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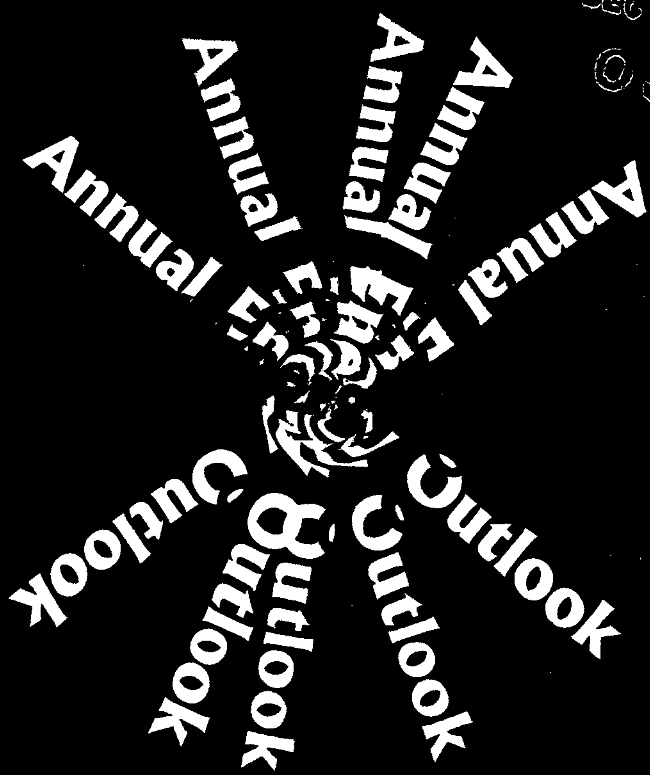
Annual Energy Outlook 1999



Energy Information Administration
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For Further Information . . .

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AEO99 will be available on the EIA Home Page (http://www.eia.doe.gov/oiaf/aeo99/homepage.html) by December 1998, including text, forecast tables, and graphics. Assumptions underlying the projections and tables of regional and other detailed results will also be available on the EIA Home Page by December 1998. *AEO99*, the assumptions, and the supplementary tables will be available on CD-ROM by February 1999.

Model documentation reports for the National Energy Modeling System (NEMS) and the report *NEMS: An Overview* are also available on CD-ROM and on the EIA Home Page. Quarterly projections of energy supply and demand for 1998 and 1999 are available in the *Short-Term Energy Outlook* (Fourth Quarter 1998). For ordering information and questions on other energy statistics available from EIA, please contact EIA's National Energy Information Center. Addresses, telephone numbers, and hours are as follows:

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Annual Energy Outlook 1999

With Projections to 2020

December 1998

Energy Information Administration
Office of Integrated Analysis and Forecasting
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This report was prepared by the Energy Information Administration, the independent statistical and analytical agency within the U.S. Department of Energy. The information contained herein should be attributed to the Energy Information Administration and should not be construed as advocating or reflecting any policy position of the Department of Energy or any other organization.

Preface

The *Annual Energy Outlook 1999* (*AEO99*) 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 *AEO99* reference case. The next section, "Legislation and Regulations," describes the assumptions made with regard to laws that affect energy markets and discusses evolving legislative and regulatory issues. "Issues in Focus" discusses current energy issues—the economic decline in East Asia, growth in demand for natural gas, vehicle emissions standards, competitive electricity pricing, renewable portfolio standards, and carbon emissions. It is followed by the analysis of energy market trends.

The analysis in *AEO99* 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 these cases are provided in Appendixes A through C. Appendixes D and E present a summary of the reference case forecasts in units of oil equivalence and household energy expenditures. Other cases explore the impacts of varying key assumptions in NEMS—generally, technology penetration. The major results are shown in Appendix F. Appendix G briefly describes NEMS and the *AEO99* assumptions, with a summary table of the cases. Appendix H provides tables of energy and metric conversion factors. *AEO99*, the detailed assumptions, and supplementary tables will be available on the EIA Home Page and on CD-ROM.

The *AEO99* projections are based on Federal, State, and local laws and regulations in effect on July 1, 1998. 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 *AEO99* projections were the most current available as of July 31, 1998, when most 1997 data but only partial 1998 data were available. Historical data are presented in this report for comparative purposes; documents referenced in the source notes should be consulted for official values. The *AEO99* projections for 1998 and 1999 incorporate the short-term projections from the September update of EIA's *Short-Term Energy Outlook* (*STEO*), Third Quarter 1998.

The *AEO99* 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 Administrator of EIA to prepare an annual report that contains trends and projections of energy consumption and supply.

The projections in *AEO99* 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 *AEO99* 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.

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Administrator's Message

As we present the projections in the *Annual Energy Outlook 1999* (*AEO99*), it is important to clarify what these projections represent. While the reference case projections do not hypothesize radical changes in energy markets and energy-using and producing technologies, they do assume continuing market changes and improvements in energy technologies, derived from past trends.

The Energy Information Administration (EIA) endeavors to represent current energy market conditions, both domestic and worldwide, and their impacts on future energy trends. An important example of such transitory issues is the ongoing economic crisis in East Asia, which currently is depressing world oil demand and prices and domestic oil production. Another is the continuing restructuring of the U.S. electricity industry and the movement to competitive pricing of electricity. Both of these topics are featured in *AEO99*, and they are included in the reference case projections.

In addition to the longer-term impacts of current market transitions, the reference case projections also include the impacts of a number of potential changes in energy markets—most notably, technology. Substantial productivity improvements and other technological advances are assumed for the fossil fuel supply sectors, in accordance with recent historical trends, accounting in part for the decline of coal prices and the relatively modest increases in oil and natural gas prices in the projections. The projections also incorporate all new and advanced energy-consuming and generating technologies that are assumed with a reasonable degree of confidence to be available by 2020. As a result, energy intensity—the amount of energy used for each dollar of output in the economy—declines by an average of 1 percent a year through 2020. In contrast, from 1986 to 1996, energy intensity was essentially flat.

Because the future cannot be known with certainty, it is possible that any of the assumptions, including the availability and characteristics of technology, may be too optimistic or pessimistic. For that reason, *AEO99* includes a wide range of alternative cases examining the effects of variations in many key assumptions.

As a policy-neutral organization, EIA does not incorporate future changes in energy-related legislation, regulation, or policy into its projections. Because of this neutrality and the "most likely" nature of the energy trends, the reference case projections provide a solid baseline against which a variety of alternative policies and assumptions can be analyzed and evaluated. One example of the analytical work performed by EIA relative to its reference projections over the past several years is the recent report, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, prepared at the request of the U.S. House of Representatives Committee on Science. Other recent work includes:

- *Analysis of S. 687, the Electric System Public Benefits Protection Act of 1997*, at the request of Senator James M. Jeffords
- *An Analysis of FERC's Final Environmental Impact Statement for Electricity Open Access and Recovery of Stranded Costs*, also at the request of Senator Jeffords
- *The Impacts on U.S. Energy Markets and the Economy of Reducing Oil Imports*, for the U.S. General Accounting Office
- *Analysis of Carbon Stabilization Cases*, for the U.S. Department of Energy, Office of Policy and International Affairs
- *The Impacts of Increased Diesel Penetration in the Transportation Sector*, for the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy.

Jay E. Hakes
Administrator
Energy Information Administration

Overview

Overview

Key Issues

A major issue in energy markets today is carbon emissions. Because the Kyoto Protocol has not been ratified by the United States and no specific policies for carbon reduction have been enacted, such policies are not included in the *Annual Energy Outlook 1999* (*AEO99*), although the Protocol and EIA's recent analysis of its potential impacts are discussed.

Economic developments in Asia over the past 18 months have weakened worldwide oil demand and lowered world oil prices—a trend that is likely to continue for several years and, therefore, is included in the *AEO99* analysis of oil markets and prices.

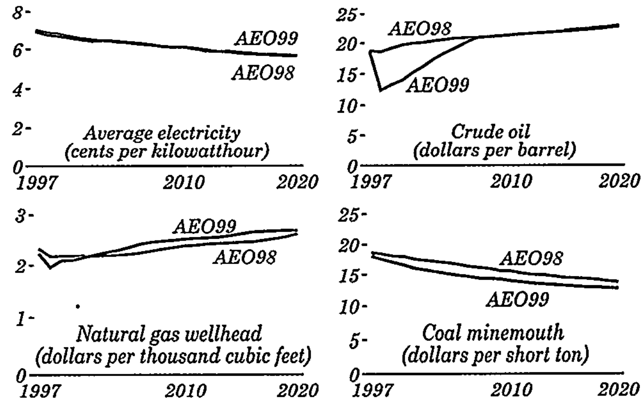
As in *AEO98*, the projections in *AEO99* reflect ongoing changes in the financial structure of the U.S. electricity industry and cost reductions that are becoming evident with increased competition. A transition to retail competitive pricing is assumed in five regions—California, New York, New England, the Mid-Atlantic Area Council (Pennsylvania, Delaware, New Jersey, and Maryland), and the Mid-America Interconnected Network (Illinois and parts of Wisconsin and Missouri). Provisions of the California legislation on stranded cost recovery and price caps are also included. In the other regions, stranded cost recovery is assumed to be phased out by 2008. No national renewable portfolio standard has been passed, but State standards and other programs intended to encourage renewables are included as enacted. The new standards for control of nitrogen oxide (NO_x) emissions by electricity generators are also incorporated.

Prices

Although average world crude oil prices in *AEO99* are similar to those in *AEO98* by 2020, the projected prices over the next several years are much lower (Figure 1). In 2020, the average crude oil price is projected to be $22.73 a barrel (in 1997 dollars), compared with $22.78 a barrel in *AEO98*. With the economic downturn in many Asian nations and lower expected growth in world oil demand, world oil prices are expected to remain low over the next several years—as much as about $5.50 a barrel lower than last year's projections in 2000.

After the start of the next decade, world oil demand is expected to rebound. Worldwide demand for oil is

Figure 1. Fuel price projections, 1997-2020: AEO98 and AEO99 compared (1997 dollars)



projected to reach 114.7 million barrels a day in 2020, only slightly lower than the *AEO98* projection of 116.6 million barrels a day.

Through 2020, the relatively low growth of prices even as the demand for oil increases reflects continued optimism about the potential growth of production in both the Organization of Petroleum Exporting Countries (OPEC) and the non-OPEC nations. Although not increasing as rapidly as in *AEO98*, OPEC oil production is expected to reach 58.8 million barrels a day in 2020, nearly double the 29.9 million barrels a day in 1997, assuming sufficient capital to expand production capacity. Once sanctions are lifted, Iraqi oil production is expected to reach 2.5 million barrels a day within 2 years and about 5 million barrels a day within a decade. Outside the Persian Gulf, expansion of production in the offshore regions of Nigeria and Algeria and in Venezuela should make a significant contribution to OPEC production.

Non-OPEC oil production is expected to increase more rapidly in *AEO99*, reaching 55.6 million barrels a day in 2020, compared with 50.4 million barrels a day in *AEO98*. Contributing to the growth are a near doubling of production in the former Soviet Union by 2020 (primarily in the Caspian Sea oil fields), new fields in the North Sea, and increases in the offshore regions of West Africa. Mexican oil production will continue to expand, and the rest of Latin America is projected to increase production by more than 50 percent, particularly in Brazil and Colombia. Lower OPEC production and higher non-OPEC production than in *AEO98* mean that OPEC does not dominate the world oil market until later in the forecast and reaches a market share of only 51 percent, compared with 57 percent in *AEO98*.

The average wellhead price of natural gas is projected to increase from $2.23 per thousand cubic feet in 1997 to $2.68 per thousand cubic feet in 2020, an average annual growth rate of 0.8 percent. Continued technological improvements in the exploration and production of natural gas moderate the price increase even as demand grows rapidly. In 2020, the price is higher than the $2.59 projected in *AEO98*, primarily because of a lower assessment of the recoverable resource base. Average delivered prices decline between 1997 and 2020 as a result of efficiency improvements in transmission and distribution; however, margins are as much as $0.20 to $0.30 per thousand cubic feet higher in *AEO99* than in *AEO98* in the 2000 to 2010 period, because recent data indicate fewer pipeline and distribution cost reductions than previously assumed.

In *AEO99*, the average minemouth price of coal is projected to decline from $18.14 per ton in 1997 to $12.74 per ton in 2020, as a result of increasing productivity in the industry, more production from lower-cost western mines, and competitive pressures on labor costs. Slightly lower production and higher productivity, as noted in recent data, lead to a price that is lower than the $13.55 in *AEO98*.

Average electricity prices decline from 6.9 cents per kilowatthour in 1997 to 5.6 cents per kilowatthour in 2020, the same as in *AEO98*. The restructuring of the electricity industry contributes to declining prices throughout the Nation through lower operating and maintenance costs, lower administrative costs, and other cost reductions. Federal Energy Regulatory Commission actions on open access and other regulatory initiatives for competitive markets enacted by some State public utility commissions are included in the projections, as are renewable portfolio standards and other mandates that have been passed in some States. Legislative actions affecting the electricity industry are discussed in the "Legislation and Regulations" section of this report (page 14), and electricity pricing is discussed in "Issues in Focus" (page 24).

Consumption

Total U.S. energy consumption is projected to increase from 94.0 to 119.9 quadrillion British thermal units (Btu) between 1997 and 2020, an average annual increase of 1.1 percent. In 2020, consumption is slightly higher than the 118.6 quadrillion Btu projected in *AEO98*, with higher commercial, industrial, and transportation demand partially offset by lower residential demand.

Consumption in the residential and commercial sectors is projected to increase at average rates of 0.8 and 0.7 percent a year, respectively, led by growth for a variety of equipment—telecommunications, computers, and other appliances. Residential demand is lower than in *AEO98*—22.9 quadrillion Btu in 2020, compared with 23.2 quadrillion Btu, because more efficient building shells in new construction offset higher growth in the housing stock. In the commercial sector, data from the *Commercial Buildings Energy Consumption Survey 1995* indicate less floorspace but higher energy intensities for some end uses. Commercial demand is projected to be 18.1 quadrillion Btu in 2020, 0.6 quadrillion Btu higher than in *AEO98*, primarily because of higher demand for natural gas and electricity.

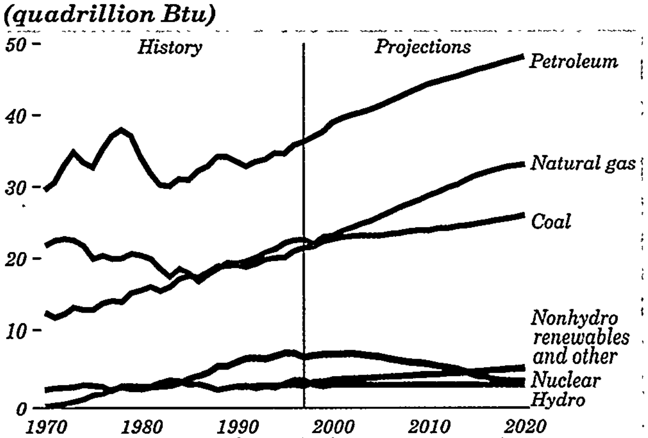
Demand in the industrial sector increases at an average of 0.8 percent a year and is about 0.6 quadrillion Btu higher in 2020 than in *AEO98*. More rapid efficiency improvement in some manufacturing sectors is offset by higher energy intensity indicated by the *Manufacturing Energy Consumption Survey 1994*. Because the economic downturn in Asia affects the market for U.S. exports, manufacturing output and industrial demand are significantly lower than in *AEO98* over the next 10 years, rebounding later in the projections.

Transportation demand grows on average by 1.7 percent a year and is 0.4 quadrillion Btu higher in 2020 than in *AEO98*. The introduction of direct-injection engines and other advanced automotive technologies improves the efficiency of light-duty vehicles, but the improvement is more than offset by higher travel, resulting from higher projected personal income. Recent data indicate higher load factors and efficiency for aircraft, which are offset by more air travel. Freight requirements for both rail and trucks are also higher, primarily because of the higher economic growth projected in *AEO99*.

AEO99, like earlier *AEO*s, incorporates efficiency standards for new energy-using equipment in buildings and for motors mandated by the National Appliance Energy Conservation Act of 1987 and the Energy Policy Act of 1992. Several alternative cases examine the impact of technology on the projections by assuming more and less rapid improvement of energy-efficient technologies in the end-use sectors relative to that projected in the reference case.

