrigeration	0.57	0.58	0.62	0.64	0.64	0.63	0.4%
Office Equipment (PC)	0.30	0.33	0.55	0.71	0.81	0.83	4.5%
Office Equipment (non-PC)	0.89	0.94	1.28	1.52	1.74	1.94	3.5%
Other Uses[7]	4.51	4.43	5.43	6.03	6.59	7.05	2.2%
Total	**15.52**	**15.61**	**18.00**	**19.30**	**20.29**	**20.75**	**1.4%**
Non-Marketed Renewable Fuels							
Solar[8]	0.02	0.02	0.02	0.03	0.03	0.03	1.5%
Total	**0.02**	**0.02**	**0.02**	**0.03**	**0.03**	**0.03**	**1.5%**

[1]Includes fuel consumption for district services.
[2]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
[3]Excludes estimated consumption from independent power producers.
[4]Includes miscellaneous uses, such as pumps, emergency electric generators, cogeneration in commercial buildings, and manufacturing performed in commercial buildings.
[5]Includes miscellaneous uses, such as cooking, emergency electric generators, and cogeneration in commercial buildings.
[6]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, cogeneration in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[8]Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.
N/A = Not applicable.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1998 and 1999: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Key Indicators							
Value of Gross Output (billion 1992 dollars)							
Manufacturing	3,704	3,749	4,399	5,089	5,828	6,726	2.8%
Nonmanufacturing	950	972	1,070	1,162	1,265	1,370	1.6%
Total	**4,654**	**4,722**	**5,469**	**6,251**	**7,093**	**8,096**	**2.6%**
Energy Prices (1999 dollars per million Btu)							
Electricity	13.34	13.09	12.34	11.24	11.27	11.62	-0.6%
Natural Gas	2.73	2.79	3.17	3.31	3.45	3.76	1.4%
Steam Coal	1.45	1.43	1.35	1.29	1.25	1.21	-0.8%
Residual Oil	2.56	2.78	3.36	3.42	3.50	3.58	1.2%
Distillate Oil	4.11	4.65	5.29	5.45	5.73	5.94	1.2%
Liquefied Petroleum Gas	7.27	8.50	7.94	8.01	7.75	7.83	-0.4%
Motor Gasoline	8.74	9.42	10.61	10.90	10.70	10.64	0.6%
Metallurgical Coal	1.73	1.65	1.59	1.54	1.49	1.44	-0.7%
Energy Consumption							
Consumption[1]							
Purchased Electricity	3.55	3.63	3.90	4.18	4.47	4.81	1.4%
Natural Gas[2]	9.78	9.43	10.43	11.11	11.76	12.34	1.3%
Steam Coal	1.79	1.73	1.82	1.85	1.87	1.90	0.4%
Metallurgical Coal and Coke[3]	0.82	0.81	0.80	0.76	0.74	0.72	-0.5%
Residual Fuel	0.26	0.22	0.22	0.25	0.26	0.27	1.1%
Distillate	1.15	1.07	1.13	1.27	1.35	1.44	1.5%
Liquefied Petroleum Gas	2.07	2.32	2.45	2.50	2.65	2.83	1.0%
Petrochemical Feedstocks	1.39	1.29	1.42	1.53	1.61	1.70	1.3%
Other Petroleum[4]	4.28	4.50	4.72	5.00	5.27	5.52	1.0%
Renewables[5]	2.10	2.15	2.42	2.64	2.86	3.08	1.7%
Delivered Energy	**27.19**	**27.15**	**29.32**	**31.10**	**32.84**	**34.63**	**1.2%**
Electricity Related Losses	7.78	7.87	8.21	8.32	8.48	8.76	0.5%
Total	**34.96**	**35.02**	**37.53**	**39.42**	**41.31**	**43.39**	**1.0%**
Consumption per Unit of Output[1] (thousand Btu per 1992 dollars)							
Purchased Electricity	0.76	0.77	0.71	0.67	0.63	0.59	-1.2%
Natural Gas[2]	2.10	2.00	1.91	1.78	1.66	1.52	-1.3%
Steam Coal	0.38	0.37	0.33	0.30	0.26	0.23	-2.1%
Metallurgical Coal and Coke[3]	0.18	0.17	0.15	0.12	0.10	0.09	-3.1%
Residual Fuel	0.06	0.05	0.04	0.04	0.04	0.03	-1.4%
Distillate	0.25	0.23	0.21	0.20	0.19	0.18	-1.1%
Liquefied Petroleum Gas	0.44	0.49	0.45	0.40	0.37	0.35	-1.6%
Petrochemical Feedstocks	0.30	0.27	0.26	0.24	0.23	0.21	-1.2%
Other Petroleum[4]	0.92	0.95	0.86	0.80	0.74	0.68	-1.6%
Renewables[5]	0.45	0.46	0.44	0.42	0.40	0.38	-0.9%
Delivered Energy	**5.84**	**5.75**	**5.36**	**4.98**	**4.63**	**4.28**	**-1.4%**
Electricity Related Losses	1.67	1.67	1.50	1.33	1.20	1.08	-2.0%
Total	**7.51**	**7.42**	**6.86**	**6.31**	**5.82**	**5.36**	**-1.5%**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net coke coal imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1998 prices for gasoline and distillate are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1998*, ftp://ftp.eia.doe.gov/pub/ oil_gas/petroleum/data_publications/petroleum_marketing_annual/historical/1998/pdf/pmaall.pdf (October 1999). 1999 prices for gasoline and distillate are based on prices in various issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380 (99/03-2000/04) (Washington, DC, 1999-2000). 1998 and 1999 coal prices are based on EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000) and EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A. 1998 and 1999 electricity prices: EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A. Other 1998 values and other 1999 prices derived from EIA, *State Energy Data Report 1997*, DOE/EIA-0214(97) (Washington, DC, September 1999). Other 1999 values: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Key Indicators							
Level of Travel (billions)							
Light-Duty Vehicles <8,500 pounds (VMT)	2329	2394	2771	3066	3334	3577	1.9%
Commercial Light Trucks (VMT)[1]	71	73	84	93	103	113	2.1%
Freight Trucks >10,000 pounds (VMT)	200	204	248	280	313	352	2.6%
Air (seat miles available)	1067	1099	1313	1592	1934	2317	3.6%
Rail (ton miles traveled)	1347	1357	1578	1706	1826	1967	1.8%
Domestic Shipping (ton miles traveled)	657	661	733	775	832	890	1.4%
Energy Efficiency Indicators							
New Light-Duty Vehicle (miles per gallon)[2]	24.5	24.2	26.0	27.1	27.6	28.0	0.7%
New Car (miles per gallon)[2]	28.3	27.9	30.9	32.3	32.4	32.5	0.7%
New Light Truck (miles per gallon)[2]	20.9	20.8	22.2	23.2	24.0	24.7	0.8%
Light-Duty Fleet (miles per gallon)[3]	20.5	20.5	20.7	20.9	21.2	21.5	0.2%
New Commercial Light Truck (MPG)[1]	20.3	20.1	21.2	22.0	22.8	23.4	0.7%
Stock Commercial Light Truck (MPG)[1]	14.7	14.8	15.6	16.1	16.6	17.0	0.7%
Aircraft Efficiency (seat miles per gallon)	51.3	51.7	54.0	56.1	58.2	60.3	0.7%
Freight Truck Efficiency (miles per gallon)	6.0	6.0	6.2	6.4	6.7	6.9	0.7%
Rail Efficiency (ton miles per thousand Btu)	2.7	2.8	2.9	3.1	3.3	3.4	1.0%
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.3	2.5	2.7	2.8	3.0	1.2%
Energy Use by Mode (quadrillion Btu)							
Light-Duty Vehicles	14.52	14.88	16.97	18.51	19.83	20.98	1.7%
Commercial Light Trucks[1]	0.61	0.62	0.67	0.73	0.78	0.83	1.4%
Freight Trucks[4]	4.40	4.54	5.30	5.78	6.24	6.74	1.9%
Air[5]	3.40	3.50	3.95	4.56	5.28	6.04	2.6%
Rail[6]	0.57	0.57	0.63	0.65	0.67	0.69	0.9%
Marine[7]	1.20	1.29	1.44	1.46	1.49	1.52	0.8%
Pipeline Fuel	0.65	0.66	0.77	0.90	0.99	1.09	2.4%
Lubricants	0.17	0.22	0.25	0.26	0.29	0.31	1.6%
Total	**25.53**	**26.28**	**30.00**	**32.89**	**35.60**	**38.23**	**1.8%**
Energy Use by Mode (million barrels per day oil equivalent)							
Light-Duty Vehicles	7.57	7.76	8.90	9.70	10.39	10.99	1.7%
Commercial Light Trucks[1]	0.32	0.32	0.35	0.38	0.41	0.43	1.4%
Freight Trucks[4]	1.96	2.03	2.38	2.60	2.81	3.04	1.9%
Railroad	0.23	0.23	0.25	0.26	0.26	0.27	0.8%
Domestic Shipping	0.13	0.13	0.14	0.13	0.14	0.14	0.2%
International Shipping	0.26	0.30	0.35	0.35	0.36	0.36	0.9%
Air[5]	1.43	1.46	1.67	1.95	2.28	2.63	2.8%
Military Use	0.26	0.28	0.29	0.32	0.34	0.36	1.1%
Bus Transportation	0.09	0.09	0.09	0.09	0.09	0.09	0.2%
Rail Transportation[6]	0.04	0.04	0.04	0.05	0.05	0.05	1.7%
Recreational Boats	0.16	0.16	0.17	0.18	0.19	0.20	1.0%
Lubricants	0.08	0.10	0.12	0.12	0.14	0.15	1.6%
Pipeline Fuel	0.33	0.33	0.39	0.45	0.50	0.55	2.4%
Total	**12.87**	**13.24**	**15.15**	**16.59**	**17.94**	**19.26**	**1.8%**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
[4]Includes energy use by buses and military distillate consumption.
[5]Includes jet fuel and aviation gasoline.
[6]Includes passenger rail.
[7]Includes military residual fuel use and recreation boats.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.

Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.

Sources: 1998: Energy Information Administration (EIA), *Natural Gas Annual 1998*, DOE/EIA-0131(98) (Washington, DC, October 1999); Federal Highway Administration, *Highway Statistics 1998* (Washington, DC, November 1999); Oak Ridge National Laboratory, *Transportation Energy Data Book: 12, 13, 14, 15, 16, 17, 18, and 19* (Oak Ridge, TN, September 1999); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance*, (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Dept. of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC97TV, (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives To Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; and EIA, *State Energy Data Report 1997*, DOE/EIA-0214(97) (Washington, DC, September 1999). 1999: U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 1999/1998* (Washington, DC, 1999); EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf; EIA, *Fuel Oil and Kerosene Sales 1998*, DOE/EIA-0535(98) (Washington, DC, August 1999); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A8. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Generation by Fuel Type							
Electric Generators[1]							
Coal	1826	1833	2085	2196	2246	2298	1.1%
Petroleum	115	100	32	17	17	19	-7.7%
Natural Gas[2]	346	371	584	900	1266	1587	7.2%
Nuclear Power	674	730	740	720	639	574	-1.1%
Pumped Storage	-2	-1	-1	-1	-1	-1	N/A
Renewable Sources[3]	359	353	370	390	395	396	0.5%
Total	**3317**	**3386**	**3810**	**4222**	**4563**	**4872**	**1.7%**
Nonutility Generation for Own Use	16	16	17	16	16	16	-0.0%
Distributed Generation	0	0	1	3	4	6	N/A
Cogenerators[4]							
Coal	52	47	52	52	52	52	0.5%
Petroleum	15	9	10	10	10	10	0.4%
Natural Gas	197	206	239	257	276	299	1.8%
Other Gaseous Fuels[5]	8	4	6	7	7	8	3.3%
Renewable Sources[3]	31	31	34	39	44	48	2.0%
Other[6]	8	5	5	5	5	5	0.3%
Total	**310**	**302**	**347**	**370**	**394**	**422**	**1.6%**
Other End-Use Generators[7]	**6**	**5**	**5**	**5**	**5**	**5**	**0.6%**
Sales to Utilities	158	151	171	176	187	200	1.4%
Generation for Own Use	158	156	181	199	213	227	1.8%
Net Imports[8]	**27**	**32**	**52**	**29**	**21**	**21**	**-2.0%**
Electricity Sales by Sector							
Residential	1128	1146	1318	1455	1573	1701	1.9%
Commercial	1068	1083	1274	1432	1559	1643	2.0%
Industrial	1040	1063	1144	1226	1309	1411	1.4%
Transportation	17	17	26	35	43	49	5.0%
Total	**3253**	**3309**	**3761**	**4147**	**4484**	**4804**	**1.8%**
End-Use Prices (1999 cents per kilowatthour)[9]							
Residential	8.3	8.1	7.5	7.5	7.5	7.6	-0.3%
Commercial	7.6	7.3	6.7	6.0	6.0	6.2	-0.8%
Industrial	4.6	4.5	4.2	3.8	3.8	4.0	-0.6%
Transportation	5.4	5.3	4.9	4.6	4.5	4.5	-0.8%
All Sectors Average	**6.8**	**6.7**	**6.2**	**5.9**	**5.9**	**6.0**	**-0.5%**
Prices by Service Category (1999 cents per kilowatthour) [9]							
Generation	4.3	4.1	3.6	3.2	3.2	3.4	-0.9%
Transmission	0.6	0.6	0.6	0.7	0.7	0.7	0.7%
Distribution	2.0	2.0	2.0	2.0	2.0	2.0	-0.0%
Emissions (million short tons)							
Sulfur Dioxide	13.13	12.46	10.30	9.28	9.33	8.95	-1.6%
Nitrogen Oxide	5.83	5.45	4.25	4.22	4.33	4.42	-1.0%

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[2]Includes electricity generation by fuel cells.
[3]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[4]Cogenerators produce electricity and other useful thermal energy. Includes sales to utilities and generation for own use.
[5]Other gaseous fuels include refinery and still gas.
[6]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[7]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]In 1999 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[9]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1998: Electric generators and cogenerators generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Electric Power Annual 1998, Volume 2,* DOE/EIA-0348(98)/2 (Washington, DC, Decemberl 1999), and supporting databases. Other generators: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility" and Department of Energy, Office of Energy Efficiency and Renewable Energy estimates. Commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 19* (Oak Ridge, TN, 1999 September 1999). Prices: EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A. **1999 and projections**: EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A9. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	Reference Case 1998	1999	2005	2010	2015	2020	Annual Growth 1999-2020 (percent)
Electric Generators[2]							
Capability							
Coal Steam	304.9	306.0	300.9	315.0	315.3	316.4	0.2%
Other Fossil Steam[3]	138.2	138.2	128.5	120.4	117.3	116.1	-0.8%
Combined Cycle	19.2	20.2	49.5	126.0	181.3	229.1	12.2%
Combustion Turbine/Diesel	66.8	75.2	130.6	164.1	184.6	210.7	5.0%
Nuclear Power	97.1	97.4	97.5	93.7	79.5	71.6	-1.5%
Pumped Storage	19.3	19.3	19.5	19.5	19.5	19.5	0.0%
Fuel Cells	0.0	0.0	0.0	0.1	0.3	0.3	34.2%
Renewable Sources[4]	87.3	88.1	92.1	95.4	96.5	97.0	0.5%
Distributed Generation[5]	0.0	0.0	2.0	6.0	8.8	12.7	N/A
Total	**732.8**	**744.6**	**818.6**	**934.3**	**994.4**	**1060.7**	**1.7%**
Cumulative Planned Additions[6]							
Coal Steam	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Other Fossil Steam[3]	0.0	0.0	0.1	0.1	0.1	0.1	N/A
Combined Cycle	0.0	0.0	8.3	8.3	8.3	8.3	N/A
Combustion Turbine/Diesel	0.0	0.0	0.7	0.7	0.7	0.7	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.1	0.3	0.3	N/A
Renewable Sources[4]	0.0	0.0	2.4	4.3	5.1	5.4	N/A
Distributed Generation[5]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Total	**0.0**	**0.0**	**11.5**	**13.6**	**14.5**	**14.8**	**N/A**
Cumulative Unplanned Additions[6]							
Coal Steam	0.0	0.0	2.4	18.5	19.5	21.8	N/A
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combined Cycle	0.0	0.0	20.9	97.5	152.8	200.5	N/A
Combustion Turbine/Diesel	0.0	0.0	58.3	93.1	114.3	140.5	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[4]	0.0	0.0	1.3	2.6	2.9	3.1	N/A
Distributed Generation[5]	0.0	0.0	2.0	6.0	8.8	12.7	N/A
Total	**0.0**	**0.0**	**84.9**	**217.7**	**298.3**	**378.7**	**N/A**
Cumulative Total Additions	**0.0**	**0.0**	**96.4**	**231.3**	**312.8**	**393.4**	**N/A**
Cumulative Retirements[7]							
Coal Steam	0.0	0.0	11.5	13.5	14.2	15.4	N/A
Other Fossil Steam[3]	0.0	0.0	9.6	17.7	20.8	22.0	N/A
Combined Cycle	0.0	0.0	0.0	0.1	0.1	0.1	N/A
Combustion Turbine/Diesel	0.0	0.0	3.8	5.1	5.8	5.9	N/A
Nuclear Power	0.0	0.0	0.0	3.7	18.0	25.9	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[4]	0.0	0.0	0.1	0.1	0.1	0.1	N/A
Total	**0.0**	**0.0**	**25.1**	**40.3**	**59.0**	**69.4**	**N/A**

Table A9. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	Reference Case 1998	1999	2005	2010	2015	2020	Annual Growth 1999-2020 (percent)
Cogenerators[8]							
Capability							
Coal	8.2	8.4	8.9	8.9	8.9	8.9	0.3%
Petroleum	2.7	2.7	2.7	2.8	2.8	2.8	0.2%
Natural Gas	33.3	33.8	40.0	43.0	45.7	49.0	1.8%
Other Gaseous Fuels	0.2	0.2	0.8	0.9	1.0	1.1	7.2%
Renewable Sources[4]	5.3	5.3	5.9	6.8	7.5	8.2	2.1%
Other	1.1	1.1	0.9	0.9	0.9	0.9	-1.1%
Total	**50.9**	**51.6**	**59.2**	**63.2**	**66.8**	**70.9**	**1.5%**
Cumulative Additions[6]	**0.0**	**0.0**	**7.6**	**11.5**	**15.2**	**19.2**	**N/A**
Other End-Use Generators[9]							
Renewable Sources[10]	1.0	1.0	1.1	1.3	1.3	1.3	1.4%
Cumulative Additions	0.0	0.0	0.1	0.3	0.3	0.3	N/A

[1]Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes grid-connected utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[3]Includes oil-, gas-, and dual-fired capability.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar and wind power.
[5]Primarily peak-load capacity fueled by natural gas.
[6]Cumulative additions after December 31, 1999.
[7]Cumulative total retirements after December 31, 1999.
[8]Nameplate capacity is reported for nonutilities on Form EIA-860B: "Annual Electric Generator Report - Nonutility." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.
[9]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[10]See Table A17 for more detail.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators to be consistent with capability estimates for electric utility generators.
Sources: 1998 electric utilities capability and projected planned additions: Energy Information Administration (EIA), Form EIA-860A: "Annual Electric Generator Report - Utility." 1998 nonutilities including cogenerators capability and projected planned additions: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility" and NewGen Data and Analysis, RDI Consulting/FT Energy (Boulder, CO, August 2000). 1998 other generators capability: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility" and Department of Energy, Office of Energy Efficiency and Renewable Energy estimates. **1999 and projections**: EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A10. Electricity Trade

(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Interregional Electricity Trade							
Gross Domestic Firm Power Trade	197.2	182.2	125.3	102.9	45.7	0.0	N/A
Gross Domestic Economy Trade	154.6	147.2	201.6	183.3	195.5	209.0	1.7%
Gross Domestic Trade	**351.7**	**329.4**	**326.9**	**286.2**	**241.3**	**209.0**	**-2.1%**
Gross Domestic Firm Power Sales (million 1999 dollars)	9293.3	8588.0	5906.0	4851.0	2156.0	0.0	N/A
Gross Domestic Economy Sales (million 1999 dollars)	4753.0	4331.0	6060.0	5042.0	5513.0	6291.0	1.8%
Gross Domestic Sales (million 1999 dollars)	**14046.4**	**12919.0**	**11965.0**	**9893.0**	**7669.0**	**6291.0**	**-3.4%**
International Electricity Trade							
Firm Power Imports From Canada and Mexico[1]	21.3	27.0	10.7	5.8	2.6	0.0	N/A
Economy Imports From Canada and Mexico[1]	24.1	20.6	58.1	39.7	30.0	28.6	1.6%
Gross Imports From Canada and Mexico[1]	**45.4**	**47.6**	**68.7**	**45.5**	**32.6**	**28.6**	**-2.4%**
Firm Power Exports To Canada and Mexico	3.8	9.2	9.7	8.7	3.9	0.0	N/A
Economy Exports To Canada and Mexico	14.1	6.3	7.0	7.7	7.7	7.7	0.9%
Gross Exports To Canada and Mexico	**17.9**	**15.5**	**16.7**	**16.4**	**11.5**	**7.7**	**-3.3%**

[1]Historically electricity imports were primarily from renewable resources, principally hydroelectric.

N/A = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 1998 interregional firm electricity trade data: North American Electric Reliability Council (NERC), Electricity Sales and Demand Database 1998. 1998 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 1998 firm/economy share: National Energy Board, *Annual Report 1998*. **1999 and projections:** Energy Information Administration, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Crude Oil							
Domestic Crude Production[1]	6.23	5.88	5.65	5.15	5.08	5.05	-0.7%
Alaska	1.18	1.05	0.79	0.64	0.70	0.64	-2.4%
Lower 48 States	5.05	4.83	4.86	4.50	4.38	4.41	-0.4%
Net Imports	8.60	8.61	10.59	11.54	11.91	12.14	1.6%
Gross Imports	8.70	8.73	10.66	11.59	11.95	12.18	1.6%
Exports	0.11	0.12	0.06	0.04	0.04	0.04	-5.3%
Other Crude Supply[2]	0.04	0.31	0.00	0.00	0.00	0.00	N/A
Total Crude Supply	**14.87**	**14.80**	**16.24**	**16.69**	**16.99**	**17.19**	**0.7%**
Natural Gas Plant Liquids	**1.76**	**1.85**	**2.14**	**2.35**	**2.63**	**2.89**	**2.1%**
Other Inputs[3]	**0.32**	**0.60**	**0.29**	**0.20**	**0.21**	**0.23**	**-4.4%**
Refinery Processing Gain[4]	**0.89**	**0.89**	**0.92**	**1.02**	**1.06**	**1.10**	**1.0%**
Net Product Imports[5]	**1.17**	**1.30**	**1.56**	**2.38**	**3.33**	**4.37**	**6.0%**
Gross Refined Product Imports[6]	1.63	1.73	1.91	2.40	3.30	4.26	4.4%
Unfinished Oil Imports	0.30	0.32	0.45	0.79	0.87	0.99	5.6%
Ether Imports	0.07	0.08	0.00	0.00	0.00	0.00	N/A
Exports	0.83	0.82	0.80	0.81	0.84	0.88	0.3%
Total Primary Supply[7]	**19.00**	**19.44**	**21.15**	**22.64**	**24.21**	**25.79**	**1.4%**
Refined Petroleum Products Supplied							
Motor Gasoline[8]	8.25	8.43	9.40	10.11	10.75	11.33	1.4%
Jet Fuel[9]	1.62	1.67	1.89	2.18	2.52	2.88	2.6%
Distillate Fuel[10]	3.50	3.52	4.12	4.47	4.78	5.10	1.8%
Residual Fuel	0.93	0.82	0.63	0.58	0.59	0.60	-1.4%
Other[11]	4.61	5.07	5.17	5.36	5.62	5.92	0.7%
Total	**18.92**	**19.50**	**21.21**	**22.70**	**24.26**	**25.83**	**1.3%**
Refined Petroleum Products Supplied							
Residential and Commercial	1.06	1.10	1.13	1.06	1.04	1.02	-0.4%
Industrial[12]	4.81	5.16	5.29	5.58	5.89	6.23	0.9%
Transportation	12.49	12.86	14.64	15.98	17.26	18.50	1.7%
Electric Generators[13]	0.55	0.38	0.14	0.07	0.07	0.08	-7.3%
Total	**18.92**	**19.50**	**21.21**	**22.70**	**24.26**	**25.83**	**1.3%**
Discrepancy[14]	**0.08**	**-0.07**	**-0.06**	**-0.06**	**-0.05**	**-0.04**	**N/A**
World Oil Price (1999 dollars per barrel)[15]	**12.02**	**17.35**	**20.83**	**21.37**	**21.89**	**22.41**	**1.2%**
Import Share of Product Supplied	**0.52**	**0.51**	**0.57**	**0.61**	**0.63**	**0.64**	**1.1%**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 1999 dollars)	**46.22**	**60.16**	**94.52**	**113.67**	**129.29**	**145.38**	**4.3%**
Domestic Refinery Distillation Capacity[16]	**16.3**	**16.5**	**17.7**	**17.9**	**18.1**	**18.2**	**0.5%**
Capacity Utilization Rate (percent)	**96.0**	**93.0**	**92.1**	**93.6**	**94.3**	**95.0**	**0.1%**

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.
[3]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, and other hydrocarbons.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[6]Includes blending components.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net petroleum imports.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes naphtha and kerosene types.
[10]Includes distillate and kerosene.
[11]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[12]Includes consumption by cogenerators.
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses and gains.
[15]Average refiner acquisition cost for imported crude oil.
[16]End-of-year capacity.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1998 and 1999 product supplied data from Table A2. Other 1998 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1998,* DOE/EIA-0340(98/1) (Washington, DC, June 1999). Other 1999 data: EIA, *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). **Projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A12. Petroleum Product Prices
(1999 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
World Oil Price (1999 dollars per barrel)	**12.02**	**17.35**	**20.83**	**21.37**	**21.89**	**22.41**	**1.2%**
Delivered Sector Product Prices							
Residential							
Distillate Fuel	86.7	87.0	101.7	104.1	108.1	110.7	1.2%
Liquefied Petroleum Gas	90.2	89.4	110.7	112.8	110.7	111.1	1.0%
Commercial							
Distillate Fuel	55.6	60.6	71.1	73.2	77.0	79.7	1.3%
Residual Fuel	36.2	39.3	54.5	55.3	56.4	57.6	1.8%
Residual Fuel (1999 dollars per barrel)	15.19	16.53	22.87	23.22	23.71	24.20	1.8%
Industrial[1]							
Distillate Fuel	57.1	64.5	73.4	75.6	79.5	82.5	1.2%
Liquefied Petroleum Gas	62.7	73.4	68.5	69.1	66.9	67.6	-0.4%
Residual Fuel	38.3	41.7	50.4	51.2	52.4	53.6	1.2%
Residual Fuel (1999 dollars per barrel)	16.10	17.50	21.16	21.51	22.00	22.50	1.2%
Transportation							
Diesel Fuel (distillate)[2]	106.2	114.0	123.2	124.0	125.5	124.6	0.4%
Jet Fuel[3]	55.8	63.5	70.9	73.8	77.7	79.4	1.1%
Motor Gasoline[4]	109.3	118.2	132.6	136.3	133.9	133.0	0.6%
Liquified Petroleum Gas	96.9	111.1	122.5	123.1	120.5	119.5	0.3%
Residual Fuel	34.2	36.8	46.5	47.5	48.7	49.8	1.5%
Residual Fuel (1999 dollars per barrel)	14.37	15.45	19.52	19.96	20.45	20.92	1.5%
Ethanol (E85)	127.7	129.2	171.2	170.1	172.2	173.3	1.4%
Methanol (M85)	65.5	76.2	96.2	100.7	105.1	105.8	1.6%
Electric Generators[5]							
Distillate Fuel	45.1	56.2	64.5	67.1	70.7	73.2	1.3%
Residual Fuel	33.2	36.2	52.7	58.1	59.9	60.9	2.5%
Residual Fuel (1999 dollars per barrel)	13.93	15.21	22.11	24.42	25.17	25.56	2.5%
Refined Petroleum Product Prices[6]							
Distillate Fuel	92.7	100.8	111.9	113.5	115.9	116.2	0.7%
Jet Fuel[3]	55.8	63.5	70.9	73.8	77.7	79.4	1.1%
Liquefied Petroleum Gas	68.0	76.3	76.3	76.6	74.1	74.4	-0.1%
Motor Gasoline[4]	109.3	118.2	132.6	136.3	133.9	133.0	0.6%
Residual Fuel	34.2	37.1	48.8	49.8	51.0	52.2	1.6%
Residual Fuel (1999 dollars per barrel)	14.38	15.59	20.49	20.93	21.44	21.94	1.6%
Average	**89.0**	**97.6**	**110.2**	**113.1**	**112.5**	**112.2**	**0.7%**

[1]Includes cogenerators. Includes Federal and State taxes while excluding county and state taxes.
[2] Low sulfur diesel fuel. Includes Federal and State taxes while excluding county and local taxes.
[3]Kerosene-type jet fuel.
[4]Sales weighted-average price for all grades. Includes Federal and State taxes while excluding county and local taxes.
[5]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1998 prices for gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1998*, ftp://ftp.eia.doe.gov/pub/ oil_gas/petroleum/data_publications/petroleum_marketing_annual/historical/1998/pdf/pmaall.pdf (October 1999). 1999 prices for gasoline, distillate, and jet fuel are based on prices in various issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380 (99/03-2000/04) (Washington, DC, 1999-2000). 1998 and 1999 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditure Report 1997*, DOE/EIA-0376(97) (Washington, DC, July 2000). **Projections**: EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Production							
Dry Gas Production[1]	18.71	18.67	20.81	23.14	26.24	29.04	2.1%
Supplemental Natural Gas[2]	0.10	0.10	0.11	0.06	0.06	0.06	-2.4%
Net Imports	**2.99**	**3.38**	**4.48**	**5.06**	**5.50**	**5.80**	**2.6%**
Canada	3.01	3.29	4.30	4.81	5.21	5.46	2.4%
Mexico	-0.04	-0.01	-0.18	-0.25	-0.33	-0.40	21.7%
Liquefied Natural Gas	0.02	0.10	0.36	0.50	0.62	0.74	10.2%
Total Supply	**21.80**	**22.15**	**25.40**	**28.25**	**31.80**	**34.90**	**2.2%**
Consumption by Sector							
Residential	4.55	4.72	5.32	5.54	5.83	6.14	1.3%
Commercial	3.02	3.07	3.62	3.78	3.94	4.02	1.3%
Industrial[3]	8.37	7.95	8.81	9.33	9.76	10.18	1.2%
Electric Generators[4]	3.68	3.78	5.35	6.94	9.30	11.34	5.4%
Lease and Plant Fuel[5]	1.16	1.23	1.35	1.49	1.68	1.84	1.9%
Pipeline Fuel	0.64	0.64	0.75	0.87	0.97	1.06	2.4%
Transportation[6]	0.01	0.02	0.05	0.09	0.13	0.15	11.7%
Total	**21.41**	**21.41**	**25.24**	**28.05**	**31.61**	**34.73**	**2.3%**
Discrepancy[7]	**0.39**	**0.74**	**0.16**	**0.21**	**0.18**	**0.17**	**N/A**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 1998 and 1999 values include net storage injections.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1998 supply values and consumption as lease, plant, and pipeline fuel: Energy Information Administration (EIA), *Natural Gas Annual 1998*, DOE/EIA-0131(98) (Washington, DC, October 1999). Other 1998 consumption derived from: EIA, *State Energy Data Report 1997*, DOE/EIA-0214(97) (Washington, DC, September 1999). 1999 supplemental natural gas: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1998 imports and dry gas production derived from: EIA, *Natural Gas Annual 1998*, DOE/EIA-0131(98) (Washington, DC, October 1999). 1999 transportation sector consumption: EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A. Other 1999 consumption: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A. **Projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A14. Natural Gas Prices, Margins, and Revenues
(1999 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Source Price							
Average Lower 48 Wellhead Price[1]	2.02	2.08	2.49	2.69	2.83	3.13	2.0%
Average Import Price	1.99	2.29	2.49	2.43	2.47	2.67	0.7%
Average[2]	**2.01**	**2.11**	**2.49**	**2.64**	**2.76**	**3.05**	**1.8%**
Delivered Prices							
Residential	6.92	6.69	6.81	6.70	6.61	6.73	0.0%
Commercial	5.62	5.49	5.45	5.65	5.65	5.86	0.3%
Industrial[3]	2.80	2.87	3.26	3.40	3.54	3.86	1.4%
Electric Generators[4]	2.46	2.59	2.94	3.08	3.30	3.66	1.6%
Transportation[5]	6.57	7.21	6.99	7.23	7.36	7.52	0.2%
Average[6]	**4.13**	**4.16**	**4.35**	**4.38**	**4.39**	**4.62**	**0.5%**
Transmission and Distribution Margins[7]							
Residential	4.91	4.58	4.32	4.07	3.85	3.68	-1.0%
Commercial	3.60	3.37	2.96	3.01	2.89	2.81	-0.9%
Industrial[3]	0.79	0.75	0.77	0.76	0.78	0.82	0.4%
Electric Generators[4]	0.44	0.48	0.44	0.45	0.54	0.61	1.2%
Transportation[5]	4.56	5.10	4.50	4.60	4.60	4.48	-0.6%
Average[6]	**2.12**	**2.04**	**1.86**	**1.74**	**1.63**	**1.57**	**-1.2%**
Transmission and Distribution Revenue (billion 1999 dollars)							
Residential	22.31	21.61	22.96	22.55	22.42	22.58	0.2%
Commercial	10.87	10.36	10.71	11.40	11.38	11.31	0.4%
Industrial[3]	6.60	6.00	6.75	7.12	7.61	8.32	1.6%
Electric Generators[4]	1.63	1.81	2.38	3.11	5.02	6.93	6.6%
Transportation[5]	0.05	0.08	0.25	0.42	0.58	0.69	11.0%
Total	**41.45**	**39.86**	**43.04**	**44.59**	**47.01**	**49.82**	**1.1%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.

Sources: 1998 residential, commercial, and transportation delivered prices; average lower 48 wellhead price; and average import price: Energy Information Administration (EIA), *Natural Gas Annual 1998*, DOE/EIA-0131(98) (Washington, DC, October 1999). 1998 electric generators delivered price: Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 1998 and 1999 industrial delivered prices based on EIA, *Manufacturing Energy Consumption Survey 1994*. 1999 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). **Other 1998 values, other 1999 values, and projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A15. Oil and Gas Supply

Production and Supply	Reference Case 1998	1999	2005	2010	2015	2020	Annual Growth 1999-2020 (percent)
Crude Oil							
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	**11.79**	**16.49**	**20.42**	**20.80**	**21.00**	**21.45**	**1.3%**
Production (million barrels per day)[2]							
U.S. Total	**6.23**	**5.88**	**5.65**	**5.15**	**5.08**	**5.05**	**-0.7%**
Lower 48 Onshore	3.60	3.27	2.75	2.46	2.52	2.64	-1.0%
Conventional	2.87	2.59	2.14	1.79	1.78	1.92	-1.4%
Enhanced Oil Recovery	0.73	0.68	0.61	0.66	0.74	0.72	0.3%
Lower 48 Offshore	1.45	1.56	2.11	2.05	1.86	1.77	0.6%
Alaska	1.18	1.05	0.79	0.64	0.70	0.64	-2.4%
Lower 48 End of Year Reserves (billion barrels)[2]	**17.32**	**18.33**	**15.48**	**13.92**	**13.50**	**13.48**	**-1.5%**
Natural Gas							
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	**2.02**	**2.08**	**2.49**	**2.69**	**2.83**	**3.13**	**2.0%**
Dry Production (trillion cubic feet)[3]							
U.S. Total	**18.71**	**18.67**	**20.81**	**23.14**	**26.24**	**29.04**	**2.1%**
Lower 48 Onshore	12.84	12.83	14.33	16.29	19.04	21.26	2.4%
Associated-Dissolved[4]	1.77	1.80	1.52	1.33	1.32	1.38	-1.3%
Non-Associated	11.08	11.03	12.81	14.96	17.72	19.88	2.8%
Conventional	6.63	6.64	7.20	8.30	10.37	11.38	2.6%
Unconventional	4.45	4.39	5.61	6.66	7.36	8.51	3.2%
Lower 48 Offshore	5.44	5.43	6.02	6.34	6.66	7.21	1.4%
Associated-Dissolved[4]	0.93	0.93	1.07	1.08	1.04	1.01	0.4%
Non-Associated	4.51	4.50	4.94	5.26	5.63	6.19	1.5%
Alaska	0.43	0.42	0.47	0.50	0.54	0.57	1.5%
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**154.11**	**157.41**	**166.63**	**174.82**	**183.82**	**190.07**	**0.9%**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.10**	**0.10**	**0.11**	**0.06**	**0.06**	**0.06**	**-2.4%**
Total Lower 48 Wells (thousands)	**23.77**	**17.94**	**23.82**	**28.63**	**31.62**	**39.14**	**3.8%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1998 lower 48 onshore, lower 48 offshore, Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 1998,* DOE/EIA-0340(98/1) (Washington, DC, June 1999). 1998 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(98) (Washington, DC, December 1999). 1998 natural gas lower 48 average wellhead price and total natural gas production: EIA, *Natural Gas Annual 1998*, DOE/EIA-0131(98) (Washington, DC, October 1999). 1999 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). 1999 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). Other 1998 and 1999 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Production[1]							
Appalachia	468	437	418	409	404	392	-0.5%
Interior	171	166	168	171	169	152	-0.4%
West	488	502	640	692	720	787	2.2%
East of the Mississippi	580	546	538	537	534	512	-0.3%
West of the Mississippi	547	559	688	735	760	819	1.8%
Total	**1127**	**1105**	**1226**	**1273**	**1294**	**1331**	**0.9%**
Net Imports							
Imports	9	9	16	17	18	20	3.8%
Exports	78	58	60	58	54	56	-0.2%
Total	**-69**	**-49**	**-44**	**-40**	**-35**	**-36**	**-1.4%**
Total Supply[2]	**1058**	**1056**	**1182**	**1232**	**1259**	**1295**	**1.0%**
Consumption by Sector							
Residential and Commercial	5	5	5	5	5	5	0.6%
Industrial[3]	81	79	83	84	85	86	0.5%
Coke Plants	28	28	26	23	21	19	-1.9%
Electric Generators[4]	923	923	1069	1122	1149	1186	1.2%
Total	**1037**	**1035**	**1183**	**1235**	**1261**	**1297**	**1.1%**
Discrepancy and Stock Change[5].	**20**	**21**	**-1**	**-2**	**-2**	**-2**	**N/A**
Average Minemouth Price							
(1999 dollars per short ton)	18.02	16.98	14.68	13.83	13.38	12.70	-1.4%
(1999 dollars per million Btu)	0.85	0.81	0.71	0.68	0.66	0.63	-1.2%
Delivered Prices (1999 dollars per short ton)[6]							
Industrial	31.91	31.43	29.50	28.40	27.49	26.48	-0.8%
Coke Plants	46.44	44.25	42.57	41.25	39.81	38.57	-0.7%
Electric Generators							
(1999 dollars per short ton)	26.00	24.69	22.73	21.04	20.25	19.45	-1.1%
(1999 dollars per million Btu)	1.27	1.21	1.13	1.05	1.01	0.98	-1.0%
Average	**27.02**	**25.74**	**23.64**	**21.92**	**21.06**	**20.19**	**-1.1%**
Exports[7]	39.84	37.45	36.43	35.53	34.38	33.09	-0.6%

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 8.5 million tons in 1995, 8.8 million tons in 1996, 8.1 million tons in 1997, 8.6 million tons in 1998, and are projected to reach 9.6 million tons in 1999, and 12.2 million tons in 2000.
[2]Production plus net imports and net storage withdrawals.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Balancing item: the sum of production, net imports, and net storage minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7] F.a.s. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1998: Energy Information Administration (EIA), *Coal Industry Annual 1998*, DOE/EIA-0584(98) (Washington, DC, June 2000). 1999 data based on EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000) and EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A. **Projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A17. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Electric Generators[1] (excluding cogenerators)							
Net Summer Capability							
Conventional Hydropower	78.12	78.14	78.62	78.74	78.74	78.74	0.0%
Geothermal[2]	2.86	2.87	3.15	4.34	4.41	4.41	2.1%
Municipal Solid Waste[3]	2.56	2.59	3.80	4.20	4.57	4.72	2.9%
Wood and Other Biomass[4]	1.46	1.52	1.68	2.04	2.33	2.37	2.2%
Solar Thermal	0.33	0.33	0.35	0.40	0.44	0.48	1.7%
Solar Photovoltaic	0.01	0.01	0.09	0.21	0.37	0.54	19.4%
Wind	1.93	2.60	4.43	5.51	5.70	5.78	3.9%
Total	**87.28**	**88.07**	**92.11**	**95.44**	**96.55**	**97.04**	**0.5%**
Generation (billion kilowatthours)							
Conventional Hydropower	315.21	307.43	299.05	298.99	298.45	297.94	-0.1%
Geothermal[2]	15.06	13.07	15.86	25.27	25.81	25.83	3.3%
Municipal Solid Waste[3]	18.88	18.05	27.35	30.00	32.88	33.96	3.1%
Wood and Other Biomass[4]	6.50	9.49	17.27	21.59	23.21	22.15	4.1%
Dedicated Plants	6.50	7.56	8.67	10.88	12.99	13.35	2.7%
Cofiring	0.00	1.93	8.61	10.71	10.22	8.80	7.5%
Solar Thermal	0.89	0.89	0.96	1.11	1.24	1.37	2.1%
Solar Photovoltaic	0.00	0.03	0.20	0.51	0.92	1.36	19.3%
Wind	2.69	4.46	9.42	12.33	12.84	13.10	5.3%
Total	**359.23**	**353.42**	**370.11**	**389.80**	**395.35**	**395.71**	**0.5%**
Cogenerators[5]							
Net Summer Capability							
Municipal Solid Waste	0.70	0.70	0.70	0.70	0.70	0.70	-0.0%
Biomass	4.64	4.65	5.17	6.06	6.85	7.54	2.3%
Total	**5.34**	**5.35**	**5.87**	**6.76**	**7.55**	**8.23**	**2.1%**
Generation (billion kilowatthours)							
Municipal Solid Waste	3.91	4.03	4.03	4.03	4.03	4.03	0.0%
Biomass	27.15	27.08	29.92	35.01	39.55	43.52	2.3%
Total	**31.07**	**31.11**	**33.95**	**39.03**	**43.58**	**47.55**	**2.0%**
Other End-Use Generators[6]							
Net Summer Capability							
Conventional Hydropower[7]	0.99	0.99	0.99	0.99	0.99	0.99	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Solar Photovoltaic	0.01	0.01	0.10	0.35	0.35	0.35	19.1%
Total	**1.00**	**1.00**	**1.09**	**1.34**	**1.34**	**1.34**	**1.4%**
Generation (billion kilowatthours)							
Conventional Hydropower[7]	5.97	4.57	4.44	4.43	4.42	4.41	-0.2%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Solar Photovoltaic	0.00	0.02	0.20	0.75	0.75	0.75	19.2%
Total	**5.97**	**4.59**	**4.64**	**5.18**	**5.18**	**5.17**	**0.6%**