Natural gas consumption increases by an average of 1.7 percent a year (Figure 2). Demand increases in all sectors, but the most rapid growth is for electricity generation, which is projected to increase from 3.3 to 9.2 trillion cubic feet between 1997 to 2020, excluding cogenerators. Total gas consumption is only 0.1 trillion cubic feet higher than in *AEO98* in 2020, with higher demand in the commercial and industrial sectors offset by lower demand in the residential and electricity generation sectors.

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



Coal consumption increases from 1,030 to 1,275 million tons between 1997 and 2020, an average annual increase of 0.9 percent. About 90 percent of the coal use is for electricity generation, and coal remains the primary fuel for generation, although its share of generation declines by 2020. Coal demand in 2020 is 18 million tons higher than in *AEO98* because of higher projected demand for electricity generation.

Petroleum demand is projected to grow at an average rate of 1.2 percent a year through 2020, led by continued growth for transportation, which accounts for about 70 percent of petroleum use in 2020. Increases in travel more than offset efficiency increases, and higher economic growth increases freight and shipping, and thus petroleum use, through 2020. Compared with *AEO98*, total transportation energy demand is slightly higher, with higher projected efficiencies for new automobiles and aircraft more than offset by higher travel and freight requirements.

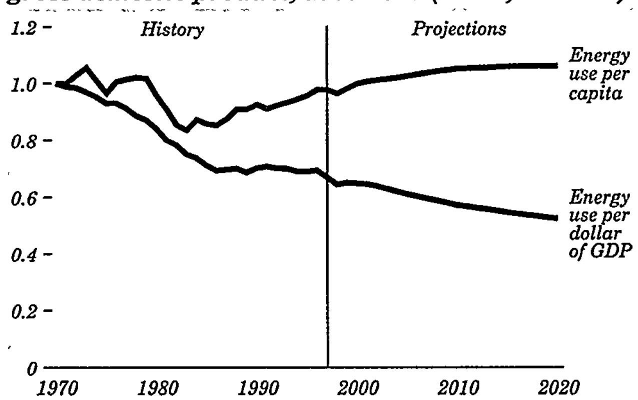
Renewable fuel consumption, including ethanol used for blending in gasoline, increases at an average rate of 0.8 percent a year through 2020. About 60 percent of renewables are used for electricity generation and the rest for dispersed heating and cooling, industrial uses, and fuel blending. In 2020, renewables are 0.7 quadrillion Btu higher than in *AEO98*, with higher demand for electricity generation, industrial uses, and ethanol blending.

Electricity demand is projected to grow by 1.4 percent a year through 2020. Efficiency gains in the use of electricity partially offset the growth of new electricity-using equipment. Electricity demand is only slightly higher than in *AEO98*, because an increase in commercial demand, resulting from more rapid growth of office equipment, computers, and other appliances is offset by a decrease in industrial demand from efficiency improvements in some manufacturing industries.

Energy Intensity

Energy intensity, measured as energy use per dollar of gross domestic product (GDP), has declined since 1970, particularly when energy prices have risen rapidly (Figure 3). Between 1970 and 1986, energy intensity declined at an average rate of 2.3 percent a year as the economy shifted to less energy-intensive industries and more efficient technologies. With moderate price increases and the growth of more energy-intensive industries, intensity improvements were flat between 1986 and 1996. From 1997

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



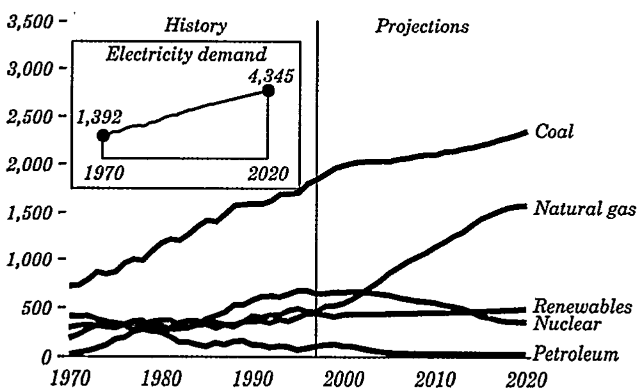
to 2020, intensity is projected to improve at an average rate of 1.0 percent a year as efficiency gains and structural shifts in the economy offset growth in demand for energy services.

Energy use per person also declined from 1970 through the mid-1980s, then increased as energy prices dropped. Per capita energy use is expected to remain stable through 2020 and below the high in the early 1970s, as efficiency gains offset higher demand for energy services.

Electricity Generation

Electricity generation from nuclear power declines significantly over the projection period (Figure 4). Of the 99 gigawatts of nuclear capacity available in 1997, 50 gigawatts are retired, and no new plants are constructed by 2020. Nuclear plant retirements are based on analyses of operating costs and the costs of life extension compared with the cost of new generating capacity. As a result, some plants are retired before the end of their 40-year operating licenses.

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



Generation from both natural gas and coal is projected to increase through 2020 to meet growing demand for electricity and offset the decline in nuclear power. Coal prices are lower than in *AEO98*, leading to slightly higher coal generation, but the share of coal generation declines by 2020 because assumptions about electricity industry restructuring favor the construction of less capital-intensive and more efficient natural gas generation technologies. The natural gas generation share increases from 14 percent to 33 percent between 1997 and 2020. The new NO_X standards lead to the installation of control technologies at many plants, with annualized costs of $2 billion, compared with $200 billion in annual electricity expenditures.

Renewable generation, including cogenerators, increases by 0.5 percent a year and in 2020 is 11 percent higher than in *AEO98*. Renewable technologies penetrate slowly because of the relatively modest increase in natural gas prices and the decrease in coal prices. In addition, electricity restructuring tends to favor natural gas over coal and baseload renewable technologies. State renewable portfolio standards, where enacted, and other programs to encourage the development of renewable technologies contribute to the growth of renewable generation.

Compared with *AEO98*, lower resource costs in the *AEO99* projections result in more biomass generation, and higher capacity factors for hydroelectric and geothermal facilities lead to higher generation from those technologies. Hydropower, currently the largest renewable resource used for generation, declines slightly through 2020. Its growth is limited by high capital costs, lack of available new sites, reduced Federal investment, and declining public support. Generation from other renewable sources—municipal solid waste, solar, and wind—increases to levels similar to those in *AEO98* in 2020.

Production and Imports

U.S. crude oil production declines at an average rate of 1.1 percent a year between 1997 and 2020 to a projected level of 5.0 million barrels a day. Advances in oil exploration and production technologies do not offset declining resources. Projected oil prices in *AEO99* are similar to those in *AEO98* in 2020, but are significantly lower earlier in the projection period. Higher domestic oil reserves, as indicated by recent data, offset the impact of lower oil prices. Production is similar to or higher than that in *AEO98* through most of the forecast. In 2020, the projected production is essentially the same as in *AEO98*. Total petroleum production (Figure 5) is shored up by production of natural gas plant liquids, which partially offsets the decline in crude oil production.

Declining production and rising demand lead to increasing petroleum imports through 2020 (Figure 6). The share of petroleum consumption met by net imports rises from 49 percent in 1997 to 65 percent however, the share is higher earlier in the projection period because of lower domestic production.

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

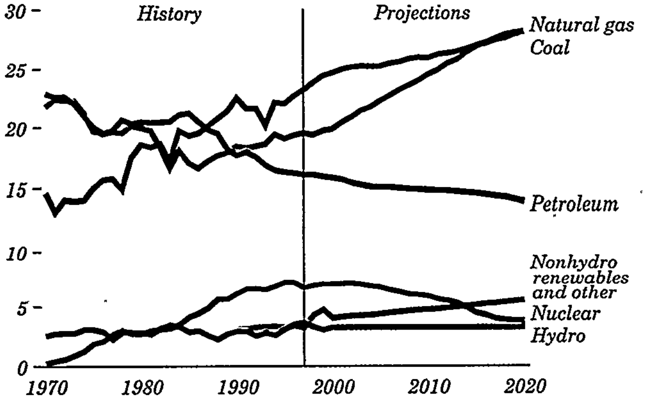
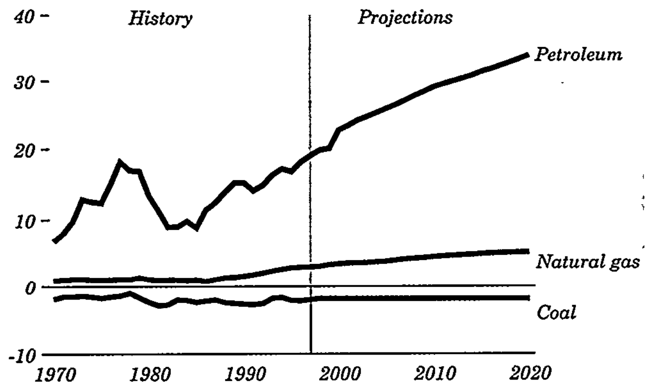


Figure 6. Net energy imports by fuel, 1970-2020 (quadrillion Btu)



In *AEO99*, natural gas production is projected to increase from 18.9 trillion cubic feet in 1997 to 27.4 trillion cubic feet in 2020, an average rate of 1.6 percent a year, to meet most of the rising domestic demand for natural gas. Additional supplies of natural gas are provided by imports. Net imports of natural gas, primarily from Canada, increase from 2.8 to 5.0 trillion cubic feet between 1997 and 2020. It is assumed that pipeline capacity from Canada will increase to accommodate imports of competitively priced Canadian gas.

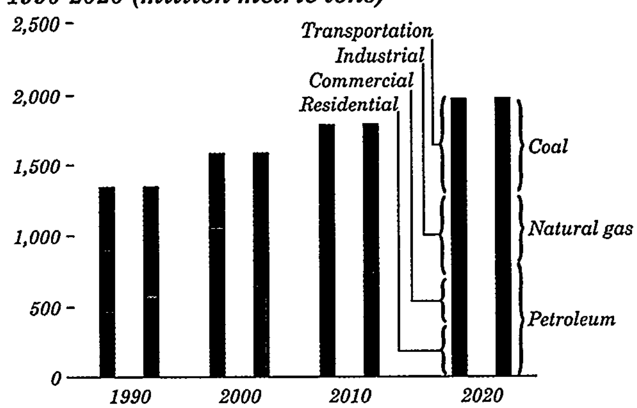
Coal production grows from 1,099 million tons in 1997 to 1,358 million tons in 2020, an average increase of 0.9 percent a year, to meet rising domestic and export demand. Most steam coal exports serve markets for electricity generation in Europe and Asia. Metallurgical coal exports to Europe and Asia decline. Export demand is lower than in *AEO98* by 35 million tons because of environmental concerns and economic problems in some countries. Because lower export demand is only partially offset by higher domestic demand, coal production in 2020 is 18 million tons lower than the *AEO98* projection.

Total renewable energy production is projected to increase from 6.8 to 8.2 quadrillion Btu between 1997 and 2020—an average annual increase of 0.8 percent—with growth in electricity generation from geothermal, biomass, and municipal solid waste generation and in industrial biomass and ethanol use. Renewable energy production in 2020 is 0.4 quadrillion Btu higher than in *AEO98*. More renewables are used for electricity generation, cogeneration, and ethanol blending, and *AEO99* incorporates ethanol production from cellulose beginning in 2001, which was not included in *AEO98*.

Carbon Emissions

Carbon emissions from energy use are projected to increase by an average of 1.3 percent a year through 2020, from 1,480 million metric tons in 1997 to 1,790 million metric tons in 2010 and 1,975 million metric tons in 2020 (Figure 7), due to rising energy demand, declining nuclear power, and slow growth of renewables. Relative to the 1990 level of 1,346 million metric tons, emissions are 33 and 47 percent higher, respectively, in 2010 and 2020. Projected emissions in 2020 are higher by 19 million metric tons than in *AEO98*, due to higher energy demand and higher levels of coal-fired electricity generation.

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



The Climate Change Action Plan (CCAP) was developed to stabilize greenhouse gas emissions in 2000 at 1990 levels. *AEO99* includes CCAP provisions, but no new carbon reduction policies are incorporated. Carbon emissions and the Kyoto Protocol are discussed in "Issues in Focus" (pages 30-41).

Table 1. Summary of results for five cases

Sensitivity Factors	1996	1997	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	16.29	16.23	13.98	13.48	14.47	12.14	15.09
Natural Gas	19.32	19.47	28.12	25.63	30.45	27.64	28.24
Coal	22.75	23.33	28.12	26.49	29.98	27.65	28.34
Nuclear Power	7.20	6.71	3.83	3.65	3.98	3.75	3.92
Renewable Energy	6.81	6.82	8.15	7.64	8.79	8.09	8.23
Other	1.28	0.66	0.65	0.50	0.79	0.56	0.75
Total Primary Production	**73.66**	**73.22**	**82.85**	**77.39**	**88.46**	**79.83**	**84.57**
Net Imports (quadrillion Btu)							
Petroleum (including SPR)	18.25	19.65	33.95	30.53	37.44	38.64	31.20
Natural Gas	2.85	2.90	5.14	4.79	5.38	5.01	5.14
Coal/Other (- indicates export)	-1.80	-1.65	-1.61	-1.70	-1.51	-1.62	-1.57
Total Net Imports	**19.28**	**20.90**	**37.47**	**33.62**	**41.31**	**42.03**	**34.77**
Discrepancy	0.68	-0.08	-0.44	-0.54	-0.40	-0.63	-0.34
Consumption (quadrillion Btu)							
Petroleum Products	36.03	36.49	48.08	43.98	52.26	50.69	46.70
Natural Gas	22.59	22.59	33.17	30.33	35.74	32.56	33.30
Coal	20.60	21.09	26.26	24.48	28.17	25.73	26.43
Nuclear Power	7.20	6.71	3.83	3.65	3.98	3.75	3.92
Renewable Energy	6.81	6.82	8.17	7.65	8.80	8.10	8.24
Other	0.39	0.33	0.39	0.38	0.40	0.40	0.41
Total Consumption	**93.63**	**94.04**	**119.89**	**110.47**	**129.36**	**121.23**	**119.00**
Prices (1997 dollars)							
World Oil Price (dollars per barrel)	21.01	18.55	22.73	21.66	23.81	14.57	29.35
Domestic Natural Gas at Wellhead (dollars per thousand cubic feet)	2.28	2.23	2.68	2.29	3.09	2.62	2.70
Domestic Coal at Minemouth (dollars per short ton)	18.85	18.14	12.74	12.47	12.89	12.66	12.76
Average Electricity Price (cents per kilowatthour)	6.9	6.9	5.6	5.1	6.1	5.6	5.6
Economic Indicators							
Real Gross Domestic Product (billion 1992 dollars)	6,995	7,270	11,680	10,256	13,106	—	—
(annual change, 1997-2020)	—	—	2.1%	1.5%	2.6%	—	—
GDP Implicit Price Deflator (index, 1992=1.00)	1.10	1.12	2.13	3.29	1.56	—	—
(annual change, 1997-2020)	—	—	2.8%	4.8%	1.5%	—	—
Real Disposable Personal Income (billion 1992 dollars)	5,043	5,183	8,905	8,030	9,770	—	—
(annual change, 1997-2020)	—	—	2.4%	1.9%	2.8%	—	—
Index of Manufacturing Gross Output (index, 1987=1.00)	1.305	1.359	2.137	1.867	2.439	—	—
(annual change, 1997-2020)	—	—	2.0%	1.4%	2.6%	—	—
Energy Intensity							
(thousand Btu per 1992 dollar of GDP)	13.39	12.94	10.27	10.78	9.88	—	—
(annual change, 1997-2020)	—	—	-1.0%	-0.8%	-1.2%	—	—
Carbon Emissions (million metric tons)	**1,461**	**1,480**	**1,975**	**1,826**	**2,124**	**2,006**	**1,953**

Notes: Specific assumptions underlying the alternative cases are defined in the Economic Activity and International Oil Markets sections beginning on page 44. 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, and C19.

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 1999* (*AEO99*) are based on Federal, State, and local laws and regulations in effect on July 1, 1998. The potential impacts of pending or proposed legislation 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 Omnibus Budget Reconciliation Act of 1993, which adds 4.3 cents per gallon to the Federal tax on highway fuels [*1*]; the National Appliance Energy Conservation Act of 1987; the Clean Air Act Amendments of 1990 (CAAA90); the Energy Policy Act of 1992 (EPACT); the Outer Continental Shelf Deep Water Royalty Relief Act of 1995; and the Tax Payer Relief Act of 1997. *AEO99* 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.

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, annual emissions of sulfur dioxide by electricity generators are, in general, capped at 8.95 million short tons a 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, leading to regulations that impose limits on electricity generators for NO_x emissions. The impacts of CAAA90 on electricity generators are discussed in "Market Trends" (see page 86).

The provisions of EPACT focus primarily on reducing energy demand. It requires 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 owners of fleets of automobiles and trucks 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 which specify efficiency levels, including the refrigerator standard that goes into effect in July 2001. *AEO98* included a discussion of proposed actions, but no additional standards have been finalized.

Climate Change Action Plan

The *AEO99* reference case projections include analysis of provisions of 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. 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.

Energy combustion is the primary source of anthropogenic (human-caused) carbon emissions. *AEO99* estimates of emissions from fuel combustion 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, such as forests. 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. The projections do not include any other carbon mitigation actions that may be enacted as a result of the Kyoto Protocol, agreed to on December 11, 1997 (see "Issues in Focus," page 30, for further discussion).

Climate Wise and Climate Challenge are two programs cosponsored by EPA and the U.S. Department of Energy (DOE) to foster voluntary reductions in emissions on the part of industry and electricity generators, as reported in the EIA publication *Mitigating Greenhouse Gas Emissions: Voluntary Reporting* [*2*]. The *AEO99* reference case includes analysis of the impacts of both programs (see Appendix G).

Extension of Outer Continental Shelf Leasing Moratoria

On June 12, 1998, the President extended the current moratoria on new leases for offshore oil drilling on the U.S. Outer Continental Shelf (OCS) through June 30, 2012. The extension withdraws from possible leasing the areas of the OCS currently under moratoria in the following OCS planning areas: the North Aleutian Basin; Washington-Oregon; Northern, Central, and Southern California; South Atlantic; Mid-Atlantic; North Atlantic; and sections of the Eastern Gulf of Mexico. Also withdrawn were those areas of the OCS designated as marine sanctuaries under the Marine Protection, Research, and Sanctuaries Act of 1972. The sanctuaries range in size from less than 1 square mile to more than 5,300 square miles [*3*]. The extension of OCS moratoria does not affect any current leases. Because the *AEO99* forecast does not include production from restricted areas, the extension has no impact on the projections.

Regulation of Natural Gas Transportation Services

On July 29, 1998, the Federal Energy Regulatory Commission (FERC) proposed changes in its regulations governing interstate natural gas pipelines. The purpose of the changes is to allow more flexibility and competitiveness in the market for short-term transportation services. Under the proposed changes, cost-based regulation would be replaced by policies intended to maximize competition, mitigate the ability of firms to exercise residual monopoly power, and provide opportunities for greater flexibility in the provision of pipeline services. Pipelines would be permitted to negotiate rates and terms of service. The Commission is also seeking comments on its pricing policies for the existing and long-term market and for new capacity. Comments on both proposed changes and existing policy are due on January 22, 1999 [*4*]. Although the specific changes proposed by the FERC are not included, the *AEO99* reference case does assume an increasingly competitive market for natural gas transportation services.

Extension of Ethanol Tax Credit

The Federal Highway Bill of 1998 included an extension of the ethanol tax credit, which has been granted since 1986 and was scheduled to expire in 2000. The tax credit is currently 54 cents per gallon and applies to ethanol and the ethanol portion of the gasoline additive ethyl tertiary butyl ether (ETBE). The Highway Bill extends the tax credit through 2007 but specifies 1-cent-per-gallon reductions in 2001, 2003, and 2005. Ethanol and ETBE may be blended into gasoline to boost either octane or oxygen content. The tax credit effectively reduces the cost of ethanol and ETBE, making them more attractive for blending with gasoline. *AEO99* assumes that the ethanol tax credit will not expire in 2007 but will continue at the nominal level of 51 cents per gallon. The benefit of the credit is eroded by inflation over time, however, reducing its value to 27 cents per gallon (in 1997 dollars) by 2020.

Tier 2 Vehicle Standards

The Clean Air Act Amendments of 1990 (CAAA90) set "Tier 1" exhaust emission standards for carbon monoxide (CO), hydrocarbons, nitrogen oxides (NO_x), and particulate matter (PM) for light-duty vehicles and trucks beginning with model year 1994. CAAA90 also required the U.S. Environmental Protection Agency (EPA) to study further "Tier 2" emission standards that would take effect between model years 2004 and 2007. EPA provided a Tier 2 study to Congress in July 1998 [*5*] and is expected to publish a Notice of Proposed Rulemaking for the Tier 2 standards early in 1999.

Air quality projections included in the EPA's Tier 2 study indicate that the existing Tier 1 vehicle emissions standards, and the implementation of the voluntary National Low Emissions Vehicle (NLEV) program set for implementation between 1999 and 2001, will not be enough to achieve attainment of National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter (PM) between 2007 and 2010. The study concludes that further emissions reductions for volatile organic compounds (VOCs), NO_x, and PM will be needed to move many areas of the country, and the Nation as a whole, toward compliance. In addition, the study concludes that more stringent Tier 2 vehicle emissions standards are a cost-effective means of improving air quality. The study also examined the feasibility of technologies that would reduce emissions from light-duty vehicles and trucks, ranging from advanced engine designs to improved exhaust after-treatment systems.

The Tier 2 study emphasizes the importance of the relationship between emissions reduction technology and gasoline sulfur content. Sulfur reduces the effectiveness of the catalyst used in the emission control systems of advanced technology vehicles, increasing their emissions of hydrocarbons, carbon monoxide, and NO_X. Because of the link between sulfur and emissions, the EPA is developing proposed restrictions on gasoline sulfur content in connection with the Tier 2 standards.

Tier 2 standards and restrictions on gasoline sulfur are not reflected in the *AEO99* reference case because the end result of the upcoming rulemaking process is unknown. Analysis of the potential costs of reducing sulfur in gasoline is included in "Issues in Focus" (see page 29).

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 program, 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 Resource Board were dedicated electric vehicles [*6*].

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 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.

Ozone Transport Rule

Over the past several years, extensive effort has gone into examining the impact of interstate ozone emissions. Many of the States in the Northeast believe that they will not be able to reduce their ozone concentrations to required levels unless out-of-state emissions are also reduced. The Ozone Transport Assessment Group (OTAG), made up of State, Federal, utility, and nonutility representatives, was established to analyze the issue. OTAG's analyses suggested that nitrogen oxide (NO_X) emissions from power plants in some midwestern States are having an impact on ozone concentrations in downwind northeastern States [*7*].

In response to OTAG's recommendations, the EPA issued a notice of proposed rulemaking (NOPR) on November 7, 1997 [*8*]. In the NOPR, EPA established summer season NO_X emission limits (referred to as budgets) for electricity power plants in 22 eastern and midwestern States. Originally the NOPR set the NO_X limit for the summer season (May 1st through September 30th) for the 22 States at 489,000 tons, but the limit was raised to 563,800 tons in the final rule issued on September 24, 1998 (Table 2). The change resulted from technical corrections made by the EPA to the population of sources of NO_X emissions in the baseline data from which the budgets were derived.

The NOPR and its supplement require States to develop plans to meet their NO_X emission budgets in 2003 and beyond. The EPA hopes to encourage States to participate in a NO_X "cap and trade"

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

State	NO_x budget	State	NO_x budget
Alabama	*37.4*	*New Jersey*	*8.8*
Connecticut	*3.3*	*New York*	*24.1*
Delaware	*3.6*	*North Carolina*	*34.6*
District of Columbia	*0.0*	*Ohio*	*46.8*
Georgia	*37.5*	*Pennsylvania*	*46.2*
Illinois	*37.9*	*Rhode Island*	*1.1*
Indiana	*47.4*	*South Carolina*	*18.0*
Kentucky	*38.4*	*Tennessee*	*23.7*
Maryland	*13.9*	*Virginia*	*19.3*
Massachusetts	*10.3*	*West Virginia*	*33.5*
Michigan	*35.0*	*Wisconsin*	*19.0*
Missouri	*24.0*	***Total***	***563.8***

program, under which the EPA would issue NO_x emission allowances to power plant operators and other large sources. Each allowance would permit the holder to emit one ton of NO_x and could either be used for the facility to which it was originally allocated or sold.

As with the sulfur dioxide (SO_2) allowance program created by CAAA90, the goal of the NO_x cap and trade program would be to reduce compliance costs through efficient market mechanisms. The program is meant to encourage reductions in NO_x emissions from facilities where they can be made relatively inexpensively, while providing the option of allowance purchases for facilities where the costs of reducing emissions would be higher.

Power plant operators have several options for reducing NO_x emissions, including low-NO_x burners, other combustion controls (flue gas recirculation, staged combustion, reduced oxygen, etc.), selective noncatalytic reduction (SNCR), and selective catalytic reduction (SCR). In addition, co-firing a coal plant with natural gas is also an option. In general, combustion controls (including low-NO_x burners) are relatively inexpensive and reduce uncontrolled NO_x emissions by 40 to 50 percent. In contrast, SNCR and SCR technologies are more expensive, but they reduce NO_x emissions by 60 to 80 percent. The option chosen for each plant will depend on its uncontrolled emission rate, boiler type, size, and operational economics.

In the *AEO99* reference case, a mix of options is chosen. By 2020, combustion controls alone are expected to be added to 10 gigawatts of capacity, SNCR units to 96 gigawatts, and SCR units to 111 gigawatts. The annualized cost of the control technologies is projected at $2 billion—very small in comparison with the approximately $200 billion that consumers spend annually on electricity purchases. However, many of the same units expected to add NO_x reduction equipment, primarily coal steam plants, would also be affected if efforts to reduce carbon emissions were undertaken in the future. It may be economical to add NO_x control equipment to such units now, but the addition of carbon reduction requirements could make retirement a more attractive option for many units. A recent EIA study [*9*] found that U.S. efforts to meet the carbon reduction targets of the Kyoto Protocol could result in the retirement of many coal-fired power plants.

Mercury Emissions Data Collection

CAAA90, Section 112(n)(1)(A), required that the EPA prepare a study of hazardous air pollutants from steam generating units. A report on the results of the study was submitted to Congress on February 24, 1998. The key finding was that mercury emissions from coal-fired power plants posed the greatest potential for harm. The levels of mercury concentration in air or water were not found to be a problem; however, it was found that mercury can accumulate in some fish species, making them dangerous to consume in large amounts.

The role of mercury emissions from particular coal-fired power plants in the process is not clear, and the EPA has decided to collect additional data from power plant operators before determining whether their mercury emissions should be regulated. The draft data collection plan states that, beginning on January 1, 1999, the owners of coal-fired power plants 25 megawatts or larger will be required to collect weekly data on the mercury contents of the coal used and the stack emissions and to submit the data to the EPA quarterly. After collecting the data for 1 year, the EPA will determine whether mercury emissions regulations are needed.

National Ambient Air Quality Particulate Standard

AEO99 does not include the new fine particulate standard proposed in the EPA's revised National Ambient Air Quality Standards (NAAQS). The NAAQS created a new standard for fine particles, smaller than 2.5 micrometers in diameter ($PM_{2.5}$). The new health-based standard sets the exceedance limits for $PM_{2.5}$ at a 3-year annual arithmetic mean of 15 micrograms per cubic meter ($\mu g/m^3$) and a 24 hour standard of 65 $\mu g/m^3$ (99th percentile of concentrations in a year averaged over 3 years). The EPA is required to take several steps, however, before the standard can be enforced.

In a memorandum dated July 16, 1997, the President directed the EPA to determine within the next 5 years, based on review of scientific data, whether to revise or maintain the proposed standard. Thus, final standards will not be issued until July 2002, at the earliest. The States will then be given 3 years to develop plans to come into compliance and will have up to 10 years to reach the required concentration levels. As a result, without any changes, the earliest full compliance date would be 2015. As the data review progresses and compliance approaches begin to take shape, the fine particle standard may be included in future *AEO*s.

Hazardous Air Pollutant Standards

During 1998 the EPA proposed two new sets of national emissions standards for hazardous air pollutants (NESHAPs) under the authority of the Clean Air Act. The first proposed NESHAP would limit emissions of hazardous air pollutants (HAPs) from oil and natural gas production and natural gas transmission and storage facilities. The EPA has determined that such oil and gas facilities emit HAPs including benzene, toluene, ethyl benzene, mixed xylenes, and *n*-hexane.

The EPA expects the proposed NESHAP to reduce HAP emissions from oil and gas production by 57 percent and from natural gas transmission and storage by 36 percent [*10*]. The proposed NESHAP would require the installation of Maximum Achievable Control Technology (MACT) at more than 400 facilities involved in the production of oil and natural gas and the transmission and storage of natural gas. Another 500 production facilities may be required to install less stringent controls. The rule was proposed in February 1998 and is expected to be finalized in mid-1999 [*11*].

A second NESHAP, proposed in September 1998, would require petroleum refineries to reduce HAPs from process vents on catalytic cracking, catalytic reforming, and sulfur plant units. NESHAPs for other refinery processing units were set in August 1995 but did not include standards for these three processes. NESHAPs for the additional processes were recently proposed, because the EPA determined that they can be expected to emit a number of HAPs. The proposed standards are specifically aimed at reducing emissions of organics, sulfur compounds, inorganics, and particulate metals. The EPA estimates that refiners would invest approximately $173 million for the required MACT control equipment and about $43 million a year for related maintenance [*12*]. Potential changes that would be associated with the two NESHAP proposals are not included in the *AEO99* reference case.

Electricity Industry Restructuring

Despite several proposals, no comprehensive Federal electricity restructuring bill had been enacted as of early August 1998. Several bills were proposed, but no consensus could be reached. It is expected that new bills will be introduced early in 1999 in the 106th Congress. At the State level the situation is moving forward more rapidly. Nearly every State has undertaken some effort to review options for or implement changes in the structure of the electricity business, and a number of States have taken regulatory or legislative action [*13*]. The critical issues in most States are whether and when to allow consumers to choose their electricity suppliers, how to deal with utility stranded costs, and what sort of market structure would most encourage competition.

Twelve States have enacted restructuring legislation and are moving toward letting consumers choose their suppliers over the next several years. Six other States have comprehensive regulatory orders in place. Barring changes, in the twelve States with legislation in place, consumers will be free to choose their electricity suppliers starting some time between 1998 and 2004 [*14*]. Most of the twelve call for consumer choice to be phased in over several years. Generally, larger industrial customers are given choice earlier, while smaller commercial and residential customers are given choice later.

Three States—California, Rhode Island, and Massachusetts—plan to allow all their consumers to choose their suppliers by the end of 1998. California opened the market to all customers on March 31, 1998 [*15*]. Consumers in California now receive bills with separate charges for the services provided. Depending on the type of customer, they could include fees for energy services, transmission services, distribution services, a competitive transition charge, a nuclear decommissioning charge, public program charges, fixed transition charges, and other charges.

The competitive transition charges—associated with paying utilities for "stranded" investments they made to serve customers that may not be recovered in a competitive market—will continue for only a fixed period of time, probably several years. All the services may still be provided by the incumbent utility, or each may come from a different company, depending on the decisions made by the customer. The situation is similar in Rhode Island and Massachusetts, where all customers are able to choose their suppliers as of 1998.

In all three States, decisions have been made about the level of stranded cost recovery allowed and the rate reductions required over the next few years, but some of the decisions are being challenged. Although ballot referendums in California and Massachusetts in the November 1998 elections failed, future challenges are likely.

The three States are taking a variety of approaches to stranded cost recovery [*16*], differing in the estimation methodology, level of recovery allowed, recovery mechanism, and length of recovery. For example, in California utilities are to be given the opportunity to recover prudently incurred stranded costs. The costs will be recovered through a competitive transition charge and financed through the issuance of rate reduction bonds. Most of the costs will be recovered by the end of 2001, but the bonds mature over a 10-year period. In Rhode Island a 2.8 cent per kilowatthour nonbypassable transition charge will be collected through December 2009. In addition, utilities are required to divest a portion of their generating assets, and the transition charge will be adjusted if market conditions warrant.

Similarly, in Massachusetts, stranded costs will be recovered over 5 to 10 years, power plant divestiture is encouraged, and the transition charge will be adjusted to reflect market conditions. The actual amount of stranded costs each utility will be able to collect in these States will depend on the price of electricity that evolves in the market and the ability of the utility to reduce its operating costs.