[1]Includes grid-connected utilities and nonutilities other than cogenerators. These nonutility facilities include small power producers and exempt wholesale generators.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Cogenerators produce electricity and other useful thermal energy.
[6]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[7]Represents own-use industrial hydroelectric power.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators for AEO2001. Net summer capability is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.
Sources: 1998 and 1999 electric utility capability: Energy Information Administration (EIA), Form EIA-860A: "Annual Electric Generator Report - Utility." 1998 and 1999 nonutility and cogenerator capability: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." 1998 and 1999 generation: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A18. Renewable Energy, Consumption by Sector and Source

(Quadrillion Btu per Year)

Sector and Source	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Marketed Renewable Energy[2]							
Residential	**0.39**	**0.41**	**0.43**	**0.43**	**0.43**	**0.44**	**0.4%**
Wood	0.39	0.41	0.43	0.43	0.43	0.44	0.4%
Commercial	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.0%**
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.0%
Industrial[3]	**2.10**	**2.15**	**2.42**	**2.64**	**2.86**	**3.08**	**1.7%**
Conventional Hydroelectric	0.18	0.18	0.18	0.18	0.18	0.18	N/A
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Biomass	1.91	1.97	2.23	2.46	2.68	2.90	1.9%
Transportation	**0.11**	**0.12**	**0.20**	**0.21**	**0.23**	**0.24**	**3.6%**
Ethanol used in E85[4]	0.00	0.00	0.02	0.03	0.03	0.04	N/A
Ethanol used in Gasoline Blending	0.11	0.12	0.18	0.19	0.20	0.21	2.8%
Electric Generators[5]	**4.05**	**3.94**	**4.19**	**4.64**	**4.71**	**4.66**	**0.8%**
Conventional Hydroelectric	3.31	3.17	3.08	3.08	3.07	3.06	-0.2%
Geothermal	0.38	0.38	0.46	0.81	0.82	0.77	3.3%
Municipal Solid Waste[6]	0.24	0.25	0.37	0.41	0.45	0.46	3.0%
Biomass	0.07	0.09	0.16	0.21	0.22	0.21	4.3%
Dedicated Plants	0.07	0.07	0.08	0.10	0.12	0.13	2.9%
Cofiring	0.00	0.02	0.08	0.10	0.10	0.08	7.7%
Solar Thermal	0.01	0.01	0.01	0.02	0.02	0.03	5.3%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Wind	0.04	0.05	0.10	0.13	0.13	0.13	5.3%
Total Marketed Renewable Energy	**6.73**	**6.70**	**7.32**	**8.01**	**8.32**	**8.51**	**1.1%**
Non-Marketed Renewable Energy[7] **Selected Consumption**							
Residential	**0.02**	**0.02**	**0.03**	**0.03**	**0.03**	**0.04**	**2.4%**
Solar Hot Water Heating	0.01	0.01	0.01	0.00	0.00	0.00	-0.4%
Geothermal Heat Pumps	0.02	0.02	0.02	0.03	0.03	0.03	2.9%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	21.6%
Commercial	**0.02**	**0.02**	**0.02**	**0.03**	**0.03**	**0.03**	**1.5%**
Solar Thermal	0.02	0.02	0.02	0.02	0.03	0.03	1.2%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	18.2%
Ethanol							
From Corn	0.11	0.12	0.19	0.19	0.19	0.17	1.9%
From Cellulose	0.00	0.00	0.01	0.02	0.04	0.07	N/A
Total	**0.11**	**0.12**	**0.20**	**0.21**	**0.23**	**0.24**	**3.6%**

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table A8.
[3]Includes all electricity production by industrial and other cogenerators for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes renewable energy delivered to the grid from electric utilities and nonutilities. Renewable energy used in generating electricity for own use is included in the individual sectoral electricity energy consumption values.
[6]Includes landfill gas.
[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1998 and 1999 ethanol: Energy Information Administration (EIA), *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). 1998 and 1999 electric generators: EIA, Form EIA-860A: "Annual Electric Generator Report - Utility" and Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 1998 and 1999: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A19. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Residential							
Petroleum	24.7	26.0	26.9	24.4	23.4	22.9	-0.6%
Natural Gas	67.2	69.5	78.6	82.0	86.2	90.8	1.3%
Coal	1.1	1.1	1.3	1.3	1.3	1.3	0.5%
Electricity	194.9	192.6	221.8	238.2	255.2	273.2	1.7%
Total	**288.0**	**289.3**	**328.6**	**345.9**	**366.2**	**388.1**	**1.4%**
Commercial							
Petroleum	13.0	13.7	12.9	13.1	13.1	12.9	-0.3%
Natural Gas	44.6	45.4	53.5	55.9	58.3	59.4	1.3%
Coal	1.7	1.7	1.8	1.9	1.9	2.0	0.6%
Electricity	184.6	182.1	214.4	234.4	253.0	263.9	1.8%
Total	**243.9**	**242.9**	**282.5**	**305.3**	**326.3**	**338.2**	**1.6%**
Industrial[1]							
Petroleum	100.9	104.2	99.0	104.7	109.9	115.5	0.5%
Natural Gas[2]	141.2	141.6	147.9	157.6	166.8	175.1	1.0%
Coal	57.7	55.9	66.5	66.3	66.2	66.4	0.8%
Electricity	179.8	178.8	192.6	200.8	212.4	226.6	1.1%
Total	**479.5**	**480.4**	**506.0**	**529.4**	**555.2**	**583.6**	**0.9%**
Transportation							
Petroleum[3]	471.5	485.8	556.8	608.5	657.3	704.9	1.8%
Natural Gas[4]	9.5	9.5	11.9	14.3	16.2	18.0	3.1%
Other[5]	0.0	0.0	0.1	0.1	0.1	0.1	N/A
Electricity	2.9	2.9	4.4	5.7	6.9	7.8	4.8%
Total[3]	**484.0**	**498.2**	**573.1**	**628.5**	**680.5**	**730.8**	**1.8%**
Total Carbon Dioxide Emissions by Delivered Fuel							
Petroleum[3]	610.1	629.7	695.5	750.6	803.7	856.1	1.5%
Natural Gas	262.5	266.0	291.9	309.8	327.5	343.3	1.2%
Coal	60.5	58.8	69.6	69.5	69.4	69.6	0.8%
Other[5]	0.0	0.0	0.1	0.1	0.1	0.1	N/A
Electricity	562.2	556.3	633.1	679.1	727.5	771.5	1.6%
Total[3]	**1495.4**	**1510.8**	**1690.2**	**1809.1**	**1928.1**	**2040.6**	**1.4%**
Electric Generators[6]							
Petroleum	24.8	20.0	6.7	3.4	3.4	3.7	-7.7%
Natural Gas	47.9	45.8	78.5	101.8	136.5	166.3	6.3%
Coal	489.5	490.5	547.9	574.0	587.6	601.5	1.0%
Total	**562.2**	**556.3**	**633.1**	**679.1**	**727.5**	**771.5**	**1.6%**
Total Carbon Dioxide Emissions By Primary Fuel[7]							
Petroleum[3]	634.9	649.7	702.3	754.0	807.1	859.9	1.3%
Natural Gas	310.5	311.8	370.4	411.5	463.9	509.6	2.4%
Coal	550.0	549.3	617.5	643.5	657.0	671.1	1.0%
Other[5]	0.0	0.0	0.1	0.1	0.1	0.1	N/A
Total[3]	**1495.4**	**1510.8**	**1690.2**	**1809.1**	**1928.1**	**2040.6**	**1.4%**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.5**	**5.9**	**6.0**	**6.2**	**6.3**	**0.6%**

[1]Includes consumption by cogenerators.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel which, by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 1998, international bunker fuels accounted for 25 to 30 million metric tons carbon equivalent of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes methanol and liquid hydrogen.
[6]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste not energy.
[7]Emissions from electric power generators are distributed to the primary fuels.
N/A = Not applicable
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1998 and 1999 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 1999,* DOE/EIA-0573(99) (Washington, DC, October 2000). **Projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A20. Macroeconomic Indicators
(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	Reference Case 1998	1999	2005	2010	2015	2020	Annual Growth 1999-2020 (percent)
GDP Chain-Type Price Index (1996=1.000)	**1.029**	**1.045**	**1.186**	**1.304**	**1.440**	**1.680**	**2.3%**
Real Gross Domestic Product	**8516**	**8876**	**10960**	**12667**	**14635**	**16515**	**3.0%**
Real Consumption	5689	5990	7365	8535	9934	11312	3.1%
Real Investment	1512	1611	2372	2917	3613	4252	4.7%
Real Government Spending	1486	1536	1721	1877	2022	2193	1.7%
Real Exports	1008	1037	1682	2445	3465	4757	7.5%
Real Imports	1225	1356	2205	3084	4336	5986	7.3%
Real Disposable Personal Income	**6165**	**6363**	**7702**	**8928**	**10361**	**11842**	**3.0%**
AA Utility Bond Rate (percent)	**6.24**	**7.05**	**7.45**	**8.76**	**8.60**	**9.51**	**N/A**
Real Yield on Government 10 Year Bonds (percent)	**4.29**	**4.75**	**4.22**	**5.59**	**5.55**	**5.43**	**N/A**
Real Utility Bond Rate (percent)	**4.66**	**5.58**	**5.27**	**6.90**	**6.49**	**6.09**	**N/A**
Energy Intensity (thousand Btu per 1996 dollar of GDP)							
Delivered Energy	8.28	8.08	7.31	6.79	6.27	5.89	-1.5%
Total Energy	11.14	10.84	9.77	9.02	8.25	7.70	-1.6%
Consumer Price Index (1982-84=1.00)	**1.63**	**1.67**	**1.95**	**2.20**	**2.49**	**2.95**	**2.8%**
Unemployment Rate (percent)	**4.50**	**4.22**	**4.39**	**4.94**	**4.32**	**4.28**	**N/A**
Housing Starts (millions)	1.99	2.02	1.98	1.89	2.10	2.09	0.2%
Single-Family	1.28	1.34	1.28	1.17	1.28	1.27	-0.2%
Multifamily	0.34	0.34	0.40	0.41	0.48	0.46	1.6%
Mobile Home Shipments	0.37	0.35	0.30	0.30	0.34	0.35	0.0%
Commercial Floorspace, Total (billion square feet)	**61.5**	**62.8**	**70.9**	**75.8**	**79.6**	**81.9**	**1.3%**
Gross Output (billion 1992 dollars)							
Total Industrial	4654	4722	5469	6251	7093	8096	2.6%
Nonmanufacturing	950	972	1070	1162	1265	1370	1.6%
Manufacturing	3704	3749	4399	5089	5828	6726	2.8%
Energy-Intensive Manufacturing	1064	1078	1174	1248	1322	1396	1.2%
Non-Energy-Intensive Manufacturing	2640	2672	3225	3841	4506	5330	3.3%
Unit Sales of Light-Duty Vehicles (millions)	**15.55**	**16.89**	**16.54**	**15.88**	**17.18**	**17.44**	**0.2%**
Population (millions)							
Population with Armed Forces Overseas	270.6	273.1	288.0	300.2	312.6	325.2	0.8%
Population (aged 16 and over)	208.6	210.9	224.8	236.6	246.7	256.5	0.9%
Employment, Non-Agriculture	125.9	128.5	139.7	149.7	157.3	165.1	1.2%
Employment, Manufacturing	18.9	18.7	18.2	18.0	17.8	17.8	-0.2%
Labor Force	137.7	139.4	149.9	158.2	164.3	169.5	0.9%

GDP = Gross domestic product.
Btu = British thermal unit.
N/A = Not applicable.
Sources: 1998 and 1999: Standard & Poor's DRI, Simulation T250200. **Projections:** Energy Information Administration, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table A21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
World Oil Price (1999 dollars per barrel)[1]	**12.02**	**17.35**	**20.83**	**21.37**	**21.89**	**22.41**	**1.2%**
Production[2]							
OECD							
U.S. (50 states)	9.19	9.22	8.96	8.72	8.98	9.27	0.0%
Canada	2.70	2.63	2.98	3.20	3.38	3.43	1.3%
Mexico	3.52	3.37	3.77	3.99	3.91	3.81	0.6%
OECD Europe[3]	6.95	7.02	7.80	7.68	7.02	6.53	-0.3%
Other OECD	0.77	0.76	0.97	0.98	0.94	0.89	0.7%
Total OECD	**23.14**	**23.00**	**24.47**	**24.57**	**24.23**	**23.93**	**0.2%**
Developing Countries							
Other South & Central America	3.64	3.85	4.07	4.61	5.12	5.48	1.7%
Pacific Rim	2.19	2.30	2.47	3.01	3.17	3.28	1.7%
OPEC	31.33	29.87	36.68	42.16	48.94	57.64	3.2%
Other Developing Countries	4.69	4.81	5.09	5.80	7.11	8.32	2.6%
Total Developing Countries	**41.86**	**40.84**	**48.31**	**55.58**	**64.35**	**74.71**	**2.9%**
Eurasia							
Former Soviet Union	7.24	7.40	7.99	10.68	12.98	14.33	3.2%
Eastern Europe	0.25	0.24	0.30	0.38	0.42	0.45	3.1%
China	3.20	3.21	3.34	3.53	3.63	3.63	0.6%
Total Eurasia	**10.69**	**10.85**	**11.63**	**14.59**	**17.02**	**18.42**	**2.6%**
Total Production	**75.68**	**74.68**	**84.41**	**94.73**	**105.60**	**117.06**	**2.2%**
Consumption							
OECD							
U.S. (50 states)	18.92	19.50	21.21	22.70	24.26	25.83	1.3%
U.S. Territories	0.31	0.34	0.38	0.41	0.44	0.46	1.5%
Canada	1.86	1.92	1.99	2.10	2.16	2.17	0.6%
Mexico	1.96	2.00	2.30	2.78	3.31	3.93	3.3%
Japan	5.51	5.56	5.62	5.85	6.06	6.18	0.5%
Australia and New Zealand	0.96	0.98	1.02	1.09	1.16	1.22	1.0%
OECD Europe[3]	14.73	14.50	15.33	15.81	16.18	16.50	0.6%
Total OECD	**44.24**	**44.81**	**47.85**	**50.74**	**53.56**	**56.29**	**1.1%**
Developing Countries							
Other South and Central America	4.07	4.14	4.86	5.86	6.98	8.39	3.4%
Pacific Rim	7.40	7.64	10.40	12.34	14.18	16.02	3.6%
OPEC	5.60	5.68	6.46	7.78	9.24	10.99	3.2%
Other Developing Countries	3.71	3.75	3.77	4.31	4.95	5.79	2.1%
Total Developing Countries	**20.78**	**21.22**	**25.48**	**30.29**	**35.35**	**41.19**	**3.2%**
Eurasia							
Former Soviet Union	3.77	3.64	4.39	5.29	6.33	7.55	3.5%
Eastern Europe	1.47	1.53	1.61	1.69	1.75	1.78	0.7%
China	4.11	4.31	5.38	7.02	8.92	10.55	4.4%
Total Eurasia	**9.35**	**9.48**	**11.38**	**13.99**	**16.99**	**19.88**	**3.6%**

Table A21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Total Consumption	**74.37**	**75.51**	**84.71**	**95.03**	**105.90**	**117.36**	**2.1%**
Non-OPEC Production	44.35	44.81	47.73	52.58	56.66	59.43	1.4%
Net Eurasia Exports	1.34	1.37	0.26	0.59	0.03	-1.46	N/A
OPEC Market Share	0.41	0.40	0.43	0.45	0.46	0.49	1.0%

[1]Average refiner acquisition cost of imported crude oil.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol, liquids produced from coal and other sources, and refinery gains.
[3]OECD Europe includes the unified Germany.
OECD = Organization for Economic Cooperation and Development - Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States (including territories).
Pacific Rim = Hong Kong, Malaysia, Philippines, Singapore, South Korea, Taiwan, and Thailand.
OPEC = Organization of Petroleum Exporting Countries - Algeria, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
Eurasia = Albania, Bulgaria, China, Czech Republic, Hungary, Poland, Romania, Slovakia, the Former Soviet Union, and the Former Yugoslavia.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1998 and 1999 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Economic Growth Case Comparisons

Table B1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production										
Crude Oil and Lease Condensate	12.45	10.75	10.90	11.03	10.45	10.76	11.06	10.30	10.69	11.13
Natural Gas Plant Liquids	2.62	3.21	3.33	3.47	3.51	3.73	3.95	3.78	4.10	4.29
Dry Natural Gas	19.16	22.85	23.74	24.79	25.27	26.92	28.59	27.44	29.79	31.17
Coal	23.09	25.45	26.06	26.85	25.69	26.42	27.47	25.97	26.95	29.42
Nuclear Power	7.79	7.69	7.69	7.69	6.74	6.82	6.94	5.91	6.13	6.31
Renewable Energy[1]	6.58	7.54	7.82	7.96	7.74	8.12	8.36	7.91	8.31	8.75
Other[2]	1.65	0.31	0.30	0.47	0.31	0.32	0.32	0.32	0.34	0.34
Total	**73.35**	**77.79**	**79.85**	**82.26**	**79.72**	**83.10**	**86.68**	**81.64**	**86.30**	**91.40**
Imports										
Crude Oil[3]	18.96	24.25	25.15	26.20	25.70	25.94	26.63	26.43	26.44	27.21
Petroleum Products[4]	4.14	6.01	6.49	7.23	6.64	8.46	10.09	7.66	10.69	13.46
Natural Gas	3.63	5.48	5.61	5.78	6.01	6.17	6.29	6.35	6.58	6.60
Other Imports[5]	0.62	0.87	0.89	0.95	0.84	0.88	0.95	0.88	0.94	1.05
Total	**27.35**	**36.61**	**38.14**	**40.16**	**39.19**	**41.44**	**43.96**	**41.33**	**44.64**	**48.31**
Exports										
Petroleum[6]	1.98	1.81	1.78	1.82	1.82	1.83	1.87	1.90	1.91	1.91
Natural Gas	0.17	0.43	0.43	0.43	0.53	0.53	0.53	0.63	0.63	0.63
Coal	1.48	1.45	1.46	1.46	1.35	1.35	1.36	1.41	1.41	1.41
Total	**3.62**	**3.70**	**3.67**	**3.70**	**3.71**	**3.72**	**3.76**	**3.94**	**3.95**	**3.95**
Discrepancy[7]	**0.94**	**0.26**	**0.18**	**0.16**	**0.17**	**0.07**	**-0.00**	**0.05**	**-0.04**	**-0.10**
Consumption										
Petroleum Products[8]	38.03	42.71	44.41	46.62	44.81	47.50	50.40	46.73	50.59	54.82
Natural Gas	21.95	27.73	28.75	29.97	30.59	32.39	34.18	33.00	35.57	36.97
Coal	21.43	24.47	25.15	25.99	24.91	25.68	26.77	25.19	26.20	28.77
Nuclear Power	7.79	7.69	7.69	7.69	6.74	6.82	6.94	5.91	6.13	6.31
Renewable Energy[1]	6.59	7.54	7.83	7.96	7.75	8.13	8.37	7.92	8.31	8.76
Other[9]	0.34	0.31	0.31	0.31	0.23	0.23	0.23	0.23	0.23	0.23
Total	**96.14**	**110.45**	**114.14**	**118.55**	**115.03**	**120.75**	**126.88**	**118.98**	**127.03**	**135.86**
Net Imports - Petroleum	**21.12**	**28.45**	**29.86**	**31.62**	**30.52**	**32.57**	**34.85**	**32.18**	**35.22**	**38.76**
Prices (1999 dollars per unit)										
World Oil Price (dollars per barrel)[10]	17.35	20.70	21.37	21.87	20.93	21.89	22.70	21.16	22.41	23.51
Gas Wellhead Price (dollars per Mcf)[11]	2.08	2.49	2.69	3.08	2.59	2.83	3.20	2.66	3.13	3.68
Coal Minemouth Price (dollars per ton)	16.98	13.74	13.83	13.93	13.23	13.38	13.28	12.79	12.70	12.80
Average Electric Price (cents per Kwh)	6.7	5.7	5.9	6.1	5.7	5.9	6.1	5.6	6.0	6.4

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table B18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Mcf = Thousand cubic feet.
Kwh = Kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 petroleum values: EIA, *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). Other 1999 values: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, AND HM2001.D101600A.

Table B2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2015 Low Economic Growth	2015 Reference	2015 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth
Energy Consumption										
Residential										
Distillate Fuel	0.86	0.81	0.81	0.81	0.78	0.77	0.77	0.76	0.75	0.75
Kerosene	0.10	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Liquefied Petroleum Gas	0.46	0.42	0.41	0.41	0.40	0.40	0.40	0.40	0.39	0.39
Petroleum Subtotal	1.42	1.30	1.29	1.29	1.25	1.24	1.24	1.22	1.21	1.21
Natural Gas	4.85	5.64	5.69	5.71	5.86	5.99	6.06	6.11	6.30	6.38
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.41	0.43	0.43	0.43	0.43	0.43	0.43	0.44	0.44	0.44
Electricity	3.91	4.89	4.96	5.01	5.25	5.37	5.46	5.61	5.80	5.92
Delivered Energy	**10.62**	**12.31**	**12.43**	**12.49**	**12.84**	**13.08**	**13.24**	**13.43**	**13.81**	**14.00**
Electricity Related Losses	8.48	9.77	9.87	9.84	10.07	10.19	10.18	10.37	10.55	10.58
Total	**19.10**	**22.08**	**22.30**	**22.34**	**22.91**	**23.27**	**23.42**	**23.81**	**24.36**	**24.59**
Commercial										
Distillate Fuel	0.36	0.40	0.41	0.42	0.40	0.40	0.42	0.38	0.39	0.41
Residual Fuel	0.10	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.11	0.11
Kerosene	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.08	0.09	0.09	0.10	0.09	0.10	0.10	0.09	0.10	0.10
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.59	0.65	0.67	0.68	0.65	0.67	0.69	0.63	0.66	0.69
Natural Gas	3.15	3.79	3.88	3.94	3.90	4.05	4.18	3.93	4.13	4.30
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.07	0.08	0.08
Renewable Energy[3]	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Electricity	3.70	4.74	4.89	5.02	5.09	5.32	5.56	5.28	5.61	5.95
Delivered Energy	**7.59**	**9.33**	**9.59**	**9.80**	**9.79**	**10.19**	**10.59**	**10.01**	**10.55**	**11.10**
Electricity Related Losses	8.01	9.46	9.71	9.87	9.74	10.10	10.36	9.76	10.20	10.63
Total	**15.61**	**18.79**	**19.30**	**19.67**	**19.53**	**20.29**	**20.95**	**19.77**	**20.75**	**21.73**
Industrial[4]										
Distillate Fuel	1.07	1.19	1.27	1.35	1.24	1.35	1.46	1.28	1.44	1.61
Liquefied Petroleum Gas	2.32	2.36	2.50	2.73	2.43	2.65	2.93	2.49	2.83	3.25
Petrochemical Feedstock	1.29	1.44	1.53	1.67	1.47	1.61	1.78	1.49	1.70	1.94
Residual Fuel	0.22	0.24	0.25	0.27	0.24	0.26	0.28	0.25	0.27	0.31
Motor Gasoline[2]	0.21	0.23	0.25	0.26	0.24	0.26	0.28	0.25	0.28	0.31
Other Petroleum[5]	4.29	4.55	4.76	5.08	4.65	5.01	5.37	4.82	5.24	5.77
Petroleum Subtotal	9.39	10.01	10.55	11.35	10.28	11.14	12.11	10.58	11.77	13.19
Natural Gas[6]	9.43	10.68	11.11	11.70	11.07	11.76	12.59	11.38	12.34	13.46
Metallurgical Coal	0.75	0.61	0.61	0.61	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	1.73	1.82	1.85	1.91	1.82	1.87	1.94	1.82	1.90	1.99
Net Coal Coke Imports	0.06	0.13	0.16	0.21	0.15	0.19	0.27	0.17	0.22	0.33
Coal Subtotal	2.54	2.55	2.62	2.73	2.52	2.61	2.76	2.49	2.62	2.83
Renewable Energy[7]	2.15	2.52	2.64	2.82	2.66	2.86	3.10	2.78	3.08	3.44
Electricity	3.63	3.97	4.18	4.53	4.14	4.47	4.92	4.35	4.81	5.47
Delivered Energy	**27.15**	**29.73**	**31.10**	**33.12**	**30.68**	**32.84**	**35.48**	**31.59**	**34.63**	**38.39**
Electricity Related Losses	7.87	7.93	8.32	8.90	7.94	8.48	9.18	8.04	8.76	9.78
Total	**35.02**	**37.66**	**39.42**	**42.02**	**38.62**	**41.31**	**44.66**	**39.63**	**43.39**	**48.17**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Transportation										
Distillate Fuel	5.13	6.63	6.99	7.45	7.05	7.60	8.23	7.44	8.21	9.14
Jet Fuel[8]	3.46	4.27	4.51	4.80	4.81	5.22	5.63	5.32	5.97	6.59
Motor Gasoline[2]	15.92	18.50	19.04	19.62	19.40	20.23	21.05	20.14	21.32	22.46
Residual Fuel	0.74	0.85	0.85	0.86	0.85	0.86	0.87	0.85	0.87	0.88
Liquefied Petroleum Gas	0.02	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.06	0.06
Other Petroleum[9]	0.26	0.29	0.31	0.32	0.31	0.33	0.35	0.32	0.35	0.39
Petroleum Subtotal	25.54	30.59	31.74	33.10	32.47	34.28	36.19	34.12	36.77	39.52
Pipeline Fuel Natural Gas	0.66	0.87	0.90	0.93	0.94	0.99	1.05	1.00	1.09	1.15
Compressed Natural Gas	0.02	0.09	0.09	0.10	0.12	0.13	0.14	0.15	0.16	0.17
Renewable Energy (E85)[10]	0.01	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.05
Methanol (M85)[11]	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.06	0.12	0.12	0.12	0.14	0.15	0.15	0.16	0.17	0.17
Delivered Energy	**26.28**	**31.69**	**32.89**	**34.29**	**33.71**	**35.60**	**37.57**	**35.48**	**38.23**	**41.06**
Electricity Related Losses	0.13	0.23	0.23	0.24	0.27	0.28	0.28	0.29	0.30	0.31
Total	**26.41**	**31.92**	**33.12**	**34.53**	**33.98**	**35.87**	**37.85**	**35.77**	**38.54**	**41.37**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.42	9.03	9.47	10.03	9.47	10.12	10.89	9.86	10.80	11.91
Kerosene	0.15	0.13	0.13	0.13	0.12	0.13	0.13	0.12	0.12	0.13
Jet Fuel[8]	3.46	4.27	4.51	4.80	4.81	5.22	5.63	5.32	5.97	6.59
Liquefied Petroleum Gas	2.88	2.91	3.05	3.28	2.98	3.20	3.49	3.04	3.38	3.81
Motor Gasoline[2]	16.17	18.76	19.31	19.91	19.67	20.52	21.36	20.42	21.63	22.80
Petrochemical Feedstock	1.29	1.44	1.53	1.67	1.47	1.61	1.78	1.49	1.70	1.94
Residual Fuel	1.05	1.19	1.21	1.23	1.20	1.22	1.26	1.20	1.25	1.30
Other Petroleum[12]	4.53	4.82	5.04	5.38	4.94	5.31	5.69	5.12	5.57	6.13
Petroleum Subtotal	36.95	42.55	44.25	46.43	44.65	47.33	50.23	46.56	50.41	54.61
Natural Gas[6]	18.11	21.06	21.68	22.38	21.88	22.91	24.02	22.58	24.02	25.46
Metallurgical Coal	0.75	0.61	0.61	0.61	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	1.84	1.94	1.98	2.03	1.94	1.99	2.06	1.94	2.02	2.12
Net Coal Coke Imports	0.06	0.13	0.16	0.21	0.15	0.19	0.27	0.17	0.22	0.33
Coal Subtotal	2.65	2.67	2.74	2.85	2.64	2.74	2.88	2.61	2.74	2.95
Renewable Energy[13]	2.65	3.06	3.19	3.37	3.21	3.42	3.66	3.34	3.65	4.01
Methanol (M85)[11]	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.29	13.72	14.15	14.67	14.62	15.30	16.09	15.41	16.39	17.52
Delivered Energy	**71.65**	**83.07**	**86.01**	**89.70**	**87.01**	**91.71**	**96.88**	**90.51**	**97.22**	**104.56**
Electricity Related Losses	24.49	27.38	28.13	28.85	28.02	29.04	30.00	28.47	29.81	31.30
Total	**96.14**	**110.45**	**114.14**	**118.55**	**115.03**	**120.75**	**126.88**	**118.98**	**127.03**	**135.86**
Electric Generators[14]										
Distillate Fuel	0.06	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Residual Fuel	1.03	0.12	0.12	0.15	0.12	0.12	0.13	0.12	0.14	0.17
Petroleum Subtotal	1.08	0.16	0.16	0.19	0.16	0.16	0.17	0.16	0.18	0.21
Natural Gas	3.85	6.66	7.07	7.59	8.70	9.48	10.16	10.42	11.55	11.51
Steam Coal	18.78	21.79	22.41	23.14	22.27	22.94	23.89	22.58	23.46	25.82
Nuclear Power	7.79	7.69	7.69	7.69	6.74	6.82	6.94	5.91	6.13	6.31
Renewable Energy[15]	3.94	4.48	4.64	4.59	4.54	4.71	4.71	4.58	4.66	4.75
Electricity Imports[16]	0.34	0.31	0.31	0.31	0.22	0.22	0.22	0.22	0.22	0.22
Total	**35.78**	**41.10**	**42.28**	**43.52**	**42.64**	**44.34**	**46.09**	**43.88**	**46.20**	**48.82**

Table B2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections 2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2015 Low Economic Growth	2015 Reference	2015 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth
Total Energy Consumption										
Distillate Fuel	7.48	9.07	9.51	10.07	9.51	10.17	10.92	9.90	10.84	11.95
Kerosene	0.15	0.13	0.13	0.13	0.12	0.13	0.13	0.12	0.12	0.13
Jet Fuel[8]	3.46	4.27	4.51	4.80	4.81	5.22	5.63	5.32	5.97	6.59
Liquefied Petroleum Gas	2.88	2.91	3.05	3.28	2.98	3.20	3.49	3.04	3.38	3.81
Motor Gasoline[2]	16.17	18.76	19.31	19.91	19.67	20.52	21.36	20.42	21.63	22.80
Petrochemical Feedstock	1.29	1.44	1.53	1.67	1.47	1.61	1.78	1.49	1.70	1.94
Residual Fuel	2.08	1.31	1.33	1.39	1.32	1.35	1.39	1.33	1.38	1.47
Other Petroleum[12]	4.53	4.82	5.04	5.38	4.94	5.31	5.69	5.12	5.57	6.13
Petroleum Subtotal	38.03	42.71	44.41	46.62	44.81	47.50	50.40	46.73	50.59	54.82
Natural Gas	21.95	27.73	28.75	29.97	30.59	32.39	34.18	33.00	35.57	36.97
Metallurgical Coal	0.75	0.61	0.61	0.61	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	20.62	23.73	24.39	25.17	24.21	24.93	25.95	24.52	25.48	27.94
Net Coal Coke Imports	0.06	0.13	0.16	0.21	0.15	0.19	0.27	0.17	0.22	0.33
Coal Subtotal	21.43	24.47	25.15	25.99	24.91	25.68	26.77	25.19	26.20	28.77
Nuclear Power	7.79	7.69	7.69	7.69	6.74	6.82	6.94	5.91	6.13	6.31
Renewable Energy[17]	6.59	7.54	7.83	7.96	7.75	8.13	8.37	7.92	8.31	8.76
Methanol (M85)[11]	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports[16]	0.34	0.31	0.31	0.31	0.22	0.22	0.22	0.22	0.22	0.22
Total	**96.14**	**110.45**	**114.14**	**118.55**	**115.03**	**120.75**	**126.89**	**118.98**	**127.04**	**135.86**
Energy Use and Related Statistics										
Delivered Energy Use	71.65	83.07	86.01	89.70	87.01	91.71	96.88	90.51	97.22	104.56
Total Energy Use	96.14	110.45	114.14	118.55	115.03	120.75	126.89	118.98	127.04	135.86
Population (millions)	273.13	292.66	300.17	307.68	301.58	312.58	323.58	310.66	325.24	339.82
Gross Domestic Product (billion 1996 dollars)	8,876	12,000	12,667	13,463	13,495	14,635	15,744	14,757	16,515	18,202
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1,510.8	1,750.0	1,809.1	1,882.6	1,840.1	1,928.1	2,027.6	1,916.4	2,040.6	2,193.3

[1]Includes wood used for residential heating. See Table B18 estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector electricity cogenerated by using wood and wood waste, landfill gas, municipal solid waste, and other biomass. See Table B18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Fuel consumption includes consumption for cogeneration, which produces electricity and other useful thermal energy.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Includes lease and plant fuel and consumption by cogenerators; excludes consumption by nonutility generators.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass; includes cogeneration, both for sale to the grid and for own use.
[8]Includes only kerosene type.
[9]Includes aviation gas and lubricants.
[10]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[11]M85 is 85 percent methanol and 15 percent motor gasoline.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes cogeneration. Excludes net electricity imports.
[16]In 1998 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[17]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1999 electric utility fuel consumption: Energy Information Administration (EIA), *Electric Power Annual 1998, Volume 1,* DOE/EIA-0348(98)/1 (Washington, DC, April 1999). 1999 nonutility consumption estimates: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 1999 values: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/ forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B3. Energy Prices by Sector and Source
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential	**13.17**	**12.81**	**13.16**	**13.75**	**12.78**	**13.33**	**13.88**	**12.82**	**13.59**	**14.39**
Primary Energy[1]	6.72	6.80	7.01	7.33	6.67	6.92	7.23	6.61	7.01	7.47
Petroleum Products[2]	7.55	9.05	9.37	9.45	9.06	9.49	9.71	9.08	9.64	9.92
Distillate Fuel	6.27	7.31	7.51	7.63	7.40	7.80	7.99	7.49	7.98	8.18
Liquefied Petroleum Gas	10.36	12.47	13.07	13.05	12.30	12.83	13.07	12.18	12.87	13.31
Natural Gas	6.52	6.33	6.53	6.91	6.21	6.44	6.77	6.15	6.55	7.05
Electricity	23.60	21.39	21.88	22.81	21.10	22.01	22.85	20.99	22.17	23.32
Commercial	**13.25**	**11.34**	**11.75**	**12.51**	**11.31**	**11.96**	**12.68**	**11.41**	**12.37**	**13.46**
Primary Energy[1]	5.22	5.34	5.53	5.86	5.30	5.55	5.86	5.32	5.74	6.21
Petroleum Products[2]	5.00	5.93	6.17	6.27	5.97	6.34	6.52	6.02	6.50	6.77
Distillate Fuel	4.37	5.09	5.28	5.40	5.17	5.55	5.75	5.25	5.75	6.01
Residual Fuel	2.63	3.59	3.69	3.77	3.62	3.77	3.90	3.65	3.85	4.02
Natural Gas[3]	5.34	5.31	5.50	5.87	5.26	5.50	5.84	5.28	5.71	6.22
Electricity	21.54	17.05	17.63	18.74	16.77	17.72	18.75	16.76	18.12	19.63
Industrial[4]	**5.33**	**5.16**	**5.45**	**5.76**	**5.19**	**5.56**	**5.93**	**5.26**	**5.85**	**6.40**
Primary Energy	3.92	4.12	4.38	4.60	4.16	4.48	4.76	4.21	4.72	5.14
Petroleum Products[2]	5.55	5.70	6.05	6.13	5.71	6.10	6.32	5.70	6.27	6.59
Distillate Fuel	4.65	5.26	5.45	5.58	5.35	5.73	5.93	5.44	5.94	6.28
Liquefied Petroleum Gas	8.50	7.39	8.01	7.99	7.26	7.75	7.97	7.15	7.83	8.27
Residual Fuel	2.78	3.32	3.42	3.50	3.35	3.50	3.62	3.39	3.58	3.75
Natural Gas[5]	2.79	3.12	3.31	3.68	3.20	3.45	3.81	3.29	3.76	4.31
Metallurgical Coal	1.65	1.53	1.54	1.55	1.47	1.49	1.50	1.43	1.44	1.46
Steam Coal	1.43	1.28	1.29	1.31	1.24	1.25	1.27	1.19	1.21	1.24
Electricity	13.09	10.86	11.24	11.92	10.67	11.27	11.97	10.69	11.62	12.67
Transportation	**8.30**	**9.19**	**9.46**	**9.75**	**9.03**	**9.38**	**9.68**	**8.92**	**9.31**	**9.67**
Primary Energy	8.29	9.17	9.45	9.74	9.01	9.36	9.66	8.90	9.29	9.65
Petroleum Products[2]	8.28	9.17	9.44	9.74	9.01	9.36	9.66	8.90	9.29	9.65
Distillate Fuel[6]	8.22	8.65	8.94	9.20	8.60	9.05	9.34	8.50	8.98	9.48
Jet Fuel[7]	4.70	5.24	5.47	5.63	5.30	5.75	6.02	5.44	5.88	6.09
Motor Gasoline[8]	9.45	10.62	10.93	11.31	10.42	10.75	11.10	10.27	10.68	11.08
Residual Fuel	2.46	3.07	3.18	3.25	3.10	3.25	3.38	3.13	3.33	3.50
Liquefied Petroleum Gas[9]	12.87	13.65	14.26	14.34	13.38	13.96	14.32	13.08	13.84	14.42
Natural Gas[10]	7.02	6.76	7.04	7.53	6.81	7.17	7.63	6.77	7.32	7.96
Ethanol (E85)[11]	14.42	19.03	19.00	19.19	19.30	19.24	19.40	18.46	19.36	19.57
Methanol (M85)[12]	10.38	13.50	13.74	14.03	13.99	14.33	14.65	13.92	14.43	14.85
Electricity	15.57	13.39	13.47	14.01	12.78	13.21	13.64	12.58	13.06	13.59
Average End-Use Energy	**8.55**	**8.67**	**8.95**	**9.29**	**8.64**	**9.01**	**9.37**	**8.65**	**9.17**	**9.66**
Primary Energy	6.33	6.93	7.18	7.44	6.89	7.21	7.49	6.88	7.30	7.68
Electricity	19.50	16.78	17.20	17.98	16.56	17.30	18.02	16.54	17.59	18.64
Electric Generators[13]										
Fossil Fuel Average	1.49	1.48	1.54	1.66	1.57	1.68	1.82	1.65	1.86	1.97
Petroleum Products	2.50	3.98	4.11	4.08	4.06	4.27	4.37	4.12	4.35	4.43
Distillate Fuel	4.05	4.65	4.84	4.97	4.74	5.10	5.30	4.82	5.28	5.63
Residual Fuel	2.42	3.77	3.88	3.86	3.84	4.00	4.10	3.90	4.07	4.15
Natural Gas	2.55	2.84	3.03	3.38	2.99	3.24	3.60	3.11	3.59	4.09
Steam Coal	1.21	1.04	1.05	1.07	1.00	1.01	1.04	0.96	0.98	1.01

Table B3. Energy Prices by Sector and Source (Continued)
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Average Price to All Users[14]										
Petroleum Products[2]	7.44	8.35	8.64	8.85	8.26	8.61	8.86	8.19	8.61	8.93
Distillate Fuel	7.27	7.91	8.18	8.42	7.92	8.36	8.63	7.89	8.38	8.83
Jet Fuel	4.70	5.24	5.47	5.63	5.30	5.75	6.02	5.44	5.88	6.09
Liquefied Petroleum Gas	8.84	8.31	8.88	8.81	8.14	8.58	8.75	8.02	8.62	8.98
Motor Gasoline[8]	9.45	10.62	10.93	11.31	10.42	10.75	11.10	10.27	10.68	11.08
Residual Fuel	2.48	3.22	3.33	3.41	3.26	3.41	3.54	3.29	3.49	3.67
Natural Gas	4.05	4.10	4.27	4.60	4.07	4.28	4.60	4.08	4.50	5.01
Coal	1.23	1.06	1.07	1.09	1.02	1.03	1.06	0.98	1.00	1.03
Ethanol (E85)[11]	14.42	19.03	19.00	19.19	19.30	19.24	19.40	18.46	19.36	19.57
Methanol (M85)[12]	10.38	13.50	13.74	14.03	13.99	14.33	14.65	13.92	14.43	14.85
Electricity	19.50	16.78	17.20	17.98	16.56	17.30	18.02	16.54	17.59	18.64
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	134.60	152.22	157.93	165.91	158.61	168.52	177.83	166.63	181.70	195.18
Commercial	99.50	104.86	111.72	121.54	109.78	120.89	133.25	113.21	129.51	148.31
Industrial	110.90	114.35	126.53	143.40	118.15	135.93	158.05	122.76	150.97	185.59
Transportation	212.63	282.57	302.06	324.75	295.27	323.87	352.66	306.62	344.96	385.10
Total Non-Renewable Expenditures	557.64	654.00	698.23	755.60	681.81	749.21	821.79	709.23	807.14	914.18
Transportation Renewable Expenditures	0.14	0.57	0.61	0.67	0.69	0.75	0.82	0.74	0.86	0.95
Total Expenditures	**557.78**	**654.57**	**698.85**	**756.27**	**682.50**	**749.96**	**822.60**	**709.96**	**808.00**	**915.13**