Throughout *AEO99*, all regions of the country are treated as being competitive in wholesale markets (no new rate-based capacity). In five regions—California, New York, New England, the Mid-Atlantic Area Council (Pennsylvania, Delaware, New Jersey, and Maryland), and the Mid-America Interconnected Network (Illinois and parts of Wisconsin and Missouri)—electricity is priced competitively, based on marginal costs, at the retail level. Competitive forces are assumed to continue to put pressure on electricity producers to reduce their costs, and, as a result, nonfuel operations and maintenance costs are assumed to decline by 25 percent over the next 10 years from their current level. It is also assumed that plants will be retired when it is no longer economical to maintain them. In other words, new capacity is built to retire existing capacity and meet growth in the demand for electricity.

Renewable Technologies

In several States, electricity restructuring legislation includes provisions to stimulate the development of renewable generating technologies for wind, solar, geothermal, and biomass plants. Many believe that these technologies may not succeed in a competitive market where investment decisions are based solely on direct market costs. In general, renewable technologies are more expensive than fossil-fueled alternatives (particularly new natural-gas-fired combined-cycle plants), and it is expected that few would be built in a competitive market.

Advocates of renewable technologies believe that their environmental benefits outweigh their higher costs, and that the costs could fall significantly if demand increased enough to allow manufacturers to take advantage of economies of scale in production. In other words, if they could be assured of selling more units, manufacturers would invest in larger, more efficient facilities and lower the per-unit costs of production.

To encourage the development of renewable technologies, some States are using a renewable mandate, specifying that a certain amount of renewable capacity must be built. Others are using a public benefit fund (PBF) financed by a small fee collected from customers for each kilowatthour of electricity purchased. The revenue is to be used to support a variety of programs, including low-income support, demand-side management, and renewable development.

A third approach is the renewable portfolio standard (RPS), which specifies that a percentage of the electricity generated (or sold) in the State must be produced by qualifying renewable power plants. In most of the bills, qualifying renewables include all renewable facilities other than hydroelectric plants and municipal solid waste. The RPS system can operate as a tradable credit system in which anyone operating a qualifying renewable plant will be issued credits equal to its generation. If the RPS requirement is 5 percent, the operator will only need to keep credits equal to 5 percent of the plant's output. The rest can be sold to suppliers selling power produced from nonqualifying facilities. Examples of State RPS programs include the following:

- Arizona has implemented a program to encourage solar power development. The program requires that 0.5 percent of new electricity sales come from solar plants in 1999 and 2000, and 1 percent thereafter.
- In Connecticut, new resources are broken into two classes. Class 1 includes sustainable biomass, fuel cells, landfill gas, solar, and wind power. Class 2 includes other biomass, municipal solid waste, and conventional hydroelectricity. The program requires that by 2001 class 1 resources provide a minimum of 0.75 percent of licensed utility output, and that another 5.5 percent be provided by a mix of class 1 and class 2 resources. By 2009, the class 1 minimum requirement grows to 6.0 percent, and an additional 7.0 percent must come from a mix of class 1 and class 2 resources.
- Massachusetts has instituted a program that requires an increase in the share of sales coming from qualifying sources (biomass, landfill gas, fuel cells, conventional hydroelectricity, ocean thermal, solar, and wind) from 1 percent in 2003 to 15 percent by 2020.
- In Nevada, the required share for nonhydroelectric renewables starts at 0.2 percent in 2001 and increases 0.2 percentage points per year until reaching 1 percent.
- In Maine, a much larger share is required. By March 2001, 30 percent of total retail sales must be generated from biomass, fuel cells, geothermal, small hydroelectric, municipal solid waste, solar, or wind.

In addition to these programs, States such as California, Colorado, Iowa, Minnesota, New York, and Wisconsin have implemented renewable mandates requiring specific generation or capacity levels or other "green power initiatives."

In order to represent these State programs in the *AEO99* projections, estimates were made of the amounts and types of capacity each of the State programs would encourage. Accordingly, new plants with the appropriate technology, capacity, and start years were added to the inventory of plants available. (For example, the Arizona program is expected to encourage 80 megawatts of solar development.) In total, the various State RPS programs are expected to encourage just over 638 megawatts of new renewable capacity between 1999 and 2011. Wind (263 megawatts), solar (163 megawatts), and biomass (137 megawatts) are expected to account for the majority of the renewable capacity encouraged by State RPS programs.

State mandates and other requirements are expected to produce another 1,372 megawatts of new renewable capacity, with wind (1,017 megawatts), geothermal (149 megawatts), biomass (137 megawatts), and landfill gas (69 megawatts) making up most of the capacity. Finally, voluntary plans, such as green power initiatives, add another 67 megawatts—47 megawatts of wind capacity, 10 megawatts of photovoltaics, and 9 megawatts of landfill gas capacity.

Issues in Focus

Issues in Focus

The Economic Decline in East Asia

Recent Developments

Although this *Annual Energy Outlook 1999* (*AEO99*) focuses on the determinants of growth for the United States in a midterm (20-year) setting, it is also important to consider how near-term events may play out over the long run. The recent economic crisis in East Asia illustrates the need to reconcile volatility in the short run with the long-run determinants of growth for the world and the U.S. economy.

The economic crisis in East Asia began in the summer of 1997 and continued to deepen throughout 1998. Currency markets in Southeast Asia became extremely volatile, with Thailand, Malaysia, and Indonesia experiencing sharp depreciations first, followed by the Philippines and South Korea. Between the end of May 1997 and September 1998, the U.S. dollar rose by 67 percent against the Thai baht, nearly 53 percent against the Malaysian ringgit, and more than 61 percent against the South Korean won. For most of the East Asian countries, however, the exchange rate fluctuations occurred between August 1997 and the end of March 1998, with currency values relatively stable during the summer of 1998 (although at much higher levels against the dollar than in January 1997). Indonesia's currency did continue to show volatility, as the country tried to accommodate increased financing needs for both economic investment and social costs.

The Asian economies affected by the crisis share many characteristics: relatively rapid economic growth over the past 3 to 6 years; high domestic savings rates; economic expansion sustained by exports rather than domestic demand growth; high current account deficits; high inflows of foreign capital before the currencies became volatile; and relatively lax financial regulations. Early in 1997 their currencies were pegged to the U.S. dollar, and they became overvalued when the countries experienced large current account trade deficits. In addition, credit was allocated in their financial sectors on non-business criteria, and excessive investments were made in real estate, leading to inefficient uses of the available capital. When the exchange rates rose loans could not be repaid, foreign portfolio capital fled, and Asian firms found it difficult to finance needed imports of essential intermediate products.

Current events have exposed significant vulnerabilities in Asian and other developing economies, raising questions about the timing and extent of short- and long-term recovery. Developing economies need to devote much of their economic resources to improving infrastructure (education, transportation, and communication as well as energy resources) and tend to rely on international capital flows to finance much of their investment. But international capital flows, especially portfolio investment, are volatile and may have substantial impacts on short-term growth. Whether long-run growth is also affected depends on the reasons for the financial instability, the underlying economic characteristics of the country (such as the skill of the labor force), the domestic savings rate, the prospects for traded goods in global competition, and the infrastructure that supports the economy.

In Thailand, Indonesia, and South Korea, the International Monetary Fund (IMF) has agreed to supply capital in exchange for agreement to a set of fiscal and monetary policies designed to reduce volatility in financial markets. The policies are aimed at decreasing government expenditures, removing some government controls over the financial sector, allowing insolvent financial institutions and businesses to fail, and allowing more foreign ownership to encourage foreign direct investment. The short-run impacts of such policies are likely to be higher inflation, lower imports, and reductions in sectors of the economy that are sensitive to interest rates (such as construction and investment). One result is projected lower economic growth for the next several years.

The Asian recession is proving to be more severe than anticipated last year when *AEO98* was being prepared. At that time, most analysts thought that the Asian crisis would follow the course of the Mexican crisis of 1994, when the Mexican economy saw a severe drop in GDP growth in 1995 (6.2 percent), followed by positive growth (5.2 percent) in 1996.

A number of factors have contributed to a deeper recession in Asia than originally expected. First, with import demand plunging in many Asian countries, intraregional trade, which fueled growth in the early 1990s, has collapsed. The Japanese economy—weak at the beginning of the Asian crisis—has not yet recovered. In contrast, during Mexico's rapid economic recovery after its 1994 currency crisis, its main trading partner, the United States, was experiencing strong economic growth. Second, high interest rates and weak currencies have made it difficult for Asian countries to obtain financing for essential intermediate inputs. Without the necessary inputs, many export products cannot be produced. Finally, with the collapse of many Asian countries and the absence of a Japanese recovery, world export demand has not been sufficient to offset the drop in intra-Asian trade. Domestic demand in the Asian countries must recover before the intraregional trade can resume its impetus for growth.

High interest rates, prescribed by the IMF, were expected to cut wasteful spending while attracting more capital to the East Asia region. In fact, however, investors have been unwilling to channel their money to countries where there is a risk of further currency devaluations. Tighter credit has substantially reduced domestic demand in the affected countries, but the region's exchange rates are still volatile.

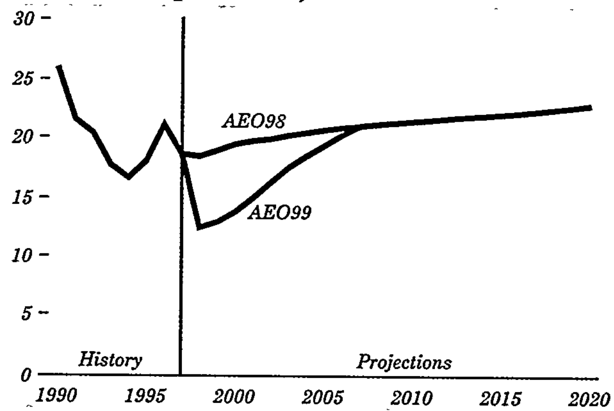
Whether the sharp currency devaluations in East Asia will lead to lower growth rates over the next 25 years will depend in large part on the policies enacted in response to short-run developments. If the financial reforms enacted make financial transactions more transparent, then market conditions will judge the efficacy of new investments. Making investment decisions more market-driven could lead to potentially higher long-run economic growth, especially given the relatively high education levels and savings rates of the labor force.

Impacts on the World Oil Market

Over the past 2 years, crude oil prices have dropped by more than 40 percent, reflecting a significant world oil surplus. Abundant supply and weak worldwide demand, especially among the struggling economies of the Pacific Rim, have combined to produce the lowest world oil prices since the early 1970s.

The timing and magnitude of an expected rebound in demand for oil and in world oil prices are the source of much uncertainty in *AEO99.* The reference case forecast assumes that real prices for oil rise at an annual rate of almost 6 percent from 1999 to 2007. After 2007, the reference case oil prices are similar to those in the *Annual Energy Outlook 1998* (*AEO98*), rising at an annual rate of less than 1 percent (Figure 8). Developments that could contribute to delaying the return until 2007, as opposed to a more rapid rebound, include the following.

Figure 8. World oil price projections in the AEO98 and AEO99 reference cases, 1990-2020
(1997 dollars per barrel)

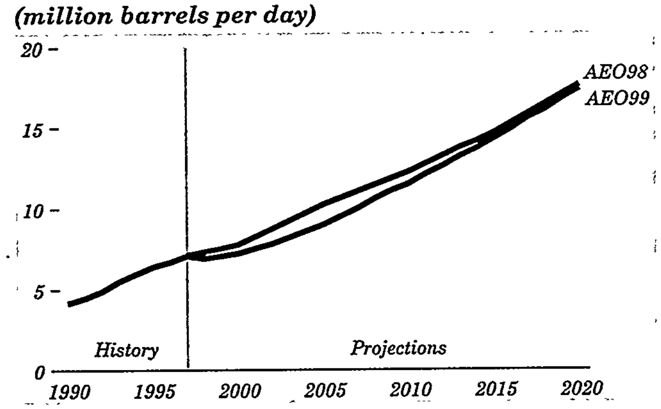


The Organization of Petroleum Exporting Countries (OPEC) has agreed on production cutbacks of about 2.6 million barrels a day in 1998 to counter the slow growth in world oil demand and the drop in oil prices. There is much skepticism, however, as to whether member nations will strictly adhere to such quotas. Prior excursions into quota-setting have resulted in temporary impacts on world oil prices, but cutbacks have been difficult to maintain and verify over the long term. Many OPEC countries are almost totally dependent on oil export revenues for their national income, and production cutbacks are especially painful. An additional factor of critical importance to OPEC supply potential is the reemergence of Iraq as an oil exporter. The United Nations Security Council has agreed to allow Iraq to export oil (for humanitarian reasons) at a rate of 1.6 million barrels a day. When Iraqi export sanctions are eventually lifted (assumed to be after 2000 in the reference case), Iraq could easily expand its production capacity to more than 3 million barrels a day by 2005. In addition, several non-Persian Gulf OPEC members (Algeria, Nigeria, and Venezuela) have active plans to expand their production capacities over the next half-dozen years.

Non-OPEC production potential continues to grow despite the low price environment. North Sea production is expected to peak by the middle of the next decade at levels that are at least 1 million barrels a day greater than current output. Other countries within the Organization for Economic Cooperation and Development (OECD) that are expected to register production increases within the next decade include Australia, Canada, and Mexico. In Latin America, Argentina, Brazil, and Colombia 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 are not expected to be delayed and will start producing significant volumes early in the next century. Because subsea oil platforms have to be scheduled so far in advance, most of the world-wide deepwater projects are proceeding on schedule even at today's prices.

The bleak economic outlook for several Southeast Asian economies has significantly dampened the growth in oil demand for the region, which in recent years has accounted for about one-half of the growth in Asia's oil demand. In 1998 demand is expected to decline, and the timing of its recovery has become increasingly uncertain. Other regions whose near-term GDP growth is less optimistic than that assumed in *AEO98* include China, the Former Soviet Union, and Japan. Even with lower oil prices, near-term oil demand is expected to increase at only about half the rate of the past 5 years (Figure 9).

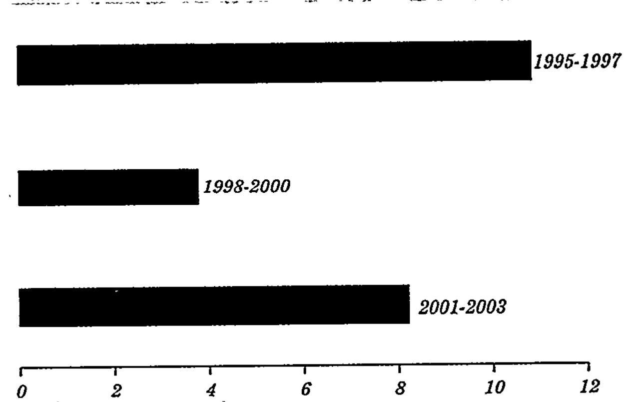
Figure 9. Oil demand projections for developing Asia in AEO98 and AEO99, 1990-2020 (million barrels per day)



Impacts on the Demand for U.S. Exports

In the near term, export demand for U.S. goods and services will suffer as world activity slows in response to these near-term volatile events (Figure 10). After expansive growth from 1995 through 1997, averaging over 11 percent a year, the growth in demand for U.S. exports slowed to less than 1 percent in 1998 and is expected to average less than 4 percent from 1998 through 2000. Export demand is expected to rebound by the year 2000 and sustain a growth rate of 8 percent a year from 2001 through 2003.

Figure 10. Projected annual growth in real U.S. exports, 1995-2003 (percent)



Because only a relatively small portion of U.S. exports goes to those countries where current economic disruptions are greatest, current Asian events are not expected to have as lasting an effect on the U.S. economy as on the world oil market. Nonetheless, compared with *AEO98*, slower growth in exports is expected from 1997 through 2010 in the *AEO99* reference case. The expected reduction in export demand is expected to reduce real GDP growth by as much as a tenth of a percentage point. The relatively lower growth in exports in the first 10 years of the forecast results in slower growth in domestic U.S. manufacturing relative to last year's expectations. Manufactured goods are affected more by export and import trends in the economy than are either services or wholesale and retail trade. As exports recover, so does the growth rate of manufactured output.

Responding to Growth in Demand for Natural Gas

In the *AEO99* reference case projections, natural gas consumption in 2020 is nearly 50 percent higher than the 1997 level of 22.0 trillion cubic feet. In order to satisfy the demand projected for 2020, a number of changes will be needed in the U.S. natural gas industry, including a significant increase in production and considerable expansion of infrastructure. Onshore and offshore production are projected to increase by 57 and 14 percent, respectively, and pipeline capacity to increase by 32 percent over 1997 levels. Although today's market differs from the markets that existed in past periods of significant growth, increases well above those projected in *AEO99* have been realized in the past, and the industry's past performance gives reason for confidence that the projected increases can be accommodated.

Interregional pipeline capacity increased by 6.9 trillion cubic feet (21 percent) over the 7-year period from 1990 (the first year EIA began compiling capacity data) to 1997. The driving force behind the expansion was not to meet an overall increase in demand *per se*—the 1997 market of 22.0 trillion cubic feet is roughly equivalent in size to the 1972 historical peak of 22.1 trillion cubic feet—but instead to provide new access corridors as supply and demand centers shifted in a changing market. Similarly, the need for additional pipeline capacity projected in *AEO99* primarily reflects the demand for greater customer access to new and expanding supply sources and for supplemental capacity into areas of growing demand where peak period utilization is approaching maximum available capacity.

As an example, proposed additional capacity from Canada will bring significantly greater volumes of gas to the midwestern marketplace. At the same time, several existing pipelines already have the capacity to move large volumes of gas from the South Central region to the same area. As capacity expansion projects proceed over the next several years, there is a strong potential for surplus supply to develop in the Chicago area. As a result, pipelines exiting the South Central region that compete with Canadian gas could become underutilized. To alleviate the situation, and to address the growing demand for natural gas in the Northeast, a number of projects have been proposed that would tap into the expanding Chicago hub and redirect some of its supplies eastward.

Much of the new capacity that has been added since 1990 or is to be completed by 2000 consists of long-haul pipelines from growing supply areas. By 2000, much of the projected new capacity will be able to link with nearby major long-haul pipelines already in operation, so that the primary short-term requirements will be for feeder lines to tap into the existing pipelines or compression and looping along existing routes where capacity needs to be augmented. Compression and looping are much less expensive than laying pipe along new routes and usually require less lead time.

Much of the expansion projected in *AEO99* before 2001 already is either under construction or planned, and more than half the pipeline expansion expected by 2020 is likely to occur between now and 2000. A number of projects have been proposed (although not all of them will actually be built), and substantial investment has been made in pipeline expansion. The added capacity will provide access to new and expanding production areas, such as Canada and the deep offshore, and will accommodate shifts in demand patterns, such as new demand for natural gas to replace electricity generation capacity lost as a result of nuclear retirements.

Government policy supports an optimistic outlook for the post-2000 pipeline expansion forecast. FERC policy allows the pipelines to assume more risk rather than requiring firm contracts to be in place before approving an expansion, and the Council on Environmental Quality has recently allocated funding to promote interagency cooperation in the review of pipeline permits, with the primary intention of speeding up the process. The FERC has responded positively to issues raised by the pipeline industry regarding its method of determining allowed rates of return by evaluating possible changes in the method it uses to calculate returns. Pipelines have claimed that they face considerable risk because of increased competition and the threat of capacity turnback, and that the 12- to 13-percent average rate of return for pipelines in 1996 was far lower than the 20-percent rate earned by most public companies [*17*].

Another issue that the industry will face in meeting the production forecast is supply availability. Uncertainty in estimates of the Nation's natural gas resources, both onshore and offshore, has always been an issue in projecting production [*18*]. Despite the fact that offshore production levels in the *AEO99* forecast do not exceed current levels until 2003—suggesting that offshore production will not be a problem—there are a number of potential problems related to the recovery of natural gas from offshore areas.

One issue is a potential shortage of offshore rigs and skilled personnel. Although the short-term situation has changed with the recent downturn in oil prices, every available offshore rig was in use throughout 1997, and the construction of new rigs has been limited by uncertainty surrounding their demand for the longer term. The lead time for construction of new rigs is 2 to 3 years, and costs range from $115 million for a 350-foot jack up to $325 million for a deepwater semisubmersible [*19*]. Training is needed to develop a work force for offshore production, and because of its cyclical history many people are reluctant to enter this work force.

An additional issue is the need for infrastructure expansion. Infrastructure to move natural gas from offshore drilling platforms to the shore will need to expand as production grows, and gathering systems for offshore production, the costs of which are not known with certainty, need to be developed. Despite the problems these issues may present, however, continuing developments in offshore technology have improved the prospects for offshore gas production. Although there have been some spending cutbacks as a result of current low oil prices, investments are being made in all these areas, and technology advances are cutting lead times and improving the economics of smaller fields.

Because of expected growth in natural gas demand, several studies are being undertaken to assess what steps the natural gas industry needs to take to be able to respond. Former Secretary of Energy Federico Peña commissioned the National Petroleum Council (NPC) to undertake a study of what is needed for the industry to be able to respond to demand increases. In addition, the Natural Gas Supply Association (NGSA) is working on a report that will analyze whether the industry can meet increased demand projections without increasing wellhead prices, and the Interstate Natural Gas Association of America (INGAA) is working on a study to determine what needs to be done for the pipeline industry to meet the needs of a market of 30 trillion cubic feet by 2010 (2 trillion cubic feet above the *AEO99* forecast). The key uncertainties in satisfying a market of that size are where the demand will occur and whether there is enough pipeline capacity to move the gas into growing demand centers.

The INGAA study addresses the question of whether the pipeline industry can provide the expanded infrastructure needed to get the gas to market. One of the problems with rapid expansions is the lead time necessary for a pipeline project. Barring unforeseen delays, capacity expansion requires a lead time of 2.5 to 3 years. If an environmental impact statement is required, it can add another 3 months to the completion time [*20*].

The pipeline capacity expansion currently underway reflects the industry's anticipation of an expanding market. Positive steps are also being taken in other parts of the industry. Again, despite recent cutbacks resulting from low oil prices, investments still are being made in exploration and production, and they are expected to continue, largely independent of lower oil prices, as higher gas prices provide a positive incentive for investment. In fact, spending on natural gas projects increased in the first quarter of 1998 and was unchanged in the second quarter [*21*].

The rising levels of demand and prices for natural gas projected in *AEO99* will provide additional economic incentives for the investments in infrastructure, rigs, drilling, and manpower development needed to meet the necessary increases in gas production. As a result, it is expected that the natural gas industry will be in a position to meet the challenge of satisfying the demand increases projected.

Renewable Portfolio Standards

Federal legislation proposed by Senator Jeffords, Senator Bumpers, and Congressman Schaefer include renewable portfolio standard (RPS) provisions that are similar to those included in State restructuring plans. Each of the Federal bills proposes a renewable credit system as described in "Legislation and Regulations" (see page 15). The key differences in the respective RPS provisions are the required renewable share and the renewable technologies that would receive credits. The share required by 2020 varies from 4 percent in H.R. 655 (Schaefer) to 20 percent in S. 687 (Jeffords). Each of the bills allows all nonhydroelectric renewable resources to receive credits. S. 237 (Bumpers) also provides partial credits to large hydroelectric facilities, greater than 80 megawatts.

In March 1998, the Clinton Administration released its Comprehensive Electricity Competition Plan [*22*], and in June 1998 the Secretary of Energy submitted the Administration's proposed legislation to implement the plan. Section 302 of the proposed Comprehensive Electricity Competition Act [*23*] calls for the establishment of a Federal RPS. Beginning in 2000, each retail electricity supplier would be required to submit to the Secretary of Energy renewable energy credits in an amount equal to the required percentage. Credits would be earned for each kilowatthour generated from solar, wind, geothermal, or biomass plants. The proposed percentage reaches 5.5 percent in 2010 and remains there through 2015. Between 2000 and 2010 the required percentage is to be determined by the Secretary of Energy, but it would be less than 5.5 percent. The following analysis illustrates the potential effects of the proposed RPS. For purposes of the analysis, it is assumed that the required share would grow linearly from 0 to 5.5 percent between 2000 and 2010 and remain at 5.5 percent through 2015, at which time the requirement would be eliminated [*24*].

The RPS would have an impact on the types of plants built to meet the growing demand for electricity. New wind and biomass plants, and geothermal to a lesser extent, are expected to make key contributions in meeting the RPS (Figure 11). In the reference case, only 9 gigawatts of new renewable plants are expected to be built, because in most situations they are not competitive with fossil alternatives. Under the proposed Federal RPS, however, renewable technologies would play a larger role. In the Federal RPS sensitivity case, more new wind plants are expected to be built in some regions of the country, particularly in the Northwest, Southwest, and Upper Midwest.

The United States has vast wind resources in some areas, but many are in regions of low demand, and there is some uncertainty about the costs of developing them and delivering their power. For example, some of the best wind resources are located far from transmission lines and load centers, in environmentally sensitive areas, or on terrain that it is not suitable for economical construction.

In terms of biomass, there are significant supplies of relatively low-cost biomass that, for the most part, are not currently being used for energy production. The low cost of fossil fuels, particularly coal, makes them unattractive. For example, there are large amounts of urban wood waste, tree trimmings, construction and demolition debris, and discards such as crates and pallets that could be burned to produce energy, rather than disposed of in landfills. These materials can be burned in standalone facilities, but a less expensive alternative may be to use them as a secondary fuel in existing coal-fired plants. Many existing coal plants may be able to consume up to 5 percent of their total fuel input as biomass with relatively minor modifications, and even higher levels are possible with more significant modifications. In this analysis, coal-fired plants are permitted to meet up to 5 percent of their fuel needs with biomass if it is economical; however, use of the biomass option is limited by the projected low cost of coal.

Although the required share for renewables is relatively low in the Federal RPS sensitivity case, it would nevertheless have an impact on electricity prices (Figure 12), which are projected to be almost 2 percent higher in 2010 and 2015 than they are in

Figure 11. Renewable electricity generation in two cases, 2020 (billion kilowatthours)

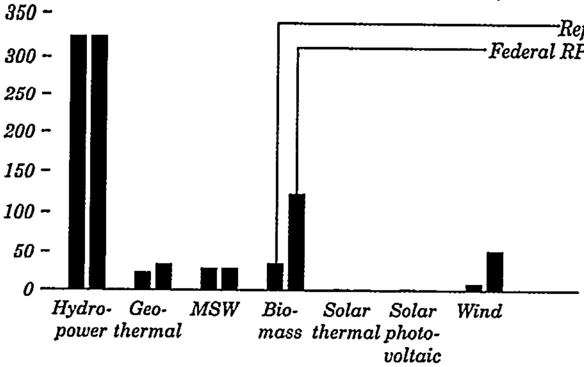
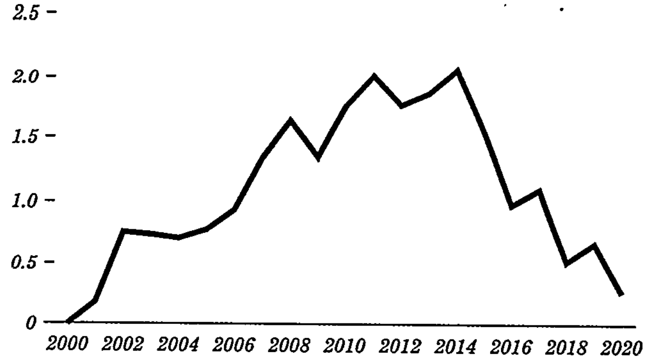
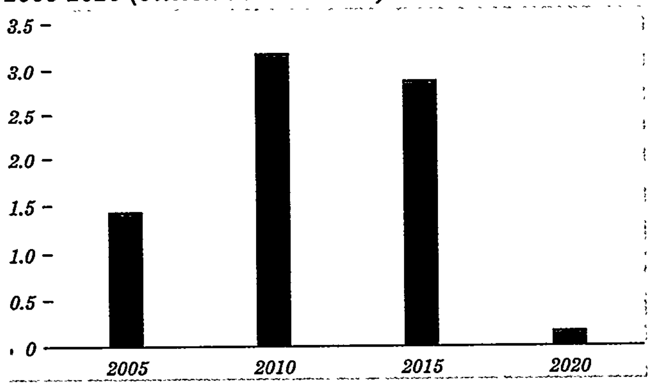


Figure 12. Change in average U.S. electricity prices in the Federal RPS sensitivity case from the reference case, 2000-2020 (percent)



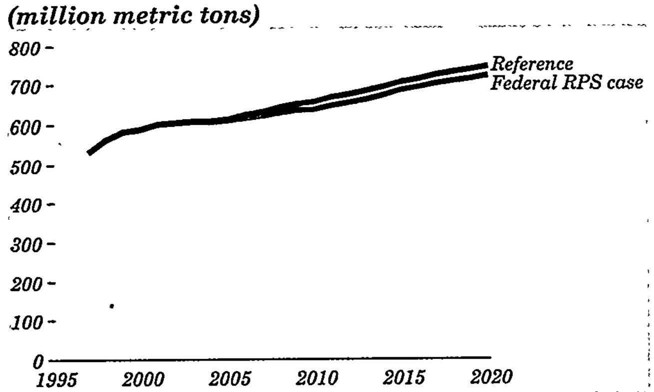
the reference case. The impact is less in the later years because renewable technologies are expected to become more economical over time, with costs declining once they begin to penetrate the market. The price impact almost disappears in 2020, when the RPS has ended. The projected price differences are relatively small, but they do amount to an added cost to consumers. The annual impact varies between \$1.4 billion and \$3.7 billion a year between 2005 and 2015, with the average residential electricity bill projected to be about \$1 a month higher than in the reference case in 2010 (Figure 13). After 2015 the impact declines sharply.

Figure 13. Variation from reference case national electricity costs in the Federal RPS sensitivity case, 2005-2020 (billion 1997 dollars)



The imposition of the RPS would have a positive effect in reducing emissions. Because the new renewable facilities built to comply with the RPS would displace output from fossil plants, total emissions would be lower. For example, the 5.5 percent RPS reduces electricity sector carbon emissions by approximately 23 million metric tons a year between 2010 and 2020 (Figure 14). Emissions of nitrogen oxides (NO_x) and sulfur dioxide (SO_2) are not significantly reduced, because their levels are explicitly capped, and implementing the RPS would not lead to further reductions. The imposition of the RPS is projected to reduce slightly the incremental cost of meeting the NO_x and SO_2 caps.

Figure 14. Projected U.S. electricity-related carbon emissions in two cases, 1996-2020 (million metric tons)



Electricity Pricing in a Competitive Environment

Electricity markets in many parts of the United States are being restructured to increase competition. Competitive pressures are affecting the operations of electricity generators, even in areas where no formal restructuring legislation has been introduced. For example, operating and maintenance costs for existing power plants have been falling in recent years, and further reductions are anticipated. To reflect this trend, the *AEO99* reference case assumes a 25-percent reduction in current nonfuel operating costs in all regions over the next 10 years. Capital costs and operating efficiencies for new plants are also assumed to improve over time in all regions.

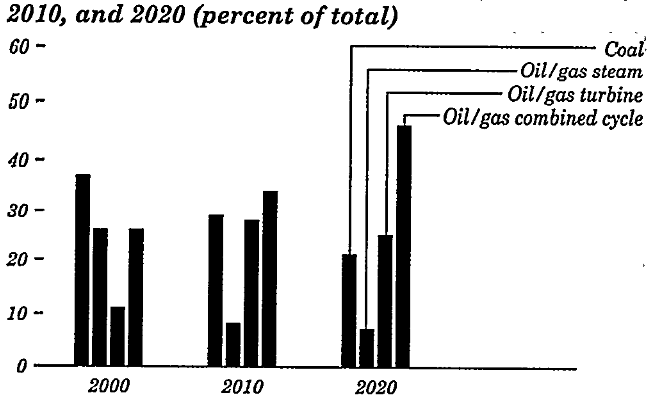
Future investment decisions may also be affected by increasing competition. Accordingly, the *AEO99* reference case assumes higher costs of capital and shorter recovery periods. Thus, the reference case forecast incorporates many of the expected effects of industry restructuring in all regions, including those where competitive pricing legislation or other binding rules have not been passed.

Historically, prices have been set administratively as the average embedded costs of producing electricity, including all fuel and operating and maintenance costs, as well as recovery of construction costs and a regulated profit. In a competitive market, generation prices will vary over time (even hour to hour), and will be set in each time period by the operating costs of the most expensive plant needed to meet demand at that point in time—the "marginal cost" of production. The marginal cost typically includes the fuel and variable operating and maintenance costs for the generator.