[1]Weighted average price includes fuels below as well as coal.
[2]This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Excludes independent power producers.
[4]Includes cogenerators.
[5]Excludes uses for lease and plant fuel.
[6]Low sulfur diesel fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[8]Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[9]Includes Federal and State taxes while excluding county and local taxes.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]M85 is 85 percent methanol and 15 percent motor gasoline.
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[14]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(99/03-2000/04) (Washington, DC, 1999-2000). 1999 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1997*, DOE/EIA-0376(97) (Washington, DC, July 2000). 1999 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1994*. 1999 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 coal prices based on EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000) and EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A. **Projections:** EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B4. Residential Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Key Indicators										
Households (millions)										
Single-Family	75.70	84.14	85.51	86.89	87.41	89.93	91.94	90.44	94.36	97.09
Multifamily	21.79	23.80	24.25	25.01	24.93	25.69	26.78	25.94	27.09	28.56
Mobile Homes	6.59	7.09	7.20	7.29	7.36	7.57	7.64	7.63	7.96	8.02
Total	**104.08**	**115.04**	**116.97**	**119.19**	**119.70**	**123.20**	**126.36**	**124.01**	**129.41**	**133.68**
Average House Square Footage	**1673**	**1720**	**1724**	**1725**	**1737**	**1744**	**1746**	**1754**	**1763**	**1766**
Energy Intensity										
(million Btu per household)										
Delivered Energy Consumption	102.1	107.0	106.3	104.8	107.3	106.2	104.8	108.3	106.7	104.8
Total Energy Consumption	183.5	191.9	190.6	187.4	191.4	188.9	185.4	192.0	188.3	183.9
(thousand Btu per square foot)										
Delivered Energy Consumption	61.0	62.2	61.7	60.8	61.7	60.9	60.0	61.8	60.5	59.3
Total Energy Consumption	109.7	111.6	110.6	108.6	110.2	108.3	106.2	109.5	106.8	104.2
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.38	0.46	0.47	0.47	0.48	0.49	0.50	0.49	0.51	0.52
Space Cooling	0.52	0.62	0.63	0.63	0.68	0.69	0.71	0.74	0.77	0.79
Water Heating	0.39	0.43	0.43	0.43	0.43	0.43	0.44	0.42	0.43	0.44
Refrigeration	0.43	0.34	0.34	0.35	0.32	0.32	0.33	0.31	0.33	0.34
Cooking	0.10	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.14
Clothes Dryers	0.22	0.26	0.26	0.26	0.27	0.27	0.28	0.28	0.29	0.29
Freezers	0.12	0.09	0.09	0.09	0.08	0.09	0.09	0.08	0.09	0.09
Lighting	0.34	0.46	0.46	0.46	0.49	0.49	0.49	0.51	0.52	0.52
Clothes Washers[1]	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Dishwashers[1]	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.12	0.19	0.19	0.19	0.21	0.21	0.22	0.23	0.24	0.24
Personal Computers	0.06	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.12
Furnace Fans	0.07	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12
Other Uses[2]	1.10	1.71	1.73	1.75	1.93	1.97	2.01	2.13	2.20	2.25
Delivered Energy	**3.91**	**4.89**	**4.96**	**5.01**	**5.25**	**5.37**	**5.46**	**5.61**	**5.80**	**5.92**
Natural Gas										
Space Heating	3.22	3.81	3.85	3.86	3.97	4.06	4.11	4.17	4.31	4.36
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Heating	1.26	1.40	1.41	1.42	1.44	1.47	1.49	1.47	1.52	1.54
Cooking	0.19	0.22	0.23	0.23	0.24	0.24	0.24	0.25	0.25	0.26
Clothes Dryers	0.07	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11
Other Uses[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Delivered Energy	**4.85**	**5.64**	**5.69**	**5.71**	**5.86**	**5.99**	**6.06**	**6.11**	**6.30**	**6.38**
Distillate										
Space Heating	0.73	0.69	0.69	0.69	0.67	0.66	0.66	0.65	0.65	0.65
Water Heating	0.13	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Other Uses[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	**0.86**	**0.81**	**0.81**	**0.81**	**0.78**	**0.77**	**0.77**	**0.76**	**0.75**	**0.75**
Liquefied Petroleum Gas										
Space Heating	0.31	0.28	0.28	0.28	0.27	0.27	0.27	0.27	0.27	0.27
Water Heating	0.11	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Other Uses[3]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Delivered Energy	**0.46**	**0.42**	**0.41**	**0.41**	**0.40**	**0.40**	**0.40**	**0.40**	**0.39**	**0.39**
Marketed Renewables (wood)[5]	0.41	0.43	0.43	0.43	0.43	0.43	0.43	0.44	0.44	0.44
Other Fuels[6]	0.14	0.13	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12

Table B4. Residential Sector Key Indicators and End-Use Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Delivered Energy Consumption by End-Use										
Space Heating	5.18	5.80	5.84	5.86	5.94	6.03	6.09	6.14	6.29	6.35
Space Cooling	0.52	0.62	0.63	0.63	0.68	0.70	0.71	0.74	0.77	0.79
Water Heating	1.89	2.03	2.05	2.06	2.06	2.10	2.13	2.09	2.14	2.17
Refrigeration	0.43	0.34	0.34	0.35	0.32	0.32	0.33	0.31	0.33	0.34
Cooking	0.32	0.37	0.38	0.38	0.39	0.40	0.40	0.40	0.42	0.43
Clothes Dryers	0.28	0.34	0.35	0.35	0.37	0.37	0.38	0.39	0.40	0.40
Freezers	0.12	0.09	0.09	0.09	0.08	0.09	0.09	0.08	0.09	0.09
Lighting	0.34	0.46	0.46	0.46	0.49	0.49	0.49	0.51	0.52	0.52
Clothes Washers	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Dishwashers	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.12	0.19	0.19	0.19	0.21	0.21	0.22	0.23	0.24	0.24
Personal Computers	0.06	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.12
Furnace Fans	0.07	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12
Other Uses[7]	1.23	1.83	1.86	1.87	2.05	2.09	2.13	2.25	2.32	2.37
Delivered Energy	**10.62**	**12.31**	**12.43**	**12.49**	**12.84**	**13.08**	**13.24**	**13.43**	**13.81**	**14.00**
Electricity Related Losses	**8.48**	**9.77**	**9.87**	**9.84**	**10.07**	**10.19**	**10.18**	**10.37**	**10.55**	**10.58**
Total Energy Consumption by End-Use										
Space Heating	6.01	6.71	6.76	6.78	6.85	6.96	7.01	7.06	7.22	7.28
Space Cooling	1.64	1.85	1.87	1.88	1.97	2.01	2.03	2.11	2.17	2.19
Water Heating	2.75	2.88	2.90	2.91	2.88	2.92	2.95	2.87	2.93	2.96
Refrigeration	1.35	1.01	1.02	1.03	0.92	0.94	0.95	0.89	0.92	0.93
Cooking	0.54	0.60	0.61	0.62	0.62	0.63	0.65	0.63	0.66	0.67
Clothes Dryers	0.75	0.85	0.86	0.86	0.88	0.89	0.89	0.91	0.93	0.93
Freezers	0.37	0.26	0.27	0.27	0.24	0.25	0.25	0.24	0.25	0.25
Lighting	1.08	1.37	1.38	1.36	1.41	1.42	1.41	1.45	1.46	1.45
Clothes Washers	0.09	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.11	0.11
Dishwashers	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.07	0.08	0.08
Color Televisions	0.38	0.56	0.57	0.57	0.61	0.62	0.62	0.66	0.67	0.68
Personal Computers	0.20	0.28	0.28	0.28	0.29	0.29	0.29	0.32	0.32	0.33
Furnace Fans	0.24	0.29	0.29	0.29	0.30	0.31	0.31	0.32	0.33	0.33
Other Uses[7]	3.62	5.24	5.30	5.31	5.75	5.84	5.87	6.18	6.32	6.39
Total	**19.10**	**22.08**	**22.30**	**22.34**	**22.91**	**23.27**	**23.42**	**23.81**	**24.36**	**24.59**
Non-Marketed Renewables										
Geothermal[8]	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Solar[9]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.03**	**0.04**	**0.04**

[1]Does not include electric water heating portion of load.
[2]Includes small electric devices, heating elements, and motors.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as swimming pool and hot tub heaters.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1997*.
[6]Includes kerosene and coal.
[7]Includes all other uses listed above.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B5. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1999	Projections 2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2015 Low Economic Growth	2015 Reference	2015 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth
Key Indicators										
Total Floor Space (billion square feet)										
Surviving	60.8	71.7	74.0	76.4	74.4	78.1	82.0	75.5	80.7	86.1
New Additions	2.0	1.5	1.8	2.0	1.2	1.5	1.8	0.9	1.3	1.7
Total	**62.8**	**73.2**	**75.8**	**78.5**	**75.7**	**79.6**	**83.8**	**76.4**	**81.9**	**87.8**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	120.9	127.5	126.6	124.9	129.3	128.0	126.4	131.0	128.8	126.4
Electricity Related Losses	127.6	129.1	128.2	125.7	128.7	126.8	123.7	127.8	124.5	121.1
Total Energy Consumption	248.5	256.6	254.8	250.6	258.0	254.9	250.1	258.7	253.2	247.5
Delivered Energy Consumption by Fuel										
Purchased Electricity										
Space Heating[1]	0.14	0.16	0.16	0.17	0.16	0.16	0.17	0.15	0.16	0.17
Space Cooling[1]	0.43	0.44	0.46	0.47	0.44	0.46	0.48	0.43	0.46	0.49
Water Heating[1]	0.14	0.16	0.16	0.16	0.15	0.16	0.17	0.15	0.16	0.16
Ventilation	0.17	0.20	0.21	0.21	0.20	0.21	0.22	0.20	0.21	0.22
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Lighting	1.21	1.38	1.42	1.46	1.42	1.48	1.54	1.41	1.47	1.55
Refrigeration	0.18	0.21	0.21	0.22	0.21	0.22	0.23	0.21	0.22	0.24
Office Equipment (PC)	0.10	0.23	0.24	0.25	0.26	0.28	0.29	0.27	0.29	0.32
Office Equipment (non-PC)	0.30	0.49	0.51	0.53	0.57	0.60	0.63	0.64	0.69	0.74
Other Uses[2]	0.99	1.44	1.48	1.53	1.63	1.71	1.79	1.79	1.91	2.03
Delivered Energy	**3.70**	**4.74**	**4.89**	**5.02**	**5.09**	**5.32**	**5.56**	**5.28**	**5.61**	**5.95**
Natural Gas[3]										
Space Heating[1]	1.42	1.70	1.74	1.76	1.73	1.80	1.85	1.73	1.81	1.88
Space Cooling[1]	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.02	0.03	0.03
Water Heating[1]	0.64	0.74	0.77	0.79	0.78	0.82	0.86	0.79	0.84	0.89
Cooking	0.21	0.24	0.25	0.25	0.25	0.26	0.27	0.25	0.27	0.29
Other Uses[4]	0.87	1.09	1.11	1.12	1.11	1.14	1.17	1.13	1.18	1.22
Delivered Energy	**3.15**	**3.79**	**3.88**	**3.94**	**3.90**	**4.05**	**4.18**	**3.93**	**4.13**	**4.30**
Distillate										
Space Heating[1]	0.23	0.25	0.25	0.26	0.24	0.25	0.26	0.23	0.24	0.25
Water Heating[1]	0.09	0.08	0.09	0.09	0.08	0.08	0.09	0.08	0.08	0.09
Other Uses[5]	0.04	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Delivered Energy	**0.36**	**0.40**	**0.41**	**0.42**	**0.40**	**0.40**	**0.42**	**0.38**	**0.39**	**0.41**
Other Fuels[6]	**0.30**	**0.32**	**0.33**	**0.34**	**0.33**	**0.34**	**0.35**	**0.32**	**0.34**	**0.36**
Marketed Renewable Fuels										
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Delivered Energy	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Delivered Energy Consumption by End-Use										
Space Heating[1]	1.79	2.11	2.15	2.18	2.13	2.21	2.28	2.12	2.21	2.30
Space Cooling[1]	0.44	0.47	0.48	0.49	0.47	0.49	0.51	0.46	0.49	0.52
Water Heating[1]	0.87	0.98	1.01	1.04	1.01	1.06	1.11	1.02	1.08	1.14
Ventilation	0.17	0.20	0.21	0.21	0.20	0.21	0.22	0.20	0.21	0.22
Cooking	0.24	0.27	0.28	0.28	0.28	0.29	0.31	0.28	0.30	0.32
Lighting	1.21	1.38	1.42	1.46	1.42	1.48	1.54	1.41	1.47	1.55
Refrigeration	0.18	0.21	0.21	0.22	0.21	0.22	0.23	0.21	0.22	0.24
Office Equipment (PC)	0.10	0.23	0.24	0.25	0.26	0.28	0.29	0.27	0.29	0.32
Office Equipment (non-PC)	0.30	0.49	0.51	0.53	0.57	0.60	0.63	0.64	0.69	0.74
Other Uses[7]	2.29	3.00	3.07	3.14	3.23	3.35	3.47	3.40	3.58	3.77
Delivered Energy	**7.59**	**9.33**	**9.59**	**9.80**	**9.79**	**10.19**	**10.59**	**10.01**	**10.55**	**11.10**

Table B5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Electricity Related Losses	**8.01**	**9.46**	**9.71**	**9.87**	**9.74**	**10.10**	**10.36**	**9.76**	**10.20**	**10.63**
Total Energy Consumption by End-Use										
Space Heating[1]	2.09	2.42	2.48	2.51	2.43	2.52	2.59	2.40	2.50	2.60
Space Cooling[1]	1.36	1.35	1.39	1.41	1.32	1.37	1.42	1.26	1.33	1.40
Water Heating[1]	1.19	1.29	1.33	1.36	1.31	1.37	1.42	1.30	1.37	1.43
Ventilation	0.55	0.60	0.61	0.62	0.58	0.61	0.62	0.56	0.59	0.62
Cooking	0.31	0.33	0.34	0.35	0.34	0.35	0.36	0.33	0.35	0.37
Lighting	3.83	4.14	4.26	4.32	4.15	4.29	4.40	4.02	4.15	4.31
Refrigeration	0.58	0.62	0.64	0.66	0.61	0.64	0.67	0.59	0.63	0.67
Office Equipment (PC)	0.33	0.69	0.71	0.73	0.77	0.81	0.84	0.78	0.83	0.88
Office Equipment (non-PC)	0.94	1.47	1.52	1.56	1.66	1.74	1.82	1.82	1.94	2.07
Other Uses[7]	4.43	5.88	6.03	6.15	6.36	6.59	6.81	6.71	7.05	7.39
Total	**15.61**	**18.79**	**19.30**	**19.67**	**19.53**	**20.29**	**20.95**	**19.77**	**20.75**	**21.73**
Non-Marketed Renewable Fuels										
Solar[8]	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

[1]Includes fuel consumption for district services.
[2]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
[3]Excludes estimated consumption from independent power producers.
[4]Includes miscellaneous uses, such as pumps, emergency electric generators, cogeneration in commercial buildings, and manufacturing performed in commercial buildings.
[5]Includes miscellaneous uses, such as cooking, emergency electric generators, and cogeneration in commercial buildings.
[6]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, cogeneration in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[8]Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Key Indicators										
Value of Gross Output (billion 1992 dollars)										
Manufacturing	3,749	4,850	5,089	5,531	5,444	5,828	6,471	6,149	6,726	7,735
Nonmanufacturing	972	1,092	1,162	1,238	1,157	1,265	1,364	1,210	1,370	1,516
Total	**4,722**	**5,942**	**6,251**	**6,769**	**6,601**	**7,093**	**7,835**	**7,359**	**8,096**	**9,251**
Energy Prices (1999 dollars per million Btu)										
Electricity	13.09	10.86	11.24	11.92	10.67	11.27	11.97	10.69	11.62	12.67
Natural Gas	2.79	3.12	3.31	3.68	3.20	3.45	3.81	3.29	3.76	4.31
Steam Coal	1.43	1.28	1.29	1.31	1.24	1.25	1.27	1.19	1.21	1.24
Residual Oil	2.78	3.32	3.42	3.50	3.35	3.50	3.62	3.39	3.58	3.75
Distillate Oil	4.65	5.26	5.45	5.58	5.35	5.73	5.93	5.44	5.94	6.28
Liquefied Petroleum Gas	8.50	7.39	8.01	7.99	7.26	7.75	7.97	7.15	7.83	8.27
Motor Gasoline	9.42	10.59	10.90	11.29	10.38	10.70	11.06	10.23	10.64	11.04
Metallurgical Coal	1.65	1.53	1.54	1.55	1.47	1.49	1.50	1.43	1.44	1.46
Energy Consumption										
Consumption[1]										
Purchased Electricity	3.63	3.97	4.18	4.53	4.14	4.47	4.92	4.35	4.81	5.47
Natural Gas[2]	9.43	10.68	11.11	11.70	11.07	11.76	12.59	11.38	12.34	13.46
Steam Coal	1.73	1.82	1.85	1.91	1.82	1.87	1.94	1.82	1.90	1.99
Metallurgical Coal and Coke[3]	0.81	0.73	0.76	0.82	0.70	0.74	0.82	0.67	0.72	0.83
Residual Fuel	0.22	0.24	0.25	0.27	0.24	0.26	0.28	0.25	0.27	0.31
Distillate	1.07	1.19	1.27	1.35	1.24	1.35	1.46	1.28	1.44	1.61
Liquefied Petroleum Gas	2.32	2.36	2.50	2.73	2.43	2.65	2.93	2.49	2.83	3.25
Petrochemical Feedstocks	1.29	1.44	1.53	1.67	1.47	1.61	1.78	1.49	1.70	1.94
Other Petroleum[4]	4.50	4.78	5.00	5.34	4.90	5.27	5.65	5.07	5.52	6.08
Renewables[5]	2.15	2.52	2.64	2.82	2.66	2.86	3.10	2.78	3.08	3.44
Delivered Energy	**27.15**	**29.73**	**31.10**	**33.12**	**30.68**	**32.84**	**35.48**	**31.59**	**34.63**	**38.39**
Electricity Related Losses	7.87	7.93	8.32	8.90	7.94	8.48	9.18	8.04	8.76	9.78
Total	**35.02**	**37.66**	**39.42**	**42.02**	**38.62**	**41.31**	**44.66**	**39.63**	**43.39**	**48.17**
Consumption per Unit of Output[1] (thousand Btu per 1992 dollars)										
Purchased Electricity	0.77	0.67	0.67	0.67	0.63	0.63	0.63	0.59	0.59	0.59
Natural Gas[2]	2.00	1.80	1.78	1.73	1.68	1.66	1.61	1.55	1.52	1.46
Steam Coal	0.37	0.31	0.30	0.28	0.28	0.26	0.25	0.25	0.23	0.22
Metallurgical Coal and Coke[3]	0.17	0.12	0.12	0.12	0.11	0.10	0.10	0.09	0.09	0.09
Residual Fuel	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03
Distillate	0.23	0.20	0.20	0.20	0.19	0.19	0.19	0.17	0.18	0.17
Liquefied Petroleum Gas	0.49	0.40	0.40	0.40	0.37	0.37	0.37	0.34	0.35	0.35
Petrochemical Feedstocks	0.27	0.24	0.24	0.25	0.22	0.23	0.23	0.20	0.21	0.21
Other Petroleum[4]	0.95	0.80	0.80	0.79	0.74	0.74	0.72	0.69	0.68	0.66
Renewables[5]	0.46	0.42	0.42	0.42	0.40	0.40	0.40	0.38	0.38	0.37
Delivered Energy	**5.75**	**5.00**	**4.98**	**4.89**	**4.65**	**4.63**	**4.53**	**4.29**	**4.28**	**4.15**
Electricity Related Losses	1.67	1.33	1.33	1.32	1.20	1.20	1.17	1.09	1.08	1.06
Total	**7.42**	**6.34**	**6.31**	**6.21**	**5.85**	**5.82**	**5.70**	**5.39**	**5.36**	**5.21**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net coke coal imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 prices for gasoline and distillate are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380 (99/03-2000/04) (Washington, DC, 1999-2000). 1999 coal prices are based on EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000) and EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A. 1999 electricity prices: EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A. Other 1999 prices derived from EIA, *State Energy Data Report 1997*, DOE/EIA-0214(97) (Washington, DC, September 1999). Other 1999 values: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf.
Projections: EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Key Indicators										
Level of Travel (billions)										
Light-Duty Vehicles <8,500 pounds (VMT)	2394	2974	3066	3163	3189	3334	3475	3372	3577	3776
Commercial Light Trucks (VMT)[1]	73	89	93	98	97	103	110	103	113	123
Freight Trucks >10,000 pounds (VMT)	204	264	280	301	289	313	343	316	352	398
Air (seat miles available)	1099	1498	1592	1706	1767	1934	2103	2039	2317	2583
Rail (ton miles traveled)	1357	1634	1706	1806	1719	1826	1968	1807	1967	2199
Domestic Shipping (ton miles traveled)	661	738	775	817	774	832	888	807	890	964
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[2]	24.2	27.0	27.1	27.1	27.6	27.6	27.6	28.1	28.0	28.0
New Car (miles per gallon)[2]	27.9	32.2	32.3	32.3	32.4	32.4	32.4	32.5	32.5	32.4
New Light Truck (miles per gallon)[2]	20.8	23.2	23.2	23.2	24.0	24.0	24.0	24.7	24.7	24.7
Light-Duty Fleet (miles per gallon)[3]	20.5	20.9	20.9	21.0	21.2	21.2	21.2	21.4	21.5	21.5
New Commercial Light Truck (MPG)[1]	20.1	22.0	22.0	22.0	22.8	22.8	22.8	23.5	23.4	23.4
Stock Commercial Light Truck (MPG)[1]	14.8	16.1	16.1	16.1	16.5	16.6	16.6	17.0	17.0	17.0
Aircraft Efficiency (seat miles per gallon)	51.7	55.9	56.1	56.3	58.0	58.2	58.4	60.0	60.3	60.6
Freight Truck Efficiency (miles per gallon)	6.0	6.4	6.4	6.5	6.7	6.7	6.7	6.9	6.9	7.0
Rail Efficiency (ton miles per thousand Btu)	2.8	3.1	3.1	3.1	3.3	3.3	3.3	3.4	3.4	3.4
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.7	2.7	2.7	2.8	2.8	2.8	3.0	3.0	3.0
Energy Use by Mode (quadrillion Btu)										
Light-Duty Vehicles	14.88	17.98	18.51	19.08	19.00	19.83	20.64	19.81	20.98	22.10
Commercial Light Trucks[1]	0.62	0.70	0.73	0.76	0.73	0.78	0.83	0.76	0.83	0.90
Freight Trucks[4]	4.54	5.48	5.78	6.19	5.78	6.24	6.79	6.08	6.74	7.55
Air[5]	3.50	4.32	4.56	4.85	4.86	5.28	5.69	5.38	6.04	6.67
Rail[6]	0.57	0.63	0.65	0.68	0.63	0.67	0.71	0.64	0.69	0.76
Marine[7]	1.29	1.44	1.46	1.49	1.46	1.49	1.52	1.48	1.52	1.56
Pipeline Fuel	0.66	0.87	0.90	0.93	0.94	0.99	1.05	1.00	1.09	1.15
Lubricants	0.22	0.25	0.26	0.28	0.27	0.29	0.31	0.28	0.31	0.35
Total	**26.28**	**31.69**	**32.89**	**34.29**	**33.71**	**35.60**	**37.57**	**35.48**	**38.23**	**41.06**
Energy Use by Mode (million barrels per day oil equivalent)										
Light-Duty Vehicles	7.76	9.42	9.70	10.00	9.95	10.39	10.81	10.37	10.99	11.57
Commercial Light Trucks[1]	0.32	0.36	0.38	0.40	0.38	0.41	0.43	0.40	0.43	0.47
Freight Trucks[4]	2.03	2.46	2.60	2.79	2.60	2.81	3.07	2.74	3.04	3.43
Railroad	0.23	0.25	0.26	0.27	0.25	0.26	0.28	0.25	0.27	0.30
Domestic Shipping	0.13	0.13	0.13	0.14	0.13	0.14	0.15	0.12	0.14	0.15
International Shipping	0.30	0.35	0.35	0.35	0.36	0.36	0.36	0.36	0.36	0.36
Air[5]	1.46	1.84	1.95	2.08	2.09	2.28	2.46	2.33	2.63	2.91
Military Use	0.28	0.31	0.32	0.33	0.32	0.34	0.35	0.33	0.36	0.38
Bus Transportation	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Rail Transportation[6]	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Recreational Boats	0.16	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.20	0.20
Lubricants	0.10	0.12	0.12	0.13	0.13	0.14	0.15	0.13	0.15	0.16
Pipeline Fuel	0.33	0.44	0.45	0.47	0.47	0.50	0.53	0.51	0.55	0.58
Total	**13.24**	**15.99**	**16.59**	**17.29**	**17.00**	**17.94**	**18.92**	**17.88**	**19.26**	**20.66**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
[4]Includes energy use by buses and military distillate consumption.
[5]Includes jet fuel and aviation gasoline.
[6]Includes passenger rail.
[7]Includes military residual fuel use and recreation boats.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999: U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 1999/1998* (Washington, DC, 1999); Energy Information Administration (EIA), *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf; EIA, *Fuel Oil and Kerosene Sales 1998*, DOE/EIA-0535(98) (Washington, DC, August 1999); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B8. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2015 Low Economic Growth	2015 Reference	2015 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth
Generation by Fuel Type										
Electric Generators[1]										
Coal	1833	2132	2196	2274	2176	2246	2362	2205	2298	2614
Petroleum	100	17	17	20	17	17	18	17	19	22
Natural Gas[2]	371	835	900	977	1145	1266	1373	1409	1587	1584
Nuclear Power	730	720	720	720	632	639	650	554	574	591
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	353	385	390	391	390	395	398	392	396	399
Total	**3386**	**4088**	**4222**	**4381**	**4358**	**4563**	**4800**	**4576**	**4872**	**5209**
Nonutility Generation for Own Use	16	16	16	16	16	16	16	16	16	16
Distributed Generation	0	2	3	4	2	4	7	3	6	10
Cogenerators[4]										
Coal	47	52	52	52	52	52	52	52	52	52
Petroleum	9	10	10	10	10	10	10	10	10	10
Natural Gas	206	253	257	264	268	276	288	284	299	320
Other Gaseous Fuels[5]	4	7	7	7	7	7	8	7	8	8
Renewable Sources[3]	31	37	39	42	40	44	47	42	48	54
Other[6]	5	5	5	5	5	5	5	5	5	5
Total	**302**	**364**	**370**	**380**	**382**	**394**	**411**	**400**	**422**	**450**
Other End-Use Generators[7]	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
Sales to Utilities	151	175	176	177	184	187	190	195	200	207
Generation for Own Use	156	194	199	208	202	213	226	210	227	248
Net Imports[8]	**32**	**29**	**29**	**29**	**21**	**21**	**21**	**21**	**21**	**21**
Electricity Sales by Sector										
Residential	1146	1435	1455	1467	1540	1573	1600	1645	1701	1736
Commercial	1083	1388	1432	1470	1490	1559	1629	1548	1643	1744
Industrial	1063	1164	1226	1327	1214	1309	1442	1276	1411	1604
Transportation	17	34	35	35	41	43	44	47	49	51
Total	**3309**	**4020**	**4147**	**4299**	**4286**	**4484**	**4715**	**4516**	**4804**	**5135**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.1	7.3	7.5	7.8	7.2	7.5	7.8	7.2	7.6	8.0
Commercial	7.3	5.8	6.0	6.4	5.7	6.0	6.4	5.7	6.2	6.7
Industrial	4.5	3.7	3.8	4.1	3.6	3.8	4.1	3.6	4.0	4.3
Transportation	5.3	4.6	4.6	4.8	4.4	4.5	4.7	4.3	4.5	4.6
All Sectors Average	**6.7**	**5.7**	**5.9**	**6.1**	**5.7**	**5.9**	**6.1**	**5.6**	**6.0**	**6.4**
Prices by Service Category[9] (1999 cents per kilowatthour)										
Generation	4.1	3.1	3.2	3.4	3.0	3.2	3.5	3.1	3.4	3.7
Transmission	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Distribution	2.0	2.0	2.0	2.0	2.0	2.0	2.0	1.9	2.0	2.0
Emissions (million short tons)										
Sulfur Dioxide	12.46	9.08	9.28	9.50	9.11	9.33	8.95	9.01	8.95	8.95
Nitrogen Oxide	5.45	4.14	4.22	4.30	4.26	4.33	4.38	4.34	4.42	4.46

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[2]Includes electricity generation by fuel cells.
[3]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[4]Cogenerators produce electricity and other useful thermal energy. Includes sales to utilities and generation for own use.
[5]Other gaseous fuels include refinery and still gas.
[6]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[7]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]In 1999 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[9]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B9. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Electric Generators[2]										
Capability										
Coal Steam	306.0	310.4	315.0	320.0	309.8	315.3	328.0	308.4	316.4	356.7
Other Fossil Steam[3]	138.2	120.9	120.4	120.3	118.1	117.3	116.7	116.8	116.1	115.5
Combined Cycle	20.2	111.8	126.0	140.9	158.1	181.3	203.0	195.4	229.1	240.4
Combustion Turbine/Diesel	75.2	155.3	164.1	175.3	175.0	184.6	197.4	195.3	210.7	222.9
Nuclear Power	97.4	93.7	93.7	93.7	78.4	79.5	80.9	68.5	71.6	73.8
Pumped Storage	19.3	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
Fuel Cells	0.0	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3
Renewable Sources[4]	88.1	95.0	95.4	95.6	96.0	96.5	96.9	96.5	97.0	97.5
Distributed Generation[5]	0.0	4.3	6.0	9.4	5.3	8.8	15.7	6.5	12.7	23.0
Total	**744.6**	**906.7**	**934.3**	**965.5**	**955.2**	**994.4**	**1042.5**	**1000.7**	**1060.7**	**1126.5**
Cumulative Planned Additions[6]										
Coal Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fossil Steam[3]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combined Cycle	0.0	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Combustion Turbine/Diesel	0.0	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3
Renewable Sources[4]	0.0	4.3	4.3	4.3	5.1	5.1	5.1	5.4	5.4	5.4
Distributed Generation[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**13.6**	**13.6**	**13.6**	**14.5**	**14.5**	**14.5**	**14.8**	**14.8**	**14.8**
Cumulative Unplanned Additions[6]										
Coal Steam	0.0	14.0	18.5	23.4	14.0	19.5	32.0	14.0	21.8	62.0
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	83.4	97.5	112.4	129.6	152.8	174.4	166.9	200.5	211.8
Combustion Turbine/Diesel	0.0	84.7	93.1	104.4	104.6	114.3	127.3	125.0	140.5	152.8
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.0	2.1	2.6	2.7	2.4	2.9	3.2	2.6	3.1	3.6
Distributed Generation[5]	0.0	4.3	6.0	9.4	5.3	8.8	15.7	6.5	12.7	23.0
Total	**0.0**	**188.4**	**217.7**	**252.3**	**255.9**	**298.3**	**352.6**	**315.0**	**378.7**	**453.2**
Cumulative Total Additions	**0.0**	**202.0**	**231.3**	**265.9**	**270.5**	**312.8**	**367.1**	**329.7**	**393.4**	**468.0**
Cumulative Retirements[7]										
Coal Steam	0.0	13.6	13.5	13.3	14.2	14.2	14.0	15.6	15.4	15.3
Other Fossil Steam[3]	0.0	17.2	17.7	17.8	20.0	20.8	21.4	21.3	22.0	22.6
Combined Cycle	0.0	0.2	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.1
Combustion Turbine/Diesel	0.0	5.8	5.1	5.2	6.0	5.8	6.0	6.0	5.9	6.0
Nuclear Power	0.0	3.7	3.7	3.7	19.1	18.0	16.6	29.0	25.9	23.7
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**40.6**	**40.3**	**40.3**	**59.6**	**59.0**	**58.2**	**72.2**	**69.4**	**67.8**

Table B9. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Petroleum	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Natural Gas	33.8	42.4	43.0	44.0	44.6	45.7	47.4	46.9	49.0	51.9
Other Gaseous Fuels	0.2	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.1	1.1
Renewable Sources[4]	5.3	6.4	6.8	7.2	6.9	7.5	8.2	7.2	8.2	9.3
Other	1.1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	**51.6**	**62.3**	**63.2**	**64.7**	**64.9**	**66.8**	**69.3**	**67.6**	**70.9**	**74.9**
Cumulative Additions[6]	**0.0**	**10.6**	**11.5**	**13.1**	**13.3**	**15.2**	**17.6**	**15.9**	**19.2**	**23.3**
Other End-Use Generators[9]										
Renewable Sources[10]	1.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Cumulative Additions	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3

[1]Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes grid-connected utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[3]Includes oil-, gas-, and dual-fired capability.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar and wind power.
[5]Primarily peak-load capacity fueled by natural gas
[6]Cumulative additions after December 31, 1999.
[7]Cumulative total retirements after December 31, 1999.
[8]Nameplate capacity is reported for nonutilities on Form EIA-860B, "Annual Electric Generator Report - Nonutility." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.
[9]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[10]See Table B17 for more detail.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model estimates and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators to be consistent with capability for electric utility generators.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Interregional Electricity Trade										
Gross Domestic Firm Power Trade	182.2	102.9	102.9	102.9	45.7	45.7	45.7	0.0	0.0	0.0
Gross Domestic Economy Trade	147.2	185.6	183.3	199.1	195.6	195.5	193.9	201.0	209.0	213.9
Gross Domestic Trade	**329.4**	**288.5**	**286.2**	**302.0**	**241.3**	**241.3**	**239.7**	**201.0**	**209.0**	**213.9**
Gross Domestic Firm Power Sales (million 1999 dollars)	8588.1	4851.0	4851.0	4851.0	2156.0	2156.0	2156.0	0.0	0.0	0.0
Gross Domestic Economy Sales (million 1999 dollars)	4331.4	4901.0	5042.0	5931.0	5255.0	5513.0	5842.0	5449.0	6291.0	6999.0
Gross Domestic Sales (million 1999 dollars)	**12919.5**	**9752.0**	**9893.0**	**10782.0**	**7411.0**	**7669.0**	**7998.0**	**5449.0**	**6291.0**	**6999.0**
International Electricity Trade										
Firm Power Imports From Canada and Mexico[1]	27.0	5.8	5.8	5.8	2.6	2.6	2.6	0.0	0.0	0.0
Economy Imports From Canada and Mexico[1]	20.6	39.7	39.7	39.6	30.0	30.0	30.1	28.6	28.6	28.6
Gross Imports From Canada and Mexico[1]	**47.6**	**45.5**	**45.5**	**45.4**	**32.6**	**32.6**	**32.6**	**28.6**	**28.6**	**28.6**
Firm Power Exports To Canada and Mexico	9.2	8.7	8.7	8.7	3.9	3.9	3.9	0.0	0.0	0.0
Economy Exports To Canada and Mexico	6.3	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**15.5**	**16.4**	**16.4**	**16.4**	**11.5**	**11.5**	**11.5**	**7.7**	**7.7**	**7.7**

[1]Historically electricity imports were primarily from renewable resources, principally hydroelectric.

Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Source: Energy Information Administration, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1999	Projections 2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2015 Low Economic Growth	2015 Reference	2015 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth
Crude Oil										
Domestic Crude Production[1]	5.88	5.08	5.15	5.21	4.94	5.08	5.22	4.86	5.05	5.26
Alaska	1.05	0.64	0.64	0.64	0.70	0.70	0.70	0.64	0.64	0.64
Lower 48 States	4.83	4.43	4.50	4.57	4.24	4.38	4.52	4.23	4.41	4.62
Net Imports	8.61	11.13	11.54	12.02	11.81	11.91	12.22	12.14	12.14	12.48
Gross Imports	8.73	11.17	11.59	12.07	11.84	11.95	12.27	12.17	12.18	12.53
Exports	0.12	0.04	0.04	0.04	0.03	0.04	0.05	0.03	0.04	0.05
Other Crude Supply[2]	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**14.80**	**16.21**	**16.69**	**17.23**	**16.74**	**16.99**	**17.44**	**17.01**	**17.19**	**17.74**
Natural Gas Plant Liquids	**1.85**	**2.26**	**2.35**	**2.45**	**2.47**	**2.63**	**2.78**	**2.67**	**2.89**	**3.02**
Other Inputs[3]	**0.60**	**0.20**	**0.20**	**0.28**	**0.21**	**0.21**	**0.22**	**0.22**	**0.23**	**0.23**
Refinery Processing Gain[4]	**0.89**	**0.99**	**1.02**	**1.10**	**0.98**	**1.06**	**1.15**	**1.02**	**1.10**	**1.21**
Net Product Imports[5]	**1.30**	**2.12**	**2.38**	**2.72**	**2.45**	**3.33**	**4.11**	**2.90**	**4.37**	**5.75**
Gross Refined Product Imports[6]	1.73	2.26	2.40	2.66	2.78	3.30	4.03	3.13	4.26	5.66
Unfinished Oil Imports	0.32	0.69	0.79	0.89	0.51	0.87	0.94	0.65	0.99	0.96
Ether Imports	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Exports	0.82	0.83	0.81	0.83	0.84	0.84	0.85	0.88	0.88	0.88
Total Primary Supply[7]	**19.44**	**21.78**	**22.64**	**23.78**	**22.85**	**24.21**	**25.70**	**23.81**	**25.79**	**27.96**
Refined Petroleum Products Supplied										
Motor Gasoline[8]	8.43	9.82	10.11	10.43	10.30	10.75	11.18	10.70	11.33	11.94
Jet Fuel[9]	1.67	2.06	2.18	2.32	2.33	2.52	2.72	2.57	2.88	3.18
Distillate Fuel[10]	3.52	4.27	4.47	4.74	4.47	4.78	5.14	4.65	5.10	5.62
Residual Fuel	0.82	0.57	0.58	0.61	0.57	0.59	0.61	0.58	0.60	0.64
Other[11]	5.07	5.11	5.36	5.75	5.22	5.62	6.10	5.35	5.92	6.61
Total	**19.50**	**21.83**	**22.70**	**23.83**	**22.89**	**24.26**	**25.75**	**23.85**	**25.83**	**28.00**
Refined Petroleum Products Supplied										
Residential and Commercial	1.10	1.06	1.06	1.08	1.03	1.04	1.05	1.01	1.02	1.03
Industrial[12]	5.16	5.29	5.58	6.01	5.43	5.89	6.42	5.58	6.23	7.01
Transportation	12.86	15.41	15.98	16.66	16.36	17.26	18.20	17.18	18.50	19.86
Electric Generators[13]	0.38	0.07	0.07	0.09	0.07	0.07	0.08	0.07	0.08	0.09
Total	**19.50**	**21.83**	**22.70**	**23.83**	**22.89**	**24.26**	**25.75**	**23.85**	**25.83**	**28.00**
Discrepancy[14]	**-0.07**	**-0.05**	**-0.06**	**-0.05**	**-0.05**	**-0.05**	**-0.04**	**-0.04**	**-0.04**	**-0.04**
World Oil Price (1999 dollars per barrel)[15]	**17.35**	**20.70**	**21.37**	**21.87**	**20.93**	**21.89**	**22.70**	**21.16**	**22.41**	**23.51**
Import Share of Product Supplied	**0.51**	**0.61**	**0.61**	**0.62**	**0.62**	**0.63**	**0.63**	**0.63**	**0.64**	**0.65**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 1999 dollars)	**60.16**	**104.46**	**113.67**	**123.12**	**114.59**	**129.29**	**144.97**	**122.68**	**145.38**	**170.75**
Domestic Refinery Distillation Capacity[16]	**16.5**	**17.5**	**17.9**	**18.4**	**17.9**	**18.1**	**18.4**	**18.2**	**18.2**	**18.8**
Capacity Utilization Rate (percent)	**93.0**	**93.0**	**93.6**	**94.2**	**93.6**	**94.3**	**95.0**	**94.0**	**95.0**	**95.1**

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.
[3]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, and other hydrocarbons.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[6]Includes blending components.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net petroleum imports.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes naphtha and kerosene types.
[10]Includes distillate and kerosene.
[11]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[12]Includes consumption by cogenerators.
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses and gains.
[15]Average refiner acquisition cost for imported crude oil.
[16]End-of-year capacity.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 product supplied data from Table B2. Other 1999 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B12. Petroleum Product Prices
(1999 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
World Oil Price (1999 dollars per barrel)	**17.35**	**20.70**	**21.37**	**21.87**	**20.93**	**21.89**	**22.70**	**21.16**	**22.41**	**23.51**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	87.0	101.4	104.1	105.9	102.7	108.1	110.8	103.9	110.7	113.4
Liquefied Petroleum Gas	89.4	107.6	112.8	112.6	106.2	110.7	112.8	105.1	111.1	114.9
Commercial										
Distillate Fuel	60.6	70.6	73.2	74.9	71.7	77.0	79.7	72.8	79.7	83.3
Residual Fuel	39.3	53.8	55.3	56.5	54.2	56.4	58.3	54.7	57.6	60.2
Residual Fuel (1999 dollars per barrel)	16.53	22.58	23.22	23.71	22.77	23.71	24.49	22.97	24.20	25.29
Industrial[1]										
Distillate Fuel	64.5	73.0	75.6	77.4	74.3	79.5	82.2	75.4	82.5	87.1
Liquefied Petroleum Gas	73.4	63.8	69.1	68.9	62.6	66.9	68.8	61.7	67.6	71.4
Residual Fuel	41.7	49.7	51.2	52.4	50.2	52.4	54.2	50.7	53.6	56.1
Residual Fuel (1999 dollars per barrel)	17.50	20.88	21.51	22.01	21.08	22.00	22.78	21.29	22.50	23.58
Transportation										
Diesel Fuel (distillate)[2]	114.0	120.0	124.0	127.6	1193	125.5	129.5	117.9	124.6	131.5
Jet Fuel[3]	63.5	70.8	73.8	76.0	71.5	77.7	81.2	73.4	79.4	82.2
Motor Gasoline[4]	118.2	132.3	136.3	141.0	129.7	133.9	138.3	128.0	133.0	138.1
Liquified Petroleum Gas	111.1	117.8	123.1	123.7	115.5	120.5	123.6	112.9	119.5	124.5
Residual Fuel	36.8	46.0	47.5	48.7	46.5	48.7	50.6	46.9	49.8	52.4
Residual Fuel (1999 dollars per barrel)	15.45	19.32	19.96	20.46	19.51	20.45	21.23	19.70	20.92	22.00
Ethanol (E85)	129.2	170.4	170.1	171.8	172.8	172.2	173.7	165.3	173.3	175.2
Methanol (M85)	76.2	99.0	100.7	102.9	102.6	105.1	107.4	102.1	105.8	108.9
Electric Generators[5]										
Distillate Fuel	56.2	64.5	67.1	68.9	65.7	70.7	73.5	66.9	73.2	78.1
Residual Fuel	36.2	56.5	58.1	57.8	57.5	59.9	61.3	58.3	60.9	62.1
Residual Fuel (1999 dollars per barrel)	15.21	23.71	24.42	24.26	24.13	25.17	25.76	24.50	25.56	26.07
Refined Petroleum Product Prices[6]										
Distillate Fuel	100.8	109.7	113.5	116.7	109.8	115.9	119.7	109.4	116.2	122.5
Jet Fuel[3]	63.5	70.8	73.8	76.0	71.5	77.7	81.2	73.4	79.4	82.2
Liquefied Petroleum Gas	76.3	71.7	76.6	76.0	70.3	74.1	75.6	69.2	74.4	77.5
Motor Gasoline[4]	118.2	132.3	136.3	141.0	129.7	133.9	138.3	128.0	133.0	138.1
Residual Fuel	37.1	48.2	49.8	51.0	48.8	51.0	53.0	49.3	52.2	54.9
Residual Fuel (1999 dollars per barrel)	15.59	20.26	20.93	21.43	20.48	21.44	22.24	20.69	21.94	23.06
Average	**97.6**	**109.5**	**113.1**	**115.9**	**108.1**	**112.5**	**115.9**	**107.1**	**112.2**	**11.56.4**

[1]Includes cogenerators. Includes Federal and State taxes while excluding county and state taxes.
[2] Low sulfur diesel fuel. Includes Federal and State taxes while excluding county and local taxes.
[3]Kerosene-type jet fuel.
[4]Sales weighted-average price for all grades. Includes Federal and State taxes while excluding county and local taxes.
[5]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380 (99/03-2000/04) (Washington, DC, 1999-2000). 1999 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditure Report 1997*, DOE/EIA-0376(97) (Washington, DC, July 2000). **Projections**: EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production										
Dry Gas Production[1]	18.67	22.27	23.14	24.16	24.63	26.24	27.86	26.74	29.04	30.38
Supplemental Natural Gas[2]	0.10	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**3.38**	**4.93**	**5.06**	**5.22**	**5.35**	**5.50**	**5.62**	**5.58**	**5.80**	**5.82**
Canada	3.29	4.68	4.81	4.97	5.05	5.21	5.33	5.24	5.46	5.48
Mexico	-0.01	-0.25	-0.25	-0.25	-0.33	-0.33	-0.33	-0.40	-0.40	-0.40
Liquefied Natural Gas	0.10	0.50	0.50	0.50	0.62	0.62	0.62	0.74	0.74	0.74
Total Supply	**22.15**	**27.26**	**28.25**	**29.44**	**30.03**	**31.80**	**33.54**	**32.38**	**34.90**	**36.25**
Consumption by Sector										
Residential	4.72	5.49	5.54	5.56	5.70	5.83	5.90	5.95	6.14	6.21
Commercial	3.07	3.69	3.78	3.84	3.79	3.94	4.07	3.83	4.02	4.19
Industrial[3]	7.95	8.95	9.33	9.85	9.18	9.76	10.50	9.36	10.18	11.20
Electric Generators[4]	3.78	6.54	6.94	7.45	8.54	9.30	9.97	10.23	11.34	11.29
Lease and Plant Fuel[5]	1.23	1.45	1.49	1.54	1.60	1.68	1.76	1.72	1.84	1.91
Pipeline Fuel	0.64	0.84	0.87	0.91	0.91	0.97	1.03	0.98	1.06	1.12
Transportation[6]	0.02	0.09	0.09	0.09	0.12	0.13	0.13	0.14	0.15	0.17
Total	**21.41**	**27.05**	**28.05**	**29.24**	**29.85**	**31.61**	**33.36**	**32.22**	**34.73**	**36.09**
Discrepancy[7]	**0.74**	**0.21**	**0.21**	**0.19**	**0.18**	**0.18**	**0.18**	**0.16**	**0.17**	**0.17**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 1999 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 transportation sector consumption: EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A. Other 1999 consumption: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A. **Projections:** EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B14. Natural Gas Prices, Margins, and Revenue
(1999 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.49	2.69	3.08	2.59	2.83	3.20	2.66	3.13	3.68
Average Import Price	2.29	2.33	2.43	2.53	2.35	2.47	2.58	2.44	2.67	2.89
Average[2]	**2.11**	**2.46**	**2.64**	**2.98**	**2.54**	**2.76**	**3.09**	**2.62**	**3.05**	**3.55**
Delivered Prices										
Residential	6.69	6.50	6.70	7.09	6.37	6.61	6.95	6.32	6.73	7.24
Commercial	5.49	5.45	5.65	6.03	5.41	5.65	6.00	5.42	5.86	6.38
Industrial[3]	2.87	3.20	3.40	3.78	3.29	3.54	3.91	3.38	3.86	4.43
Electric Generators[4]	2.59	2.90	3.08	3.45	3.05	3.30	3.67	3.17	3.66	4.17
Transportation[5]	7.21	6.95	7.23	7.74	6.99	7.36	7.84	6.96	7.52	8.17
Average[6]	**4.16**	**4.21**	**4.38**	**4.72**	**4.17**	**4.39**	**4.72**	**4.19**	**4.62**	**5.14**
Transmission & Distribution Margins[7]										
Residential	4.58	4.05	4.07	4.12	3.83	3.85	3.86	3.70	3.68	3.69
Commercial	3.37	2.99	3.01	3.05	2.86	2.89	2.91	2.80	2.81	2.84
Industrial[3]	0.75	0.74	0.76	0.80	0.74	0.78	0.82	0.76	0.82	0.88
Electric Generators[4]	0.48	0.44	0.45	0.47	0.50	0.54	0.59	0.55	0.61	0.62
Transportation[5]	5.10	4.49	4.60	4.76	4.45	4.60	4.75	4.34	4.48	4.62
Average[6]	**2.04**	**1.75**	**1.74**	**1.74**	**1.63**	**1.63**	**1.63**	**1.57**	**1.57**	**1.60**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.61	22.21	22.55	22.88	21.83	22.42	22.78	22.03	22.58	22.93
Commercial	10.36	11.05	11.40	11.72	10.85	11.38	11.84	10.73	11.31	11.88
Industrial[3]	6.00	6.66	7.12	7.88	6.80	7.61	8.66	7.08	8.32	9.86
Electric Generators[4]	1.81	2.87	3.11	3.48	4.29	5.02	5.84	5.67	6.93	7.05
Transportation[5]	0.08	0.39	0.42	0.45	0.53	0.58	0.63	0.62	0.69	0.77
Total	**39.86**	**43.18**	**44.59**	**46.40**	**44.31**	**47.01**	**49.76**	**46.13**	**49.82**	**52.48**

[1]Represents lower 48 onshore and offshore supplies.
[2]Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.