During periods of high demand in a competitive market, when the demand for electricity approaches the available generating capacity, prices might rise over the operating costs of the most expensive generator operating. Such occasional price spikes can encourage consumers to reduce their usage so that supply and demand are kept in balance. Similarly, prices consistently over the marginal operating costs will provide incentives for the construction of new generating capacity.

In *AEO99*, a full competitive pricing sensitivity case assumes that competitive pricing will be phased in throughout the United States over 10 years, with full competitive pricing based entirely on marginal costs occurring by 2008. Currently, marginal operating costs are generally lower than average embedded costs, which include the recovery of construction costs on plants that are not competitive in today's market. With a gradual shift to full competitive pricing, it is assumed that a portion of such costs will be recovered in the competitive price. When the uneconomical generators have either been paid for or retired, average costs are expected to approach, and possibly fall below, marginal costs. In the early years of the forecast, coal-fired units are projected to be used most often to set the marginal cost (Figure 15). In the later years, as demand increases and most new capacity is gas-fired, the projected marginal unit is more often a combined-cycle or turbine unit, and the marginal costs are dependent on gas prices. As a result, by 2020, marginal costs are projected to be slightly higher than average costs.

Figure 15. Percentage of time that different plant types set national marginal electricity prices, 2000, 2010, and 2020 (percent of total)



It is worth noting that the areas with the highest electricity prices under regulation (New York, New England, and California) were among the first to pass legislation allowing competition between electricity suppliers. Because the *AEO99* reference case assumes marginal cost pricing for electricity generation in those regions that have enacted restructuring legislation, the regions that would expect the largest price declines as a result of competitive pricing are assumed to have competitive electricity prices in both the reference and full competitive pricing cases. (The reference case assumes a transition to competitive pricing in California, New York, the New England States, the Mid-Atlantic States, and the Mid-America Interconnected Network—Illinois and parts of Wisconsin and Missouri.) As a result, the projected differences in national average electricity prices between the two cases are relatively modest, ranging from 5 percent lower in 2005 to 4 percent higher in 2020 in the full competitive pricing case than in the reference case. In 2020, the electricity price in the full competitive pricing case is higher than in the reference case because of increasing natural gas prices, which affect marginal electricity prices more directly than average prices. Detailed results from the full competitive pricing case are presented in Appendix F, Table F9.

The full competitive pricing case also assumes that some consumers will be able to respond to time-of-use pricing by altering their demand patterns. Through "load-shifting," consumers can reduce usage during a peak period, when prices are high and supply is tight, and shift that usage to an off-peak period. The net effect is lower peak demand and a flatter demand pattern for the year, with less variation between the lowest and highest points. Load shifting could also reduce the need for new capacity, because peak demand would be lower, so that different types of capacity would be built. In the full competitive pricing case, 28 gigawatts less new capacity is projected to be built by 2020 than in the reference case. Some of the difference results from lower reserve margins overall under full competitive pricing (reserve margins are projected to be as much as 3 percentage points lower nationally), but a portion is also due to the flatter load pattern.

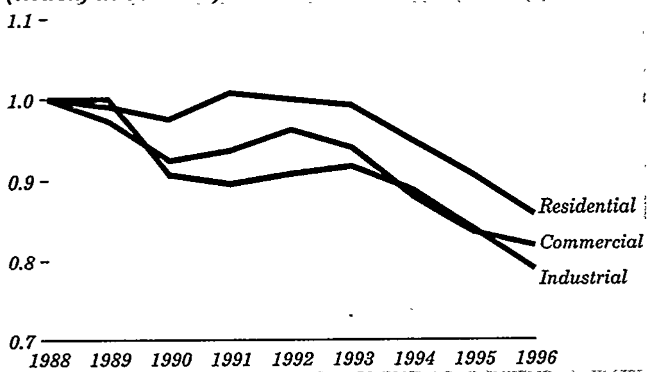
Sectoral Pricing of Electricity in Competitive Markets

The emergence of competitive markets for generation in the electricity industry has created the potential for a new distribution of costs and benefits among classes of utility customers. Traditionally, rates were set by regulators on the basis of "embedded costs"—the average cost of producing electricity and serving the customer, including both short-run costs such as fuel and long-run costs such as plant and capital recovery. Because rates were set to cover all costs, including return on capital invested, this was referred to as "rate-of return regulation." Rates were generally set to reflect average costs rather than the more volatile fluctuations in marginal costs.

Historically, given the large transaction costs associated with real-time pricing, average cost pricing was seen as ensuring that revenues would cover total costs. Because some activities or investments, such as maintenance of a substation, serve multiple customer classes, regulators developed various methods of allocating the costs to different customer classes. Typically, both fairness and efficiency [25] played a role in setting customer class tariffs [26].

The changing nature of the electric utility industry will undoubtedly modify the pattern of allocations of costs among customer classes, with market forces having a greater role. Although all customers are expected to benefit eventually from the introduction of competition in the generation function, the rate and degree of such benefits may vary by customer class. Figure 16 shows sectoral prices of electricity in the United Kingdom during the period 1988-1996—when the electricity industry was privatized and competition was introduced in the generation sector—indexed to 1988 prices. Profitability in the regulated market was allowed to rise for 2 years before the introduction of competition in 1990. Savings from the introduction of competition were realized more quickly by the larger customers first.

Figure 16. Real electricity prices in the United Kingdom after deregulation, 1988-1996 (index, 1988 = 1.0)

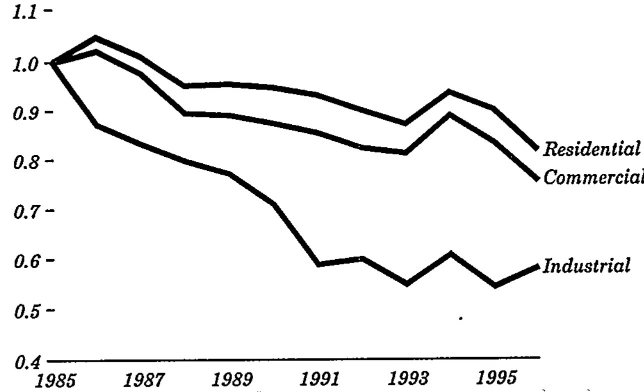


Initially only the largest customers in the United Kingdom, those with peak loads of more than 1 megawatt (approximately the size of 500 households), had a choice of suppliers. These customers were referred to as non-franchise customers, and they had the choice of any of the 12 Regional Electricity Companies (RECs), or other independent generating companies. Franchise customers, primarily residential and small commercial, were required to purchase electricity through their local RECs. The franchise threshold was lowered to 100 kilowatts in 1994, and all customers were to have choice of suppliers by the end of 1998.

In general, over this time, small consumers have seen only modest price reductions. As the franchise limitations were removed, first large and then medium industrial customers received greater benefits, although there was a good deal of variation in the experience of industrial customers. Some very large industrial customers, participants in the "qualifying industrial customer scheme" (QUICS) program before privatization, initially saw price increases and have received relatively little benefit from the competitive market [27]. As shown in Figure 16, even after a transition period, it is likely that the effect of deregulation will vary by customer class.

As markets are restructured, firms have incentives to change their pricing to meet specialized demands. An example is the U.S. natural gas market for transmission services, where restructuring resulted in a wider array of options for some customers. In particular, those customers with more flexibility in their transmission and distribution requirements were in a position to reduce their overall price of service. Those users, primarily large industrial consumers, benefited most from the restructured natural gas market [28]. Figure 17 shows the transmission and distribution markup (the difference

Figure 17. Index of real U.S. natural gas transmission and distribution markups by end-use sector, 1985-1996 (index, 1985 = 1.0)



between the wellhead and end-use prices of natural gas) by sector from 1985 to 1996, indexed to 1985. As shown, the average price of transmission and distribution for industrial users declined significantly more (on a percentage basis) than that for residential users.

Traditionally, an electric utility was granted an exclusive franchise over its territory and served as a regulated monopoly. Because customers are easily identified by demand level and have different price elasticities of demand, a utility can charge different prices to different customers. In a regulated monopoly, there is no inherent requirement that prices equal long-run average costs. In order for the revenue requirements of the utility to be met, some price differentials must be established. That is, if every customer class were charged its incremental cost of service, a utility might not cover its total costs. Allocation of such costs over and above the incremental costs are decided by regulators. Such allocations, translated into rates, result in different prices per kilowatthour for different customers. Such differences are inherent in traditional rate development [*29*].

Given the traditional market structure of a regulated monopoly, efficiency considerations encourage the adoption of a pricing approach whereby classes of customers with inelastic demands pay a higher markup over marginal cost than those with more elastic demands [*30*]. However, the goal of equity leads policymakers to set prices that are seen as fair and reasonable. This goal can lead regulators to deviate from the economically optimal pricing methodology so as to avoid imposing "unreasonably" high prices on groups with inelastic demands. Thus, regulated sectoral pricing deviates from economically optimal pricing, because both equity and efficiency are important in setting rates.

Figure 18 compares actual prices of electricity by customer class in 1996 with an estimate of what such prices would look like if the costs were allocated in an economically optimal (market-based) manner. The results indicate that current industrial and commercial prices are largely higher and current residential prices are lower than the prices associated with the economically optimal solution. Significant changes may occur when there is a restructured electricity generation market. Figure 19 compares the generation price by customer class in the full competition case, in which generation is assumed to be priced on a marginal cost basis. It is also assumed that, through the function of an independent system operator (ISO) or other market structure, the generation component of price at any one time will be equal for all customers. That is, the difference between the average yearly price of the generation component of electricity for different customer classes depends only on the fraction of annual electricity requirements purchased during high-priced periods. With these assumptions, the average annual generation prices are nearly equal for the different customer classes.

Figure 18. Actual 1997 electricity prices by sector and calculated prices with optimal pricing (1997 mills per kilowatthour)

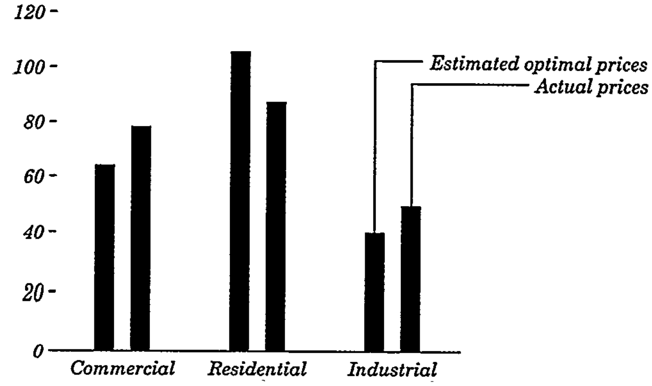
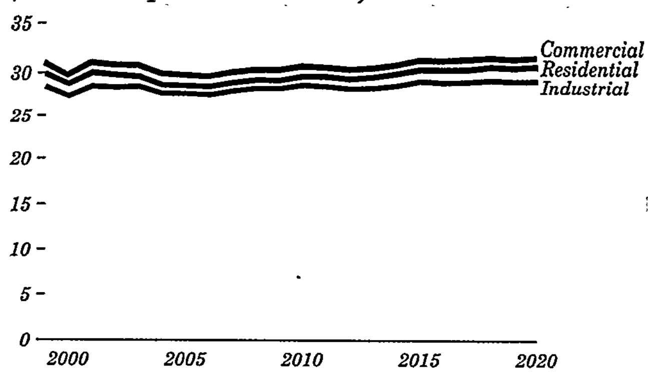


Figure 19. Generation component of electricity prices by end-use sector, 1999-2020 (1997 mills per kilowatthour)



The reason that sectoral generation prices are nearly equivalent is illustrated by the representative price-duration curve shown in Figure 20, depicting the ranked hourly price of electricity from the most expensive to the least expensive hour. The key feature of the graph is that the price-duration curve is relatively flat on a per-kilowatthour basis. A flat

Figure 20. Electricity generation price duration curve for the New England region (1997 mills per kilowatthour)

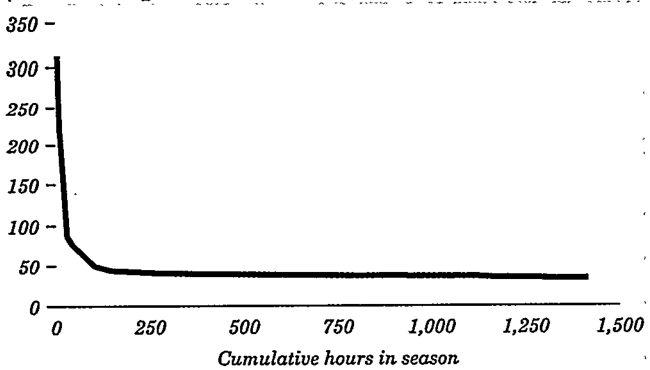
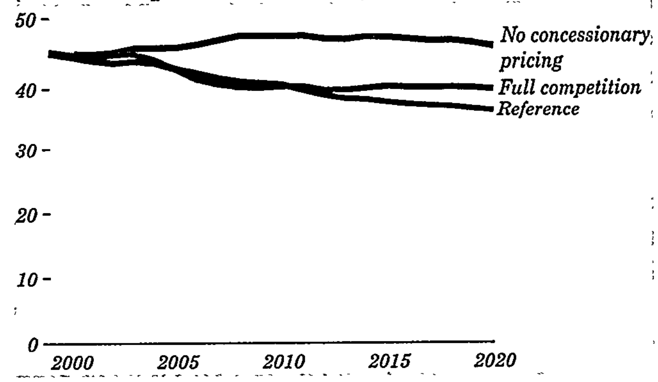


Figure 21. U.S. industrial electricity prices under three fixed cost allocation options, 1999-2020 (1997 mills per kilowatthour)



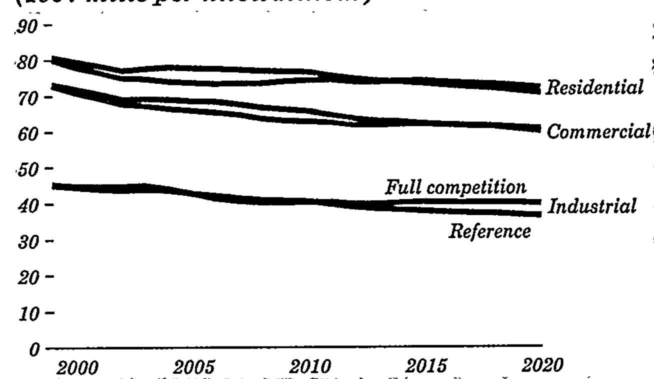
curve shows that, except for a limited number of peak hours, the price of generating electricity is relatively constant. Therefore, in a fully competitive market, the generation price is similar for all customer classes.

Although both transmission and distribution are assumed to be regulated, there is reason to believe that the unbundling of generation from transmission and distribution may provide medium and large consumers with a greater ability to obtain price concessions from the operator of the distribution system. Specifically, under the new market structure, some consumers may have the ability to bypass the distribution system at relatively low cost by connecting directly to the transmission system or building an on-site generator. Concessionary pricing, i.e., changes in the allocation of fixed costs among the customer classes, may be necessary to retain such customers.

Figure 21 compares the industrial price in the reference case with that in the fully competitive case, including concessionary pricing of transmission and distribution. As a counterpoint, another projection is shown, based on the assumption that industrial customers would be unable to obtain any additional concessions from the operators of the transmission and distribution system (no concessionary pricing). If average generation prices by customer class tend to converge, it is possible that industrial prices could rise significantly above the reference case price without reallocation of costs within the regulated transmission and distribution sector. Prices would be modestly higher than those in the reference case if such reallocation occurred.

Figure 22 compares national sectoral prices in the fully competitive market case with those in the reference case. Given that similar efficiency improvements are assumed in the reference and full competition cases, it is not surprising that the price paths are similar. However, this analysis assumes that, if pricing is nondiscriminatory in the generation market, larger customers will nonetheless maintain their ability to achieve lower rates through market pressures on the remaining regulated portions of the industry.

Figure 22. U.S. electricity prices by end-use sector in the reference and full competition cases, 1999-2020 (1997 mills per kilowatthour)



Although the approach toward analyzing sectoral prices represents an advance over previous EIA analyses, a great deal of uncertainty remains. Clearly, the precise market structures that evolve will have a significant effect on price, as will the extent and speed at which new technologies, as well as market forces, influence the ratemaking process. Moreover, the validity of these projections depends on the consistency between EIA's assumptions about market structures and their actual performance. Finally, any assumptions about regulators' behavior are subject to changes in the overall regulatory environment.