Sources: 1999 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1994*. 1999 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). **Other 1999 values and projections:** EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B15. Oil and Gas Supply

Production and Supply	1999	Projections 2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2015 Low Economic Growth	2015 Reference	2015 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth
Crude Oil										
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	**16.49**	**20.05**	**20.80**	**21.29**	**20.16**	**21.00**	**21.87**	**20.40**	**21.45**	**22.57**
Production (million barrels per day)[2]										
U.S. Total	**5.88**	**5.08**	**5.15**	**5.21**	**4.94**	**5.08**	**5.22**	**4.86**	**5.05**	**5.26**
Lower 48 Onshore	3.27	2.42	2.46	2.48	2.45	2.52	2.57	2.54	2.64	2.74
Conventional	2.59	1.77	1.79	1.83	1.74	1.78	1.85	1.87	1.92	1.98
Enhanced Oil Recovery	0.68	0.65	0.66	0.65	0.72	0.74	0.72	0.67	0.72	0.76
Lower 48 Offshore	1.56	2.02	2.05	2.09	1.79	1.86	1.95	1.68	1.77	1.88
Alaska	1.05	0.64	0.64	0.64	0.70	0.70	0.70	0.64	0.64	0.64
Lower 48 End of Year Reserves (billion barrels)[2]	**18.33**	**13.73**	**13.92**	**14.22**	**13.07**	**13.50**	**13.89**	**12.89**	**13.48**	**14.16**
Natural Gas										
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	**2.08**	**2.49**	**2.69**	**3.08**	**2.59**	**2.83**	**3.20**	**2.66**	**3.13**	**3.68**
Dry Production (trillion cubic feet)[3]										
U.S. Total	**18.67**	**22.27**	**23.14**	**24.16**	**24.63**	**26.24**	**27.86**	**26.74**	**29.04**	**30.38**
Lower 48 Onshore	12.83	15.38	16.29	17.28	17.77	19.04	20.48	19.50	21.26	22.09
Associated-Dissolved[4]	1.80	1.31	1.33	1.35	1.29	1.32	1.36	1.37	1.38	1.39
Non-Associated	11.03	14.07	14.96	15.93	16.48	17.72	19.12	18.13	19.88	20.69
Conventional	6.64	8.26	8.30	8.56	10.05	10.37	10.55	10.78	11.38	11.58
Unconventional	4.39	5.80	6.66	7.37	6.43	7.36	8.57	7.35	8.51	9.11
Lower 48 Offshore	5.43	6.39	6.34	6.37	6.33	6.66	6.84	6.68	7.21	7.71
Associated-Dissolved[4]	0.93	1.07	1.08	1.08	1.02	1.04	1.06	0.99	1.01	1.04
Non-Associated	4.50	5.31	5.26	5.29	5.31	5.63	5.78	5.69	6.19	6.67
Alaska	0.42	0.50	0.50	0.51	0.53	0.54	0.55	0.56	0.57	0.58
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**157.41**	**164.09**	**174.82**	**187.72**	**173.37**	**183.82**	**197.83**	**182.29**	**190.07**	**199.63**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.10**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**
Total Lower 48 Wells (thousands)	**17.94**	**26.21**	**28.63**	**33.62**	**29.47**	**31.62**	**33.51**	**34.38**	**39.14**	**45.45**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). 1999 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). Other 1999 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Economic Growth Case Comparisons

Table B16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production[1]										
Appalachia	437	400	409	423	391	404	409	385	392	408
Interior	166	168	171	172	167	169	163	154	152	169
West	502	674	692	717	702	720	780	740	787	883
East of the Mississippi	546	526	537	551	518	534	533	507	512	541
West of the Mississippi	559	717	735	761	741	760	819	772	819	920
Total	**1105**	**1243**	**1273**	**1312**	**1259**	**1294**	**1352**	**1279**	**1331**	**1461**
Net Imports										
Imports	9	17	17	17	18	18	18	20	20	20
Exports	58	58	58	58	54	54	54	56	56	56
Total	**-49**	**-40**	**-40**	**-40**	**-35**	**-35**	**-35**	**-36**	**-36**	**-36**
Total Supply[2]	**1056**	**1203**	**1232**	**1272**	**1224**	**1259**	**1317**	**1243**	**1295**	**1424**
Consumption by Sector										
Residential and Commercial	5	5	5	6	5	5	6	5	5	6
Industrial[3]	79	83	84	87	83	85	88	83	86	91
Coke Plants	28	23	23	23	21	21	21	19	19	19
Electric Generators[4]	923	1091	1122	1159	1117	1149	1203	1138	1186	1311
Total	**1035**	**1202**	**1235**	**1274**	**1226**	**1261**	**1318**	**1245**	**1297**	**1426**
Discrepancy and Stock Change[5].	**21**	**0**	**-2**	**-2**	**-2**	**-2**	**-1**	**-2**	**-2**	**-2**
Average Minemouth Price										
(1999 dollars per short ton)	16.98	13.74	13.83	13.93	13.23	13.38	13.28	12.79	12.70	12.80
(1999 dollars per million Btu)	0.81	0.67	0.68	0.68	0.65	0.66	0.65	0.63	0.63	0.64
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.43	28.17	28.40	28.79	27.11	27.49	27.92	26.12	26.48	27.22
Coke Plants	44.25	41.10	41.25	41.58	39.45	39.81	40.13	38.30	38.57	39.05
Electric Generators										
(1999 dollars per short ton)	24.69	20.86	21.04	21.45	19.96	20.25	20.65	19.11	19.45	19.83
(1999 dollars per million Btu)	1.21	1.04	1.05	1.07	1.00	1.01	1.04	0.96	0.98	1.01
Average	**25.74**	**21.75**	**21.92**	**22.31**	**20.77**	**21.06**	**21.45**	**19.87**	**20.19**	**20.56**
Exports[7]	37.45	35.38	35.53	35.88	34.02	34.38	34.79	32.82	33.09	33.64

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 8.5 million tons in 1995, 8.8 million tons in 1996, 8.1 million tons in 1997, 8.6 million tons in 1998, and are projected to reach 9.6 million tons in 1999, and 12.2 million tons in 2000.

[2]Production plus net imports and net storage withdrawals.

[3]Includes consumption by cogenerators.

[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.

[5]Balancing item: the sum of production, net imports, and net storage minus total consumption.

[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.

[7]F.a.s. price at U.S. port of exit.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.

Sources: 1999 data based on Energy Information Administration (EIA), *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000) and EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A. **Projections:** EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B17. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Electric Generators[1] (excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	78.14	78.74	78.74	78.74	78.74	78.74	78.74	78.74	78.74	78.74
Geothermal[2]	2.87	4.03	4.34	4.37	4.08	4.41	4.61	4.08	4.41	4.74
Municipal Solid Waste[3]	2.59	4.03	4.20	4.33	4.40	4.57	4.70	4.54	4.72	4.85
Wood and Other Biomass[4]	1.52	2.04	2.04	2.04	2.33	2.33	2.33	2.37	2.37	2.37
Solar Thermal	0.33	0.40	0.40	0.40	0.44	0.44	0.44	0.48	0.48	0.48
Solar Photovoltaic	0.01	0.21	0.21	0.21	0.37	0.37	0.37	0.54	0.54	0.54
Wind	2.60	5.51	5.51	5.51	5.70	5.70	5.70	5.73	5.78	5.81
Total	**88.07**	**94.95**	**95.44**	**95.60**	**96.05**	**96.55**	**96.88**	**96.49**	**97.04**	**97.53**
Generation (billion kilowatthours)										
Conventional Hydropower	307.43	298.95	298.99	299.04	298.39	298.45	298.53	297.85	297.94	298.06
Geothermal[2]	13.07	22.80	25.27	25.48	23.24	25.81	27.38	23.26	25.83	28.47
Municipal Solid Waste[3]	18.05	28.65	30.00	31.09	31.49	32.88	33.94	32.56	33.96	35.03
Wood and Other Biomass[4]	9.49	21.01	21.59	21.24	21.51	23.21	22.77	22.85	22.15	21.81
Dedicated Plants	7.56	10.88	10.88	10.89	12.99	12.99	13.00	13.34	13.35	13.36
Cofiring	1.93	10.13	10.71	10.35	8.52	10.22	9.77	9.52	8.80	8.45
Solar Thermal	0.89	1.11	1.11	1.11	1.24	1.24	1.24	1.37	1.37	1.37
Solar Photovoltaic	0.03	0.51	0.51	0.51	0.92	0.92	0.92	1.36	1.36	1.36
Wind	4.46	12.33	12.33	12.33	12.84	12.84	12.84	12.93	13.10	13.19
Total	**353.42**	**385.36**	**389.80**	**390.80**	**389.62**	**395.35**	**397.62**	**392.18**	**395.71**	**399.28**
Cogenerators[5]										
Net Summer Capability										
Municipal Solid Waste	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Biomass	4.65	5.72	6.06	6.52	6.19	6.85	7.51	6.50	7.54	8.61
Total	**5.35**	**6.41**	**6.76**	**7.21**	**6.89**	**7.55**	**8.21**	**7.20**	**8.23**	**9.31**
Generation (billion kilowatthours)										
Municipal Solid Waste	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03
Biomass	27.08	33.06	35.01	37.56	35.76	39.55	43.33	37.54	43.52	49.68
Total	**31.11**	**37.08**	**39.03**	**41.59**	**39.78**	**43.58**	**47.35**	**41.57**	**47.55**	**53.71**
Other End-Use Generators[6]										
Net Summer Capability										
Conventional Hydropower[7]	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.01	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Total	**1.00**	**1.34**	**1.34**	**1.34**	**1.34**	**1.34**	**1.34**	**1.34**	**1.34**	**1.34**
Generation (billion kilowatthours)										
Conventional Hydropower[7]	4.57	4.43	4.43	4.43	4.42	4.42	4.42	4.41	4.41	4.41
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
Total	**4.59**	**5.18**	**5.18**	**5.18**	**5.18**	**5.18**	**5.18**	**5.17**	**5.17**	**5.5.17**

[1]Includes grid-connected utilities and nonutilities other than cogenerators. These nonutility facilities include small power producers and exempt wholesale generators.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Cogenerators produce electricity and other useful thermal energy.
[6]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[7]Represents own-use industrial hydroelectric power.

Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators for AEO2001. Net summer capability is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.

Sources: 1999 electric utility capability: Energy Information Administration (EIA), Form EIA-860A: "Annual Electric Generator Report - Utility." 1999 nonutility and cogenerator capability: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." 1999 generation: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B18. Renewable Energy Consumption by Sector and Source
(Quadrillion Btu per Year)

Sector and Source	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.43**	**0.43**	**0.43**	**0.43**	**0.43**	**0.43**	**0.44**	**0.44**	**0.44**
Wood	0.41	0.43	0.43	0.43	0.43	0.43	0.43	0.44	0.44	0.44
Commercial	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Industrial[3]	**2.15**	**2.52**	**2.64**	**2.82**	**2.66**	**2.86**	**3.10**	**2.78**	**3.08**	**3.44**
Conventional Hydroelectric	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	1.97	2.33	2.46	2.63	2.47	2.68	2.91	2.60	2.90	3.25
Transportation	**0.12**	**0.21**	**0.21**	**0.22**	**0.22**	**0.23**	**0.24**	**0.23**	**0.24**	**0.26**
Ethanol used in E85[4]	0.00	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04
Ethanol used in Gasoline Blending	0.12	0.18	0.19	0.20	0.19	0.20	0.20	0.20	0.21	0.22
Electric Generators[5]	**3.94**	**4.48**	**4.64**	**4.59**	**4.54**	**4.71**	**4.71**	**4.58**	**4.66**	**4.75**
Conventional Hydroelectric	3.17	3.08	3.08	3.08	3.07	3.07	3.07	3.06	3.06	3.06
Geothermal	0.38	0.67	0.81	0.75	0.69	0.82	0.81	0.70	0.77	0.84
Municipal Solid Waste[6]	0.25	0.39	0.41	0.42	0.43	0.45	0.46	0.44	0.46	0.48
Biomass	0.09	0.20	0.21	0.20	0.20	0.22	0.22	0.22	0.21	0.21
Dedicated Plants	0.07	0.10	0.10	0.10	0.12	0.12	0.12	0.13	0.13	0.13
Cofiring	0.02	0.10	0.10	0.10	0.08	0.10	0.09	0.09	0.08	0.08
Solar Thermal	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.05	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.14
Total Marketed Renewable Energy	**6.70**	**7.72**	**8.01**	**8.15**	**7.93**	**8.32**	**8.56**	**8.11**	**8.51**	**8.97**
Non-Marketed Renewable Energy[7]										
Selected Consumption										
Residential	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.03**	**0.04**	**0.04**
Solar Hot Water Heating	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal Heat Pumps	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ethanol										
From Corn	0.12	0.18	0.19	0.20	0.18	0.19	0.20	0.16	0.17	0.18
From Cellulose	0.00	0.02	0.02	0.02	0.04	0.04	0.04	0.07	0.07	0.08
Total	**0.12**	**0.21**	**0.21**	**0.22**	**0.22**	**0.23**	**0.24**	**0.23**	**0.24**	**0.26**

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table B8.
[3]Includes all electricity production by industrial and other cogenerators for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes renewable energy delivered to the grid from electric utilities and nonutilities. Renewable energy used in generating electricity for own use is included in the individual sectoral electricity energy consumption values.
[6]Includes landfill gas.
[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 ethanol: Energy Information Administration (EIA), *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). 1999 electric generators: EIA, Form EIA-860A: "Annual Electric Generator Report - Utility" and Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 1999: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B19. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential										
Petroleum	26.0	24.5	24.4	24.4	23.6	23.4	23.5	23.1	22.9	22.9
Natural Gas	69.5	81.2	82.0	82.2	84.3	86.2	87.2	88.0	90.8	91.9
Coal	1.1	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.2
Electricity	192.6	234.6	238.2	240.9	251.2	255.2	258.6	266.8	273.2	281.5
Total	**289.3**	**341.6**	**345.9**	**348.9**	**360.4**	**366.2**	**370.6**	**379.1**	**388.1**	**397.5**
Commercial										
Petroleum	13.7	12.8	13.1	13.4	12.7	13.1	13.6	12.4	12.9	13.5
Natural Gas	45.4	54.6	55.9	56.8	56.1	58.3	60.2	56.6	59.4	61.9
Coal	1.7	1.8	1.9	1.9	1.8	1.9	2.0	1.8	2.0	2.1
Electricity	182.1	227.0	234.4	241.4	243.2	253.0	263.3	251.1	263.9	282.8
Total	**242.9**	**296.2**	**305.3**	**313.5**	**313.8**	**326.3**	**339.0**	**322.0**	**338.2**	**360.2**
Industrial[1]										
Petroleum	104.2	100.0	104.7	112.3	102.1	109.9	118.4	105.4	115.5	128.1
Natural Gas[2]	141.6	151.6	157.6	165.6	157.2	166.8	178.5	161.5	175.1	190.9
Coal	55.9	64.7	66.3	69.1	63.9	66.2	69.9	63.1	66.4	71.6
Electricity	178.8	190.3	200.8	217.8	198.1	212.4	233.1	206.9	226.6	260.1
Total	**480.4**	**506.5**	**529.4**	**564.9**	**521.3**	**555.2**	**599.9**	**536.9**	**583.6**	**650.7**
Transportation										
Petroleum[3]	485.8	586.3	608.5	634.5	622.5	657.3	693.8	654.1	704.9	757.6
Natural Gas[4]	9.5	13.8	14.3	14.8	15.2	16.2	17.1	16.6	18.0	19.0
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	2.9	5.5	5.7	5.8	6.7	6.9	7.1	7.6	7.8	8.2
Total[3]	**498.2**	**605.7**	**628.5**	**655.3**	**644.5**	**680.5**	**718.1**	**678.4**	**730.8**	**784.9**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	723.6	750.6	784.7	760.9	803.7	849.2	795.0	856.1	922.1
Natural Gas	266.0	301.1	309.8	319.5	312.8	327.5	343.1	322.8	343.3	363.6
Coal	58.8	67.8	69.5	72.4	67.1	69.4	73.1	66.2	69.6	74.9
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	556.3	657.4	679.1	706.0	699.2	727.5	762.1	732.3	771.5	832.6
Total[3]	**1510.8**	**1750.0**	**1809.1**	**1882.6**	**1840.1**	**1928.1**	**2027.6**	**1916.4**	**2040.6**	**2193.3**
Electric Generators[6]										
Petroleum	20.0	3.3	3.4	4.0	3.4	3.4	3.6	3.4	3.7	4.5
Natural Gas	45.8	96.0	101.8	109.3	125.3	136.5	146.3	150.1	166.3	165.7
Coal	490.5	558.1	574.0	592.7	570.5	587.6	612.2	578.8	601.5	662.4
Total	**556.3**	**657.4**	**679.1**	**706.0**	**699.2**	**727.5**	**762.1**	**732.3**	**771.5**	**832.6**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	726.9	754.0	788.7	764.3	807.1	852.8	798.4	859.9	926.6
Natural Gas	311.8	397.1	411.5	428.8	438.1	463.9	489.3	472.9	509.6	529.3
Coal	549.3	625.9	643.5	665.1	637.6	657.0	685.4	645.0	671.1	737.4
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total[3]	**1510.8**	**1750.0**	**1809.1**	**1882.6**	**1840.1**	**1928.1**	**2027.6**	**1916.4**	**2040.6**	**2193.3**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**6.0**	**6.0**	**6.1**	**6.1**	**6.2**	**6.3**	**6.2**	**6.3**	**6.5**

[1]Includes consumption by cogenerators.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel which, by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 1998, international bunker fuels accounted for 25 to 30 million metric tons carbon equivalent of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes methanol and liquid hydrogen.
[6]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste not energy.
[7]Emissions from electric power generators are distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 1999,* DOE/EIA-0573(99) (Washington, DC, October 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B20. Macroeconomic Indicators
(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
GDP Chain-Type Price Index (1996=1.000)	**1.045**	**1.391**	**1.304**	**1.203**	**1.592**	**1.440**	**1.303**	**1.907**	**1.680**	**1.472**
Real Gross Domestic Product	**8876**	**12000**	**12667**	**13463**	**13495**	**14635**	**15744**	**14757**	**16515**	**18202**
Real Consumption	5990	8143	8535	8911	9222	9934	10442	10198	11312	12144
Real Investment	1611	2636	2917	3215	3118	3613	4020	3407	4252	4921
Real Government Spending	1536	1767	1877	1941	1863	2022	2122	1976	2193	2339
Real Exports	1037	2278	2445	2698	3104	3465	3908	4048	4757	5493
Real Imports	1356	2803	3084	3181	3734	4336	4506	4811	5986	6366
Real Disposable Personal Income	**6363**	**8537**	**8928**	**9356**	**9726**	**10361**	**10977**	**10907**	**11842**	**12739**
AA Utility Bond Rate (percent)	**7.05**	**9.90**	**8.76**	**7.95**	**9.81**	**8.60**	**7.56**	**11.99**	**9.51**	**7.95**
Real Yield on Government 10 Year Bonds (percent)	**4.75**	**5.41**	**5.59**	**5.53**	**5.59**	**5.55**	**5.17**	**6.99**	**5.43**	**4.88**
Real Utility Bond Rate (percent)	**5.58**	**7.27**	**6.90**	**6.47**	**6.97**	**6.49**	**5.89**	**8.08**	**6.09**	**5.23**
Energy Intensity (thousand Btu per 1996 dollar of GDP)										
Delivered Energy	8.08	6.93	6.79	6.67	6.45	6.27	6.16	6.14	5.89	5.75
Total Energy	10.84	9.21	9.02	8.81	8.53	8.25	8.06	8.07	7.70	7.47
Consumer Price Index (1982-84=1.00)	**1.67**	**2.36**	**2.20**	**2.03**	**2.78**	**2.49**	**2.25**	**3.42**	**2.95**	**2.59**
Unemployment Rate (percent)	**4.22**	**5.39**	**4.94**	**4.41**	**4.88**	**4.32**	**4.31**	**5.04**	**4.28**	**4.16**
Housing Starts (millions)	2.02	1.60	1.89	2.09	1.75	2.10	2.31	1.66	2.09	2.35
Single-Family	1.34	0.97	1.17	1.30	1.03	1.28	1.42	0.96	1.27	1.44
Multifamily	0.34	0.35	0.41	0.48	0.41	0.48	0.55	0.38	0.46	0.56
Mobile Home Shipments	0.35	0.28	0.30	0.31	0.31	0.34	0.34	0.31	0.35	0.35
Commercial Floorspace, Total (billion square feet)	**62.8**	**73.2**	**75.8**	**78.5**	**75.7**	**79.6**	**83.8**	**76.4**	**81.9**	**87.8**
Gross Output (billion 1992 dollars)										
Total Industrial	4722	5942	6251	6769	6601	7093	7835	7359	8096	9251
Nonmanufacturing	972	1092	1162	1238	1157	1265	1364	1210	1370	1516
Manufacturing	3749	4850	5089	5531	5444	5828	6471	6149	6726	7735
Energy-Intensive Manufacturing	1078	1187	1248	1326	1230	1322	1422	1267	1396	1536
Non-Energy-Intensive Manufacturing	2672	3663	3841	4205	4214	4506	5049	4882	5330	6199
Unit Sales of Light-Duty Vehicles (millions)	**16.89**	**15.11**	**15.88**	**16.76**	**16.08**	**17.18**	**18.30**	**15.32**	**17.44**	**19.71**
Population (millions)										
Population with Armed Forces Overseas)	273.1	292.7	300.2	307.7	301.6	312.6	323.6	310.7	325.2	339.8
Population (aged 16 and over)	210.9	231.1	236.6	242.0	238.7	246.7	254.7	245.7	256.5	267.2
Employment, Non-Agriculture	128.5	145.4	149.7	155.2	150.0	157.3	163.7	153.9	165.1	175.1
Employment, Manufacturing	18.7	17.4	18.0	19.2	16.9	17.8	19.1	16.5	17.8	19.6
Labor Force	139.4	154.0	158.2	163.2	158.0	164.3	171.1	160.7	169.5	178.6

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 1999: Standard & Poor's DRI, Simulation T250200. **Projections:** Energy Information Administration, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Table B21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
World Oil Price (1999 dollars per barrel)[1]	**17.35**	**20.70**	**21.37**	**21.87**	**20.93**	**21.89**	**22.70**	**21.16**	**22.41**	**23.51**
Production[2]										
OECD										
U.S. (50 states)	9.22	8.52	8.72	9.00	8.60	8.98	9.37	8.77	9.27	9.72
Canada	2.63	3.20	3.20	3.20	3.38	3.38	3.39	3.42	3.43	3.44
Mexico	3.37	3.98	3.99	4.00	3.90	3.91	3.92	3.79	3.81	3.82
OECD Europe[3]	7.02	7.67	7.68	7.69	7.01	7.02	7.03	6.51	6.53	6.54
Other OECD	0.76	0.98	0.98	0.98	0.94	0.94	0.95	0.89	0.89	0.90
Total OECD	**23.00**	**24.35**	**24.57**	**24.87**	**23.82**	**24.23**	**24.65**	**23.38**	**23.93**	**24.41**
Developing Countries										
Other South & Central America	3.85	4.60	4.61	4.61	5.10	5.12	5.13	5.45	5.48	5.50
Pacific Rim	2.30	3.01	3.01	3.02	3.16	3.17	3.18	3.26	3.28	3.29
OPEC	29.87	41.84	42.16	42.76	48.62	48.94	49.54	57.18	57.64	58.55
Other Developing Countries	4.81	5.79	5.80	5.81	7.08	7.11	7.13	8.28	8.32	8.35
Total Developing Countries	**40.84**	**55.23**	**55.58**	**56.20**	**63.97**	**64.35**	**64.99**	**74.17**	**74.71**	**75.69**
Eurasia										
Former Soviet Union	7.40	10.66	10.68	10.69	12.94	12.98	13.02	14.27	14.33	14.39
Eastern Europe	0.24	0.38	0.38	0.38	0.42	0.42	0.42	0.45	0.45	0.45
China	3.21	3.52	3.53	3.53	3.61	3.63	3.64	3.62	3.63	3.65
Total Eurasia	**10.85**	**14.56**	**14.59**	**14.61**	**16.97**	**17.02**	**17.07**	**18.33**	**18.42**	**18.49**
Total Production	**74.68**	**94.14**	**94.73**	**95.68**	**104.75**	**105.60**	**106.71**	**115.88**	**117.06**	**118.59**
Consumption										
OECD										
U.S. (50 states)	19.50	21.83	22.70	23.83	22.89	24.26	25.75	23.85	25.83	28.00
U.S. Territories	0.34	0.41	0.41	0.41	0.44	0.44	0.43	0.47	0.46	0.46
Canada	1.92	2.11	2.10	2.08	2.19	2.16	2.13	2.20	2.17	2.13
Mexico	2.00	2.80	2.78	2.77	3.34	3.31	3.28	3.98	3.93	3.89
Japan	5.56	5.90	5.85	5.81	6.16	6.06	5.99	6.33	6.18	6.06
Australia and New Zealand.	0.98	1.10	1.09	1.09	1.17	1.16	1.16	1.23	1.22	1.22
OECD Europe[3]	14.50	15.87	15.81	15.77	16.28	16.18	16.10	16.64	16.50	16.39
Total OECD	**44.81**	**50.03**	**50.74**	**51.77**	**52.47**	**53.56**	**54.84**	**54.72**	**56.29**	**58.14**
Developing Countries										
Other South and Central America	4.14	5.87	5.86	5.85	7.01	6.98	6.96	8.44	8.39	8.36
Pacific Rim	7.64	12.37	12.34	12.31	14.24	14.18	14.13	16.11	16.02	15.94
OPEC	5.68	7.78	7.78	7.78	9.24	9.24	9.24	10.99	10.99	10.99
Other Developing Countries	3.75	4.33	4.31	4.30	5.00	4.95	4.92	5.87	5.79	5.72
Total Developing Countries	**21.22**	**30.36**	**30.29**	**30.24**	**35.48**	**35.35**	**35.25**	**41.40**	**41.19**	**41.02**
Eurasia										
Former Soviet Union	3.64	5.31	5.29	5.28	6.36	6.33	6.30	7.60	7.55	7.51
Eastern Europe	1.53	1.69	1.69	1.68	1.75	1.75	1.74	1.79	1.78	1.77
China	4.31	7.05	7.02	6.99	9.00	8.92	8.86	10.67	10.55	10.45
Total Eurasia	**9.48**	**14.05**	**13.99**	**13.95**	**17.11**	**16.99**	**16.90**	**20.06**	**19.88**	**19.74**

Table B21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1999	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Total Consumption	**75.51**	**94.44**	**95.03**	**95.98**	**105.05**	**105.90**	**107.01**	**116.18**	**117.36**	**118.89**
Non-OPEC Production	44.81	52.30	52.58	52.91	56.14	56.66	57.16	58.70	59.43	60.05
Net Eurasia Exports	1.37	0.50	0.59	0.65	-0.14	0.03	0.16	-1.73	-1.46	-1.24
OPEC Market Share	0.40	0.44	0.45	0.45	0.46	0.46	0.46	0.49	0.49	0.49

[1]Average refiner acquisition cost of imported crude oil.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol, liquids produced from coal and other sources, and refinery gains.
[3]OECD Europe includes the unified Germany.
OECD = Organization for Economic Cooperation and Development - Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States (including territories).
Pacific Rim = Hong Kong, Malaysia, Philippines, Singapore, South Korea, Taiwan, and Thailand.
OPEC = Organization of Petroleum Exporting Countries - Algeria, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
Eurasia = Albania, Bulgaria, China, Czech Republic, Hungary, Poland, Romania, Slovakia, the Former Soviet Union, and the Former Yugoslavia.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs LM2001.D101600A, AEO2001.D101600A, and HM2001.D101600A.

Oil Price Case Comparisons

Table C1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections 2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2015 Low World Oil Price	2015 Reference	2015 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price
Production										
Crude Oil and Lease Condensate	12.45	9.55	10.90	11.72	9.25	10.76	12.21	9.22	10.69	12.24
Natural Gas Plant Liquids	2.62	3.32	3.33	3.40	3.70	3.73	3.79	3.99	4.10	4.10
Dry Natural Gas	19.16	23.62	23.74	24.22	26.65	26.92	27.41	28.99	29.79	29.80
Coal	23.09	25.59	26.06	26.44	25.92	26.42	26.92	26.20	26.95	27.66
Nuclear Power	7.79	7.69	7.69	7.69	6.79	6.82	6.79	6.09	6.13	6.09
Renewable Energy[1]	6.58	7.65	7.82	7.84	7.99	8.12	8.14	8.19	8.31	8.37
Other[2]	1.65	0.31	0.30	0.48	0.33	0.32	0.39	0.33	0.34	0.40
Total	**73.35**	**77.72**	**79.85**	**81.78**	**80.63**	**83.10**	**85.64**	**83.02**	**86.30**	**88.67**
Imports										
Crude Oil[3]	18.96	25.85	25.15	24.36	28.11	25.94	24.43	28.93	26.44	25.01
Petroleum Products[4]	4.14	8.44	6.49	5.34	9.66	8.46	7.16	12.59	10.69	9.41
Natural Gas	3.63	5.73	5.61	5.36	6.20	6.17	5.92	6.50	6.58	6.29
Other Imports[5]	0.62	0.89	0.89	0.89	0.88	0.88	0.88	0.94	0.94	0.94
Total	**27.35**	**40.91**	**38.14**	**35.95**	**44.85**	**41.44**	**38.38**	**48.96**	**44.64**	**41.64**
Exports										
Petroleum[6]	1.98	1.74	1.78	1.87	1.80	1.83	1.94	1.95	1.91	2.03
Natural Gas	0.17	0.43	0.43	0.43	0.53	0.53	0.53	0.63	0.63	0.63
Coal	1.48	1.45	1.46	1.45	1.37	1.35	1.35	1.41	1.41	1.41
Total	**3.62**	**3.62**	**3.67**	**3.75**	**3.71**	**3.72**	**3.82**	**3.99**	**3.95**	**4.07**
Discrepancy[7]	**0.94**	**0.40**	**0.18**	**0.09**	**0.51**	**0.07**	**-0.12**	**0.60**	**-0.04**	**-0.17**
Consumption										
Petroleum Products[8]	38.03	45.55	44.41	43.54	48.95	47.50	46.34	52.74	50.59	49.49
Natural Gas	21.95	28.73	28.75	28.98	32.14	32.39	32.64	34.68	35.57	35.31
Coal	21.43	24.67	25.15	25.51	25.15	25.68	26.19	25.45	26.20	26.92
Nuclear Power	7.79	7.69	7.69	7.69	6.79	6.82	6.79	6.09	6.13	6.09
Renewable Energy[1]	6.59	7.66	7.83	7.85	8.00	8.13	8.14	8.20	8.31	8.38
Other[9]	0.34	0.31	0.31	0.31	0.23	0.23	0.23	0.23	0.23	0.23
Total	**96.14**	**114.61**	**114.14**	**113.89**	**121.25**	**120.75**	**120.33**	**127.39**	**127.03**	**126.42**
Net Imports - Petroleum	**21.12**	**32.55**	**29.86**	**27.83**	**35.97**	**32.57**	**29.64**	**39.57**	**35.22**	**32.38**
Prices (1999 dollars per unit)										
World Oil Price (dollars per barrel)[10]	17.35	15.10	21.37	26.66	15.10	21.89	28.23	15.10	22.41	28.42
Gas Wellhead Price (dollars per Mcf)[11]	2.08	2.66	2.69	2.77	2.77	2.83	2.95	3.01	3.13	3.25
Coal Minemouth Price (dollars per ton)	16.98	13.94	13.83	13.76	13.44	13.38	13.40	12.84	12.70	12.87
Average Electric Price (cents per Kwh)	6.7	5.9	5.9	6.0	5.9	5.9	6.0	5.9	6.0	6.1

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table C18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Mcf = Thousand cubic feet.
Kwh = Kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 petroleum values: *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). Other 1999 values: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Energy Consumption										
Residential										
Distillate Fuel	0.86	0.86	0.81	0.77	0.84	0.77	0.72	0.83	0.75	0.70
Kerosene	0.10	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.06
Liquefied Petroleum Gas	0.46	0.46	0.41	0.40	0.46	0.40	0.37	0.46	0.39	0.37
Petroleum Subtotal	1.42	1.39	1.29	1.23	1.37	1.24	1.16	1.36	1.21	1.13
Natural Gas	4.85	5.69	5.69	5.67	5.98	5.99	5.96	6.30	6.30	6.26
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.41	0.44	0.43	0.42	0.45	0.43	0.42	0.46	0.44	0.43
Electricity	3.91	4.95	4.96	4.94	5.36	5.37	5.35	5.81	5.80	5.78
Delivered Energy	**10.62**	**12.52**	**12.43**	**12.31**	**13.20**	**13.08**	**12.94**	**13.98**	**13.81**	**13.65**
Electricity Related Losses	8.48	9.97	9.87	9.83	10.30	10.19	10.17	10.62	10.55	10.56
Total	**19.10**	**22.49**	**22.30**	**22.15**	**23.50**	**23.27**	**23.11**	**24.60**	**24.36**	**24.20**
Commercial										
Distillate Fuel	0.36	0.52	0.41	0.38	0.56	0.40	0.37	0.57	0.39	0.36
Residual Fuel	0.10	0.11	0.11	0.10	0.11	0.11	0.11	0.11	0.11	0.11
Kerosene	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.59	0.78	0.67	0.63	0.82	0.67	0.63	0.84	0.66	0.62
Natural Gas	3.15	3.82	3.88	3.87	3.96	4.05	4.03	4.03	4.13	4.09
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08
Renewable Energy[3]	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Electricity	3.70	4.88	4.89	4.87	5.32	5.32	5.29	5.62	5.61	5.58
Delivered Energy	**7.59**	**9.64**	**9.59**	**9.52**	**10.26**	**10.19**	**10.11**	**10.65**	**10.55**	**10.45**
Electricity Related Losses	8.01	9.83	9.71	9.69	10.21	10.10	10.07	10.27	10.20	10.19
Total	**15.61**	**19.46**	**19.30**	**19.22**	**20.47**	**20.29**	**20.18**	**20.92**	**20.75**	**20.64**
Industrial[4]										
Distillate Fuel	1.07	1.28	1.27	1.26	1.37	1.35	1.34	1.47	1.44	1.43
Liquefied Petroleum Gas	2.32	2.64	2.50	2.50	2.88	2.65	2.63	3.20	2.83	2.80
Petrochemical Feedstock	1.29	1.53	1.53	1.53	1.61	1.61	1.61	1.70	1.70	1.69
Residual Fuel	0.22	0.37	0.25	0.21	0.38	0.26	0.22	0.40	0.27	0.26
Motor Gasoline[2]	0.21	0.25	0.25	0.25	0.26	0.26	0.26	0.28	0.28	0.28
Other Petroleum[5]	4.29	4.67	4.76	4.24	4.81	5.01	4.43	5.02	5.24	4.85
Petroleum Subtotal	9.39	10.74	10.55	9.99	11.33	11.14	10.49	12.08	11.77	11.32
Natural Gas[6]	9.43	10.68	11.11	11.80	11.17	11.76	12.52	11.48	12.34	12.87
Metallurgical Coal	0.75	0.61	0.61	0.61	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	1.73	1.85	1.85	1.86	1.87	1.87	1.88	1.89	1.90	1.90
Net Coal Coke Imports	0.06	0.16	0.16	0.16	0.19	0.19	0.19	0.22	0.22	0.22
Coal Subtotal	2.54	2.61	2.62	2.62	2.61	2.61	2.62	2.62	2.62	2.62
Renewable Energy[7]	2.15	2.65	2.64	2.64	2.87	2.86	2.86	3.09	3.08	3.08
Electricity	3.63	4.15	4.18	4.19	4.43	4.47	4.48	4.76	4.81	4.82
Delivered Energy	**27.15**	**30.83**	**31.10**	**31.24**	**32.41**	**32.84**	**32.96**	**34.03**	**34.63**	**34.71**
Electricity Related Losses	7.87	8.36	8.32	8.34	8.51	8.48	8.53	8.71	8.76	8.81
Total	**35.02**	**39.18**	**39.42**	**39.58**	**40.92**	**41.31**	**41.50**	**42.74**	**43.39**	**43.52**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Transportation										
Distillate Fuel	5.13	6.95	6.99	7.00	7.55	7.60	7.61	8.15	8.21	8.22
Jet Fuel[8]	3.46	4.55	4.51	4.48	5.27	5.22	5.15	6.02	5.97	5.88
Motor Gasoline[2]	15.92	19.40	19.04	18.88	20.71	20.23	19.94	21.95	21.32	20.91
Residual Fuel	0.74	0.85	0.85	0.85	0.86	0.86	0.86	0.86	0.87	0.87
Liquefied Petroleum Gas	0.02	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.06	0.06
Other Petroleum[9]	0.26	0.31	0.31	0.31	0.33	0.33	0.33	0.36	0.35	0.35
Petroleum Subtotal	25.54	32.10	31.74	31.56	34.77	34.28	33.94	37.40	36.77	36.29
Pipeline Fuel Natural Gas	0.66	0.89	0.90	0.90	0.99	0.99	1.00	1.07	1.09	1.08
Compressed Natural Gas	0.02	0.09	0.09	0.09	0.13	0.13	0.13	0.15	0.16	0.16
Renewable Energy (E85)[10]	0.01	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.05
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.06	0.12	0.12	0.12	0.15	0.15	0.14	0.17	0.17	0.17
Delivered Energy	**26.28**	**33.24**	**32.89**	**32.71**	**36.08**	**35.60**	**35.26**	**38.84**	**38.23**	**37.75**
Electricity Related Losses	0.13	0.24	0.23	0.23	0.28	0.28	0.28	0.30	0.30	0.30
Total	**26.41**	**33.48**	**33.12**	**32.94**	**36.36**	**35.87**	**35.54**	**39.14**	**38.54**	**38.05**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.42	9.61	9.47	9.40	10.32	10.12	10.04	11.02	10.80	10.71
Kerosene	0.15	0.13	0.13	0.12	0.13	0.13	0.12	0.13	0.12	0.12
Jet Fuel[8]	3.46	4.55	4.51	4.48	5.27	5.22	5.15	6.02	5.97	5.88
Liquefied Petroleum Gas	2.88	3.23	3.05	3.03	3.48	3.20	3.15	3.82	3.38	3.32
Motor Gasoline[2]	16.17	19.67	19.31	19.15	21.00	20.52	20.23	22.25	21.63	21.22
Petrochemical Feedstock	1.29	1.53	1.53	1.53	1.61	1.61	1.61	1.70	1.70	1.69
Residual Fuel	1.05	1.33	1.21	1.17	1.35	1.22	1.19	1.37	1.25	1.23
Other Petroleum[12]	4.53	4.96	5.04	4.53	5.13	5.31	4.73	5.36	5.57	5.18
Petroleum Subtotal	36.95	45.01	44.25	43.41	48.29	47.33	46.22	51.67	50.41	49.35
Natural Gas[6]	18.11	21.17	21.68	22.34	22.23	22.91	23.64	23.04	24.02	24.46
Metallurgical Coal	0.75	0.61	0.61	0.61	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	1.84	1.98	1.98	1.98	1.99	1.99	2.00	2.02	2.02	2.03
Net Coal Coke Imports	0.06	0.16	0.16	0.16	0.19	0.19	0.19	0.22	0.22	0.22
Coal Subtotal	2.65	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.75
Renewable Energy[13]	2.65	3.20	3.19	3.18	3.44	3.42	3.40	3.67	3.65	3.63
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.29	14.09	14.15	14.11	15.25	15.30	15.27	16.36	16.39	16.35
Delivered Energy	**71.65**	**86.22**	**86.01**	**85.78**	**91.95**	**91.71**	**91.28**	**97.50**	**97.22**	**96.55**
Electricity Related Losses	24.49	28.39	28.13	28.11	29.30	29.04	29.05	29.90	29.81	29.86
Total	**96.14**	**114.61**	**114.14**	**113.89**	**121.25**	**120.75**	**120.33**	**127.39**	**127.03**	**126.42**
Electric Generators[14]										
Distillate Fuel	0.06	0.11	0.04	0.03	0.22	0.04	0.04	0.61	0.04	0.04
Residual Fuel	1.03	0.43	0.12	0.10	0.43	0.12	0.09	0.46	0.14	0.10
Petroleum Subtotal	1.08	0.54	0.16	0.13	0.65	0.16	0.13	1.07	0.18	0.14
Natural Gas	3.85	7.56	7.07	6.64	9.92	9.48	9.00	11.63	11.55	10.84
Steam Coal	18.78	21.93	22.41	22.77	22.41	22.94	23.45	22.71	23.46	24.17
Nuclear Power	7.79	7.69	7.69	7.69	6.79	6.82	6.79	6.09	6.13	6.09
Renewable Energy[15]	3.94	4.46	4.64	4.67	4.57	4.71	4.74	4.53	4.66	4.75
Electricity Imports[16]	0.34	0.31	0.31	0.31	0.22	0.22	0.22	0.22	0.22	0.22
Total	**35.78**	**42.48**	**42.28**	**42.21**	**44.56**	**44.34**	**44.32**	**46.25**	**46.20**	**46.21**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Total Energy Consumption										
Distillate Fuel	7.48	9.71	9.51	9.43	10.54	10.17	10.07	11.63	10.84	10.75
Kerosene	0.15	0.13	0.13	0.12	0.13	0.13	0.12	0.13	0.12	0.12
Jet Fuel[8]	3.46	4.55	4.51	4.48	5.27	5.22	5.15	6.02	5.97	5.88
Liquefied Petroleum Gas	2.88	3.23	3.05	3.03	3.48	3.20	3.15	3.82	3.38	3.32
Motor Gasoline[2]	16.17	19.67	19.31	19.15	21.00	20.52	20.23	22.25	21.63	21.22
Petrochemical Feedstock	1.29	1.53	1.53	1.53	1.61	1.61	1.61	1.70	1.70	1.69
Residual Fuel	2.08	1.76	1.33	1.27	1.78	1.35	1.27	1.83	1.38	1.33
Other Petroleum[12]	4.53	4.96	5.04	4.53	5.13	5.31	4.73	5.36	5.57	5.18
Petroleum Subtotal	38.03	45.55	44.41	43.54	48.95	47.50	46.34	52.74	50.59	49.49
Natural Gas	21.95	28.73	28.75	28.98	32.14	32.39	32.64	34.68	35.57	35.31
Metallurgical Coal	0.75	0.61	0.61	0.61	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	20.62	23.91	24.39	24.75	24.41	24.93	25.45	24.72	25.48	26.19
Net Coal Coke Imports	0.06	0.16	0.16	0.16	0.19	0.19	0.19	0.22	0.22	0.22
Coal Subtotal	21.43	24.67	25.15	25.51	25.15	25.68	26.19	25.45	26.20	26.92
Nuclear Power	7.79	7.69	7.69	7.69	6.79	6.82	6.79	6.09	6.13	6.09
Renewable Energy[17]	6.59	7.66	7.83	7.85	8.00	8.13	8.15	8.20	8.31	8.38
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports[16]	0.34	0.31	0.31	0.31	0.22	0.22	0.22	0.22	0.22	0.22
Total	**96.14**	**114.61**	**114.14**	**113.89**	**121.26**	**120.75**	**120.33**	**127.39**	**127.04**	**126.42**
Energy Use and Related Statistics										
Delivered Energy Use	71.65	86.22	86.01	85.78	91.95	91.71	91.28	97.50	97.22	96.55
Total Energy Use	96.14	114.61	114.14	113.89	121.26	120.75	120.33	127.39	127.04	126.42
Population (millions)	273.13	300.17	300.17	300.17	312.58	312.58	312.58	325.24	325.24	325.24
Gross Domestic Product (billion 1996 dollars)	8,876	12,686	12,667	12,659	14,674	14,635	14,607	16,565	16,515	16,474
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1,510.8	1,819.0	1,809.1	1,804.5	1,939.8	1,928.1	1,922.5	2,050.9	2,040.6	2,033.5

[1]Includes wood used for residential heating. See Table C18 estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector electricity cogenerated by using wood and wood waste, landfill gas, municipal solid waste, and other biomass. See Table C18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Fuel consumption includes consumption for cogeneration, which produces electricity and other useful thermal energy.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Includes lease and plant fuel and consumption by cogenerators; excludes consumption by nonutility generators.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass; includes cogeneration, both for sale to the grid and for own use.
[8]Includes only kerosene type.
[9]Includes aviation gas and lubricants.
[10]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[11]M85 is 85 percent methanol and 15 percent motor gasoline.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes cogeneration. Excludes net electricity imports.
[16]In 1998 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[17]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1999 electric utility fuel consumption: Energy Information Administration (EIA), *Electric Power Annual 1998, Volume 1,* DOE/EIA-0348(98)/1 (Washington, DC, April 1999). 1999 nonutility consumption estimates: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 1999 values: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C3. Energy Prices by Sector and Source
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Residential	**13.17**	**12.98**	**13.16**	**13.48**	**13.09**	**13.33**	**13.70**	**13.22**	**13.59**	**13.97**
Primary Energy[1]	6.72	6.72	7.01	7.26	6.62	6.92	7.24	6.66	7.01	7.36
Petroleum Products[2]	7.55	8.06	9.37	10.20	8.15	9.49	10.70	8.30	9.64	10.65
Distillate Fuel	6.27	6.37	7.51	8.38	6.47	7.80	8.92	6.59	7.98	9.00
Liquefied Petroleum Gas	10.36	11.28	13.07	13.76	11.29	12.83	14.21	11.45	12.87	13.84
Natural Gas	6.52	6.45	6.53	6.68	6.32	6.44	6.62	6.35	6.55	6.81
Electricity	23.60	21.99	21.88	22.25	22.01	22.01	22.37	21.92	22.17	22.48
Commercial	**13.25**	**11.66**	**11.75**	**12.08**	**11.78**	**11.96**	**12.38**	**11.96**	**12.37**	**12.81**
Primary Energy[1]	5.22	5.26	5.53	5.78	5.24	5.55	5.86	5.35	5.74	6.10
Petroleum Products[2]	5.00	4.83	6.17	7.06	4.87	6.34	7.54	4.95	6.50	7.59
Distillate Fuel	4.37	4.12	5.28	6.17	4.21	5.55	6.69	4.32	5.75	6.84
Residual Fuel	2.63	2.75	3.69	4.52	2.75	3.77	4.76	2.75	3.85	4.78
Natural Gas[3]	5.34	5.42	5.50	5.65	5.39	5.50	5.68	5.51	5.71	5.97
Electricity	21.54	17.80	17.63	18.01	17.76	17.72	18.20	17.78	18.12	18.55
Industrial[4]	**5.33**	**4.98**	**5.45**	**5.76**	**5.06**	**5.56**	**6.03**	**5.25**	**5.85**	**6.31**
Primary Energy	3.92	3.79	4.38	4.70	3.86	4.48	4.97	4.03	4.72	5.21
Petroleum Products[2]	5.55	4.81	6.05	6.85	4.81	6.10	7.23	4.91	6.27	7.27
Distillate Fuel	4.65	4.32	5.45	6.33	4.41	5.73	6.85	4.55	5.94	7.09
Liquefied Petroleum Gas	8.50	6.49	8.01	8.63	6.48	7.75	9.04	6.65	7.83	8.70
Residual Fuel	2.78	2.38	3.42	4.24	2.38	3.50	4.49	2.38	3.58	4.51
Natural Gas[5]	2.79	3.25	3.31	3.41	3.37	3.45	3.59	3.62	3.76	3.95
Metallurgical Coal	1.65	1.53	1.54	1.55	1.47	1.49	1.49	1.43	1.44	1.45
Steam Coal	1.43	1.28	1.29	1.30	1.24	1.25	1.27	1.20	1.21	1.22
Electricity	13.09	11.37	11.24	11.48	11.34	11.27	11.64	11.42	11.62	11.93
Transportation	**8.30**	**8.09**	**9.46**	**10.31**	**7.99**	**9.38**	**10.60**	**7.73**	**9.31**	**10.62**
Primary Energy	8.29	8.07	9.45	10.30	7.97	9.36	10.59	7.71	9.29	10.61
Petroleum Products[2]	8.28	8.07	9.44	10.30	7.96	9.36	10.59	7.70	9.29	10.61
Distillate Fuel[6]	8.22	7.80	8.94	9.79	7.75	9.05	10.17	7.72	8.98	10.13
Jet Fuel[7]	4.70	4.33	5.47	6.33	4.46	5.75	6.96	4.47	5.88	7.11
Motor Gasoline[8]	9.45	9.38	10.93	11.80	9.26	10.75	12.03	8.87	10.68	12.12
Residual Fuel	2.46	2.20	3.18	4.01	2.19	3.25	4.26	2.18	3.33	4.28
Liquefied Petroleum Gas[9]	12.87	12.61	14.26	14.99	12.55	13.96	15.32	12.52	13.84	14.79
Natural Gas[10]	7.02	6.90	7.04	7.19	6.95	7.17	7.36	6.97	7.32	7.59
Ethanol (E85)[11]	14.42	18.24	19.00	19.80	18.47	19.24	20.22	18.32	19.36	20.52
Methanol (M85)[12]	10.38	12.23	13.74	15.42	12.13	14.33	16.42	11.94	14.43	16.40
Electricity	15.57	13.84	13.47	13.79	13.40	13.21	13.39	13.11	13.06	13.25
Average End-Use Energy	**8.55**	**8.22**	**8.95**	**9.46**	**8.26**	**9.01**	**9.75**	**8.25**	**9.17**	**9.95**
Primary Energy	6.33	6.29	7.18	7.74	6.28	7.21	8.01	6.25	7.30	8.17
Electricity	19.50	17.34	17.20	17.52	17.35	17.30	17.69	17.35	17.59	17.93
Electric Generators[13]										
Fossil Fuel Average	1.49	1.55	1.54	1.55	1.68	1.68	1.71	1.83	1.86	1.89
Petroleum Products	2.50	2.80	4.11	5.10	2.97	4.27	5.51	3.30	4.35	5.57
Distillate Fuel	4.05	3.74	4.84	5.73	3.78	5.10	6.22	3.85	5.28	6.39
Residual Fuel	2.42	2.57	3.88	4.88	2.55	4.00	5.22	2.56	4.07	5.24
Natural Gas	2.55	2.92	3.03	3.20	3.12	3.24	3.44	3.38	3.59	3.86
Steam Coal	1.21	1.05	1.05	1.05	1.01	1.01	1.02	0.97	0.98	0.98

Table C3. Energy Prices by Sector and Source (Continued)
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2015 Low World Oil Price	2015 Reference	2015 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price
Average Price to All Users[14]										
Petroleum Products[2]	7.44	7.25	8.64	9.50	7.19	8.61	9.83	7.01	8.61	9.85
Distillate Fuel	7.27	6.97	8.18	9.05	6.94	8.36	9.50	6.87	8.38	9.53
Jet Fuel	4.70	4.33	5.47	6.33	4.46	5.75	6.96	4.47	5.88	7.11
Liquefied Petroleum Gas	8.84	7.33	8.88	9.49	7.29	8.58	9.86	7.39	8.62	9.47
Motor Gasoline[8]	9.45	9.38	10.93	11.80	9.26	10.75	12.03	8.87	10.68	12.12
Residual Fuel	2.48	2.36	3.33	4.16	2.35	3.41	4.41	2.36	3.49	4.44
Natural Gas	4.05	4.17	4.27	4.40	4.17	4.28	4.45	4.33	4.50	4.75
Coal	1.23	1.07	1.07	1.07	1.03	1.03	1.04	0.99	1.00	1.00
Ethanol (E85)[11]	14.42	18.24	19.00	19.80	18.47	19.24	20.22	18.32	19.36	20.52
Methanol (M85)[12]	10.38	12.23	13.74	15.42	12.13	14.33	16.42	11.94	14.43	16.40
Electricity	19.50	17.34	17.20	17.52	17.35	17.30	17.69	17.35	17.59	17.93
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	134.60	156.73	157.93	160.33	166.95	168.52	171.52	178.74	181.70	184.68
Commercial	99.50	111.41	111.72	114.04	119.90	120.89	124.08	126.41	129.51	132.72
Industrial	110.90	116.10	126.53	135.18	124.05	135.93	148.74	135.73	150.97	163.47
Transportation	212.63	261.28	302.06	327.38	279.86	323.87	362.32	291.23	344.96	388.44
Total Non-Renewable Expenditures	557.64	645.51	698.23	736.93	690.77	749.21	806.66	732.11	807.14	869.30
Transportation Renewable Expenditures	0.14	0.55	0.61	0.66	0.69	0.75	0.83	0.78	0.86	0.96
Total Expenditures	**557.78**	**646.07**	**698.85**	**737.59**	**691.46**	**749.96**	**807.49**	**732.89**	**808.00**	**870.26**

[1]Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Excludes independent power producers.
[4]Includes cogenerators.
[5]Excludes uses for lease and plant fuel.
[6] Low sulfur diesel fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[8]Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[9]Includes Federal and State taxes while excluding county and local taxes.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]M85 is 85 percent methanol and 15 percent motor gasoline.
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[14]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(99/03-2000/04) (Washington, DC, 1999-2000). 1999 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1997*, DOE/EIA-0376(97) (Washington, DC, July 2000). 1999 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1994*. 1999 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 coal prices based on EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000) and EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A. **Projections:** EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C4. Residential Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Key Indicators										
Households (millions)										
Single-Family	75.70	85.55	85.51	85.49	89.99	89.93	89.89	94.44	94.36	94.30
Multifamily	21.79	24.28	24.25	24.23	25.73	25.69	25.67	27.14	27.09	27.05
Mobile Homes	6.59	7.20	7.20	7.20	7.56	7.57	7.57	7.95	7.96	7.96
Total	**104.08**	**117.02**	**116.97**	**116.93**	**123.29**	**123.20**	**123.13**	**129.53**	**129.41**	**129.32**
Average House Square Footage	**1673**	**1724**	**1724**	**1724**	**1744**	**1744**	**1744**	**1763**	**1763**	**1763**
Energy Intensity										
(million Btu per household)										
Delivered Energy Consumption	102.1	107.0	106.3	105.3	107.1	106.2	105.1	107.9	106.7	105.5
Total Energy Consumption	183.5	192.1	190.6	189.4	190.6	188.9	187.7	189.9	188.3	187.2
(thousand Btu per square foot)										
Delivered Energy Consumption	61.0	62.1	61.7	61.1	61.4	60.9	60.3	61.2	60.5	59.9
Total Energy Consumption	109.7	111.5	110.6	109.9	109.3	108.3	107.7	107.7	106.8	106.2
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.38	0.46	0.47	0.46	0.48	0.49	0.49	0.51	0.51	0.51
Space Cooling	0.52	0.62	0.63	0.62	0.69	0.69	0.69	0.77	0.77	0.77
Water Heating	0.39	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43
Refrigeration	0.43	0.34	0.34	0.34	0.32	0.32	0.32	0.33	0.33	0.32
Cooking	0.10	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.13	0.13
Clothes Dryers	0.22	0.26	0.26	0.26	0.27	0.27	0.27	0.29	0.29	0.29
Freezers	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.34	0.46	0.46	0.46	0.49	0.49	0.49	0.52	0.52	0.51
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Dishwashers[1]	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.12	0.19	0.19	0.19	0.21	0.21	0.21	0.24	0.24	0.24
Personal Computers	0.06	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.07	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12
Other Uses[2]	1.10	1.73	1.73	1.72	1.97	1.97	1.96	2.21	2.20	2.19
Delivered Energy	**3.91**	**4.95**	**4.96**	**4.94**	**5.36**	**5.37**	**5.35**	**5.81**	**5.80**	**5.78**
Natural Gas										
Space Heating	3.22	3.84	3.85	3.84	4.05	4.06	4.05	4.30	4.31	4.28
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Heating	1.26	1.41	1.41	1.40	1.47	1.47	1.46	1.53	1.52	1.51
Cooking	0.19	0.22	0.23	0.23	0.24	0.24	0.24	0.25	0.25	0.25
Clothes Dryers	0.07	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11
Other Uses[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Delivered Energy	**4.85**	**5.69**	**5.69**	**5.67**	**5.98**	**5.99**	**5.96**	**6.30**	**6.30**	**6.26**
Distillate										
Space Heating	0.73	0.73	0.69	0.65	0.72	0.66	0.62	0.72	0.65	0.60
Water Heating	0.13	0.12	0.12	0.11	0.12	0.11	0.10	0.11	0.10	0.10
Other Uses[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	**0.86**	**0.86**	**0.81**	**0.77**	**0.84**	**0.77**	**0.72**	**0.83**	**0.75**	**0.70**
Liquefied Petroleum Gas										
Space Heating	0.31	0.31	0.28	0.27	0.31	0.27	0.25	0.31	0.27	0.25
Water Heating	0.11	0.10	0.09	0.09	0.10	0.09	0.08	0.10	0.09	0.08
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Other Uses[3]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Delivered Energy	**0.46**	**0.46**	**0.41**	**0.40**	**0.46**	**0.40**	**0.37**	**0.46**	**0.39**	**0.37**
Marketed Renewables (wood)[5]	0.41	0.44	0.43	0.42	0.45	0.43	0.42	0.46	0.44	0.43
Other Fuels[6]	0.14	0.13	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.11

Table C4. Residential Sector Key Indicators and End-Use Consumption (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Delivered Energy Consumption by End-Use										
Space Heating	5.18	5.92	5.84	5.77	6.13	6.03	5.94	6.42	6.29	6.18
Space Cooling	0.52	0.63	0.63	0.62	0.70	0.70	0.69	0.78	0.77	0.77
Water Heating	1.89	2.07	2.05	2.03	2.12	2.10	2.08	2.17	2.14	2.12
Refrigeration	0.43	0.34	0.34	0.34	0.32	0.32	0.32	0.33	0.33	0.32
Cooking	0.32	0.38	0.38	0.38	0.40	0.40	0.40	0.42	0.42	0.42
Clothes Dryers	0.28	0.35	0.35	0.35	0.37	0.37	0.37	0.40	0.40	0.40
Freezers	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.34	0.46	0.46	0.46	0.49	0.49	0.49	0.52	0.52	0.51
Clothes Washers	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Dishwashers	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.12	0.19	0.19	0.19	0.21	0.21	0.21	0.24	0.24	0.24
Personal Computers	0.06	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.07	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12
Other Uses[7]	1.23	1.85	1.86	1.84	2.10	2.09	2.08	2.33	2.32	2.31
Delivered Energy	**10.62**	**12.52**	**12.43**	**12.31**	**13.20**	**13.08**	**12.94**	**13.98**	**13.81**	**13.65**
Electricity Related Losses	**8.48**	**9.97**	**9.87**	**9.83**	**10.30**	**10.19**	**10.17**	**10.62**	**10.55**	**10.56**
Total Energy Consumption by End-Use										
Space Heating	6.01	6.85	6.76	6.69	7.06	6.96	6.87	7.34	7.22	7.12
Space Cooling	1.64	1.89	1.87	1.86	2.03	2.01	2.00	2.19	2.17	2.17
Water Heating	2.75	2.93	2.90	2.89	2.95	2.92	2.90	2.96	2.93	2.91
Refrigeration	1.35	1.03	1.02	1.02	0.95	0.94	0.94	0.92	0.92	0.92
Cooking	0.54	0.62	0.61	0.61	0.64	0.63	0.63	0.66	0.66	0.66
Clothes Dryers	0.75	0.87	0.86	0.86	0.90	0.89	0.89	0.93	0.93	0.92
Freezers	0.37	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.25	0.25
Lighting	1.08	1.39	1.38	1.37	1.43	1.42	1.41	1.47	1.46	1.45
Clothes Washers	0.09	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11
Dishwashers	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08
Color Televisions	0.38	0.57	0.57	0.56	0.62	0.62	0.62	0.68	0.67	0.67
Personal Computers	0.20	0.28	0.28	0.28	0.29	0.29	0.29	0.32	0.32	0.32
Furnace Fans	0.24	0.29	0.29	0.29	0.31	0.31	0.31	0.33	0.33	0.33
Other Uses[7]	3.62	5.33	5.30	5.27	5.89	5.84	5.82	6.36	6.32	6.30
Total	**19.10**	**22.49**	**22.30**	**22.15**	**23.50**	**23.27**	**23.11**	**24.60**	**24.36**	**24.20**
Non-Marketed Renewables										
Geothermal[8]	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Solar[9]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**

[1]Does not include electric water heating portion of load.
[2]Includes small electric devices, heating elements, and motors.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as swimming pool and hot tub heaters.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1997*.
[6]Includes kerosene and coal.
[7]Includes all other uses listed above.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf.
Projections: EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C5. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Key Indicators										
Total Floor Space (billion square feet)										
Surviving	60.8	74.0	74.0	74.0	78.1	78.1	78.1	80.7	80.7	80.6
New Additions	2.0	1.8	1.8	1.8	1.5	1.5	1.5	1.3	1.3	1.3
Total	**62.8**	**75.8**	**75.8**	**75.7**	**79.7**	**79.6**	**79.6**	**82.0**	**81.9**	**81.9**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	120.9	127.2	126.6	125.7	128.8	128.0	127.0	129.9	128.8	127.5
Electricity Related Losses	127.6	129.7	128.2	128.0	128.2	126.8	126.6	125.3	124.5	124.4
Total Energy Consumption	248.5	256.9	254.8	253.7	257.0	254.9	253.5	255.2	253.2	252.0
Delivered Energy Consumption by Fuel										
Purchased Electricity										
Space Heating[1]	0.14	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Space Cooling[1]	0.43	0.46	0.46	0.45	0.46	0.46	0.46	0.46	0.46	0.46
Water Heating[1]	0.14	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Ventilation	0.17	0.20	0.21	0.20	0.21	0.21	0.21	0.21	0.21	0.21
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Lighting	1.21	1.42	1.42	1.41	1.48	1.48	1.47	1.48	1.47	1.46
Refrigeration	0.18	0.21	0.21	0.21	0.22	0.22	0.22	0.22	0.22	0.22
Office Equipment (PC)	0.10	0.24	0.24	0.24	0.28	0.28	0.28	0.29	0.29	0.29
Office Equipment (non-PC)	0.30	0.51	0.51	0.51	0.60	0.60	0.60	0.69	0.69	0.69
Other Uses[2]	0.99	1.48	1.48	1.48	1.71	1.71	1.71	1.91	1.91	1.91
Delivered Energy	**3.70**	**4.88**	**4.89**	**4.87**	**5.32**	**5.32**	**5.29**	**5.62**	**5.61**	**5.58**
Natural Gas[3]										
Space Heating[1]	1.42	1.68	1.74	1.74	1.71	1.80	1.80	1.71	1.81	1.80
Space Cooling[1]	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Water Heating[1]	0.64	0.76	0.77	0.76	0.81	0.82	0.81	0.83	0.84	0.83
Cooking	0.21	0.25	0.25	0.25	0.27	0.26	0.26	0.27	0.27	0.27
Other Uses[4]	0.87	1.11	1.11	1.10	1.15	1.14	1.14	1.19	1.18	1.16
Delivered Energy	**3.15**	**3.82**	**3.88**	**3.87**	**3.96**	**4.05**	**4.03**	**4.03**	**4.13**	**4.09**
Distillate										
Space Heating[1]	0.23	0.34	0.25	0.23	0.38	0.25	0.22	0.39	0.24	0.21
Water Heating[1]	0.09	0.10	0.09	0.08	0.11	0.08	0.08	0.11	0.08	0.08
Other Uses[5]	0.04	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.07	0.07
Delivered Energy	**0.36**	**0.52**	**0.41**	**0.38**	**0.56**	**0.40**	**0.37**	**0.57**	**0.39**	**0.36**
Other Fuels[6]	**0.30**	**0.33**	**0.33**	**0.33**	**0.34**	**0.34**	**0.33**	**0.34**	**0.34**	**0.34**
Marketed Renewable Fuels										
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Delivered Energy	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Delivered Energy Consumption by End-Use										
Space Heating[1]	1.79	2.18	2.15	2.13	2.25	2.21	2.18	2.26	2.21	2.17
Space Cooling[1]	0.44	0.48	0.48	0.48	0.49	0.49	0.49	0.49	0.49	0.49
Water Heating[1]	0.87	1.02	1.01	1.00	1.07	1.06	1.05	1.10	1.08	1.06
Ventilation	0.17	0.20	0.21	0.20	0.21	0.21	0.21	0.21	0.21	0.21
Cooking	0.24	0.28	0.28	0.28	0.30	0.29	0.29	0.30	0.30	0.29
Lighting	1.21	1.42	1.42	1.41	1.48	1.48	1.47	1.48	1.47	1.46
Refrigeration	0.18	0.21	0.21	0.21	0.22	0.22	0.22	0.22	0.22	0.22
Office Equipment (PC)	0.10	0.24	0.24	0.24	0.28	0.28	0.28	0.29	0.29	0.29
Office Equipment (non-PC)	0.30	0.51	0.51	0.51	0.60	0.60	0.60	0.69	0.69	0.69
Other Uses[7]	2.29	3.08	3.07	3.06	3.36	3.35	3.33	3.60	3.58	3.56
Delivered Energy	**7.59**	**9.64**	**9.59**	**9.52**	**10.26**	**10.19**	**10.11**	**10.65**	**10.55**	**10.45**

Table C5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Electricity Related Losses	**8.01**	**9.83**	**9.71**	**9.69**	**10.21**	**10.10**	**10.07**	**10.27**	**10.20**	**10.19**
Total Energy Consumption by End-Use										
Space Heating[1]	2.09	2.51	2.48	2.45	2.56	2.52	2.49	2.56	2.50	2.46
Space Cooling[1]	1.36	1.40	1.39	1.38	1.38	1.37	1.36	1.34	1.33	1.33
Water Heating[1]	1.19	1.34	1.33	1.32	1.38	1.37	1.35	1.38	1.37	1.35
Ventilation	0.55	0.62	0.61	0.61	0.61	0.61	0.60	0.59	0.59	0.59
Cooking	0.31	0.34	0.34	0.34	0.35	0.35	0.35	0.35	0.35	0.34
Lighting	3.83	4.29	4.26	4.23	4.32	4.29	4.25	4.18	4.15	4.12
Refrigeration	0.58	0.64	0.64	0.64	0.65	0.64	0.64	0.64	0.63	0.63
Office Equipment (PC)	0.33	0.72	0.71	0.71	0.82	0.81	0.81	0.83	0.83	0.83
Office Equipment (non-PC)	0.94	1.53	1.52	1.52	1.76	1.74	1.74	1.95	1.94	1.95
Other Uses[7]	4.43	6.07	6.03	6.01	6.65	6.59	6.58	7.09	7.05	7.04
Total	**15.61**	**19.46**	**19.30**	**19.22**	**20.47**	**20.29**	**20.18**	**20.92**	**20.75**	**20.64**
Non-Marketed Renewable Fuels										
Solar[8]	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

[1]Includes fuel consumption for district services.
[2]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
[3]Excludes estimated consumption from independent power producers.
[4]Includes miscellaneous uses, such as pumps, emergency electric generators, cogeneration in commercial buildings, and manufacturing performed in commercial buildings.
[5]Includes miscellaneous uses, such as cooking, emergency electric generators, and cogeneration in commercial buildings.
[6]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, cogeneration in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[8]Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Key Indicators										
Value of Gross Output (billion 1992 dollars)										
Manufacturing	3,749	5,083	5,089	5,092	5,830	5,828	5,829	6,730	6,726	6,724
Nonmanufacturing	972	1,158	1,162	1,166	1,260	1,265	1,268	1,360	1,370	1,372
Total	**4,722**	**6,240**	**6,251**	**6,258**	**7,090**	**7,093**	**7,097**	**8,089**	**8,096**	**8,096**
Energy Prices (1999 dollars per million Btu)										
Electricity	13.09	11.37	11.24	11.48	11.34	11.27	11.64	11.42	11.62	11.93
Natural Gas	2.79	3.25	3.31	3.41	3.37	3.45	3.59	3.62	3.76	3.95
Steam Coal	1.43	1.28	1.29	1.30	1.24	1.25	1.27	1.20	1.21	1.22
Residual Oil	2.78	2.38	3.42	4.24	2.38	3.50	4.49	2.38	3.58	4.51
Distillate Oil	4.65	4.32	5.45	6.33	4.41	5.73	6.85	4.55	5.94	7.09
Liquefied Petroleum Gas	8.50	6.49	8.01	8.63	6.48	7.75	9.04	6.65	7.83	8.70
Motor Gasoline	9.42	9.33	10.90	11.76	9.21	10.70	12.00	8.84	10.64	12.11
Metallurgical Coal	1.65	1.53	1.54	1.55	1.47	1.49	1.49	1.43	1.44	1.45
Energy Consumption										
Consumption[1]										
Purchased Electricity	3.63	4.15	4.18	4.19	4.43	4.47	4.48	4.76	4.81	4.82
Natural Gas[2]	9.43	10.68	11.11	11.80	11.17	11.76	12.52	11.48	12.34	12.87
Steam Coal	1.73	1.85	1.85	1.86	1.87	1.87	1.88	1.89	1.90	1.90
Metallurgical Coal and Coke[3]	0.81	0.76	0.76	0.76	0.74	0.74	0.74	0.72	0.72	0.72
Residual Fuel	0.22	0.37	0.25	0.21	0.38	0.26	0.22	0.40	0.27	0.26
Distillate	1.07	1.28	1.27	1.26	1.37	1.35	1.34	1.47	1.44	1.43
Liquefied Petroleum Gas	2.32	2.64	2.50	2.50	2.88	2.65	2.63	3.20	2.83	2.80
Petrochemical Feedstocks	1.29	1.53	1.53	1.53	1.61	1.61	1.61	1.70	1.70	1.69
Other Petroleum[4]	4.50	4.92	5.00	4.49	5.08	5.27	4.69	5.30	5.52	5.14
Renewables[5]	2.15	2.65	2.64	2.64	2.87	2.86	2.86	3.09	3.08	3.08
Delivered Energy	**27.15**	**30.83**	**31.10**	**31.24**	**32.41**	**32.84**	**32.96**	**34.03**	**34.63**	**34.71**
Electricity Related Losses	7.87	8.36	8.32	8.34	8.51	8.48	8.53	8.71	8.76	8.81
Total	**35.02**	**39.18**	**39.42**	**39.58**	**40.92**	**41.31**	**41.50**	**42.74**	**43.39**	**43.52**
Consumption per Unit of Output[1] (thousand Btu per 1992 dollars)										
Purchased Electricity	0.77	0.66	0.67	0.67	0.62	0.63	0.63	0.59	0.59	0.60
Natural Gas[2]	2.00	1.71	1.78	1.89	1.58	1.66	1.76	1.42	1.52	1.59
Steam Coal	0.37	0.30	0.30	0.30	0.26	0.26	0.26	0.23	0.23	0.23
Metallurgical Coal and Coke[3]	0.17	0.12	0.12	0.12	0.10	0.10	0.10	0.09	0.09	0.09
Residual Fuel	0.05	0.06	0.04	0.03	0.05	0.04	0.03	0.05	0.03	0.03
Distillate	0.23	0.21	0.20	0.20	0.19	0.19	0.19	0.18	0.18	0.18
Liquefied Petroleum Gas	0.49	0.42	0.40	0.40	0.41	0.37	0.37	0.40	0.35	0.35
Petrochemical Feedstocks	0.27	0.25	0.24	0.24	0.23	0.23	0.23	0.21	0.21	0.21
Other Petroleum[4]	0.95	0.79	0.80	0.72	0.72	0.74	0.66	0.66	0.68	0.63
Renewables[5]	0.46	0.42	0.42	0.42	0.40	0.40	0.40	0.38	0.38	0.38
Delivered Energy	**5.75**	**4.94**	**4.98**	**4.99**	**4.57**	**4.63**	**4.64**	**4.21**	**4.28**	**4.29**
Electricity Related Losses	1.67	1.34	1.33	1.33	1.20	1.20	1.20	1.08	1.08	1.09
Total	**7.42**	**6.28**	**6.31**	**6.33**	**5.77**	**5.82**	**5.85**	**5.28**	**5.36**	**5.38**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net coke coal imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 prices for gasoline and distillate are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380 (99/03-2000/04) (Washington, DC, 1999-2000). 1999 coal prices are based on EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000) and EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A. 1999 electricity prices: EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A. Other 1999 prices derived from EIA, *State Energy Data Report 1997*, DOE/EIA-0214(97) (Washington, DC, September 1999). Other 1999 values: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf.
Projections: EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	1999	Projections 2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2015 Low World Oil Price	2015 Reference	2015 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price
Key Indicators										
Level of Travel (billions)										
Light-Duty Vehicles <8,500 pounds (VMT)	2394	3089	3066	3055	3357	3334	3314	3605	3577	3552
Commercial Light Trucks (VMT)[1]	73	94	93	93	103	103	102	113	113	112
Freight Trucks >10,000 pounds (VMT)	204	280	280	280	314	313	313	353	352	352
Air (seat miles available)	1099	1608	1592	1582	1955	1934	1917	2342	2317	2294
Rail (ton miles traveled)	1357	1690	1706	1717	1813	1826	1840	1944	1967	1983
Domestic Shipping (ton miles traveled)	661	761	775	784	815	832	845	858	890	899
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[2]	24.2	26.6	27.1	27.3	27.1	27.6	28.0	27.4	28.0	28.5
New Car (miles per gallon)[2]	27.9	31.6	32.3	32.6	31.7	32.4	32.9	31.7	32.5	33.0
New Light Truck (miles per gallon)[2]	20.8	22.8	23.2	23.4	23.6	24.0	24.3	24.2	24.7	25.0
Light-Duty Fleet (miles per gallon)[3]	20.5	20.7	20.9	21.0	20.9	21.2	21.4	21.1	21.5	21.7
New Commercial Light Truck (MPG)[1]	20.1	21.8	22.0	22.1	22.4	22.8	23.0	23.0	23.4	23.7
Stock Commercial Light Truck (MPG)[1]	14.8	16.0	16.1	16.1	16.4	16.6	16.6	16.8	17.0	17.1
Aircraft Efficiency (seat miles per gallon)	51.7	56.1	56.1	56.2	58.2	58.2	58.5	60.3	60.3	60.7
Freight Truck Efficiency (miles per gallon)	6.0	6.4	6.4	6.4	6.7	6.7	6.7	6.9	6.9	6.9
Rail Efficiency (ton miles per thousand Btu)	2.8	3.1	3.1	3.1	3.3	3.3	3.3	3.4	3.4	3.4
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.7	2.7	2.7	2.8	2.8	2.8	3.0	3.0	3.0
Energy Use by Mode (quadrillion Btu)										
Light-Duty Vehicles	14.88	18.82	18.51	18.37	20.24	19.83	19.58	21.51	20.98	20.62
Commercial Light Trucks[1]	0.62	0.73	0.73	0.72	0.78	0.78	0.77	0.84	0.83	0.82
Freight Trucks[4]	4.54	5.79	5.78	5.78	6.26	6.24	6.23	6.76	6.74	6.72
Air[5]	3.50	4.60	4.56	4.53	5.33	5.28	5.21	6.10	6.04	5.95
Rail[6]	0.57	0.64	0.65	0.65	0.66	0.67	0.67	0.68	0.69	0.69
Marine[7]	1.29	1.46	1.46	1.47	1.49	1.49	1.50	1.51	1.52	1.52
Pipeline Fuel	0.66	0.89	0.90	0.90	0.99	0.99	1.00	1.07	1.09	1.08
Lubricants	0.22	0.27	0.26	0.26	0.29	0.29	0.28	0.32	0.31	0.31
Total	**26.28**	**33.24**	**32.89**	**32.71**	**36.08**	**35.60**	**35.26**	**38.84**	**38.23**	**37.75**
Energy Use by Mode (million barrels per day oil equivalent)										
Light-Duty Vehicles	7.76	9.87	9.70	9.63	10.62	10.39	10.25	11.28	10.99	10.79
Commercial Light Trucks[1]	0.32	0.38	0.38	0.38	0.41	0.41	0.40	0.44	0.43	0.43
Freight Trucks[4]	2.03	2.60	2.60	2.60	2.82	2.81	2.81	3.06	3.04	3.04
Railroad	0.23	0.26	0.26	0.26	0.26	0.26	0.27	0.27	0.27	0.27
Domestic Shipping	0.13	0.13	0.13	0.14	0.13	0.14	0.14	0.13	0.14	0.14
International Shipping	0.30	0.35	0.35	0.35	0.36	0.36	0.36	0.36	0.36	0.36
Air[5]	1.46	1.97	1.95	1.93	2.30	2.28	2.24	2.66	2.63	2.59
Military Use	0.28	0.32	0.32	0.32	0.34	0.34	0.34	0.36	0.36	0.36
Bus Transportation	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Rail Transportation[6]	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Recreational Boats	0.16	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20
Lubricants	0.10	0.13	0.12	0.12	0.14	0.14	0.13	0.15	0.15	0.15
Pipeline Fuel	0.33	0.45	0.45	0.46	0.50	0.50	0.51	0.54	0.55	0.55
Total	**13.24**	**16.78**	**16.59**	**16.50**	**18.20**	**17.94**	**17.77**	**19.58**	**19.26**	**19.00**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
[4]Includes energy use by buses and military distillate consumption.
[5]Includes jet fuel and aviation gasoline.
[6]Includes passenger rail.
[7]Includes military residual fuel use and recreation boats.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999: U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 1999/1998* (Washington, DC, 1999); Energy Information Administration (EIA), *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf; EIA, *Fuel Oil and Kerosene Sales 1998*, DOE/EIA-0535(98) (Washington, DC, August 1999); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C8. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Generation by Fuel Type										
Electric Generators[1]										
Coal	1833	2132	2196	2234	2178	2246	2301	2206	2298	2380
Petroleum	100	55	17	14	70	17	13	127	19	14
Natural Gas[2]	371	913	900	849	1275	1266	1206	1564	1587	1496
Nuclear Power	730	720	720	720	635	639	635	571	574	571
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	353	383	390	393	388	395	398	391	396	398
Total	**3386**	**4202**	**4222**	**4209**	**4546**	**4563**	**4553**	**4858**	**4872**	**4859**
Nonutility Generation for Own Use	16	16	16	16	16	16	16	16	16	16
Distributed Generation	0	3	3	2	4	4	4	6	6	6
Cogenerators[4]										
Coal	47	52	52	52	52	52	52	52	52	52
Petroleum	9	10	10	10	11	10	10	11	10	10
Natural Gas[2]	206	258	257	257	280	276	279	305	299	302
Other Gaseous Fuels[5]	4	7	7	7	8	7	7	9	8	8
Renewable Sources[3]	31	39	39	39	44	44	44	48	48	47
Other[6]	5	5	5	5	5	5	5	6	5	5
Total	**302**	**372**	**370**	**371**	**401**	**394**	**397**	**431**	**422**	**425**
Other End-Use Generators[7]	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
Sales to Utilities	151	178	176	176	191	187	187	205	200	200
Generation for Own Use	156	199	199	200	215	213	215	231	227	230
Net Imports[8]	**32**	**29**	**29**	**29**	**21**	**21**	**21**	**21**	**21**	**21**
Electricity Sales by Sector										
Residential	1146	1450	1455	1447	1571	1573	1567	1703	1701	1694
Commercial	1083	1430	1432	1426	1558	1559	1552	1647	1643	1636
Industrial	1063	1216	1226	1228	1299	1309	1314	1396	1411	1414
Transportation	17	35	35	35	43	43	42	49	49	48
Total	**3309**	**4130**	**4147**	**4135**	**4471**	**4484**	**4475**	**4794**	**4804**	**4792**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.1	7.5	7.5	7.6	7.5	7.5	7.6	7.5	7.6	7.7
Commercial	7.3	6.1	6.0	6.1	6.1	6.0	6.2	6.1	6.2	6.3
Industrial	4.5	3.9	3.8	3.9	3.9	3.8	4.0	3.9	4.0	4.1
Transportation	5.3	4.7	4.6	4.7	4.6	4.5	4.6	4.5	4.5	4.5
All Sectors Average	**6.7**	**5.9**	**5.9**	**6.0**	**5.9**	**5.9**	**6.0**	**5.9**	**6.0**	**6.1**
Prices by Service Category[9] (1999 cents per kilowatthour)										
Generation	4.1	3.2	3.2	3.3	3.2	3.2	3.4	3.3	3.4	3.5
Transmission	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Distribution	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Emissions (million short tons)										
Sulfur Dioxide	12.46	9.20	9.28	8.95	9.15	9.33	8.95	8.95	8.95	8.95
Nitrogen Oxide	5.45	4.29	4.22	4.20	4.38	4.33	4.34	4.44	4.42	4.42