Gasoline Sulfur Reduction

In early 1999, the U.S. Environmental Protection Agency (EPA) is expected to propose tighter restrictions on the amount of sulfur allowed in gasoline. Because gasoline sulfur and automotive emissions are linked, the proposal will be issued in conjunction with the new "Tier 2" vehicle exhaust emissions standards that would take effect between model years 2004 and 2007 (see "Legislation and Regulations," page 11). Sulfur reduces the effectiveness of the catalyst used in the emissions control systems of advanced technology engines, increasing their emissions of hydrocarbons, carbon monoxide, and NO_x. As a result, gasoline with significantly reduced sulfur levels will be required for the control systems to work properly and meet the new Tier 2 standards.

The EPA has been considering lowering the average annual sulfur content of gasoline to between 150 and 30 parts per million (ppm), from the existing standard of 1,000 ppm. The current national average gasoline sulfur content is 340 ppm [*31*]. The existing limit for all gasoline in California is an annual average of 30 ppm, with a cap of 80 ppm, or a flat (unaveraged) limit of 40 ppm. Discussions of California-like sulfur limits may be framed in terms of a "30 ppm" or a "40 ppm" limit, but for all intents and purposes, the two are the same.

A joint study by the EPA and the U.S. Department of Energy (DOE) put preliminary sulfur reduction costs for East Coast and Gulf Coast refiners at 5.1 to 8.0 cents a gallon for 40 ppm gasoline and 1.1 to 1.8 cents a gallon for 150 ppm gasoline. A study sponsored by the American Automobile Manufacturers Association estimated the cost of reducing sulfur to 40 ppm at 5.5 cents a gallon for refiners in the eastern half of the country. Another study sponsored by the American Petroleum Institute (API) estimated the costs of sulfur reduction at 5.1 cents a gallon for 40 ppm gasoline and 2.7 cents a gallon for 150 ppm gasoline [*32*].

Although there is a broad consensus that gasoline sulfur must be reduced, the level of reduction and the application of the requirement have been intensely debated. In addition to determining the appropriate sulfur level, the EPA is considering whether to make sulfur reduction a national or regional requirement. The range of sulfur reduction options under consideration by the EPA is bounded by proposals from two groups: automakers—the American Automobile Manufacturers Association and the Association of International Automobile Manufacturers—and gasoline producers—the American Petroleum Institute (API) and the National Petrochemical and Refiners Association (NPRA). *AEO99* includes the two proposals as alternative cases to explore their potential impacts on the long-term projections of gasoline supply and prices.

The automakers propose to reduce the average allowable sulfur content of gasoline in the United States to 40 ppm, which is equivalent to the current standard in the State of California. The API/NPRA submitted a less stringent regional proposal in which all gasoline in Federal reformulated gasoline areas, in 23 States, and in East Texas would meet an annual average of 150 ppm [*33*]; gasoline in California would continue to meet the State's gasoline requirements, including the 40 ppm annual average sulfur limit; and gasoline in all other parts of the country would have an annual average of 300 ppm. API/NPRA proposes further sulfur reductions by 2010 in areas that require year-round NO_x control. The areas of coverage and the level of sulfur reductions would be determined by an EPA study. In the API/NPRA analysis case, all the areas required to use 150 ppm gasoline in 2004 were assumed to require further reductions to 40 ppm by 2010.

As expected, the price impact is greater in the case based on the automakers' proposal (which is a more severe, nationwide plan) than in the API/NPRA case. Both cases assume that the additional costs associated with sulfur reductions would be passed on to consumers. Relative to the *AEO99* reference case, the API/NPRA scenario increases the average price of gasoline by 1.3 cents a gallon in 2004 and by 4.9 cents a gallon in 2010. The automakers' scenario increases the price by 8.3 cents a gallon in 2004 and 6.8 cents in 2010. The API/NPRA scenario increases total consumer spending for gasoline by $1.8 billion in 2004 relative to the *AEO99* reference case and by $7.6 billion in 2010. In the automakers' scenario, the corresponding increases are $11.7 billion in 2004 and $10.5 billion in 2010. In both cases, the price increases reflect investments in sulfur reduction processes at refineries, as well as changes in the selection of refinery inputs.

Before 2010, the cost of sulfur reduction is lower in the API/NPRA scenario because sulfur reduction to the 300 and 150 ppm levels can be achieved largely by adjustments in refinery processes. On the other hand, sulfur reduction to the 40 ppm level, reflected in the automakers' scenario and after 2010 in the API/NPRA scenario, can only be achieved by more costly refinery upgrades, including naphtha hydrotreating, gas oil desulfurization, alkylation, and hydrogen units.

An interesting feature of both scenarios is that they lead to a projected increase in domestic production of gasoline and blending components relative to the reference case projections, with a corresponding reduction in projected imports. On the other hand, the reductions in imports of gasoline and blending components are more than offset by increased requirements for crude oil imports. The net result is that imports represent the same share of total projected petroleum requirements in the API/NPRA scenario as in the *AEO99* reference case and a slightly higher percentage in the automakers' scenario.

The Kyoto Protocol and Carbon Emissions

Greenhouse Gas Emissions and the Framework Convention

The greenhouse effect is a natural process by which some of the radiant heat from the sun is captured in the lower atmosphere of the Earth, thus maintaining the temperature of the Earth's surface. The gases that help capture the heat, called "greenhouse gases," include water vapor, carbon dioxide, methane, nitrous oxide, and a variety of manufactured chemicals. Some are emitted from natural sources; others result from anthropogenic, or human, activities. Over the past several decades, rising concentrations of greenhouse gases have been detected in the Earth's atmosphere, and it has been suggested that this may lead to an increase in the average temperature of the Earth's surface and consequently to detrimental effects.

In 1988, the Intergovernmental Panel on Climate Change (IPCC) was established by the World Meteorological Organization and the United Nations Environment Programme to assess the scientific, technical, and socioeconomic information in the field of climate change. The most recent report of the IPCC concluded that: "Our ability to quantify the human influence on global climate is currently limited because the expected signal is still emerging from the noise of natural variability, and because there are uncertainties in key factors. These include the magnitude and patterns of long term natural variability and the time-evolving pattern of forcing by, and response to, changes in concentrations of greenhouse gases and aerosols, and land surface changes. Nevertheless, the balance of evidence suggests that there is a discernible human influence on global climate" [*34*].

Following 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, Brazil, on June 4. 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." The signatories agreed to formulate programs to mitigate climate change. Furthermore, the developed country signatories agreed to adopt national policies to return anthropogenic emissions of greenhouse gases to their 1990 levels. The Convention excludes chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs), greenhouse gases that are deemed to cause damage to the Earth's stratospheric ozone and are controlled by the 1987 Montreal Protocol on Substances that Deplete the Ozone Layer.

Responding to the Framework Convention, on April 21, 1993, President Clinton called upon the United States to stabilize greenhouse gas emissions by 2000 at 1990 levels. Specific steps to achieve U.S. stabilization were enumerated in the Climate Change Action Plan (CCAP) [*35*], published in October 1993, which consists of a series of 44 actions to reduce greenhouse gas emissions. These actions include voluntary programs, industry partnerships, government incentives, research and development, regulatory programs, including energy efficiency standards, and forestry actions. Greenhouse gases affected by these actions include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs). At the time CCAP was developed, the Administration estimated that the actions in CCAP would reduce the total net emissions [*36*] of these greenhouse gases to 1990 levels by 2000.

In addition to the climate-related actions of CCAP, the Energy Policy Act of 1992 (EPACT), Section 1605(a), provided for an annual inventory of U.S. greenhouse gas emissions, which is contained in the EIA publication series, *Emissions of Greenhouse Gases in the United States* [*37*]. Also, Section 1605(b) of EPACT established the Voluntary Reporting Program, permitting corporations, government agencies, households, and voluntary organizations to report to EIA on actions that have reduced or avoided emissions of greenhouse gases. The results of the Voluntary Reporting Program are reported annually by EIA, most recently in *Mitigating Greenhouse Gas Emissions: Voluntary Reporting 1996* [*38*]. Entities providing data to the Voluntary Reporting Program include some participants in government-sponsored voluntary programs, such as the Climate Wise and Climate Challenge programs, which are cosponsored by the EPA and DOE to foster reductions in greenhouse gas emissions by industry and electricity generators.

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." The first and second Conference of the Parties in 1995 and 1996 agreed to address the issue of greenhouse gas emissions for the period beyond 2000 and negotiate quantified emission limitations and reductions for the third Conference of the Parties. On December 1 through 11, 1997, representatives from more than 160 countries met in Kyoto, Japan, to negotiate binding limits for greenhouse gas emissions for developed nations. In the resulting Kyoto Protocol, emissions targets were established for these nations, the Annex I countries [*39*], relative to their emissions in 1990, to achieve an overall reduction of about 5.2 percent [*40*].

The individual targets for the Annex I countries range from an 8-percent reduction for the European Union (EU) (or its individual member states) to a 10-percent increase allowed for Iceland. Australia and Norway are also allowed increases of 8 and 1 percent, respectively, while New Zealand, the Russian Federation, and the Ukraine are held to their 1990 levels. Other Eastern European countries undergoing transition to a market economy have reduction targets of between 5 and 8 percent. The reduction targets for Canada and Japan are 6 percent and for the United States 7 percent. 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 greenhouse gases covered by the Protocol are carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride [*41*]. The aggregate target is established using the carbon dioxide equivalent of each of the greenhouse gases. For the three synthetic greenhouse gases, countries have the option of using 1995 as the base year. Sources of emissions include energy combustion, fugitive emissions from fuels, industrial processes, solvents, agriculture, and waste management and disposal. The Protocol does not prescribe specific actions to be taken but lists a number of potential actions, including energy efficiency improvements, enhancement of carbon-absorbing sinks, such as forests and other vegetation, research and development of sequestration technologies, phasing out of fiscal incentives and subsidies that may inhibit the goal of emissions reductions, and reduction of methane emissions in waste management and in energy production, distribution, and transportation.

The targets must be achieved on average over the commitment period 2008 to 2012, the first commitment period. Each country can average its emissions over that 5-year period to establish compliance, smoothing out short-term fluctuations that might occur due to economic cycles or extreme weather patterns. Countries must have made demonstrable progress by 2005, but no targets are established for the period after 2012 (although lower targets may be set by future Conferences of the Parties). Banking—carrying over of unused allowances from one commitment period to the next—is allowed; however, the borrowing of emissions allowances from a future commitment period is not permitted.

Several provisions of the Protocol allow for some flexibility in meeting the emissions targets. Net changes in emissions by direct anthropogenic land-use changes and forestry activities will also be used in meeting the commitment; however, they are limited to afforestation, reforestation, and deforestation since 1990. Emissions trading among the Annex I countries is permitted. According to EIA's *International Energy Outlook 1998* (*IEO98*) [*42*], the amount of carbon that may be available for trade from the Annex I countries of the former Soviet Union as a result of the economic decline in those countries in the 1990s is estimated at 165 million metric tons in 2010. Also, additional carbon permits may be available. Joint implementation projects are allowed among the Annex I countries, allowing a nation to take emissions credits for projects that reduce emissions or enhance emissions-absorbing sinks, such as forests and other vegetation, in other Annex I countries. It is specifically indicated that trading and joint implementation are supplemental to domestic actions.

The Protocol also establishes a Clean Development Mechanism (CDM), under which Annex I countries can earn credits for projects that reduce emissions in non-Annex I countries provided that the projects lead to measurable, long-term benefits. Reductions from such projects undertaken from 2000 until the first commitment period can be used to assist with compliance in the first commitment period. This provision calls for the establishment of an executive board to oversee the projects. In addition, an unspecified share of the proceeds from the project activities must be used to cover administrative expenses and to assist with adaptation in countries that are particularly vulnerable to climate change.

Annex I countries, such as the EU, may create a bubble or umbrella to meet the total commitment of all the member nations. In a bubble, countries agree to meet the total commitment jointly by allocating a share to each member. In an umbrella arrangement, the total reduction of all member nations is met collectively through the trading of emissions rights. There is potential interest in the United States entering into an umbrella trading arrangement.

The Protocol became open for signature on March 16, 1998, for a one-year period. It enters into force 90 days following the acceptance by 55 Parties, including Annex I countries accounting for at least 55 percent of the 1990 carbon dioxide emissions from Annex I nations. Signature by the United States would need to be followed by Senate ratification. As of September 29, 1998, 57 countries had signed the Protocol, including 26 Annex I nations that accounted for about 38 percent of Annex I carbon emissions in 1990.

In 1990, total greenhouse gas emissions in the United States were 1,633 million metric tons carbon equivalent. Of this total, 1,346 million metric tons, or 82 percent, was due to carbon emissions from the combustion of energy fuels. By 1997, total U.S. greenhouse gas emissions had risen to 1,791 million metric tons carbon equivalent, of which 83 percent, or 1,480 million metric tons, were carbon emissions from energy combustion. EIA now projects that energy-related carbon emissions will reach 1,790 million metric tons in 2010, 33 percent above the 1990 level, increasing to 1,975 million metric tons in 2020. Because energy-related carbon emissions constitute such a large percentage of the total greenhouse gas emissions, any action or policy to reduce emissions will affect U.S. energy markets; however, there are a number of factors outside the domestic energy market that influence emissions and may offset the impacts on domestic energy.

To put U.S. emissions in a global perspective, the United States produced about 24 percent of the worldwide energy-related carbon emissions in 1996, which totaled 6.0 billion metric tons, according to *IEO98*. Although carbon emissions continue to increase in the United States and other industrialized countries, they are increasing at a much more rapid rate in the developing countries of Asia, the Middle East, Africa, and Central and South America. As a result, global carbon emissions from energy are expected to increase at an average annual rate of 2.4 percent from 1996 through 2010, reaching 8.3 billion metric tons, to which the United States is expected to contribute about 22 percent.

EIA Analysis of the Kyoto Protocol

At the request of the U.S. House of Representatives Committee on Science, EIA performed an analysis of the Kyoto Protocol in the summer of 1998, focusing on the impacts of the Protocol on U.S. energy prices, energy use, and the economy in the 2008 to 2012 time frame. The analysis was published in *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* [*43*]. The request specified that the analysis use the same methodologies and assumptions as the *AEO98* [*44*], with no changes in policy, regulatory actions, or funding for energy and environmental programs. The Committee indicated that no new nuclear plants should be allowed, although economic life extensions of nuclear plants should be permitted. Construction of new nuclear plants, variations in economic growth, and different assumptions concerning technology characteristics were all to be analyzed as sensitivities to the target cases.

The EIA analysis assumes that the Government would hold an auction of carbon permits. The cost of the permits is reflected in energy prices, and the revenues collected from the permits are recycled either to individuals by means of an income tax rebate or to individuals and businesses through a social security tax rebate.

The Protocol includes a number of international provisions, including international emissions trading, joint implementation projects, and CDM, which may reduce the cost of compliance; however, guidelines for the provisions must be resolved at future meetings of the Conferences of the Parties. (The fourth Conference was underway in Buenos Aires, Argentina, at the time *AEO99* went to press.) In addition, rules and guidelines for the accounting of emissions and sinks from activities related to agriculture, land use, and forestry activities must be developed. The specific guidelines may have a significant impact on the level of reductions from other sources that a country must undertake. Reductions in the other greenhouse gases may also offset the reductions required from carbon dioxide. A fact sheet issued by the U.S. Department of State on January 15, 1998, discussing the Protocol, estimated that the method of accounting for sinks and the flexibility to use 1995 as the base year for the synthetic greenhouse gases may reduce the U.S. target for energy-related carbon emissions to 3 percent below 1990 levels [*45*].

Because of these uncertainties concerning the final implementation of the Protocol, EIA's analysis includes cases with a range of reductions for energy-related carbon emissions within the United States in order to analyze the energy and economic impacts of achieving those reductions on the U.S. energy system and the economy. The cases assume that the reductions needed to meet the target of 7 percent below the 1990 emissions level that are not obtained from domestic energy-related reductions would come from some combination of forestry and agricultural sinks, offsets from other greenhouse gases, international trading, and other international activities. For example, the cases with the least stringent reductions in energy-related carbon emissions implicitly assume considerable international actions.