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[2]Includes electricity generation by fuel cells.
[3]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[4]Cogenerators produce electricity and other useful thermal energy. Includes sales to utilities and generation for own use.
[5]Other gaseous fuels include refinery and still gas.
[6]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[7]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]In 1999 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[9]Prices represent average revenue per kilowatthour.
Kwh = Kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C9. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2015 Low World Oil Price	2015 Reference	2015 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price
		Projections								
Electric Generators[2]										
Capability										
Coal Steam	306.0	301.6	315.0	320.7	302.7	315.3	322.2	302.7	316.4	326.5
Other Fossil Steam[3]	138.2	122.4	120.4	118.2	119.6	117.3	115.3	118.3	116.1	114.3
Combined Cycle	20.2	108.0	126.0	126.3	161.8	181.3	180.3	213.7	229.1	227.5
Combustion Turbine/Diesel	75.2	183.0	164.1	154.4	208.6	184.6	174.7	238.6	210.7	203.4
Nuclear Power	97.4	93.7	93.7	93.7	79.1	79.5	79.1	71.1	71.6	71.1
Pumped Storage	19.3	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
Fuel Cells	0.0	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3
Renewable Sources[4]	88.1	94.8	95.4	95.7	95.8	96.5	96.9	96.4	97.0	97.4
Distributed Generation[5]	0.0	6.5	6.0	5.6	10.1	8.8	9.4	14.2	12.7	13.8
Total	**744.6**	**923.1**	**934.3**	**928.7**	**987.4**	**994.4**	**988.3**	**1060.6**	**1060.7**	**1060.1**
Cumulative Planned Additions[6]										
Coal Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fossil Steam[3]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combined Cycle	0.0	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Combustion Turbine/Diesel	0.0	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3
Renewable Sources[4]	0.0	4.3	4.3	4.3	5.1	5.1	5.1	5.4	5.4	5.4
Distributed Generation[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**13.6**	**13.6**	**13.6**	**14.5**	**14.5**	**14.5**	**14.8**	**14.8**	**14.8**
Cumulative Unplanned Additions[6]										
Coal Steam	0.0	6.7	18.5	24.2	8.4	19.5	26.6	9.6	21.8	32.1
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	79.4	97.5	97.7	133.2	152.8	151.7	185.2	200.5	198.9
Combustion Turbine/Diesel	0.0	112.4	93.1	83.8	138.8	114.3	104.4	168.8	140.5	133.1
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.0	1.9	2.6	2.8	2.1	2.9	3.2	2.5	3.1	3.5
Distributed Generation[5]	0.0	6.5	6.0	5.6	10.1	8.8	9.4	14.2	12.7	13.8
Total	**0.0**	**206.9**	**217.7**	**214.2**	**292.6**	**298.3**	**295.2**	**380.2**	**378.7**	**381.4**
Cumulative Total Additions	**0.0**	**220.5**	**231.3**	**227.7**	**307.1**	**312.8**	**309.7**	**395.0**	**393.4**	**396.1**
Cumulative Retirements[7]										
Coal Steam	0.0	15.1	13.5	13.6	15.6	14.2	14.3	16.8	15.4	15.6
Other Fossil Steam[3]	0.0	15.7	17.7	19.9	18.5	20.8	22.8	19.8	22.0	23.8
Combined Cycle	0.0	0.1	0.1	0.0	0.1	0.1	0.0	0.1	0.1	0.0
Combustion Turbine/Diesel	0.0	5.8	5.1	5.7	6.5	5.8	6.0	6.6	5.9	6.1
Nuclear Power	0.0	3.7	3.7	3.7	18.4	18.0	18.4	26.3	25.9	26.3
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**40.5**	**40.3**	**43.1**	**59.3**	**59.0**	**61.7**	**69.8**	**69.4**	**71.9**

Table C9. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Petroleum	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Natural Gas	33.8	43.1	43.0	43.2	46.2	45.7	46.2	49.8	49.0	49.5
Other Gaseous Fuels	0.2	1.0	0.9	0.9	1.1	1.0	1.0	1.1	1.1	1.0
Renewable Sources[4]	5.3	6.8	6.8	6.8	7.6	7.5	7.5	8.3	8.2	8.2
Other	1.1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	**51.6**	**63.4**	**63.2**	**63.3**	**67.4**	**66.8**	**67.3**	**71.9**	**70.9**	**71.3**
Cumulative Additions[6]	**0.0**	**11.7**	**11.5**	**11.7**	**15.8**	**15.2**	**15.6**	**20.2**	**19.2**	**19.6**
Other End-Use Generators[9]										
Renewable Sources[10]	1.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Cumulative Additions	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3

[1]Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes grid-connected utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[3]Includes oil-, gas-, and dual-fired capability.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar and wind power.
[5]Primarily peak-load capacity fueled by natural gas.
[6]Cumulative additions after December 31, 1999.
[7]Cumulative total retirements after December 31, 1999.
[8]Nameplate capacity is reported for nonutilities on Form EIA-860B, "Annual Electric Generator Report - Nonutility." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.
[9]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[10]See Table C17 for more detail.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model estimates and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators to be consistent with capability for electric utility generators.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Interregional Electricity Trade										
Gross Domestic Firm Power Trade	182.2	102.9	102.9	102.9	45.7	45.7	45.7	0.0	0.0	0.0
Gross Domestic Economy Trade	147.2	220.5	183.3	178.3	229.9	195.5	191.4	228.2	209.0	200.6
Gross Domestic Trade	**329.4**	**323.4**	**286.2**	**281.2**	**275.6**	**241.3**	**237.1**	**228.2**	**209.0**	**200.6**
Gross Domestic Firm Power Sales (million 1999 dollars)	8588.1	4851.2	4851.2	4851.2	2156.1	2156.1	2156.1	0.0	0.0	0.0
Gross Domestic Economy Sales (million 1999 dollars)	4331.4	6121.3	5041.6	5043.1	6478.0	5512.9	5639.2	6745.2	6291.3	6372.2
Gross Domestic Sales (million 1999 dollars)	**12919.5**	**10972.5**	**9892.8**	**9894.4**	**8634.1**	**7669.0**	**7795.3**	**6745.2**	**6291.3**	**6372.2**
International Electricity Trade										
Firm Power Imports From Canada & Mexico[1]	27.0	5.8	5.8	5.8	2.6	2.6	2.6	0.0	0.0	0.0
Economy Imports From Canada and Mexico[1]	20.6	39.5	39.7	39.6	30.0	30.0	30.0	28.6	28.6	28.6
Gross Imports From Canada and Mexico[1]	**47.6**	**45.3**	**45.5**	**45.4**	**32.6**	**32.6**	**32.6**	**28.6**	**28.6**	**28.6**
Firm Power Exports To Canada and Mexico	9.2	8.7	8.7	8.7	3.9	3.9	3.9	0.0	0.0	0.0
Economy Exports To Canada and Mexico	6.3	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**15.5**	**16.4**	**16.4**	**16.4**	**11.5**	**11.5**	**11.5**	**7.7**	**7.7**	**7.7**

[1]Historically electricity imports were primarily from renewable resources, principally hydroelectric.

Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Source: Energy Information Administration, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Crude Oil										
Domestic Crude Production[1]	5.88	4.51	5.15	5.54	4.37	5.08	5.77	4.35	5.05	5.78
Alaska	1.05	0.62	0.64	0.66	0.68	0.70	0.71	0.62	0.64	0.65
Lower 48 States	4.83	3.89	4.50	4.88	3.69	4.38	5.05	3.74	4.41	5.13
Net Imports	8.61	11.89	11.54	11.16	12.94	11.91	11.18	13.31	12.14	11.45
Gross Imports	8.73	11.91	11.59	11.22	12.95	11.95	11.25	13.32	12.18	11.52
Exports	0.12	0.01	0.04	0.06	0.01	0.04	0.07	0.01	0.04	0.07
Other Crude Supply[2]	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**14.80**	**16.40**	**16.69**	**16.70**	**17.31**	**16.99**	**16.95**	**17.67**	**17.19**	**17.23**
Natural Gas Plant Liquids	**1.85**	**2.34**	**2.35**	**2.39**	**2.61**	**2.63**	**2.67**	**2.81**	**2.89**	**2.89**
Other Inputs[3]	**0.60**	**0.21**	**0.20**	**0.31**	**0.22**	**0.21**	**0.27**	**0.23**	**0.23**	**0.28**
Refinery Processing Gain[4]	**0.89**	**0.87**	**1.02**	**1.08**	**0.85**	**1.06**	**1.13**	**0.77**	**1.10**	**1.14**
Net Product Imports[5]	**1.30**	**3.42**	**2.38**	**1.79**	**4.02**	**3.33**	**2.65**	**5.46**	**4.37**	**3.72**
Gross Refined Product Imports[6]	1.73	3.43	2.40	2.04	4.25	3.30	2.69	5.54	4.26	3.79
Unfinished Oil Imports	0.32	0.80	0.79	0.58	0.62	0.87	0.82	0.85	0.99	0.83
Ether Imports	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Exports	0.82	0.82	0.81	0.84	0.86	0.84	0.86	0.93	0.88	0.90
Total Primary Supply[7]	**19.44**	**23.25**	**22.64**	**22.26**	**25.00**	**24.21**	**23.67**	**26.95**	**25.79**	**25.26**
Refined Petroleum Products Supplied										
Motor Gasoline[8]	8.43	10.31	10.11	10.03	11.01	10.75	10.60	11.67	11.33	11.11
Jet Fuel[9]	1.67	2.20	2.18	2.16	2.54	2.52	2.49	2.91	2.88	2.84
Distillate Fuel[10]	3.52	4.57	4.47	4.44	4.96	4.78	4.74	5.47	5.10	5.06
Residual Fuel	0.82	0.77	0.58	0.55	0.78	0.59	0.56	0.80	0.60	0.58
Other[11]	5.07	5.46	5.36	5.11	5.76	5.62	5.32	6.15	5.92	5.69
Total	**19.50**	**23.30**	**22.70**	**22.29**	**25.05**	**24.26**	**23.70**	**27.00**	**25.83**	**25.28**
Refined Petroleum Products Supplied										
Residential and Commercial	1.10	1.18	1.06	1.02	1.19	1.04	0.97	1.19	1.02	0.95
Industrial[12]	5.16	5.71	5.58	5.32	6.04	5.89	5.59	6.48	6.23	6.01
Transportation	12.86	16.18	15.98	15.89	17.52	17.26	17.08	18.84	18.50	18.25
Electric Generators[13]	0.38	0.24	0.07	0.06	0.29	0.07	0.06	0.49	0.08	0.06
Total	**19.50**	**23.30**	**22.70**	**22.29**	**25.05**	**24.26**	**23.70**	**27.00**	**25.83**	**25.28**
Discrepancy[14]	**-0.07**	**-0.05**	**-0.06**	**-0.03**	**-0.05**	**-0.05**	**-0.03**	**-0.05**	**-0.04**	**-0.02**
World Oil Price (1999 dollars per barrel)[15]	**17.35**	**15.10**	**21.37**	**26.66**	**15.10**	**21.89**	**28.23**	**15.10**	**22.41**	**28.42**
Import Share of Product Supplied	**0.51**	**0.66**	**0.61**	**0.58**	**0.68**	**0.63**	**0.58**	**0.70**	**0.64**	**0.60**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 1999 dollars)	**60.16**	**91.01**	**113.67**	**129.69**	**102.07**	**129.29**	**148.28**	**115.80**	**145.38**	**165.99**
Domestic Refinery Distillation Capacity[16]	**16.5**	**17.5**	**17.9**	**17.9**	**18.3**	**18.1**	**18.0**	**18.7**	**18.2**	**18.2**
Capacity Utilization Rate (percent)	**93.0**	**94.0**	**93.6**	**93.4**	**94.8**	**94.3**	**94.3**	**95.1**	**95.0**	**95.1**

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.
[3]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, and other hydrocarbons.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[6]Includes blending components.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net petroleum imports.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes naphtha and kerosene types.
[10]Includes distillate and kerosene.
[11]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[12]Includes consumption by cogenerators.
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses and gains.
[15]Average refiner acquisition cost for imported crude oil.
[16]End-of-year capacity.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 product supplied data from Table C2. Other 1999 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Oil Price Case Comparisons

Table C12. Petroleum Product Prices
(1999 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
World Oil Price (1999 dollars per barrel)	**17.35**	**15.10**	**21.37**	**26.66**	**15.10**	**21.89**	**28.23**	**15.10**	**22.41**	**28.42**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	87.0	88.3	104.1	116.3	89.8	108.1	123.8	91.4	110.7	124.9
Liquefied Petroleum Gas	89.4	97.3	112.8	118.8	97.5	110.7	122.7	98.9	111.1	119.4
Commercial										
Distillate Fuel	60.6	57.2	73.2	85.5	58.4	77.0	92.8	60.0	79.7	94.8
Residual Fuel	39.3	41.1	55.3	67.6	41.1	56.4	71.2	41.1	57.6	71.6
Residual Fuel (1999 dollars per barrel)	16.53	17.28	23.22	28.39	17.27	23.71	29.91	17.26	24.20	30.07
Industrial[1]										
Distillate Fuel	64.5	59.9	75.6	87.8	61.2	79.5	95.1	63.1	82.5	98.3
Liquefied Petroleum Gas	73.4	56.0	69.1	74.4	56.0	66.9	78.1	57.4	67.6	75.1
Residual Fuel	41.7	35.7	51.2	63.5	35.7	52.4	67.1	35.7	53.6	67.5
Residual Fuel (1999 dollars per barrel)	17.50	14.99	21.51	26.69	14.98	22.00	28.20	14.99	22.50	28.37
Transportation										
Diesel Fuel (distillate)[2]	114.0	108.1	124.0	135.7	107.5	125.5	141.0	107.1	124.6	140.5
Jet Fuel[3]	63.5	58.4	73.8	85.5	60.2	77.7	94.0	60.3	79.4	95.9
Motor Gasoline[4]	118.2	116.8	136.3	147.0	115.2	133.9	150.0	110.4	133.0	151.0
Liquified Petroleum Gas	111.1	108.9	123.1	129.4	108.3	120.5	132.2	108.0	119.5	127.6
Residual Fuel	36.8	32.9	47.5	60.1	32.8	48.7	63.8	32.7	49.8	64.1
Residual Fuel (1999 dollars per barrel)	15.45	13.83	19.96	25.24	13.78	20.45	26.78	13.72	20.92	26.93
Ethanol (E85)	129.2	163.3	170.1	177.2	165.3	172.2	181.0	164.0	173.3	183.7
Methanol (M85)	76.2	89.7	100.7	113.1	89.0	105.1	120.4	87.6	105.8	120.2
Electric Generators[5]										
Distillate Fuel	56.2	51.9	67.1	79.4	52.4	70.7	86.2	53.4	73.2	88.6
Residual Fuel	36.2	38.4	58.1	73.0	38.2	59.9	78.2	38.4	60.9	78.5
Residual Fuel (1999 dollars per barrel)	15.21	16.15	24.42	30.65	16.05	25.17	32.84	16.11	25.56	32.96
Refined Petroleum Product Prices[6]										
Distillate Fuel	100.8	96.7	113.5	125.6	96.3	115.9	131.7	95.3	116.2	132.2
Jet Fuel[3]	63.5	58.4	73.8	85.5	60.2	77.7	94.0	60.3	79.4	95.9
Liquefied Petroleum Gas	76.3	63.3	76.6	81.9	62.9	74.1	85.1	63.8	74.4	81.8
Motor Gasoline[4]	118.2	116.8	136.3	147.0	115.2	133.9	149.9	110.4	133.0	151.0
Residual Fuel	37.1	35.4	49.8	62.3	35.2	51.0	66.0	35.3	52.2	66.4
Residual Fuel (1999 dollars per barrel)	15.59	14.85	20.93	26.15	14.80	21.44	27.71	14.81	21.94	27.90
Average	**97.6**	**95.0**	**113.1**	**123.7**	**94.1**	**112.5**	**128.0**	**91.4**	**112.2**	**128.2**

[1]Includes cogenerators. Includes Federal and State taxes while excluding county and state taxes.
[2] Low sulfur diesel fuel. Includes Federal and State taxes while excluding county and local taxes.
[3]Kerosene-type jet fuel.
[4]Sales weighted-average price for all grades. Includes Federal and State taxes while excluding county and local taxes.
[5]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380 (99/03-2000/04) (Washington, DC, 1999-2000). 1999 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditure Report 1997*, DOE/EIA-0376(97) (Washington, DC, July 2000). **Projections**: EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Production										
Dry Gas Production[1]	18.67	23.02	23.14	23.60	25.98	26.24	26.72	28.25	29.04	29.04
Supplemental Natural Gas[2]	0.10	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**3.38**	**5.17**	**5.06**	**4.82**	**5.53**	**5.50**	**5.26**	**5.73**	**5.80**	**5.53**
Canada	3.29	4.92	4.81	4.57	5.24	5.21	4.97	5.39	5.46	5.19
Mexico	-0.01	-0.25	-0.25	-0.25	-0.33	-0.33	-0.33	-0.40	-0.40	-0.40
Liquefied Natural Gas	0.10	0.50	0.50	0.50	0.62	0.62	0.62	0.74	0.74	0.74
Total Supply	**22.15**	**28.25**	**28.25**	**28.48**	**31.57**	**31.80**	**32.04**	**34.04**	**34.90**	**34.62**
Consumption by Sector										
Residential	4.72	5.54	5.54	5.52	5.82	5.83	5.81	6.14	6.14	6.10
Commercial	3.07	3.72	3.78	3.77	3.86	3.94	3.92	3.93	4.02	3.98
Industrial[3]	7.95	8.92	9.33	9.97	9.21	9.76	10.48	9.38	10.18	10.69
Electric Generators[4]	3.78	7.42	6.94	6.52	9.73	9.30	8.83	11.42	11.34	10.64
Lease and Plant Fuel[5]	1.23	1.48	1.49	1.52	1.67	1.68	1.71	1.80	1.84	1.85
Pipeline Fuel	0.64	0.87	0.87	0.88	0.96	0.97	0.97	1.05	1.06	1.05
Transportation[6]	0.02	0.09	0.09	0.09	0.12	0.13	0.13	0.15	0.15	0.16
Total	**21.41**	**28.04**	**28.05**	**28.27**	**31.38**	**31.61**	**31.86**	**33.86**	**34.73**	**34.46**
Discrepancy[7]	**0.74**	**0.21**	**0.21**	**0.20**	**0.19**	**0.18**	**0.18**	**0.18**	**0.17**	**0.16**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 1999 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 transportation sector consumption: EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A. Other 1999 consumption: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A. **Projections:** EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C14. Natural Gas Prices, Margins, and Revenue
(1999 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.66	2.69	2.77	2.77	2.83	2.95	3.01	3.13	3.25
Average Import Price	2.29	2.12	2.43	2.81	2.09	2.47	2.95	2.12	2.67	3.54
Average[2]	**2.11**	**2.55**	**2.64**	**2.78**	**2.65**	**2.76**	**2.95**	**2.85**	**3.05**	**3.30**
Delivered Prices										
Residential	6.69	6.62	6.70	6.86	6.49	6.61	6.80	6.52	6.73	7.00
Commercial	5.49	5.57	5.65	5.80	5.53	5.65	5.84	5.66	5.86	6.13
Industrial[3]	2.87	3.34	3.40	3.50	3.46	3.54	3.69	3.72	3.86	4.05
Electric Generators[4]	2.59	2.98	3.08	3.26	3.17	3.30	3.51	3.45	3.66	3.93
Transportation[5]	7.21	7.09	7.23	7.39	7.14	7.36	7.56	7.16	7.52	7.80
Average[6]	**4.16**	**4.28**	**4.38**	**4.51**	**4.28**	**4.39**	**4.56**	**4.44**	**4.62**	**4.87**
Transmission and Distribution Margins[7]										
Residential	4.58	4.07	4.07	4.08	3.84	3.85	3.85	3.67	3.68	3.70
Commercial	3.37	3.02	3.01	3.03	2.89	2.89	2.89	2.81	2.81	2.83
Industrial[3]	0.75	0.79	0.76	0.73	0.82	0.78	0.74	0.87	0.82	0.75
Electric Generators[4]	0.48	0.42	0.45	0.49	0.53	0.54	0.56	0.60	0.61	0.63
Transportation[5]	5.10	4.54	4.60	4.61	4.49	4.60	4.61	4.31	4.48	4.49
Average[6]	**2.04**	**1.73**	**1.74**	**1.74**	**1.63**	**1.63**	**1.62**	**1.60**	**1.57**	**1.57**
Transmission and Distribution Revenue (billion 1999 dollars)										
Residential	21.61	22.53	22.55	22.54	22.35	22.42	22.35	22.55	22.58	22.54
Commercial	10.36	11.24	11.40	11.39	11.14	11.38	11.34	11.04	11.31	11.26
Industrial[3]	6.00	7.02	7.12	7.26	7.52	7.61	7.77	8.16	8.32	8.05
Electric Generators[4]	1.81	3.15	3.11	3.16	5.15	5.02	4.97	6.82	6.93	6.67
Transportation[5]	0.08	0.40	0.42	0.42	0.55	0.58	0.60	0.64	0.69	0.72
Total	**39.86**	**44.35**	**44.59**	**44.78**	**46.71**	**47.01**	**47.03**	**49.21**	**49.82**	**49.23**

[1]Represents lower 48 onshore and offshore supplies.
[2]Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.

Sources: 1999 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1994*. 1999 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). **Other 1999 values and projections:** EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C15. Oil and Gas Supply

Production and Supply	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Crude Oil										
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	**16.49**	**14.47**	**20.80**	**26.11**	**14.37**	**21.00**	**27.50**	**14.40**	**21.45**	**27.65**
Production (million barrels per day)[2]										
U.S. Total	**5.88**	**4.51**	**5.15**	**5.54**	**4.37**	**5.08**	**5.77**	**4.35**	**5.05**	**5.78**
Lower 48 Onshore	3.27	2.17	2.46	2.74	2.08	2.52	2.92	2.21	2.64	3.08
Conventional	2.59	1.73	1.79	1.87	1.71	1.78	1.86	1.88	1.92	1.96
Enhanced Oil Recovery	0.68	0.44	0.66	0.87	0.38	0.74	1.06	0.32	0.72	1.13
Lower 48 Offshore	1.56	1.72	2.05	2.14	1.61	1.86	2.14	1.53	1.77	2.04
Alaska	1.05	0.62	0.64	0.66	0.68	0.70	0.71	0.62	0.64	0.65
Lower 48 End of Year Reserves (billion barrels)[2]	**18.33**	**12.35**	**13.92**	**15.20**	**11.38**	**13.50**	**15.76**	**11.13**	**13.48**	**16.10**
Natural Gas										
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	**2.08**	**2.66**	**2.69**	**2.77**	**2.77**	**2.83**	**2.95**	**3.01**	**3.13**	**3.25**
Dry Production (trillion cubic feet)[3]										
U.S. Total	**18.67**	**23.02**	**23.14**	**23.60**	**25.98**	**26.24**	**26.72**	**28.25**	**29.04**	**29.04**
Lower 48 Onshore	12.83	15.96	16.29	16.78	18.76	19.04	19.33	20.97	21.26	21.12
Associated-Dissolved[4]	1.80	1.28	1.33	1.37	1.27	1.32	1.36	1.37	1.38	1.39
Non-Associated	11.03	14.68	14.96	15.41	17.49	17.72	17.96	19.60	19.88	19.73
Conventional	6.64	8.13	8.30	8.56	10.34	10.37	10.25	11.30	11.38	11.19
Unconventional	4.39	6.55	6.66	6.86	7.15	7.36	7.71	8.30	8.51	8.54
Lower 48 Offshore	5.43	6.55	6.34	6.32	6.68	6.66	6.85	6.71	7.21	7.36
Associated-Dissolved[4]	0.93	1.00	1.08	1.10	0.98	1.04	1.09	0.96	1.01	1.07
Non-Associated	4.50	5.55	5.26	5.22	5.71	5.63	5.76	5.75	6.19	6.28
Alaska	0.42	0.50	0.50	0.50	0.54	0.54	0.54	0.57	0.57	0.57
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**157.41**	**174.84**	**174.82**	**177.94**	**182.43**	**183.82**	**185.23**	**187.53**	**190.07**	**191.27**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.10**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**
Total Lower 48 Wells (thousands)	**17.94**	**26.67**	**28.63**	**29.97**	**29.76**	**31.62**	**33.48**	**36.67**	**39.14**	**41.11**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). 1999 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). Other 1999 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Production[1]										
Appalachia	437	411	409	410	402	404	402	393	392	396
Interior	166	172	171	176	170	169	177	154	152	169
West	502	663	692	708	695	720	743	741	787	801
East of the Mississippi	546	541	537	543	533	534	539	516	512	530
West of the Mississippi	559	705	735	751	734	760	782	771	819	836
Total	**1105**	**1246**	**1273**	**1294**	**1267**	**1294**	**1322**	**1288**	**1331**	**1366**
Net Imports										
Imports	9	17	17	17	18	18	18	20	20	20
Exports	58	57	58	58	54	54	54	56	56	56
Total	**-49**	**-40**	**-40**	**-40**	**-36**	**-35**	**-35**	**-36**	**-36**	**-36**
Total Supply[2]	**1056**	**1206**	**1232**	**1254**	**1231**	**1259**	**1287**	**1251**	**1295**	**1330**
Consumption by Sector										
Residential and Commercial	5	5	5	5	5	5	5	5	5	5
Industrial[3]	79	84	84	85	85	85	86	86	86	87
Coke Plants	28	23	23	23	21	21	21	19	19	19
Electric Generators[4]	923	1095	1122	1142	1122	1149	1177	1142	1186	1221
Total	**1035**	**1207**	**1235**	**1255**	**1233**	**1261**	**1289**	**1253**	**1297**	**1332**
Discrepancy and Stock Change[5].	**21**	**-2**	**-2**	**-1**	**-2**	**-2**	**-2**	**-1**	**-2**	**-2**
Average Minemouth Price										
(1999 dollars per short ton)	16.98	13.94	13.83	13.76	13.44	13.38	13.40	12.84	12.70	12.87
(1999 dollars per million Btu)	0.81	0.68	0.68	0.67	0.66	0.66	0.66	0.63	0.63	0.64
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.43	28.18	28.40	28.53	27.28	27.49	27.75	26.19	26.48	26.77
Coke Plants	44.25	40.97	41.25	41.63	39.37	39.81	40.05	38.28	38.57	38.80
Electric Generators										
(1999 dollars per short ton)	24.69	21.07	21.04	20.95	20.18	20.25	20.30	19.30	19.45	19.48
(1999 dollars per million Btu)	1.21	1.05	1.05	1.05	1.01	1.01	1.02	0.97	0.98	0.98
Average	**25.74**	**21.94**	**21.92**	**21.83**	**20.99**	**21.06**	**21.11**	**20.06**	**20.19**	**20.23**
Exports[7]	37.45	35.25	35.53	35.80	34.07	34.38	34.60	32.84	33.09	33.35

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 8.5 million tons in 1995, 8.8 million tons in 1996, 8.1 million tons in 1997, 8.6 million tons in 1998, and are projected to reach 9.6 million tons in 1999, and 12.2 million tons in 2000.
[2]Production plus net imports and net storage withdrawals.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Balancing item: the sum of production, net imports, and net storage minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 data based on Energy Information Administration (EIA), *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000) and EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A. **Projections:** EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C17. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Electric Generators[1] (excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	78.14	78.74	78.74	78.74	78.74	78.74	78.74	78.74	78.74	78.74
Geothermal[2]	2.87	3.93	4.34	4.69	3.95	4.41	4.81	3.95	4.41	4.81
Municipal Solid Waste[3]	2.59	3.93	4.20	4.11	4.29	4.57	4.49	4.53	4.72	4.64
Wood and Other Biomass[4]	1.52	2.04	2.04	2.04	2.33	2.33	2.33	2.37	2.37	2.37
Solar Thermal	0.33	0.40	0.40	0.40	0.44	0.44	0.44	0.48	0.48	0.48
Solar Photovoltaic	0.01	0.21	0.21	0.21	0.37	0.37	0.37	0.54	0.54	0.54
Wind	2.60	5.51	5.51	5.51	5.70	5.70	5.70	5.78	5.78	5.81
Total	**88.07**	**94.75**	**95.44**	**95.70**	**95.82**	**96.55**	**96.87**	**96.39**	**97.04**	**97.39**
Generation (billion kilowatthours)										
Conventional Hydropower	307.43	298.98	298.99	298.99	298.44	298.45	298.45	297.94	297.94	297.94
Geothermal[2]	13.07	22.02	25.27	27.98	22.20	25.81	28.99	22.22	25.83	29.02
Municipal Solid Waste[3]	18.05	27.87	30.00	29.34	30.71	32.88	32.23	32.49	33.96	33.32
Wood and Other Biomass[4]	9.49	20.37	21.59	22.95	21.40	23.21	22.91	22.05	22.15	21.93
Dedicated Plants	7.56	10.88	10.88	10.89	12.99	12.99	13.00	13.34	13.35	13.36
Cofiring	1.93	9.50	10.71	12.06	8.42	10.22	9.91	8.71	8.80	8.57
Solar Thermal	0.89	1.11	1.11	1.11	1.24	1.24	1.24	1.37	1.37	1.37
Solar Photovoltaic	0.03	0.51	0.51	0.51	0.92	0.92	0.92	1.36	1.36	1.36
Wind	4.46	12.33	12.33	12.33	12.84	12.84	12.84	13.10	13.10	13.19
Total	**353.42**	**383.19**	**389.80**	**393.21**	**387.75**	**395.35**	**397.58**	**390.53**	**395.71**	**398.13**
Cogenerators[5]										
Net Summer Capability										
Municipal Solid Waste	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Biomass	4.65	6.06	6.06	6.07	6.86	6.85	6.84	7.56	7.54	7.51
Total	**5.35**	**6.76**	**6.76**	**6.77**	**7.56**	**7.55**	**7.54**	**8.25**	**8.23**	**8.21**
Generation (billion kilowatthours)										
Municipal Solid Waste	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03
Biomass	27.08	34.98	35.01	35.05	39.61	39.55	39.49	43.64	43.52	43.40
Total	**31.11**	**39.01**	**39.03**	**39.08**	**43.64**	**43.58**	**43.52**	**47.66**	**47.55**	**47.43**
Other End-Use Generators[6]										
Net Summer Capability										
Conventional Hydropower[7]	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.01	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Total	**1.00**	**1.34**	**1.34**	**1.34**	**1.34**	**1.34**	**1.34**	**1.34**	**1.34**	**1.34**
Generation (billion kilowatthours)										
Conventional Hydropower[7]	4.57	4.43	4.43	4.43	4.42	4.42	4.42	4.41	4.41	4.41
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
Total	**4.59**	**5.18**	**5.18**	**5.18**	**5.18**	**5.18**	**5.18**	**5.17**	**5.17**	**5.17**

[1]Includes grid-connected utilities and nonutilities other than cogenerators. These nonutility facilities include small power producers and exempt wholesale generators.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Cogenerators produce electricity and other useful thermal energy.
[6] Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[7]Represents own-use industrial hydroelectric power.

Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators for AEO2001. Net summer capability is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.

Sources: 1999 electric utility capability: Energy Information Administration (EIA), Form EIA-860A: "Annual Electric Generator Report - Utility." 1999 nonutility and cogenerator capability: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." 1999 generation: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C18. Renewable Energy Consumption by Sector and Source
(Quadrillion Btu per Year)

Sector and Source	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.44**	**0.43**	**0.42**	**0.45**	**0.43**	**0.42**	**0.46**	**0.44**	**0.43**
Wood	0.41	0.44	0.43	0.42	0.45	0.43	0.42	0.46	0.44	0.43
Commercial	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Industrial[3]	**2.15**	**2.65**	**2.64**	**2.64**	**2.87**	**2.86**	**2.86**	**3.09**	**3.08**	**3.08**
Conventional Hydroelectric	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	1.97	2.46	2.46	2.45	2.68	2.68	2.67	2.91	2.90	2.89
Transportation	**0.12**	**0.22**	**0.21**	**0.28**	**0.23**	**0.23**	**0.30**	**0.23**	**0.24**	**0.32**
Ethanol used in E85[4]	0.00	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04
Ethanol used in Gasoline Blending	0.12	0.19	0.19	0.26	0.20	0.20	0.27	0.20	0.21	0.28
Electric Generators[5]	**3.94**	**4.46**	**4.64**	**4.67**	**4.57**	**4.71**	**4.74**	**4.53**	**4.66**	**4.75**
Conventional Hydroelectric	3.17	3.08	3.08	3.08	3.07	3.07	3.07	3.06	3.06	3.06
Geothermal	0.38	0.66	0.81	0.83	0.72	0.82	0.86	0.65	0.77	0.87
Municipal Solid Waste[6]	0.25	0.38	0.41	0.40	0.42	0.45	0.44	0.44	0.46	0.45
Biomass	0.09	0.19	0.21	0.22	0.20	0.22	0.22	0.21	0.21	0.21
Dedicated Plants	0.07	0.10	0.10	0.10	0.12	0.12	0.12	0.13	0.13	0.13
Cofiring	0.02	0.09	0.10	0.12	0.08	0.10	0.09	0.08	0.08	0.08
Solar Thermal	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.05	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.14
Total Marketed Renewable Energy	**6.70**	**7.84**	**8.01**	**8.10**	**8.19**	**8.32**	**8.40**	**8.39**	**8.51**	**8.66**
Non-Marketed Renewable Energy[7] **Selected Consumption**										
Residential	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**
Solar Hot Water Heating	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal Heat Pumps	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ethanol										
From Corn	0.12	0.19	0.19	0.26	0.19	0.19	0.26	0.16	0.17	0.25
From Cellulose	0.00	0.02	0.02	0.02	0.04	0.04	0.04	0.07	0.07	0.07
Total	**0.12**	**0.22**	**0.21**	**0.28**	**0.23**	**0.23**	**0.30**	**0.23**	**0.24**	**0.32**

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table C8.
[3]Includes all electricity production by industrial and other cogenerators for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes renewable energy delivered to the grid from electric utilities and nonutilities. Renewable energy used in generating electricity for own use is included in the individual sectoral electricity energy consumption values.
[6]Includes landfill gas.
[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 ethanol: Energy Information Administration (EIA), *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). 1999 electric generators: EIA, Form EIA-860A: "Annual Electric Generator Report - Utility" and Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 1999: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C19. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Residential										
Petroleum	26.0	26.2	24.4	23.3	25.8	23.4	21.9	25.6	22.9	21.3
Natural Gas	69.5	81.9	82.0	81.7	86.0	86.2	85.9	90.8	90.8	90.2
Coal	1.1	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Electricity	192.6	239.3	238.2	238.5	256.7	255.2	256.6	273.9	273.2	275.3
Total	**289.3**	**348.8**	**345.9**	**344.8**	**369.8**	**366.2**	**365.6**	**391.6**	**388.1**	**388.0**
Commercial										
Petroleum	13.7	15.3	13.1	12.4	16.1	13.1	12.2	16.5	12.9	12.1
Natural Gas	45.4	55.1	55.9	55.7	57.1	58.3	58.0	58.1	59.4	58.9
Coal	1.7	1.9	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.0
Electricity	182.1	235.9	234.4	235.1	254.5	253.0	254.1	264.9	263.9	265.7
Total	**242.9**	**308.1**	**305.3**	**305.0**	**329.7**	**326.3**	**326.3**	**341.4**	**338.2**	**338.7**
Industrial[1]										
Petroleum	104.2	108.6	104.7	94.6	113.9	109.9	98.5	121.5	115.5	107.7
Natural Gas[2]	141.6	151.4	157.6	167.5	158.4	166.8	177.8	162.8	175.1	182.7
Coal	55.9	66.2	66.3	66.4	66.2	66.2	66.4	66.4	66.4	66.5
Electricity	178.8	200.6	200.8	202.4	212.1	212.4	215.3	224.6	226.6	229.7
Total	**480.4**	**526.9**	**529.4**	**530.9**	**550.6**	**555.2**	**557.8**	**575.3**	**583.6**	**586.7**
Transportation										
Petroleum[3]	485.8	615.3	608.5	603.7	666.6	657.3	649.4	717.0	704.9	694.3
Natural Gas[4]	9.5	14.2	14.3	14.4	16.1	16.2	16.3	17.6	18.0	17.9
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	2.9	5.7	5.7	5.7	7.0	6.9	7.0	7.9	7.8	7.9
Total[3]	**498.2**	**635.2**	**628.5**	**623.8**	**689.7**	**680.5**	**672.7**	**742.5**	**730.8**	**720.2**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	765.4	750.6	734.0	822.4	803.7	782.0	880.6	856.1	835.4
Natural Gas	266.0	302.5	309.8	319.3	317.5	327.5	337.9	329.3	343.3	349.6
Coal	58.8	69.4	69.5	69.6	69.5	69.4	69.6	69.6	69.6	69.7
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	556.3	681.6	679.1	681.6	730.4	727.5	732.9	771.3	771.5	778.6
Total[3]	**1510.8**	**1819.0**	**1809.1**	**1804.5**	**1939.8**	**1928.1**	**1922.5**	**2050.9**	**2040.6**	**2033.5**
Electric Generators[6]										
Petroleum	20.0	11.3	3.4	2.7	13.6	3.4	2.6	21.8	3.7	2.8
Natural Gas	45.8	108.9	101.8	95.7	142.8	136.5	129.6	167.5	166.3	156.1
Coal	490.5	561.5	574.0	583.2	574.0	587.6	600.7	581.9	601.5	619.7
Total	**556.3**	**681.6**	**679.1**	**681.6**	**730.4**	**727.5**	**732.9**	**771.3**	**771.5**	**778.6**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	776.6	754.0	736.7	836.0	807.1	784.6	902.4	859.9	838.2
Natural Gas	311.8	411.4	411.5	414.9	460.4	463.9	467.6	496.9	509.6	505.8
Coal	549.3	630.9	643.5	652.8	643.4	657.0	670.2	651.5	671.1	689.4
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total[3]	**1510.8**	**1819.0**	**1809.1**	**1804.5**	**1939.8**	**1928.1**	**1922.5**	**2050.9**	**2040.6**	**2033.5**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**6.1**	**6.0**	**6.0**	**6.2**	**6.2**	**6.2**	**6.3**	**6.3**	**6.3**

[1]Includes consumption by cogenerators.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel which, by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 1998, international bunker fuels accounted for 25 to 30 million metric tons carbon equivalent of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes methanol and liquid hydrogen.
[6]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste not energy.
[7]Emissions from electric power generators are distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 1999,* DOE/EIA-0573(99) (Washington, DC, October 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Oil Price Case Comparisons

Table C20. Macroeconomic Indicators

(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
GDP Chain-Type Price Index										
(1996=1.000)	**1.045**	**1.299**	**1.304**	**1.306**	**1.434**	**1.440**	**1.446**	**1.674**	**1.680**	**1.686**
Real Gross Domestic Product	**8876**	**12686**	**12667**	**12659**	**14674**	**14635**	**14607**	**16565**	**16515**	**16474**
Real Consumption	5990	8564	8535	8522	9980	9934	9895	11374	11312	11250
Real Investment	1611	2925	2917	2914	3630	3613	3600	4274	4252	4234
Real Government Spending	1536	1880	1877	1876	2026	2022	2020	2198	2193	2189
Real Exports	1037	2455	2445	2441	3483	3465	3449	4786	4757	4726
Real Imports	1356	3131	3084	3063	4411	4336	4269	6104	5986	5847
Real Disposable Personal Income	**6363**	**8959**	**8928**	**8915**	**10407**	**10361**	**10325**	**11902**	**11842**	**11786**
AA Utility Bond Rate (percent)	**7.05**	**8.64**	**8.76**	**8.82**	**8.44**	**8.60**	**8.73**	**9.35**	**9.51**	**9.63**
Real Yield on Government 10 Year Bonds										
(percent)	**4.75**	**5.55**	**5.59**	**5.61**	**5.49**	**5.55**	**5.63**	**5.35**	**5.43**	**5.56**
Real Utility Bond Rate (percent)	**5.58**	**6.80**	**6.90**	**6.96**	**6.33**	**6.49**	**6.56**	**5.92**	**6.09**	**6.23**
Energy Intensity										
(thousand Btu per 1996 dollar of GDP)										
Delivered Energy	8.08	6.80	6.79	6.78	6.27	6.27	6.25	5.89	5.89	5.86
Total Energy	10.84	9.04	9.02	9.00	8.27	8.25	8.24	7.69	7.70	7.68
Consumer Price Index (1982-84=1.00)	**1.67**	**2.18**	**2.20**	**2.21**	**2.47**	**2.49**	**2.50**	**2.93**	**2.95**	**2.97**
Unemployment Rate (percent)	**4.22**	**4.92**	**4.94**	**4.94**	**4.27**	**4.32**	**4.36**	**4.24**	**4.28**	**4.28**
Housing Starts (millions)	2.02	1.89	1.89	1.88	2.11	2.10	2.10	2.09	2.09	2.09
Single-Family	1.34	1.17	1.17	1.17	1.29	1.28	1.28	1.28	1.27	1.27
Multifamily	0.34	0.42	0.41	0.41	0.48	0.48	0.48	0.47	0.46	0.46
Mobile Home Shipments	0.35	0.30	0.30	0.30	0.34	0.34	0.34	0.35	0.35	0.35
Commercial Floorspace, Total										
(billion square feet)	**62.8**	**75.8**	**75.8**	**75.7**	**79.7**	**79.6**	**79.6**	**82.0**	**81.9**	**81.9**
Gross Output (billion 1992 dollars)										
Total Industrial	4722	6240	6251	6258	7090	7093	7097	8089	8096	8096
Nonmanufacturing	972	1158	1162	1166	1260	1265	1268	1360	1370	1372
Manufacturing	3749	5083	5089	5092	5830	5828	5829	6730	6726	6724
Energy-Intensive Manufacturing	1078	1246	1248	1248	1324	1322	1321	1398	1396	1392
Non-Energy-Intensive Manufacturing	2672	3836	3841	3844	4506	4506	4508	5331	5330	5332
Unit Sales of Light-Duty Vehicles (millions)	**16.89**	**16.38**	**15.88**	**15.69**	**17.86**	**17.18**	**16.75**	**18.24**	**17.44**	**16.94**
Population (millions)										
Population with Armed Forces Overseas)	273.1	300.2	300.2	300.2	312.6	312.6	312.6	325.2	325.2	325.2
Population (aged 16 and over)	210.9	236.6	236.6	236.6	246.7	246.7	246.7	256.5	256.5	256.5
Employment, Non-Agriculture	128.5	150.0	149.7	149.6	157.9	157.3	156.9	165.8	165.1	164.4
Employment, Manufacturing	18.7	18.0	18.0	18.1	17.8	17.8	17.8	17.9	17.8	17.8
Labor Force	139.4	158.3	158.2	158.2	164.4	164.3	164.3	169.6	169.5	169.4

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 1999: Standard & Poor's DRI, Simulation T250200. **Projections:** Energy Information Administration, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Table C21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
World Oil Price (1999 dollars per barrel)[1]	**17.35**	**15.10**	**21.37**	**26.66**	**15.10**	**21.89**	**28.23**	**15.10**	**22.41**	**28.42**
Production[2]										
OECD										
U.S. (50 states)	9.22	7.94	8.72	9.31	8.04	8.98	9.84	8.16	9.27	10.09
Canada	2.63	3.15	3.20	3.24	3.31	3.38	3.43	3.35	3.43	3.48
Mexico	3.37	3.88	3.99	4.07	3.78	3.91	4.00	3.67	3.81	3.90
OECD Europe[3]	7.02	7.57	7.68	7.76	6.90	7.02	7.10	6.41	6.53	6.60
Other OECD	0.76	0.95	0.98	1.00	0.90	0.94	0.97	0.85	0.89	0.92
Total OECD	**23.00**	**23.48**	**24.57**	**25.38**	**22.94**	**24.23**	**25.34**	**22.43**	**23.93**	**25.00**
Developing Countries										
Other South & Central America	3.85	4.48	4.61	4.70	4.95	5.12	5.24	5.28	5.48	5.61
Pacific Rim	2.30	2.93	3.01	3.07	3.07	3.17	3.25	3.16	3.28	3.36
OPEC	29.87	48.64	42.16	37.88	57.51	48.94	43.13	68.41	57.64	51.21
Other Developing Countries	4.81	5.64	5.80	5.91	6.87	7.11	7.27	8.02	8.32	8.52
Total Developing Countries	**40.84**	**61.67**	**55.58**	**51.56**	**72.40**	**64.35**	**58.89**	**84.86**	**74.71**	**68.69**
Eurasia										
Former Soviet Union	7.40	10.38	10.68	10.89	12.55	12.98	13.28	13.81	14.33	14.68
Eastern Europe	0.24	0.37	0.38	0.39	0.40	0.42	0.43	0.44	0.45	0.46
China	3.21	3.43	3.53	3.59	3.51	3.63	3.71	3.50	3.63	3.72
Total Eurasia	**10.85**	**14.17**	**14.59**	**14.87**	**16.46**	**17.02**	**17.42**	**17.75**	**18.42**	**18.87**
Total Production	**74.68**	**99.32**	**94.73**	**91.80**	**111.79**	**105.60**	**101.65**	**125.04**	**117.06**	**112.56**
Consumption										
OECD										
U.S. (50 states)	19.50	23.30	22.70	22.29	25.05	24.26	23.70	27.00	25.83	25.28
U.S. Territories	0.34	0.46	0.41	0.38	0.50	0.44	0.40	0.54	0.46	0.42
Canada	1.92	2.34	2.10	1.95	2.45	2.16	1.98	2.49	2.17	1.98
Mexico	2.00	3.02	2.78	2.64	3.66	3.31	3.09	4.41	3.93	3.65
Japan	5.56	6.68	5.85	5.33	7.26	6.06	5.35	7.68	6.18	5.35
Australia and New Zealand	0.98	1.14	1.09	1.06	1.22	1.16	1.12	1.29	1.22	1.18
OECD Europe[3]	14.50	16.65	15.81	15.28	17.15	16.18	15.55	17.58	16.50	15.86
Total OECD	**44.81**	**53.59**	**50.74**	**48.93**	**57.29**	**53.56**	**51.19**	**60.98**	**56.29**	**53.71**
Developing Countries										
Other South and Central America	4.14	6.04	5.86	5.74	7.22	6.98	6.82	8.70	8.39	8.21
Pacific Rim	7.64	12.78	12.34	12.05	14.75	14.18	13.80	16.72	16.02	15.58
OPEC	5.68	7.78	7.78	7.78	9.24	9.24	9.24	10.99	10.99	10.99
Other Developing Countries	3.75	4.65	4.31	4.09	5.50	4.95	4.60	6.59	5.79	5.30
Total Developing Countries	**21.22**	**31.25**	**30.29**	**29.67**	**36.71**	**35.35**	**34.46**	**43.01**	**41.19**	**40.09**
Eurasia										
Former Soviet Union	3.64	5.51	5.29	5.15	6.62	6.33	6.13	7.94	7.55	7.32
Eastern Europe	1.53	1.73	1.69	1.66	1.80	1.75	1.71	1.83	1.78	1.74
China	4.31	7.53	7.02	6.70	9.66	8.92	8.45	11.49	10.55	9.99
Total Eurasia	**9.48**	**14.78**	**13.99**	**13.50**	**18.08**	**16.99**	**16.30**	**21.26**	**19.88**	**19.06**

Table C21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1999	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Total Consumption	**75.51**	**99.62**	**95.03**	**92.10**	**112.09**	**105.90**	**101.95**	**125.34**	**117.36**	**112.86**
Non-OPEC Production	44.81	50.69	52.58	53.92	54.29	56.66	58.52	56.63	59.43	61.35
Net Eurasia Exports	1.37	-0.61	0.59	1.37	-1.62	0.03	1.12	-3.51	-1.46	-0.19
OPEC Market Share	0.40	0.49	0.45	0.41	0.51	0.46	0.42	0.55	0.49	0.45

[1]Average refiner acquisition cost of imported crude oil.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol, liquids produced from coal and other sources, and refinery gains.
[3]OECD Europe includes the unified Germany.
OECD = Organization for Economic Cooperation and Development - Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States (including territories).
Pacific Rim = Hong Kong, Malaysia, Philippines, Singapore, South Korea, Taiwan, and Thailand.
OPEC = Organization of Petroleum Exporting Countries - Algeria, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
Eurasia = Albania, Bulgaria, China, Czech Republic, Hungary, Poland, Romania, Slovakia, the Former Soviet Union, and the Former Yugoslavia.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs LW2001.D101600A, AEO2001.D101600A, and HW2001.D101600A.

Crude Oil Equivalency Summary

Table D1. Total Energy Supply and Disposition Summary
(Million Barrels per Day Oil Equivalent, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Production							
Crude Oil and Lease Condensate	6.23	5.88	5.65	5.15	5.08	5.05	-0.7%
Natural Gas Plant Liquids	1.18	1.24	1.43	1.57	1.76	1.94	2.2%
Dry Natural Gas	9.07	9.05	10.09	11.21	12.72	14.03	2.1%
Coal	11.22	10.91	11.91	12.31	12.48	12.69	0.7%
Nuclear Power	3.40	3.68	3.73	3.63	3.22	2.89	-1.1%
Renewable Energy[1]	3.13	3.11	3.37	3.70	3.84	3.91	1.1%
Other[2]	0.31	0.78	0.27	0.14	0.15	0.16	-7.3%
Total	**34.53**	**34.65**	**36.45**	**37.72**	**39.25**	**40.68**	**0.8%**
Imports							
Crude Oil [3]	8.70	8.73	10.66	11.59	11.95	12.18	1.6%
Petroleum Products[4]	1.88	1.96	2.27	3.06	4.00	5.05	4.6%
Natural Gas	1.52	1.71	2.32	2.65	2.91	3.10	2.9%
Other Imports[5]	0.27	0.29	0.50	0.42	0.41	0.44	1.9%
Total	**12.39**	**12.70**	**15.74**	**17.72**	**19.27**	**20.77**	**2.4%**
Exports							
Petroleum[6]	0.92	0.94	0.86	0.84	0.87	0.90	-0.2%
Natural Gas	0.08	0.08	0.15	0.20	0.25	0.30	6.5%
Coal	0.94	0.70	0.71	0.69	0.64	0.66	-0.2%
Total	**1.93**	**1.71**	**1.72**	**1.73**	**1.76**	**1.86**	**0.4%**
Discrepancy[7]	**-0.21**	**-0.25**	**0.03**	**0.14**	**0.18**	**0.16**	**N/A**
Consumption							
Petroleum Products[8]	17.55	17.96	19.56	20.98	22.44	23.83	1.4%
Natural Gas	10.37	10.37	12.22	13.58	15.30	16.76	2.3%
Coal	10.17	10.10	11.35	11.81	12.04	12.24	0.9%
Nuclear Power	3.40	3.68	3.73	3.63	3.22	2.89	-1.1%
Renewable Energy[1]	3.13	3.11	3.37	3.70	3.84	3.92	1.1%
Other[9]	0.14	0.16	0.26	0.15	0.11	0.11	-1.9%
Total	**44.77**	**45.39**	**50.50**	**53.84**	**56.95**	**59.74**	**1.3%**
Net Imports - Petroleum	**9.89**	**9.98**	**12.34**	**14.10**	**15.38**	**16.59**	**2.5%**
Prices (1999 dollars per unit)							
World Oil Price (dollars per barrel)[10]	12.02	17.35	20.83	21.37	21.89	22.41	1.2%
Gas Wellhead Price (dollars per Mcf)[11]	2.02	2.08	2.49	2.69	2.83	3.13	2.0%
Coal Minemouth Price (dollars per ton)	18.02	16.98	14.68	13.83	13.38	12.70	-1.4%
Average Electric Price (cents per kilowatthour)	6.8	6.7	6.2	5.9	5.9	6.0	-0.5%

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Mcf = Thousand cubic feet.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1998 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1998*, DOE/EIA-0131(98) (Washington, DC, October 1999). 1998 coal minemouth prices: EIA, *Coal Industry Annual 1998*, DOE/EIA-0584(98) (Washington, DC, June 2000). Other 1998 values: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). 1999 natural gas values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 petroleum values: EIA, *Petroleum Supply Annual 1999*, DOE/EIA-0340(99/1) (Washington, DC, June 2000). Other 1999 values: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000). **Projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Crude Oil Equivalency Summary

Table D2. Total Energy Supply and Disposition Summary
(Million Tons of Oil Equivalent, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case						Annual Growth 1999-2020 (percent)
	1998	1999	2005	2010	2015	2020	
Production							
Crude Oil and Lease Condensate	332.32	313.85	301.43	274.67	271.04	269.45	-0.7%
Natural Gas Plant Liquids	62.84	66.09	76.41	83.89	93.95	103.33	2.2%
Dry Natural Gas	483.69	482.81	538.06	598.24	678.45	750.78	2.1%
Coal	598.67	581.91	635.21	656.70	665.91	679.02	0.7%
Nuclear Power	181.28	196.37	199.15	193.82	171.94	154.53	-1.1%
Renewable Energy[1]	166.90	165.82	179.75	197.15	204.71	209.29	1.1%
Other[2]	16.45	41.60	14.33	7.65	7.99	8.45	-7.3%
Total	**1842.15**	**1848.46**	**1944.33**	**2012.12**	**2094.00**	**2174.84**	**0.8%**
Imports							
Crude Oil[3]	476.25	477.67	582.95	633.88	653.57	666.35	1.6%
Petroleum Products[4]	100.56	104.41	121.13	163.43	213.26	269.27	4.6%
Natural Gas	81.26	91.46	123.70	141.36	155.39	165.75	2.9%
Other Imports[5]	14.51	15.73	26.63	22.53	22.07	23.63	2.0%
Total	**672.58**	**689.27**	**854.42**	**961.19**	**1044.29**	**1125.00**	**2.4%**
Exports							
Petroleum[6]	48.95	49.90	45.61	44.89	46.16	48.19	-0.2%
Natural Gas	4.05	4.25	8.19	10.82	13.44	15.99	6.5%
Coal	50.12	37.18	38.01	36.68	34.11	35.43	-0.2%
Total	**103.12**	**91.33**	**91.82**	**92.38**	**93.71**	**99.61**	**0.4%**
Discrepancy[7]	**21.62**	**23.69**	**9.83**	**4.54**	**1.73**	**-1.02**	**N/A**
Consumption							
Petroleum Products[8]	936.49	958.35	1043.47	1119.09	1196.95	1274.85	1.4%
Natural Gas	553.31	553.24	652.15	724.41	816.25	896.46	2.3%
Coal	544.50	540.12	608.50	633.88	647.05	660.21	1.0%
Nuclear Power	181.28	196.37	199.15	193.82	171.94	154.53	-1.1%
Renewable Energy[1]	167.05	166.07	179.86	197.32	204.91	209.51	1.1%
Other[9]	7.36	8.57	13.97	7.88	5.74	5.71	-1.9%
Total	**2389.99**	**2422.72**	**2697.11**	**2876.39**	**3042.84**	**3201.26**	**1.3%**
Net Imports - Petroleum	**527.86**	**532.18**	**658.47**	**752.42**	**820.67**	**887.43**	**2.5%**
Prices (1999 dollars per unit)							
World Oil Price (dollars per barrel)[10]	12.02	17.35	20.83	21.37	21.89	22.41	1.2%
Gas Wellhead Price (dollars per Mcf)[11]	2.02	2.08	2.49	2.69	2.83	3.13	2.0%
Coal Minemouth Price (dollars per ton)	18.02	16.98	14.68	13.83	13.38	12.70	-1.4%
Average Electric Price (cents per kilowatthour)	6.8	6.7	6.2	5.9	5.9	6.0	-0.5%

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Mcf = Thousand cubic feet.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 and 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1998 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1998*, DOE/EIA-0131(98) (Washington, DC, October 1999). 1998 coal minemouth prices: EIA, *Coal Industry Annual 1998*, DOE/EIA-0584(98) (Washington, DC, June 2000). Other 1998 values: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). 1999 natural gas values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 petroleum values: EIA, *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). Other 1999 values: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000). **Projections:** EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Household Expenditures

Table E1. 1999 Average Household Expenditures for Energy by Household Characteristic (1999 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2351.32**	**1201.58**	**843.17**	**301.00**	**57.41**	**1149.73**
Households by Income Quintile						
1st	1394.22	891.10	599.14	241.00	50.96	503.11
2nd	1982.04	1024.97	736.86	249.04	39.07	957.06
3rd	2301.79	1152.98	807.92	284.23	60.83	1148.81
4th	2598.96	1259.56	884.03	324.94	50.60	1339.40
5th	3154.63	1538.41	1084.98	377.03	76.40	1616.22
Households by Census Division						
New England	2658.26	1474.33	859.09	271.17	344.07	1183.93
Middle Atlantic	2421.74	1467.83	816.12	449.42	202.28	953.91
South Atlantic	2495.48	1219.05	700.62	496.87	21.56	1276.43
East North Central	2539.22	1146.20	733.82	383.37	29.01	1393.02
East South Central	2231.43	1157.23	982.84	150.84	23.55	1074.20
West North Central	2328.70	1234.93	1063.92	169.02	1.98	1093.77
West South Central	2303.16	1249.62	998.27	251.34	0.00	1053.55
Mountain	2197.17	986.74	705.18	276.48	5.08	1210.43
Pacific	2193.85	966.82	751.35	208.84	6.63	1227.03

Source: Energy Information Administration, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table E2. 2005 Average Household Expenditures for Energy by Household Characteristic (1999 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2568.09**	**1226.09**	**838.99**	**322.76**	**64.34**	**1342.00**
Households by Income Quintile						
1st	1504.86	916.27	602.27	257.90	56.11	588.58
2nd	2164.56	1047.83	735.30	268.87	43.65	1116.73
3rd	2523.19	1176.60	803.33	305.26	68.01	1346.58
4th	2842.70	1281.38	877.79	346.94	56.65	1561.32
5th	3447.08	1565.29	1075.04	403.73	86.53	1881.78
Households by Census Division						
New England	2959.14	1536.89	853.24	259.98	423.67	1422.25
Middle Atlantic	2642.93	1479.48	790.82	455.00	233.66	1163.45
South Atlantic	2718.59	1242.04	681.62	537.86	22.56	1476.55
East North Central	2833.66	1179.59	724.31	422.91	32.37	1654.07
East South Central	2442.57	1188.18	1005.22	158.93	24.03	1254.38
West North Central	2548.54	1256.39	1065.43	188.94	2.02	1292.15
West South Central	2507.65	1266.73	982.39	284.34	0.00	1240.92
Mountain	2456.93	1064.01	743.59	315.15	5.28	1392.92
Pacific	2354.02	983.51	727.12	248.63	7.76	1370.51

Source: Energy Information Administration, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table E3. 2010 Average Household Expenditures for Energy by Household Characteristic
(1999 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2663.92**	**1252.56**	**880.25**	**315.10**	**57.20**	**1411.36**
Households by Income Quintile						
1st	1557.70	936.01	634.90	251.56	49.55	621.69
2nd	2250.06	1073.53	771.78	263.07	38.68	1176.52
3rd	2619.24	1201.24	842.70	298.24	60.30	1418.00
4th	2948.65	1308.32	920.99	337.08	50.24	1640.33
5th	3573.54	1597.98	1125.81	394.68	77.48	1975.56
Households by Census Division						
New England	3009.96	1511.34	858.54	255.27	397.53	1498.62
Middle Atlantic	2671.76	1455.58	799.97	442.24	213.37	1216.18
South Atlantic	2805.60	1257.27	728.43	509.87	18.96	1548.34
East North Central	2957.81	1217.53	782.49	407.79	27.25	1740.28
East South Central	2575.32	1256.75	1069.21	167.30	20.24	1318.57
West North Central	2673.73	1315.24	1121.54	192.13	1.57	1358.49
West South Central	2598.41	1304.46	1032.70	271.76	0.00	1293.95
Mountain	2602.13	1112.23	796.13	311.82	4.27	1489.90
Pacific	2454.07	1002.51	736.59	258.19	7.74	1451.56

Source: Energy Information Administration, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table E4. 2015 Average Household Expenditures for Energy by Household Characteristic
(1999 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2669.73**	**1272.32**	**908.09**	**310.18**	**54.05**	**1397.41**
Households by Income Quintile						
1st	1566.38	949.69	655.92	247.32	46.44	616.69
2nd	2255.18	1090.03	794.48	259.11	36.45	1165.15
3rd	2625.22	1219.47	868.64	293.87	56.96	1405.75
4th	2951.11	1327.57	948.67	331.39	47.51	1623.55
5th	3583.37	1626.82	1164.27	388.94	73.61	1956.54
Households by Census Division						
New England	3064.73	1553.73	908.25	253.11	392.38	1511.00
Middle Atlantic	2690.73	1481.11	842.83	431.58	206.70	1209.62
South Atlantic	2792.62	1272.00	751.68	502.28	18.04	1520.62
East North Central	2943.72	1232.75	800.82	406.06	25.87	1710.98
East South Central	2582.91	1281.18	1093.64	169.13	18.40	1301.73
West North Central	2653.85	1321.37	1124.90	195.04	1.44	1332.47
West South Central	2611.10	1344.97	1077.06	267.91	0.00	1266.12
Mountain	2622.69	1124.30	811.17	309.29	3.83	1498.39
Pacific	2470.99	1015.37	751.26	256.52	7.58	1455.62

Source: Energy Information Administration, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table E5. 2020 Average Household Expenditures for Energy by Household Characteristic
(1999 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2696.32**	**1304.76**	**938.10**	**315.62**	**51.04**	**1391.56**
Households by Income Quintile						
1st	1588.67	973.43	678.51	251.48	43.44	615.24
2nd	2278.89	1117.62	819.63	263.66	34.34	1161.26
3rd	2652.63	1249.40	896.24	299.39	53.78	1403.23
4th	2975.63	1359.56	977.75	336.86	44.96	1616.07
5th	3618.87	1671.87	1205.86	396.15	69.86	1947.00
Households by Census Division						
New England	3096.04	1577.12	932.39	259.53	385.20	1518.92
Middle Atlantic	2724.62	1520.76	884.34	437.05	199.37	1203.86
South Atlantic	2817.36	1305.57	773.97	514.07	17.52	1511.80
East North Central	2962.15	1260.28	816.33	418.97	24.98	1701.86
East South Central	2620.19	1314.93	1120.86	177.11	16.96	1305.26
West North Central	2675.00	1348.43	1143.29	203.80	1.34	1326.58
West South Central	2680.98	1426.83	1154.02	272.82	0.00	1254.15
Mountain	2692.50	1137.43	817.95	316.05	3.43	1555.07
Pacific	2443.12	1028.13	762.40	258.28	7.46	1414.99

Source: Energy Information Administration, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Appendix F
Results from Side Cases

Table F1. Key Results for Residential Sector Technology Cases

Energy Consumption	1999	2005 2001 Technology	2005 Reference Case	2005 High Technology	2005 Best Available Technology	2010 2001 Technology	2010 Reference Case	2010 High Technology	2010 Best Available Technology
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.86	0.89	0.88	0.85	0.82	0.82	0.81	0.74	0.69
Kerosene	0.10	0.09	0.08	0.08	0.08	0.08	0.07	0.07	0.06
Liquefied Petroleum Gas	0.46	0.46	0.45	0.44	0.43	0.43	0.41	0.39	0.37
Petroleum Subtotal	1.42	1.44	1.42	1.37	1.33	1.33	1.29	1.20	1.12
Natural Gas	4.85	5.49	5.46	5.30	4.92	5.74	5.69	5.37	4.52
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy	0.41	0.43	0.43	0.40	0.40	0.44	0.43	0.39	0.38
Electricity	3.91	4.51	4.50	4.45	4.28	5.05	4.96	4.86	4.43
Delivered Energy	**10.62**	**11.93**	**11.86**	**11.57**	**10.98**	**12.61**	**12.43**	**11.87**	**10.50**
Electricity Related Losses	8.48	9.49	9.45	9.36	9.00	10.03	9.87	9.67	8.81
Total	**19.10**	**21.41**	**21.31**	**20.94**	**19.98**	**22.64**	**22.30**	**21.53**	**19.31**
Delivered Energy Consumption per Household (million Btu per household)	**102.1**	**107.0**	**106.4**	**103.8**	**98.5**	**107.8**	**106.3**	**101.5**	**89.8**

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all feedbacks are captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.

Source: Energy Information Administration, AEO2001 National Energy Modeling System, runs RSFRZN.D101800A, AEO2001.D101600A, RSHIGH.D101800A, and RSBEST.D101800A

Table F2. Key Results for Commercial Sector Technology Cases

Energy Consumption	1999	2005 2001 Technology	2005 Reference Case	2005 High Technology	2005 Best Available Technology	2010 2001 Technology	2010 Reference Case	2010 High Technology	2010 Best Available Technology
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.36	0.41	0.41	0.41	0.40	0.41	0.41	0.40	0.39
Residual Fuel	0.10	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11
Kerosene	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Motor Gasoline	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.59	0.66	0.66	0.66	0.65	0.67	0.67	0.66	0.65
Natural Gas	3.15	3.72	3.71	3.70	3.64	3.90	3.88	3.85	3.75
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Renewable Energy	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Electricity	3.70	4.36	4.35	4.30	4.05	4.93	4.89	4.77	4.26
Delivered Energy	**7.59**	**8.89**	**8.87**	**8.82**	**8.49**	**9.66**	**9.59**	**9.44**	**8.82**
Electricity Related Losses	8.01	9.16	9.14	9.05	8.52	9.81	9.71	9.49	8.48
Total	**15.61**	**18.04**	**18.00**	**17.86**	**17.02**	**19.46**	**19.30**	**18.92**	**17.29**
Delivered Energy Consumption per Square Foot (thousand Btu per square foot)	**120.9**	**125.4**	**125.2**	**124.4**	**119.9**	**127.5**	**126.6**	**124.6**	**116.4**

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all feedbacks are captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.

Source: Energy Information Administration, AEO2001 National Energy Modeling System, runs COMFRZN.D101800C, AEO2001.D101600A, COMHIGH.D101700A, and COMBEST.D101700A

Table F1. Key Results for Residential Sector Technology Cases (Continued)

2015				2020				Annual Growth 1999-2020			
2001 Technology	Reference Case	High Technology	Best Available Technology	2001 Technology	Reference Case	High Technology	Best Available Technology	2001 Technology	Reference Case	High Technology	Best Available Technology
0.80	0.77	0.69	0.61	0.80	0.75	0.65	0.56	-0.4%	-0.7%	-1.4%	-2.1%
0.07	0.07	0.06	0.06	0.07	0.07	0.06	0.05	-1.4%	-1.7%	-2.6%	-3.0%
0.42	0.40	0.37	0.33	0.42	0.39	0.36	0.31	-0.4%	-0.7%	-1.2%	-1.8%
1.30	1.24	1.12	1.00	1.29	1.21	1.06	0.92	-0.4%	-0.7%	-1.4%	-2.0%
6.05	5.99	5.54	4.21	6.39	6.30	5.73	4.05	1.3%	1.3%	0.8%	-0.9%
0.05	0.05	0.04	0.04	0.05	0.05	0.04	0.04	0.7%	0.5%	-0.6%	-0.6%
0.45	0.43	0.38	0.37	0.47	0.44	0.37	0.36	0.7%	0.4%	-0.3%	-0.6%
5.51	5.37	5.20	4.55	6.01	5.80	5.57	4.80	2.1%	1.9%	1.7%	1.0%
13.37	**13.08**	**12.28**	**10.17**	**14.20**	**13.81**	**12.77**	**10.16**	**1.4%**	**1.3%**	**0.9%**	**-0.2%**
10.46	10.19	9.87	8.64	10.92	10.55	10.12	8.73	1.2%	1.0%	0.8%	0.1%
23.83	**23.27**	**22.15**	**18.81**	**25.12**	**24.36**	**22.89**	**18.89**	**1.3%**	**1.2%**	**0.9%**	**-0.1%**
108.5	**106.2**	**99.7**	**82.6**	**109.7**	**106.7**	**98.6**	**78.5**	**0.3%**	**0.2%**	**-0.2%**	**-1.2%**

Table F2. Key Results for Commercial Sector Technology Cases (Continued)

2015				2020				Annual Growth 1999-2020			
2001 Technology	Reference Case	High Technology	Best Available Technology	2001 Technology	Reference Case	High Technology	Best Available Technology	2001 Technology	Reference Case	High Technology	Best Available Technology
0.41	0.40	0.39	0.38	0.40	0.39	0.38	0.37	0.5%	0.4%	0.3%	0.2%
0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.4%	0.4%	0.4%	0.4%
0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.6%	0.6%	0.6%	0.6%
0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	1.0%	1.0%	1.0%	1.0%
0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.5%	-0.5%	-0.5%	-0.5%
0.67	0.67	0.66	0.65	0.66	0.66	0.65	0.64	0.5%	0.5%	0.4%	0.3%
4.07	4.05	4.00	3.87	4.14	4.13	4.07	3.93	1.3%	1.3%	1.2%	1.1%
0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.7%	0.7%	0.7%	0.7%
0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.0%	0.0%	0.0%	0.0%
5.42	5.32	5.14	4.48	5.78	5.61	5.38	4.65	2.2%	2.0%	1.8%	1.1%
10.32	**10.19**	**9.96**	**9.15**	**10.74**	**10.55**	**10.25**	**9.37**	**1.7%**	**1.6%**	**1.4%**	**1.0%**
10.28	10.10	9.76	8.51	10.51	10.20	9.78	8.45	1.3%	1.2%	1.0%	0.3%
20.60	**20.29**	**19.72**	**17.66**	**21.25**	**20.75**	**20.03**	**17.82**	**1.5%**	**1.4%**	**1.2%**	**0.6%**
129.6	**128.0**	**125.1**	**115.0**	**131.1**	**128.8**	**125.1**	**114.4**	**0.4%**	**0.3%**	**0.2%**	**-0.3%**

Table F3. Key Results for Industrial Sector Technology Cases

Consumption	1999	2010			2015			2020		
		2001 Technology	Reference Case	High Technology	2001 Technology	Reference Case	High Technology	2001 Technology	Reference Case	High Technology
Energy Consumption (quadrillion Btu)										
Distillate Fuel	1.07	1.29	1.27	1.25	1.39	1.35	1.33	1.50	1.44	1.41
Liquefied Petroleum Gas	2.32	2.54	2.50	2.48	2.70	2.65	2.62	2.89	2.83	2.79
Petrochemical Feedstocks	1.29	1.55	1.53	1.52	1.63	1.61	1.59	1.73	1.70	1.67
Residual Fuel	0.22	0.27	0.25	0.24	0.29	0.26	0.24	0.32	0.27	0.25
Motor Gasoline	0.21	0.25	0.25	0.24	0.27	0.26	0.26	0.29	0.28	0.28
Other Petroleum	4.29	4.83	4.76	4.72	5.11	5.01	4.94	5.38	5.24	5.15
Petroleum Subtotal	9.39	10.73	10.55	10.45	11.40	11.14	10.98	12.11	11.77	11.55
Natural Gas	9.43	11.50	11.11	10.90	12.29	11.76	11.42	13.01	12.34	11.88
Metallurgical Coal[1]	0.81	0.84	0.76	0.67	0.85	0.74	0.61	0.85	0.72	0.55
Steam Coal	1.73	1.91	1.85	1.84	1.94	1.87	1.83	1.99	1.90	1.84
Coal Subtotal	2.54	2.75	2.62	2.51	2.79	2.61	2.44	2.84	2.62	2.39
Renewable Energy	2.15	2.60	2.64	2.89	2.79	2.86	3.25	2.97	3.08	3.64
Electricity	3.63	4.35	4.18	4.06	4.71	4.47	4.28	5.15	4.81	4.55
Delivered Energy	**27.15**	**31.93**	**31.10**	**30.81**	**33.98**	**32.84**	**32.37**	**36.09**	**34.63**	**34.01**
Electricity Related Losses	7.87	8.64	8.32	8.08	8.94	8.48	8.12	9.36	8.76	8.28
Total	**35.02**	**40.57**	**39.42**	**38.88**	**42.92**	**41.31**	**40.49**	**45.46**	**43.39**	**42.29**
Delivered Energy Use per Dollar of Output (thousand Btu per 1992 dollar)	**5.75**	**5.11**	**4.98**	**4.93**	**4.79**	**4.63**	**4.56**	**4.46**	**4.28**	**4.20**

[1]Includes net coal coke imports.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.

Source: Energy Information Administration, AEO2001 National Energy Modeling System runs INDFRZTECH.D101700A, AEO2001.D101600A, and INDHITECH.D101700A.

Table F4. Key Results for Transportation Sector Technology Cases

Consumption and Indicators	1999	2010			2015			2020		
		2001 Technology	Reference Case	High Technology	2001 Technology	Reference Case	High Technology	2001 Technology	Reference Case	High Technology
Energy Consumption (quadrillion Btu)										
Distillate Fuel	5.13	7.21	6.99	6.59	8.11	7.60	6.94	9.07	8.21	7.35
Jet Fuel	3.46	4.56	4.51	4.51	5.35	5.22	5.14	6.23	5.97	5.80
Motor Gasoline	15.92	19.49	19.04	17.87	21.13	20.23	18.13	22.67	21.32	18.36
Residual Fuel	0.74	0.87	0.85	0.85	0.88	0.86	0.85	0.89	0.87	0.85
Liquefied Petroleum Gas	0.02	0.04	0.04	0.09	0.05	0.05	0.11	0.06	0.06	0.14
Other Petroleum	0.26	0.31	0.31	0.31	0.33	0.33	0.33	0.35	0.35	0.35
Petroleum Subtotal	25.54	32.48	31.74	30.21	35.84	34.28	31.51	39.28	36.77	32.85
Pipeline Fuel Natural Gas	0.66	0.90	0.90	0.90	0.99	0.99	0.99	1.09	1.09	1.09
Compressed Natural Gas	0.02	0.10	0.09	0.14	0.14	0.13	0.19	0.17	0.16	0.23
Renewables (E85)	0.01	0.03	0.03	0.05	0.04	0.04	0.06	0.05	0.04	0.07
Methanol (M85)	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.01	0.00	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.06	0.13	0.12	0.09	0.17	0.15	0.11	0.19	0.17	0.12
Delivered Energy	**26.28**	**33.64**	**32.89**	**31.39**	**37.19**	**35.60**	**32.87**	**40.78**	**38.23**	**34.36**
Electricity Related Losses	0.13	0.25	0.23	0.18	0.31	0.28	0.21	0.35	0.30	0.22
Total	**26.41**	**33.89**	**33.12**	**31.57**	**37.50**	**35.87**	**33.08**	**41.13**	**38.54**	**34.59**
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[1]	24.2	25.3	27.1	31.9	25.3	27.6	33.8	25.3	28.0	35.0
New Car (miles per gallon)[1]	27.9	29.6	32.3	36.3	29.6	32.4	38.0	29.7	32.5	39.2
New Light Truck (miles per gallon)[1]	20.8	22.0	23.2	28.4	22.1	24.0	30.3	22.1	24.7	31.5
Light-Duty Fleet (miles per gallon)[2]	20.5	20.4	20.9	22.3	20.3	21.2	23.7	20.1	21.5	25.1
New Commercial Light Truck (MPG)[3]	20.1	20.9	22.0	26.8	20.8	22.8	28.4	20.8	23.4	29.5
Stock Commercial Light Truck (MPG)[3]	14.8	15.8	16.1	17.2	16.0	16.6	18.5	16.1	17.0	19.6
Aircraft Efficiency (seat miles per gallon)	51.7	55.4	56.1	56.2	56.6	58.2	59.1	57.5	60.3	62.2
Freight Truck Efficiency (miles per gallon)	6.0	6.3	6.4	6.7	6.3	6.7	7.1	6.4	6.9	7.5
Rail Efficiency (ton miles per thousand Btu)	2.8	2.8	3.1	3.3	2.8	3.3	3.5	2.8	3.4	3.8
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.3	2.7	2.7	2.3	2.8	3.0	2.3	3.0	3.2
Light-Duty Vehicles Less Than 8500 Pounds (vehicle miles traveled)	**2394**	**3064**	**3066**	**3074**	**3328**	**3334**	**3347**	**3568**	**3577**	**3596**

[1]Environmental Protection Agency rated miles per gallon.
[2]Combined car and light truck "on-the-road" estimate.
[3]Commercial trucks 8,500 to 10,000 pounds.
Btu = British thermal unit.
MPG = Miles per gallon.

Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.

Source: Energy Information Administration, AEO2001 National Energy Modeling System runs FRZ.D101700A, AEO2001.D101600A, and TEK.D101700A

Table F5. Key Results for Integrated Technology Cases

Consumption and Emissions	1999	2010			2015			2020		
		2001 Technology	Reference Case	High Technology	2001 Technology	Reference Case	High Technology	2001 Technology	Reference Case	High Technology
Consumption by Sector (quadrillion Btu)										
Residential	19.10	22.71	22.30	21.75	23.89	23.27	22.24	25.13	24.36	22.83
Commercial	15.61	19.53	19.30	19.16	20.66	20.29	19.80	21.28	20.75	19.95
Industrial	35.02	40.84	39.42	38.75	43.20	41.31	40.12	45.79	43.39	41.56
Transportation	26.41	33.93	33.12	31.58	37.54	35.87	33.07	41.12	38.54	34.61
Total	**96.14**	**117.00**	**114.14**	**111.24**	**125.28**	**120.75**	**115.23**	**133.31**	**127.04**	**118.94**
Consumption by Fuel (quadrillion Btu)										
Petroleum Products	38.03	45.52	44.41	42.60	49.52	47.50	44.24	53.68	50.59	45.96
Natural Gas	21.95	29.37	28.75	27.52	33.56	32.39	30.74	36.84	35.57	33.15
Coal	21.43	26.26	25.15	24.23	26.85	25.68	24.56	27.76	26.20	24.53
Nuclear Power	7.79	7.69	7.69	7.67	6.94	6.82	6.13	6.31	6.13	5.18
Renewable Energy	6.59	7.86	7.83	8.90	8.18	8.13	9.33	8.49	8.31	9.88
Other	0.34	0.31	0.31	0.31	0.23	0.23	0.23	0.23	0.23	0.23
Total	**96.14**	**117.00**	**114.14**	**111.24**	**125.28**	**120.75**	**115.23**	**133.31**	**127.04**	**118.94**
Energy Intensity (thousand Btu per 1996 dollar of GDP)	**10.84**	**9.24**	**9.02**	**8.78**	**8.57**	**8.25**	**7.87**	**8.09**	**7.70**	**7.19**
Carbon Dioxide Emissions by Sector (million metric tons carbon equivalent)										
Residential	289.3	355.3	345.9	330.9	377.9	366.2	347.3	402.0	388.1	360.0
Commercial	242.9	311.7	305.3	296.0	333.9	326.3	315.0	348.4	338.2	320.8
Industrial	480.4	555.5	529.4	508.6	588.5	555.2	526.3	626.0	583.6	540.4
Transportation	498.2	643.8	628.5	598.7	712.1	680.5	626.4	780.1	730.8	653.8
Total	**1,510.8**	**1,866.3**	**1,809.1**	**1,734.3**	**2,012.5**	**1,928.1**	**1,815.1**	**2,156.6**	**2,040.7**	**1,875.0**
Carbon Dioxide Emissions by End-Use Fuel (million metric tons carbon equivalent)										
Petroleum	629.7	769.8	750.6	717.1	840.3	803.7	743.1	912.0	856.1	769.8
Natural Gas	266.0	315.9	309.8	302.2	335.6	327.5	316.7	350.7	343.3	330.0
Coal	58.8	73.0	69.5	66.4	74.2	69.4	64.8	75.7	69.6	63.3
Other	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	556.3	707.5	679.1	648.5	762.3	727.5	690.4	818.0	771.5	711.8
Total	**1,510.8**	**1,866.3**	**1,809.1**	**1,734.3**	**2,012.5**	**1,928.1**	**1,815.1**	**2,156.6**	**2,040.7**	**1,875.0**
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)										
Petroleum	20.0	4.0	3.4	3.2	3.8	3.4	3.3	5.3	3.7	2.8
Natural Gas	45.8	104.7	101.8	91.8	145.2	136.5	123.4	176.9	166.3	144.3
Coal	490.5	598.9	574.0	553.5	613.4	587.6	563.7	635.8	601.5	564.6
Total	**556.3**	**707.5**	**679.1**	**648.5**	**762.3**	**727.5**	**690.4**	**818.0**	**771.5**	**711.8**
Carbon Dioxide Emissions by Primary Fuel (million metric tons carbon equivalent)										
Petroleum	649.7	773.8	754.0	720.3	844.1	807.1	746.3	917.3	859.9	772.7
Natural Gas	311.8	420.5	411.5	393.9	480.8	463.9	440.2	527.7	509.6	474.3
Coal	549.3	671.9	643.5	619.9	687.6	657.0	628.5	711.5	671.1	627.9
Other	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**1,510.8**	**1,866.3**	**1,809.1**	**1,734.3**	**2,012.5**	**1,928.1**	**1,815.1**	**2,156.6**	**2,040.7**	**1,875.0**

Btu = British thermal unit.
GDP = Gross domestic product.
Note: Includes end-use, fossil electricity, and renewable technology assumptions. Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs LTRKITEN.D101800A, AEO2001.D101600A, and HTRKITEN.D101800A.

Table F6. Key Results for Nuclear Generation Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capability, Generation, Emissions, and Fuel Prices	1999	Projections							
		2010				2020			
		Reference	Low Nuclear	High Nuclear	Nuclear Penetration	Reference	Low Nuclear	High Nuclear	Nuclear Penetration
Capability									
Coal Steam	306.0	315.0	314.5	314.5	314.7	316.4	316.6	314.1	315.2
Other Fossil Steam	138.2	120.4	120.2	120.3	120.2	116.1	116.0	116.1	116.0
Combined Cycle	20.2	126.0	127.3	124.0	125.8	229.1	241.9	217.9	230.8
Combustion Turbine/Diesel	75.2	164.1	165.7	165.2	163.7	210.7	215.0	210.1	209.3
Nuclear Power	97.4	93.7	89.9	96.9	93.7	71.6	55.3	88.5	72.0
Pumped Storage	19.3	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
Fuel Cells	0.0	0.1	0.1	0.1	0.1	0.3	0.3	0.3	0.3
Renewable Sources	88.1	95.4	95.4	95.4	95.4	97.0	97.0	97.0	97.0
Distributed Generation	0.0	6.0	5.9	6.0	6.0	12.7	12.8	13.1	12.9
Cogenerators/Other Generators[1]	52.6	64.5	64.5	64.5	64.5	72.2	72.2	72.2	72.2
Total	**797.2**	**1004.8**	**1003.1**	**1006.4**	**1003.7**	**1145.6**	**1146.6**	**1148.8**	**1145.2**
Cumulative Additions									
Coal Steam	0.0	18.5	18.3	18.2	18.5	21.8	22.4	19.7	20.9
Other Fossil Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combined Cycle	0.0	105.8	107.1	103.8	105.5	208.9	221.6	197.7	210.6
Combustion Turbine/Diesel	0.0	93.8	95.2	94.7	93.2	141.2	145.4	140.4	139.6
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.1	0.1	0.1	0.1	0.3	0.3	0.3	0.3
Renewable Sources	0.0	6.9	6.9	6.9	6.9	8.5	8.5	8.5	8.5
Distributed Generation	0.0	6.0	5.9	6.0	6.0	12.7	12.8	13.1	12.9
Cogenerators/Other Generators[1]	0.0	11.9	11.9	11.9	11.9	19.6	19.6	19.6	19.6
Total	**0.0**	**243.2**	**245.5**	**241.7**	**242.2**	**413.0**	**430.7**	**399.3**	**412.8**
Cumulative Retirements	**0.0**	**40.3**	**44.7**	**37.5**	**40.8**	**69.4**	**86.3**	**52.8**	**69.8**
Generation by Fuel (billion kilowatthours)									
Coal	1833	2196	2200	2189	2195	2298	2321	2266	2292
Petroleum	100	17	17	17	17	19	21	17	19
Natural Gas	371	900	911	886	900	1587	1686	1506	1589
Nuclear Power	730	720	706	741	720	574	450	688	578
Pumped Power	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources	353	390	389	390	390	396	396	396	396
Distributed Generation	0	3	3	3	3	6	6	6	6
Cogenerators/Other Generators[1]	307	375	375	375	375	427	427	427	427
Total	**3693**	**4599**	**4599**	**4599**	**4599**	**5305**	**5306**	**5305**	**5305**
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)[2]									
Petroleum	20.0	3.4	3.5	3.4	3.5	3.7	4.2	3.5	3.8
Natural Gas	45.8	101.8	103.1	100.5	102.0	166.3	175.4	158.8	166.3
Coal	490.5	574.0	575.1	572.1	573.8	601.5	608.0	593.6	600.5
Total	**556.3**	**679.1**	**681.6**	**676.0**	**679.3**	**771.5**	**787.6**	**755.9**	**770.5**
Prices to Electric Generators (1999 dollars per million Btu)									
Petroleum	2.50	4.11	4.10	4.11	4.10	4.35	4.25	4.42	4.34
Natural Gas	2.55	3.03	3.05	3.02	3.03	3.59	3.89	3.39	3.59
Coal	1.21	1.05	1.05	1.05	1.05	0.98	0.99	0.98	0.98

[1] Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.

[2] Excludes cogenerators and other generators

Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators to be consistent with electric utility capability estimates. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured.

Source: Energy Information Administration, AEO2001 National Energy Modeling System runs AEO2001.D101600A, LNUC01.D101700C, HNUC01.D101700B, and ADVNUC1.D101700A.

Table F7. Key Results for Electricity Demand Case

Net Summer Capability, Generation, Consumption, Emissions, and Prices	1999	2005		2010		2020		Annual Growth 1999-2020	
		Reference Case	High Demand	Reference Case	High Demand	Reference Case	High Demand	Reference Case	High Demand
Electricity Sales (billion kilowatthours)	**3309**	**3,761**	**3,892**	**4,147**	**4,442**	**4,804**	**5,514**	**1.8%**	**2.5%**
Electricity Prices (1999 cents per kilowatthour)	**6.7**	**6.2**	**6.3**	**5.9**	**6.0**	**6.0**	**6.4**	**-0.5%**	**-0.2%**
Capability (gigawatts)									
Coal Steam	306.0	300.9	301.0	315.0	332.0	316.4	385.0	0.2%	1.1%
Other Fossil Steam	138.2	128.5	128.3	120.4	119.8	116.1	117.6	-0.8%	-0.8%
Combined Cycle	20.2	49.5	51.4	126.0	146.6	229.1	275.5	12.2%	13.2%
Combustion Turbine/Diesel	75.2	130.6	139.9	164.1	193.3	210.7	258.4	5.0%	6.1%
Nuclear Power	97.4	97.5	97.5	93.7	93.7	71.6	73.8	-1.5%	-1.3%
Fuel Cells	0.0	0.0	0.0	0.1	0.1	0.3	0.3	34.2%	34.2%
Renewable Sources/Pumped Storage	107.4	111.6	111.8	114.9	115.2	116.5	117.0	0.4%	0.4%
Distributed Generation	0.0	2.0	2.2	6.0	7.8	12.7	20.0	N/A	N/A
Cogenerators/Other Generators[1]	52.6	60.3	60.3	64.5	64.5	72.2	72.2	1.5%	1.5%
Total	**797.2**	**880.9**	**892.4**	**1,004.8**	**1,073.1**	**1,145.6**	**1,319.9**	**1.7%**	**2.4%**
Cumulative Additions (gigawatts)									
Coal Steam	0.0	2.4	2.8	18.5	35.8	21.8	90.7	N/A	N/A
Other Fossil Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	N/A	N/A
Combined Cycle	0.0	29.3	31.2	105.8	126.4	208.9	255.3	N/A	N/A
Combustion Turbine/Diesel	0.0	59.0	68.1	93.8	122.6	141.2	188.7	N/A	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A	N/A
Fuel Cells	0.0	0.0	0.0	0.1	0.1	0.3	0.3	N/A	N/A
Renewable Sources/Pumped Storage	0.0	3.7	3.8	6.9	7.2	8.5	8.9	N/A	N/A
Distributed Generation	0.0	2.0	2.2	6.0	7.8	12.7	20.0	N/A	N/A
Cogenerators/Other Generators[1]	0.0	7.7	7.7	11.9	11.9	19.6	19.6	N/A	N/A
Total	**0.0**	**104.1**	**115.9**	**243.2**	**311.8**	**413.0**	**583.6**	**N/A**	**N/A**
Generation by Fuel (billion kilowatthours)									
Coal	1833	2,085	2,128	2,196	2,372	2,298	2,833	1.1%	2.1%
Petroleum	100	32	43	17	22	19	31	-7.7%	-5.4%
Natural Gas	371	584	670	900	1,032	1,587	1,767	7.2%	7.7%
Nuclear Power	730	740	740	720	720	574	591	-1.1%	-1.0%
Renewable Sources/Pumped Storage	352	369	369	389	391	395	398	0.5%	0.6%
Distributed Generation	0	1	1	3	3	6	9	N/A	N/A
Cogenerators/Other Generators[1]	307	352	352	375	374	427	426	1.6%	1.6%
Total	**3693**	**4,163**	**4,304**	**4,599**	**4,914**	**5,305**	**6,054**	**1.7%**	**2.4%**
Fossil Fuel Consumption by Electric Generators (quadrillion Btu)[2]									
Petroleum	1.08	0.32	0.44	0.16	0.21	0.18	0.29	-8.2%	-6.0%
Natural Gas	3.85	5.45	6.27	7.07	8.01	11.55	12.63	5.4%	5.8%
Coal	18.78	21.40	21.89	22.41	24.03	23.46	27.55	1.1%	1.8%
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)[2]									
Petroleum	20.0	6.7	9.3	3.4	4.4	3.7	6.1	-7.7%	-5.5%
Natural Gas	45.8	78.5	90.4	101.8	115.3	166.3	181.8	6.3%	6.8%
Coal	490.5	547.9	560.4	574.0	615.6	601.5	707.0	1.0%	1.8%
Total	**556.3**	**633.1**	**660.0**	**679.1**	**735.3**	**771.5**	**894.9**	**1.6%**	**2.3%**
Prices to Electric Generators (1999 dollars per million Btu)									
Petroleum	2.50	3.70	3.64	4.11	3.98	4.35	4.33	2.7%	2.6%
Natural Gas	2.55	2.88	3.11	3.03	3.35	3.59	4.29	1.6%	2.5%
Coal	1.21	1.13	1.14	1.05	1.06	0.98	0.99	-1.0%	-0.9%

[1] Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2] Excludes cogenerators and other generators
Btu = British thermal unit.
N/A = not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Other includes non-coal fossil steam, pumped storage, methane, propane and blast furnace gas. Side case was run without the fully integrated modeling system, so not all potential feedbacks were captured.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs AEO2001.D101600A, and HDEM01.D101700A.

Table F8. Key Results for Electricity Sector Fossil Technology Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capability, Generation Consumption, and Emissions	1999	2005			2010			2020		
		Low Fossil	Reference Case	High Fossil	Low Fossil	Reference Case	High Fossil	Low Fossil	Reference Case	High Fossil
Capability										
Pulverized Coal	305.5	299.5	299.8	299.6	316.5	311.3	302.7	318.7	310.4	298.9
Coal Gasification Combined-Cycle	0.5	0.8	1.1	1.4	2.2	3.7	17.5	2.2	6.0	27.3
Conventional Natural Gas Combined-Cycle	20.2	44.6	36.3	32.3	108.2	69.0	39.1	220.2	87.2	39.1
Advanced Natural Gas Combined-Cycle	0.0	5.0	13.2	15.8	12.6	57.0	71.7	12.6	141.8	186.3
Conventional Combustion Turbine	75.2	131.5	127.0	123.6	165.7	152.3	148.5	198.5	184.4	171.3
Advanced Combustion Turbine	0.0	1.1	3.6	9.2	3.1	11.8	26.8	3.1	26.3	53.8
Fuel Cells	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.3	0.3	0.3
Nuclear	97.4	97.5	97.5	97.5	93.7	93.7	93.0	73.1	71.6	59.7
Oil and Gas Steam	138.2	128.3	128.5	128.3	119.8	120.4	120.2	115.6	116.1	115.2
Renewable Sources/Pumped Storage	107.4	111.6	111.6	111.5	115.3	114.9	114.4	117.4	116.5	115.9
Distributed Generation	0.0	2.3	2.0	1.7	7.0	6.0	4.9	13.3	12.7	10.2
Cogenerators/Other Generators[1]	52.6	60.3	60.3	60.3	64.5	64.5	64.5	72.2	72.2	72.2
Total	**797.2**	**882.6**	**880.9**	**881.3**	**1008.8**	**1004.8**	**1003.7**	**1147.1**	**1145.6**	**1150.1**
Cumulative Additions										
Pulverized Coal	0.0	1.9	1.9	1.9	20.8	15.3	7.0	24.8	16.4	7.0
Coal Gasification Combined-Cycle	0.0	0.3	0.5	0.9	1.7	3.2	17.0	1.7	5.5	26.7
Conventional Natural Gas Combined-Cycle	0.0	24.3	16.0	12.1	88.0	48.8	18.9	200.0	67.0	18.9
Advanced Natural Gas Combined-Cycle	0.0	5.0	13.2	15.8	12.6	57.0	71.7	12.6	141.8	186.3
Conventional Combustion Turbine	0.0	59.7	55.4	51.9	95.3	82.1	78.1	129.0	114.9	101.6
Advanced Combustion Turbine	0.0	1.1	3.6	9.2	3.1	11.8	26.8	3.1	26.3	53.8
Fuel Cells	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.3	0.3	0.3
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil and Gas Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Renewable Sources	0.0	3.7	3.7	3.6	7.3	6.9	6.4	9.4	8.5	7.9
Distributed Generation	0.0	2.3	2.0	1.7	7.0	6.0	4.9	13.3	12.7	10.2
Cogenerators/Other Generators[1]	0.0	7.7	7.7	7.7	11.9	11.9	11.9	19.6	19.6	19.6
Total	**0.0**	**106.1**	**104.1**	**104.8**	**247.8**	**243.2**	**242.9**	**413.7**	**413.0**	**432.3**
Cumulative Retirements	**0.0**	**25.6**	**25.1**	**25.6**	**41.2**	**40.3**	**41.6**	**68.9**	**69.4**	**84.5**
Generation by Fuel (billion kilowatthours)										
Coal	1833	2088	2085	2082	2242	2196	2199	2346	2298	2305
Petroleum	100	32	32	31	18	17	17	20	19	15
Natural Gas	371	581	584	590	850	900	905	1519	1587	1672
Nuclear Power	730	740	740	740	720	720	718	586	574	491
Renewable Sources/Pumped Storage	353	369	369	367	392	389	385	401	395	391
Distributed Generation	0	1	1	1	3	3	2	6	6	5
Cogenerators/Other Generators[1]	307	352	352	351	375	375	374	427	427	426
Total	**3693**	**4163**	**4163**	**4163**	**4600**	**4599**	**4600**	**5306**	**5305**	**5305**
Fuel Consumption by Electric Generators (quadrillion Btu)[2]										
Coal	18.78	21.45	21.40	21.36	22.89	22.41	22.16	23.99	23.46	22.96
Petroleum	1.08	0.32	0.32	0.31	0.17	0.16	0.16	0.19	0.18	0.15
Natural Gas	3.85	5.52	5.45	5.39	7.03	7.07	6.79	11.73	11.55	10.53
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.69	7.67	6.26	6.13	5.25
Renewable Sources	3.94	4.19	4.19	4.17	4.68	4.64	4.48	4.84	4.66	4.55
Total	**35.44**	**39.38**	**39.26**	**39.13**	**42.47**	**41.98**	**41.26**	**47.01**	**45.98**	**43.43**
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)[2]										
Petroleum	20.0	6.8	6.7	6.6	3.5	3.4	3.3	3.9	3.7	3.0
Natural Gas	45.8	79.4	78.5	77.6	101.3	101.8	97.8	168.9	166.3	151.6
Coal	490.5	549.0	547.9	546.9	586.3	574.0	567.6	615.4	601.5	588.5
Total	**556.3**	**635.2**	**633.1**	**631.0**	**691.0**	**679.1**	**668.7**	**788.3**	**771.5**	**743.2**

[1] Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2] Excludes cogenerators and other generators.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators to be consistent with electric utility capability estimates. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs LFOSS01.D101700A, AEO2001.D101600A, and HFOSS01.D101800B.

Table F9. Key Results for High Renewable Energy Case

Capacity, Generation, and Emissions	1999	2010 Reference	2010 High Renewables	2020 Reference	2020 High Renewables
Renewable Capability (Gigawatts)					
Net Summer Capability					
Electric Generators[1]					
Conventional Hydropower	78.14	78.74	78.74	78.74	78.74
Geothermal[2]	2.87	4.34	8.81	4.41	9.56
Municipal Solid Waste[3]	2.59	4.20	4.49	4.72	5.02
Wood and Other Biomass[4]	1.52	2.04	2.04	2.37	3.22
Solar Thermal	0.33	0.40	0.40	0.48	0.48
Solar Photovoltaic	0.01	0.21	0.21	0.54	0.54
Wind	2.60	5.51	7.13	5.78	18.97
Total	**88.07**	**95.44**	**101.81**	**97.04**	**116.52**
Cogenerators[5]					
Municipal Solid Waste	0.70	0.70	0.70	0.70	0.70
Wood and Other Biomass	4.65	6.06	6.06	7.54	7.54
Total	**5.35**	**6.76**	**6.76**	**8.23**	**8.23**
Other End-Use Generators[6]					
Conventional Hydropower	0.99	0.99	0.99	0.99	0.99
Geothermal	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.01	0.35	0.35	0.35	0.89
Total	**1.00**	**1.34**	**1.34**	**1.34**	**1.88**
Generation (billion kilowatthours)					
Electric Generators					
Coal	1833	2196	2176	2298	2268
Petroleum	100	17	17	19	18
Natural Gas	371	900	877	1587	1532
Total Fossil	**2304**	**3112**	**3070**	**3903**	**3818**
Conventional Hydropower	307.43	298.99	298.99	297.94	297.95
Geothermal	13.07	25.27	60.48	25.83	66.38
Municipal Solid Waste[3]	18.05	30.00	32.29	33.96	36.37
Wood and Other Biomass[4]	9.49	21.59	23.63	22.15	22.93
Dedicated Plants	7.56	10.88	10.88	13.35	18.97
Cofiring	1.93	10.71	12.75	8.80	3.95
Solar Thermal	0.89	1.11	1.11	1.37	1.37
Solar Photovoltaic	0.03	0.51	0.51	1.36	1.36
Wind	4.46	12.33	18.44	13.10	64.17
Total Renewable	**353.42**	**389.80**	**435.45**	**395.71**	**490.52**
Cogenerators[5]					
Coal	47	52	52	52	52
Petroleum	9	10	10	10	10
Natural Gas	206	257	256	299	298
Total Fossil	**262**	**319**	**318**	**361**	**360**
Municipal Solid Waste	4.03	4.03	4.03	4.03	4.03
Wood and Other Biomass	27.08	35.01	35.01	43.52	43.52
Total Renewables	**31.11**	**39.03**	**39.03**	**47.55**	**47.55**
Other End-Use Generators[6]					
Conventional Hydropower[7]	4.57	4.43	4.43	4.41	4.41
Geothermal	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.75	0.76	0.75	1.91
Total	**4.59**	**5.18**	**5.19**	**5.17**	**6.32**
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)[8]					
Petroleum	20.0	3.4	3.3	3.7	3.6
Natural Gas	45.8	101.8	99.2	166.3	159.6
Coal	490.5	574.0	569.3	601.5	594.5
Total	**556.3**	**679.1**	**671.8**	**771.5**	**757.6**

[1]Includes grid-connected utilities and nonutilities other than cogenerators. These nonutility facilities include small power producers and exempt wholesale generators.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Cogenerators produce electricity and other useful thermal energy.
[6]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[7]Represents own-use industrial hydroelectric power.
[8]Excludes cogenerators and other generators.

Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Side case was run without the fully integrated modeling system, so not all potential feedbacks were captured.

Source: Energy Information Administration, AEO2001 National Energy Modeling System runs AEO2001.D101600A, and HIRENEW.D101800A.

Table F10. Total Energy Supply and Disposition Summary, Oil and Gas Technological Progress Cases

(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2010			2015			2020		
		Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress
Production										
Crude Oil and Lease Condensate	12.45	10.31	10.90	11.42	9.95	10.76	11.44	9.79	10.69	11.41
Natural Gas Plant Liquids	2.62	3.27	3.33	3.37	3.61	3.73	3.80	3.83	4.10	4.25
Dry Natural Gas	19.16	23.35	23.74	24.01	26.11	26.92	27.47	27.82	29.79	30.92
Coal	23.09	26.36	26.06	25.88	26.85	26.42	26.06	27.60	26.95	26.28
Nuclear Power	7.79	7.69	7.69	7.69	6.82	6.82	6.82	6.20	6.13	6.05
Renewable Energy[1]	6.58	7.77	7.82	7.77	8.06	8.12	8.06	8.30	8.31	8.33
Other[2]	1.65	0.30	0.30	0.35	0.32	0.32	0.32	0.33	0.34	0.33
Total	**73.35**	**79.05**	**79.85**	**80.48**	**81.71**	**83.10**	**83.97**	**83.87**	**86.30**	**87.57**
Imports										
Crude Oil[3]	18.96	25.87	25.15	24.59	26.71	25.94	25.26	27.32	26.44	25.69
Petroleum Products[4]	4.14	6.50	6.49	6.44	8.78	8.46	8.32	11.67	10.69	10.46
Natural Gas	3.63	5.59	5.61	5.61	6.10	6.17	6.22	6.33	6.58	6.69
Other Imports[5]	0.62	0.89	0.89	0.89	0.88	0.88	0.88	0.94	0.94	0.94
Total	**27.35**	**38.85**	**38.14**	**37.53**	**42.46**	**41.44**	**40.67**	**46.26**	**44.64**	**43.77**
Exports										
Petroleum[6]	1.98	1.79	1.78	1.79	1.83	1.83	1.85	1.92	1.91	1.93
Natural Gas	0.17	0.43	0.43	0.43	0.53	0.53	0.53	0.63	0.63	0.63
Coal	1.48	1.45	1.46	1.45	1.35	1.35	1.35	1.41	1.41	1.41
Total	**3.62**	**3.68**	**3.67**	**3.67**	**3.71**	**3.72**	**3.73**	**3.96**	**3.95**	**3.97**
Consumption										
Petroleum Products[8]	38.03	44.48	44.41	44.38	47.63	47.50	47.45	51.20	50.59	50.47
Natural Gas	21.95	28.34	28.75	29.02	31.52	32.39	33.00	33.36	35.57	36.82
Coal	21.43	25.44	25.15	24.96	26.12	25.68	25.30	26.84	26.20	25.53
Nuclear Power	7.79	7.69	7.69	7.69	6.82	6.82	6.82	6.20	6.13	6.05
Renewable Energy[1]	6.59	7.78	7.83	7.77	8.07	8.13	8.06	8.31	8.31	8.34
Other[9]	0.34	0.31	0.31	0.31	0.23	0.23	0.23	0.23	0.23	0.23
Total	**96.14**	**114.05**	**114.14**	**114.13**	**120.38**	**120.75**	**120.87**	**126.15**	**127.03**	**127.43**
Net Imports - Petroleum	**21.12**	**30.57**	**29.86**	**29.24**	**33.65**	**32.57**	**31.73**	**37.07**	**35.22**	**34.21**
Prices (1999 dollars per unit)										
World Oil Price (dollars per barrel)[10]	17.35	21.37	21.37	21.37	21.89	21.89	21.89	22.41	22.41	22.41
Gas Wellhead Price (dollars per Mcf)[11]	2.08	2.92	2.69	2.54	3.32	2.83	2.54	4.23	3.13	2.50
Coal Minemouth Price (dollars per ton)	16.98	13.95	13.83	13.73	13.18	13.38	13.26	12.71	12.70	12.77
Average Electric Price (cents per Kwh)	6.7	6.0	5.9	5.8	6.1	5.9	5.8	6.5	6.0	5.7
Carbon Dioxide Emissions (million metric tons carbon equivalent)	**1510.8**	**1812.0**	**1809.1**	**1807.5**	**1929.8**	**1928.1**	**1926.6**	**2037.7**	**2040.6**	**2039.1**

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Mcf = Thousand cubic feet.
Kwh = Kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 petroleum values: EIA, *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). Other 1999 values: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000) **Projections:** EIA, AEO2001 National Energy Modeling System runs OGLTEC.D101600A, AEO2001.D101600A, and OGHTEC.D101600A.

Table F11. Natural Gas Supply and Disposition, Oil and Gas Technological Progress Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2010			2015			2020		
		Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress
Lower 48 Average Wellhead Price (1999 dollars per thousand cubic feet)	**2.08**	**2.92**	**2.69**	**2.54**	**3.32**	**2.83**	**2.54**	**4.23**	**3.13**	**2.50**
Dry Gas Production[1]										
U.S. Total	**18.67**	**22.75**	**23.14**	**23.40**	**25.44**	**26.24**	**26.78**	**27.11**	**29.04**	**30.14**
Lower 48 Onshore	12.83	15.96	16.29	16.45	17.96	19.04	19.91	19.34	21.26	23.06
Associated-Dissolved	1.80	1.32	1.33	1.34	1.28	1.32	1.35	1.35	1.38	1.43
Non-Associated	11.03	14.64	14.96	15.11	16.67	17.72	18.55	17.99	19.88	21.63
Conventional	6.64	8.27	8.30	8.48	9.42	10.37	10.73	10.31	11.38	11.98
Unconventional	4.39	6.38	6.66	6.63	7.25	7.36	7.82	7.68	8.51	9.66
Lower 48 Offshore	5.43	6.29	6.34	6.45	6.95	6.66	6.33	7.21	7.21	6.51
Associated-Dissolved	0.93	1.05	1.08	1.10	1.00	1.04	1.06	0.98	1.01	1.03
Non-Associated	4.50	5.24	5.26	5.35	5.95	5.63	5.27	6.23	6.19	5.47
Alaska	0.42	0.50	0.50	0.50	0.54	0.54	0.54	0.57	0.57	0.57
Supplemental Natural Gas[2]	**0.10**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**
Net Imports	**3.38**	**5.04**	**5.06**	**5.06**	**5.44**	**5.50**	**5.56**	**5.56**	**5.80**	**5.91**
Total Supply	**22.15**	**27.85**	**28.25**	**28.52**	**30.93**	**31.80**	**32.39**	**32.73**	**34.90**	**36.10**
Consumption by Sector										
Residential	4.72	5.49	5.54	5.58	5.72	5.83	5.90	5.90	6.14	6.29
Commercial	3.07	3.74	3.78	3.81	3.86	3.94	3.99	3.83	4.02	4.13
Industrial[3]	7.95	9.28	9.33	9.37	9.61	9.76	9.84	9.79	10.18	10.33
Electric Generators[4]	3.78	6.71	6.94	7.08	8.86	9.30	9.65	10.15	11.34	12.05
Lease and Plant Fuel[5]	1.23	1.47	1.49	1.50	1.64	1.68	1.71	1.75	1.84	1.89
Pipeline Fuel	0.64	0.86	0.87	0.89	0.94	0.97	0.99	1.00	1.06	1.10
Transportation[6]	0.02	0.09	0.09	0.09	0.13	0.13	0.13	0.15	0.15	0.16
Total	**21.41**	**27.65**	**28.05**	**28.31**	**30.76**	**31.61**	**32.21**	**32.57**	**34.73**	**35.95**
Discrepancy[7]	**0.74**	**0.20**	**0.21**	**0.21**	**0.18**	**0.18**	**0.18**	**0.17**	**0.17**	**0.15**
Lower 48 End of Year Reserves	**157.41**	**165.16**	**174.82**	**181.81**	**169.68**	**183.82**	**205.02**	**166.49**	**190.07**	**223.21**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 1999 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 transportation sector consumption: Energy Information Administration (EIA), AEO2001 National Energy Modeling System runs OGLTEC.D101600A, AEO2001.D101600A, and OGHTEC.D101600A. 1999 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). Other 1999 consumption: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO2001 National Energy Modeling System runs OGLTEC.D101600A, AEO2001.D101600A, and OGHTEC.D101600A. **Other 1999 values and projections:** EIA, AEO2001 National Energy Modeling System runs OGLTEC.D101600A, AEO2001.D101600A, and OGHTEC.D101600A.

Table F12. Crude Oil Supply and Disposition, Oil and Gas Technological Progress Cases
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2010			2015			2020		
		Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress
World Oil Price										
(1999 dollars per barrel)	**17.35**	**21.37**	**21.37**	**21.37**	**21.89**	**21.89**	**21.89**	**22.41**	**22.41**	**22.41**
Production[1]										
U.S. Total	**5.88**	**4.87**	**5.15**	**5.40**	**4.70**	**5.08**	**5.41**	**4.63**	**5.05**	**5.39**
Lower 48 Onshore	3.27	2.37	2.46	2.54	2.34	2.52	2.70	2.42	2.64	2.85
Conventional	2.59	1.77	1.79	1.82	1.72	1.78	1.86	1.83	1.92	2.04
Enhanced Oil Recovery	0.68	0.60	0.66	0.72	0.62	0.74	0.84	0.59	0.72	0.81
Lower 48 Offshore	1.56	1.89	2.05	2.18	1.71	1.86	1.96	1.61	1.77	1.85
Alaska	1.05	0.61	0.64	0.68	0.66	0.70	0.75	0.59	0.64	0.69
Net Crude Imports	**8.61**	**11.89**	**11.54**	**11.28**	**12.28**	**11.91**	**11.58**	**12.57**	**12.14**	**11.78**
Other Crude Supply	**0.31**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Total Crude Supply	**14.80**	**16.76**	**16.69**	**16.67**	**16.98**	**16.99**	**16.99**	**17.19**	**17.19**	**17.17**
Natural Gas Plant Liquids	**1.85**	**2.31**	**2.35**	**2.37**	**2.55**	**2.63**	**2.68**	**2.70**	**2.89**	**3.00**
Other Inputs[2]	**0.60**	**0.20**	**0.20**	**0.22**	**0.21**	**0.21**	**0.22**	**0.22**	**0.23**	**0.23**
Refinery Processing Gain[3]	**0.89**	**1.05**	**1.02**	**1.01**	**1.08**	**1.06**	**1.04**	**1.13**	**1.10**	**1.08**
Net Product Imports[4]	**1.30**	**2.36**	**2.38**	**2.36**	**3.46**	**3.33**	**3.27**	**4.83**	**4.37**	**4.27**
Total Primary Supply[5]	**19.44**	**22.68**	**22.64**	**22.63**	**24.28**	**24.21**	**24.19**	**26.08**	**25.79**	**25.74**
Refined Petroleum Products Supplied										
Residential and Commercial	1.10	1.07	1.06	1.06	1.04	1.04	1.04	1.02	1.02	1.02
Industrial[6]	5.16	5.60	5.58	5.57	5.94	5.89	5.87	6.36	6.23	6.19
Transportation	12.86	15.99	15.98	15.98	17.26	17.26	17.26	18.49	18.50	18.50
Electric Generators[7]	0.38	0.08	0.07	0.07	0.09	0.07	0.07	0.24	0.08	0.06
Total	**19.50**	**22.73**	**22.70**	**22.68**	**24.33**	**24.26**	**24.24**	**26.12**	**25.83**	**25.77**
Discrepancy[8]	**-0.07**	**-0.06**	**-0.06**	**-0.06**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.04**	**-0.04**
Lower 48 End of Year Reserves										
(billion barrels)[1]	**18.33**	**13.28**	**13.92**	**14.53**	**12.48**	**13.50**	**14.40**	**12.32**	**13.48**	**14.41**

[1]Includes lease condensate.
[2]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, and other hydrocarbons.
[3]Represents volumetric gain in refinery distillation and cracking processes.
[4]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[5]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net petroleum imports.
[6]Includes consumption by cogenerators.
[7]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[8]Balancing item. Includes unaccounted for supply, losses and gains.

Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.

Sources: 1999 product supplied data from Table A2. Other 1999 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs OGLTEC.D101600A, AEO2001.D101600A, and OGHTEC.D101600A.

Table F13. Petroleum and Natural Gas Supply and Disposition, Oil and Gas Resource Cases

Supply, Disposition, and Prices	1999	Projections								
		2010			2015			2020		
		Low Resource	Reference	High Resource	Low Resource	Reference	High Resource	Low Resource	Reference	High Resource
Crude Oil										
World Oil Price (1999 dollars per barrel)	**17.35**	**21.37**	**21.37**	**21.37**	**21.89**	**21.89**	**21.89**	**22.41**	**22.41**	**22.41**
Petroleum Supply and Disposition (million barrels per day)										
Crude Oil Production[1]	5.88	4.86	5.15	5.41	4.78	5.08	5.31	4.58	5.05	5.45
Onshore	3.27	2.32	2.46	2.58	2.29	2.52	2.70	2.38	2.64	2.97
Offshore	1.56	1.94	2.05	2.16	1.83	1.86	1.87	1.64	1.77	1.79
Alaska	1.05	0.60	0.64	0.67	0.66	0.70	0.74	0.57	0.64	0.70
Net Crude Oil Imports	8.61	11.91	11.54	11.24	12.21	11.91	11.68	12.70	12.14	11.72
Natural Gas Plant Liquids	1.85	2.22	2.35	2.42	2.43	2.63	2.72	2.45	2.89	3.02
Net Petroleum Product Imports[2]	1.30	2.48	2.38	2.35	3.60	3.33	3.23	5.32	4.37	4.24
Other Petroleum Supply[3]	1.79	1.26	1.22	1.21	1.32	1.27	1.25	1.40	1.33	1.30
Total Primary Supply	**19.44**	**22.73**	**22.64**	**22.63**	**24.33**	**24.21**	**24.19**	**26.44**	**25.79**	**25.74**
Refined Petroleum Products Supplied	**19.50**	**22.79**	**22.70**	**22.68**	**24.38**	**24.26**	**24.23**	**26.49**	**25.83**	**25.77**
Discrepancy[4]	**-0.07**	**-0.06**	**-0.06**	**-0.05**	**-0.05**	**-0.05**	**-0.04**	**-0.05**	**-0.04**	**-0.03**
Lower 48 End of Year Reserves (billion barrels)[1]	**18.33**	**13.37**	**13.92**	**14.51**	**12.77**	**13.50**	**14.01**	**12.13**	**13.48**	**14.46**
Natural Gas										
Lower 48 Average Wellhead Price (1999 dollars per thousand cubic feet)	**2.08**	**3.16**	**2.69**	**2.44**	**3.54**	**2.83**	**2.55**	**4.53**	**3.13**	**2.62**
Natural Gas Supply and Disposition (trillion cubic feet)										
Dry Gas Production[5]	18.67	21.83	23.14	23.86	24.26	26.24	27.14	24.60	29.04	30.38
Onshore	12.83	15.06	16.29	16.64	16.76	19.04	20.21	18.26	21.26	22.92
Conventional	8.43	9.63	9.63	9.86	10.96	11.68	12.30	11.85	12.75	13.39
Unconventional	4.39	5.43	6.66	6.78	5.81	7.36	7.91	6.40	8.51	9.54
Offshore	5.43	6.26	6.34	6.71	6.96	6.66	6.40	5.77	7.21	6.88
Alaska	0.42	0.50	0.50	0.50	0.54	0.54	0.54	0.57	0.57	0.57
Supplemental Natural Gas[6]	0.10	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	3.38	5.63	5.06	4.90	6.21	5.50	5.35	6.69	5.80	5.70
Total Supply	**22.15**	**27.51**	**28.25**	**28.81**	**30.53**	**31.80**	**32.54**	**31.35**	**34.90**	**36.13**
Natural Gas Consumption	**21.41**	**27.31**	**28.05**	**28.60**	**30.34**	**31.61**	**32.35**	**31.19**	**34.73**	**35.97**
Discrepancy[7]	**0.74**	**0.21**	**0.21**	**0.21**	**0.19**	**0.18**	**0.19**	**0.15**	**0.17**	**0.16**
Lower 48 End of Year Reserves	**157.41**	**154.74**	**174.82**	**182.46**	**159.18**	**183.82**	**196.95**	**148.41**	**190.07**	**210.80**
Carbon Dioxide Emissions (million metric tons carbon equivalent)	**1510.8**	**1806.0**	**1809.1**	**1807.6**	**1924.3**	**1928.1**	**1926.2**	**2033.4**	**2040.6**	**2039.1**

[1]Includes lease condensate.
[2]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[3]Includes refinery processing gain, strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied, alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, and other hydrocarbons.
[4]Balancing item. Includes unaccounted for supply, losses and gains.
[5]Marketed production (wet) minus extraction losses.
[6]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 1999 values include net storage injections.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 petroleum supply: Energy Information Administration (EIA), *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). 1999 natural gas lower 48 average wellhead price, production, and supplemental natural gas: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 1999,* DOE/EIA-0573(99) (Washington, DC, October 2000). Other 1999 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2001 National Energy Modeling System runs OGLRES.D111400A, AEO2001.D101600A, and OGHRES.D111400A.

Table F14. Key Results for MTBE Reduction Case

Change in Gasoline Blending, Imports, and Prices	1999	2004			2005			2006		
		Reference Case	MTBE Ban	Change from Reference	Reference Case	MTBE Ban	Change from Reference	Reference Case	MTBE Ban	Change from Reference
MTBE Blended with Gasoline (thousand barrels per day)	**281**	**214**	**0**	**-214**	**220**	**0**	**-220**	**223**	**0**	**-223**
Ethanol Blended with Gasoline (thousand barrels per day)										
United States	91	139	194	55	144	196	52	145	198	53
California	N/A	68	36	-32	70	37	-33	70	37	-33
Net Petroleum Product Imports (million barrels per day)	**1.30**	**1.51**	**1.68**	**0.17**	**1.56**	**1.76**	**0.2**	**1.74**	**1.89**	**0.15**
Net Crude Oil Imports (million barrels per day)	**8.61**	**10.24**	**10.06**	**-0.18**	**10.59**	**10.37**	**-0.22**	**10.89**	**10.74**	**-0.15**
Gasoline Prices (1999 cents per gallon)										
National Average Gasoline Price	118	132	136	4	133	136	3	135	139	4
National Average Reformulated Gasoline Price	125	139	147	8	139	147	8	142	151	9

MTBE = Methyl tertiary butyl ether.
N/A = Not applicable.
Note: Side case was run without the fully integrated modeling system, so not all potential feedbacks are captured.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs AEO2001.D101600A and MTBEBAN5.D101900A.

Table F15. Key Results for Coal Mining Cost Cases

Prices, Productivity, Wages, and Emissions	1999	2005			2010			2020		
		Low Cost	Reference Case	High Cost	Low Cost	Reference Case	High Cost	Low Cost	Reference Case	High Cost
Minemouth Price (1999 dollars per short ton)	**16.98**	**13.90**	**14.68**	**15.39**	**12.48**	**13.83**	**14.99**	**10.84**	**12.70**	**15.18**
Delivered Price to Electric Generators (1999 dollars per million Btu)	**1.21**	**1.10**	**1.13**	**1.17**	**0.99**	**1.05**	**1.12**	**0.88**	**0.98**	**1.11**
Labor Productivity (short tons per miner per hour)	**6.59**	**9.16**	**8.30**	**7.50**	**10.98**	**9.16**	**7.75**	**14.20**	**10.31**	**7.47**
Labor Productivity (average annual growth from 1999)	**N/A**	**5.6**	**3.9**	**2.2**	**4.8**	**3.0**	**1.5**	**3.7**	**2.2**	**0.6**
Average Coal Miner Wage (1999 dollars per hour)	**19.34**	**18.77**	**19.34**	**19.93**	**18.30**	**19.34**	**20.43**	**17.41**	**19.34**	**21.48**
Average Coal Miner Wage (average annual growth from 1999)	**N/A**	**-0.5**	**0.0**	**0.5**	**-0.5**	**0.0**	**0.5**	**-0.5**	**0.0**	**0.5**
Carbon Dioxide Emissions by Electric Generators (million metric tons carbon equivalent)[1]										
Petroleum	20.0	6.6	6.7	6.7	3.4	3.4	3.5	3.7	3.7	3.8
Natural Gas	45.8	77.9	78.5	78.5	100.5	101.8	103.6	164.6	166.3	169.0
Coal	490.5	549.6	547.9	548.0	577.7	574.0	569.3	606.6	601.5	592.9
Total	**556.3**	**634.1**	**633.1**	**633.2**	**681.6**	**679.1**	**676.4**	**775.0**	**771.5**	**765.7**
Electric Generator Capability (gigawatts)	**744.6**	**819.1**	**818.6**	**819.2**	**933.5**	**934.3**	**933.1**	**1059.5**	**1060.7**	**1059.5**

[1] Excludes cogenerators and other generators.
Btu = British thermal unit.
N/A = Not applicable.
Note: Side cases were run without the fully integrated modeling system, so not all potential feedbacks are captured. Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs LMCST01.D101900A, AEO2001.D101600A, and HMCST01.D101900A.

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 mine-mouth 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.

Conversion Factors

Table H1. Heat Rates

Fuel	Units	Approximate Heat Content
Coal[1]		
Production	million Btu per short ton	21.224
Consumption	million Btu per short ton	20.760
Coke Plants	million Btu per short ton	26.800
Industrial	million Btu per short ton	22.104
Residential and Commercial	million Btu per short ton	22.783
Electric Utilities	million Btu per short ton	20.479
Imports	million Btu per short ton	25.000
Exports	million Btu per short ton	26.243
Coal Coke	million Btu per short ton	24.800
Crude Oil		
Production	million Btu per barrel	5.800
Imports	million Btu per barrel	5.948
Petroleum Products		
Consumption[2]	million Btu per barrel	5.360
Motor Gasoline[2]	million Btu per barrel	5.234
Jet Fuel	million Btu per barrel	5.670
Distillate Fuel Oil	million Btu per barrel	5.825
Residual Fuel Oil	million Btu per barrel	6.287
Liquefied Petroleum Gas	million Btu per barrel	3.625
Kerosene	million Btu per barrel	5.670
Petrochemical Feedstocks	million Btu per barrel	5.630
Unfinished Oils	million Btu per barrel	5.825
Imports[2]	million Btu per barrel	5.487
Exports[2]	million Btu per barrel	5.709
Natural Gas Plant Liquids		
Production[2]	million Btu per barrel	3.886
Natural Gas		
Production, Dry	Btu per cubic foot	1,026
Consumption	Btu per cubic foot	1,026
Non-electric Utilities	Btu per cubic foot	1,027
Electric Utilities	Btu per cubic foot	1,019
Imports	Btu per cubic foot	1,023
Exports	Btu per cubic foot	1,011
Electricity Consumption	Btu per kilowatthour	3,412

Btu = British thermal unit.
[1]Coal conversion factors vary from year to year. Values correspond to those published by EIA for 1998 and may differ slightly from model results.
[2]Conversion factors vary from year to year. 2010 values are reported.
Sources: Energy Information Administration (EIA), *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000), and EIA, AEO2001 National Energy Modeling System run AEO2001.D101600A.

Table H2. Metric Conversion Factors

United States Unit	multiplied by	Conversion Factor	equals	Metric Unit
Mass				
Pounds (lb)	X	0.453 592 37	=	kilograms (kg)
Short Tons (2000 lb)	X	0.907 184 7	=	metric tons (t)
Length	X	1.609 344	=	kilometers (km)
Miles				
Energy				
British Thermal Unit (Btu)	X	1055.056[a]	=	joules(J)
Quadrillion Btu	X	25.2	=	million tons of oil equivalent (Mtoe)
Kilowatthours (kWh)	X	3.6	=	megajoules(MJ)
Volume				
Barrels of Oil (bbl)	X	0.158 987 3	=	cubic meters (m^3)
Cubic Feet (ft^3)	X	0.028 316 85	=	cubic meters (m^3)
U.S. Gallons (gal)	X	3.785 412	=	liters (L)
Area				
Square feet (ft^2)	X	0.092 903 04	=	square meters (m^2)

Note: Spaces have been inserted after every third digit to the right of the decimal for ease of reading.
[a]The Btu used in this table is the International Table Btu adopted by the Fifth International Conference on Properties of Steam, London, 1956.
Source: Energy Information Administration (EIA), *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000), Table B1 and EIA, *International Energy Outlook 2000,* DOE/EIA-0484 (2000) (Washington, DC, March 2000).

Table H3. Metric Prefixes

Unit Multiple	Prefix	Symbol
10^3	kilo	k
10^6	mega	M
10^9	giga	G
10^{12}	tera	T
10^{15}	peta	P
10^{18}	exa	E

Source: Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000), Table B2.

The Energy Information Administration
National Energy Modeling System/Annual Energy Outlook Conference

Crystal Gateway Marriott, Arlington, VA ***March 27, 2001***

Morning Program

8:30 a.m. - 8:45	**Opening Remarks -** *Administrator*, Energy Information Administration
8:45 a.m. - 9:15	**Overview of the *Annual Energy Outlook 2001* - *Mary J. Hutzler,*** *Director*, Office of Integrated Analysis and Forecasting, Energy Information Administration
9:15 a.m. - 10:00	**Keynote Address - *Henry D. Jacoby***, Joint Program on the Science and Policy of Global Change, Massachusetts Institute of Technology
10:15 a.m. - 12:00	**Concurrent Sessions A** **1. Greenhouse Gas Challenges: Current Perspectives** **2. The Natural Gas Frontier: 2015 and Beyond** **3. Forecasting International Oil Demand and Supply**
1:15 p.m. - 3:00	**Concurrent Sessions B** **1. Macroeconomic Forecasting with the Revised National Income and Product Accounts** **2. Electricity Competition: An Update** **3. Transportation for the 21st Century**
3:15 p.m. - 5:00	**Concurrent Sessions C** **1. Distributed Generation: Costs, Technologies, and Opportunities** **2. Transportation Fuels: Reduced Sulfur and Oxygenates** **3. Exploring Uncertainty in the *Annual Energy Outlook***

Hotel

The conference will be held at the *Crystal Gateway Marriott*, not to be confused with the Crystal City Marriott. The *Crystal Gateway Marriott* is located near the Crystal City Metro subway station at 1700 Jefferson Davis Highway, Arlington, VA 22202. For room reservations, contact the *Crystal Gateway Marriott* directly by telephone: (703) 920-3230. A block of rooms has been reserved in the name of the NEMS conference and will be held until March 5, 2001.

Information

For information, contact Susan H. Holte, Energy Information Administration, at (202) 586-4838, susan.holte@eia.doe.gov or Peggy Wells, Energy Information Administration, at (202) 586-0109, peggy.wells@eia.doe.gov.

Conference Handouts

Handouts provided in advance by the conference speakers will be posted online by March 22, 2001, at www.eia.doe.gov/oiaf/aeo/conf/handouts.html in lieu of being provided at the conference.

Conference Registration

Conference registration is free, but space is limited.
Please register by March 15, 2001.

Register online at www.eia.doe.gov/oiaf/aeo/conf/

Or mail or fax this form to:

Peggy Wells
Energy Information Administration, EI-84
1000 Independence Avenue, SW
Washington, DC 20585
Phone: (202) 586-0109
Fax: (202) 586-3045

Or register by e-mail to peggy.wells@eia.doe.gov.

Please provide the information requested below:

Name: ______________________

Title: ______________________

Organization: ______________________

Address: ______________________

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Phone: ______________________

Fax: ______________________

Please indicate which sessions you will be attending:

- ❒ Opening Remarks/Overview/Keynote Address

Concurrent Sessions A

- ❒ Greenhouse Gas Challenges: Current Perspectives
- ❒ The Natural Gas Frontier: 2015 and Beyond
- ❒ Forecasting International Oil Demand and Supply

Concurrent Sessions B

- ❒ Macroeconomic Forecasting with the Revised National Income and Product Accounts
- ❒ Electricity Competition: An Update
- ❒ Transportation for the 21st Century

Concurrent Sessions C

- ❒ Distributed Generation: Costs, Technologies, and Opportunities
- ❒ Transportation Fuels: Reduced Sulfur and Oxygenates
- ❒ Exploring Uncertainty in the *Annual Energy Outlook*

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