The analysis includes six carbon emissions reduction cases, plus a reference case, defined as follows:

Reference Case (33 Percent above 1990 Levels). This case represents the reference projections of energy markets and carbon emissions without any enforced reductions, in order to compare the energy market impacts in the reduction cases with a reference case. Although this case is based on the reference case from *AEO98*, there are small differences in order to permit additional flexibility in response to higher energy prices or to include certain analyses previously done offline directly within the modeling framework, such as nuclear plant life extension and generating plant retirements. Also, some assumptions are modified to reflect more recent assessments of technological improvements and costs. As a result of these modifications, energy-related carbon emissions in 2010 are slightly reduced from the *AEO98* reference case level of 1,803 million metric tons to 1,791 million metric tons.

24 Percent above 1990 Levels (1990+24%). This case assumes that carbon emissions can increase to an average of 1,670 million metric tons between 2008 and 2012, 24 percent above the 1990 levels. Compared to the average emissions in the reference case, carbon emissions are reduced by an average of 122 million metric tons during the commitment period.

14 Percent Above 1990 Levels (1990+14%). This case assumes that carbon emissions average 1,539 between 2008 and 2012, approximately at the level estimated for 1998 in *AEO98*, 1,533 million metric tons. This target is 14 percent above 1990 levels and represents an average annual reduction of 253 million metric tons from the reference case.

9 Percent Above 1990 Levels (1990+9%). This case assumes that energy-related carbon emissions can increase to an average of 1,467 million metric tons between 2008 and 2012, 9 percent above 1990 levels, an average annual reduction of 325 million metric tons from the reference case.

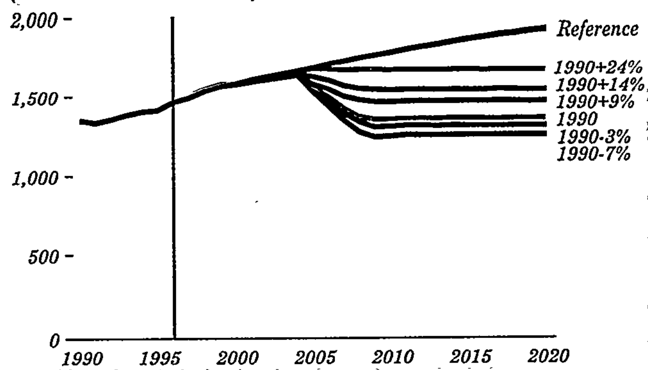
Stabilization at 1990 Levels (1990). This case assumes that carbon emissions reach an average of 1,345 million metric tons during the commitment period of 2008 through 2012, stabilizing approximately at the 1990 level of 1,346 million metric tons. This is an average annual reduction of 447 million metric tons from the reference case.

3 Percent Below 1990 Levels (1990-3%). This case assumes that energy-related carbon emissions are reduced to an average of 1,307 million metric tons between 2008 and 2012, an average annual reduction of 485 million metric tons from the reference case projections.

7 Percent Below 1990 Levels (1990-7%). Energy-related carbon emissions are reduced from the level of 1,346 million metric tons in 1990 to an average of 1,250 million metric tons in the commitment period, 2008 to 2012. Compared to the reference case, this is an average annual reduction of 542 million metric tons of energy-related carbon emissions during that period. This case essentially assumes that the 7-percent target in the Kyoto Protocol must be shared evenly by all emitting sources, with no net offsets for energy-related carbon emissions from sinks, other greenhouse gases, or international activities.

In each of the carbon reduction cases, the target is achieved on average for each of the years in the first commitment period, 2008 through 2012 (Figure 23). Because the Protocol does not specify any targets beyond the first commitment period, the target is assumed to hold constant from 2013 through 2020, the end of the forecast horizon, although more stringent requirements may be set by future Conferences of the Parties. The target is assumed to be phased in over a 3-year period, beginning in 2005, because the Protocol indicates that demonstrable progress toward reducing emissions must be shown by 2005. This allows energy markets to begin adjustments to meet the reduction targets in the absence of complete foresight. In the analysis, some carbon reductions occur before 2005 because of capacity expansion decisions by electricity generators that incorporate the future increases in energy prices.

Figure 23: U.S. carbon emissions in seven Kyoto Protocol analysis cases, 1990-2020 (million metric tons)



There are three ways to reduce energy-related carbon emissions: reducing the demand for energy services, adopting more energy-efficient equipment, and shifting to noncarbon or less carbon-intensive fuels. To reduce emissions, the price of carbon permits is applied to each of the fuels at its point of consumption relative to its carbon content. Electricity does not directly receive a carbon price; however, the fossil fuels used for generation receive the price, and this cost, as well as the increased cost of investment in generation plants, is reflected in the delivered price of electricity.

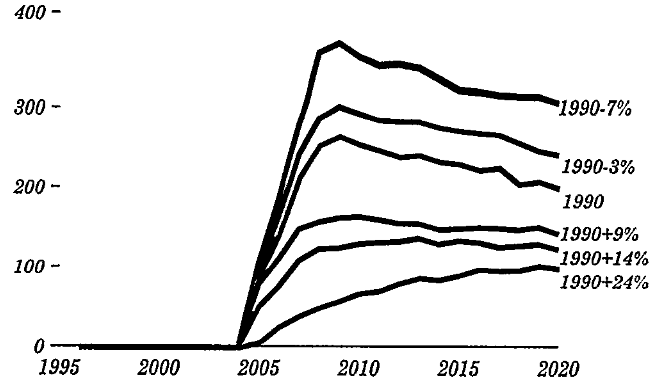
In the analysis, the carbon prices represent the marginal cost of reducing carbon emissions to the specified level, reflecting the price the United States would be willing to pay in order to purchase carbon permits domestically. Because the study does not include an analysis of trade and other flexible mechanisms to reduce carbon emissions internationally, the carbon prices do not represent the international market-clearing price of carbon permits or the price other countries would be willing to pay for permits.

Because of its representation of technology, NEMS captures the most significant factors that influence the turnover of energy-using and producing equipment and the choice of new technologies. Thus, it is well-suited for the analysis of the transitional impacts of policies designed to influence the choice of energy-consuming technologies, as new equipment is needed to meet growing demand for energy services or to replace retired equipment. Many sectors of NEMS include explicit treatment of individual technologies and their characteristics, such as initial cost, operating cost, date of commercial availability, efficiency, and other characteristics specific to the sector. Higher energy prices induce more rapid adoption of more efficient or advanced technologies because consumers have more incentive to purchase them. In addition, for new generating technologies, the electricity sector accounts for technological optimism in the capital costs of first-of-a-kind plants; and several sectors, including the generation sector, account for a decline in the costs as experience with the technologies is gained.

Energy Market and Macroeconomic Analysis. The analysis indicates that significant changes in the mix of energy fuels, as well as higher energy efficiency and lower consumption, will be needed for the required reductions. To induce the changes, the price of energy will increase. Some of the most significant results from the analysis are as follows:

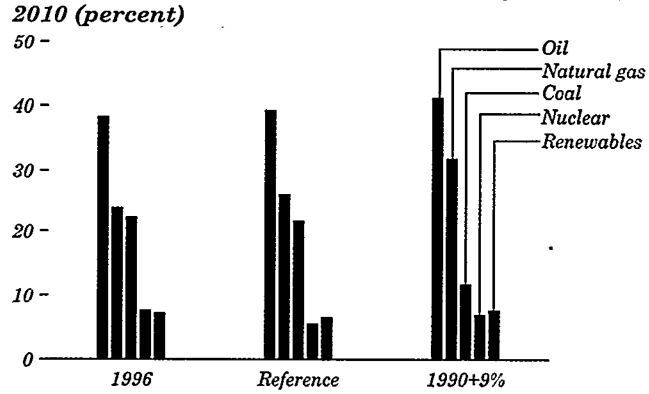
- The cost of the Kyoto Protocol will depend on the amount of permits that can be purchased on the international market and on cost-effective projects to reduce emissions or develop carbon-absorbing sinks in other countries. Domestic actions to reduce other greenhouse gases covered by the Protocol and to develop sinks may also serve to reduce the costs.
- The carbon price necessary to reduce U.S. energy-related carbon emissions to the required level ranges from $67 to $348 per metric ton (1996 dollars) in 2010. In the more stringent reduction cases, the carbon price falls by 2020 as more efficient and lower-carbon technologies become economically available and penetrate later in the forecast horizon (Figure 24).
- Higher energy prices and their impact on the broader U.S. economy will encourage consumers to reduce energy consumption by reducing the demand for energy services and purchasing more efficient equipment. However, consumption will increase later with a growing economy and lower carbon prices. Shifts from more to less carbon-intensive fuels also occur.

Figure 24. Carbon prices in six Kyoto Protocol analysis cases, 1996-2020 (1996 dollars per metric ton)



- Because coal is the most carbon-intensive of the fossil fuels, the price of coal will rise dramatically, and coal use will be sharply curtailed, particularly for electricity generation. If the carbon price increases to its highest level, the use of coal for generation may nearly disappear by 2020 in the more stringent reduction cases. Shrinking domestic and international markets will lead to sharply reduced coal production and employment.
- Coal-fired electricity generation will be replaced by generation from natural gas and renewables and also by the continued operation of many existing nuclear plants. Increases in natural gas generation will more than offset reductions in natural gas use by residential, commercial, and industrial consumers. As a result, the natural gas industry will expand production and distribution services (Figure 25).

Figure 25. Projected fuel shares of U.S. energy consumption in two Kyoto Protocol analysis cases, 2010 (percent)



- Renewable generation will also increase as more of the technologies become economical in light of higher fossil fuel prices. Renewables could capture as much as a 22-percent share of the generation market by 2020, with more than half supplied by nonhydroelectric renewable generation in the more stringent cases. Within the energy industry, increased employment in the natural gas and renewables industries could offset some reductions in coal employment.

- Nuclear generation's decline will slow as it becomes economical under higher carbon prices to extend the operating lives of existing plants rather than retire them.

- Petroleum consumption will be lower than expected in the reference case but will likely remain above current levels. Although petroleum consumption is lower, the petroleum share of total energy consumption is higher than in the reference case, because the total is lower. The majority of petroleum is used for transportation, where there are limited economically attractive options for shifting to less carbon-intensive fuels.

- Recycling carbon revenues back to consumers will offset some of the negative impacts on the economy. The economy will continue to grow; however, the growth in the gross domestic product (GDP) could be lower than reference case levels during the transition period. As carbon prices decline and the economy adjusts, GDP will rebound by 2020 to about the level it would have been in the absence of a carbon reduction program (Figures 26 and 27).

- The loss in GDP, plus the funds used to purchase permits internationally, represents the total cost to the economy. Over the first compliance period, from 2008 to 2012, the total cost ranges from an annual average of $77 billion (1992 dollars) to almost four times that amount, depending on the required carbon reductions and how the revenues are recycled to the economy. This is relative to a total economy of $7 trillion in 1996, which is expected to grow to $9.5 trillion in 2010 and $11 trillion in 2020.

Sensitivity Cases. The analysis includes several sensitivity cases to examine factors that may affect energy demand and carbon emissions over the next 20 years, including economic growth, the rate of improvement of technology, and nuclear power. With the exception of the nuclear sensitivity case, the sensitivity cases were analyzed relative to the 1990+9% case. Because each of the sensitivity cases is constrained to the same level of carbon emissions as the case to which it is compared, the primary impact is on the carbon price required to meet the emissions target.

- *Macroeconomic Growth.* The assumed rate of economic growth has a significant impact on projected energy demand and carbon emissions. The reference and carbon reduction cases in the analysis assume an average growth rate of 1.9 percent a year between 1996 and 2020, and higher and lower growth rates of 2.4 and 1.3 percent a year are analyzed as sensitivities. Higher growth results in higher manufacturing output and income, increasing the demand for energy services and resulting in higher energy demand

Figure 26. Annual GDP growth rates in four Kyoto Protocol analysis cases, 2005-2010 (percent)

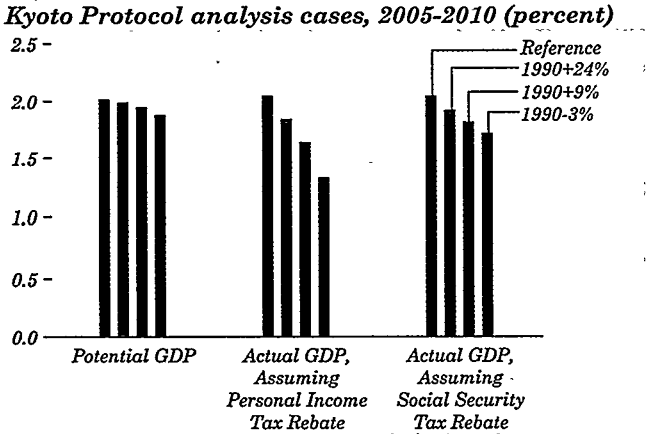
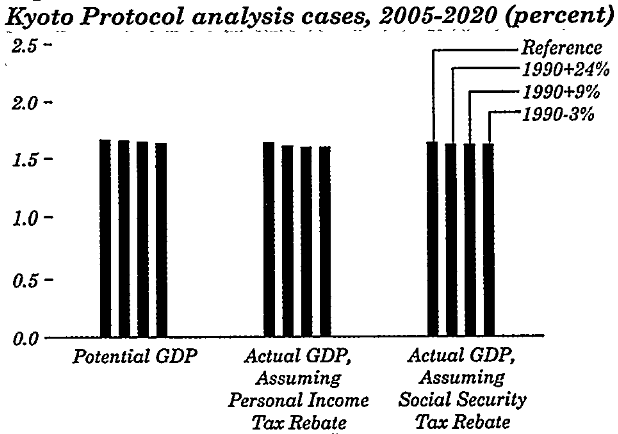


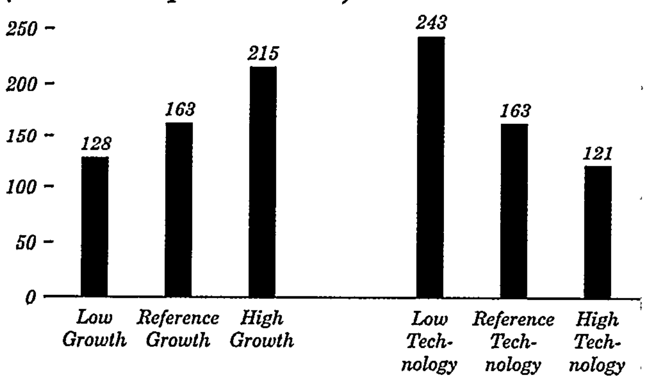
Figure 27. Annual GDP growth rates in four Kyoto Protocol analysis cases, 2005-2020 (percent)



and carbon emissions. Converse trends hold for the lower economic growth case.

Because higher growth increases energy consumption, carbon prices must be higher to attain a given carbon emissions target. In the high growth case, the carbon price in 2010 is $215 per metric ton, $52 per metric ton higher than the reference case carbon price of $163 per metric ton (Figure 28). In the low growth case, the carbon price in 2010 is $128 per metric ton. Total energy consumption in 2010 is higher and lower by 2.2 quadrillion Btu with higher and lower growth, relative to the 1990+9% case with reference economic growth.

Figure 28. Projected carbon prices in four Kyoto Protocol sensitivity analysis cases, 2010 (1996 dollars per metric ton)



- *Technological Progress.* High technology assumptions were developed by technology experts for the end-use sectors—residential, commercial, industrial, and transportation—considering the potential impacts of increased research and development for more advanced technologies [*46*]. The revised assumptions include earlier years of introduction, lower costs, high maximum market potential, and higher efficiencies than assumed in the reference case. For the electricity generation sector, the cost and efficiencies of advanced fossil-fired and renewable generating technologies are assumed to improve from reference case values. The low technology case assumes that all future equipment choices are made from the end-use equipment available in 1998, with building shell and industrial plant efficiencies frozen at 1998 levels, and no new advanced fossil-fired generating technologies are assumed.

  Because faster technology development makes advanced energy-efficient and low-carbon technologies more economically attractive, the carbon prices required to meet carbon reduction levels are significantly reduced. Conversely, slower technology improvement requires higher carbon prices. With high technology assumptions, the carbon price in 2010 is $121 per metric ton, compared to the carbon price of $163 per metric ton with the reference technology assumptions. With the low technology assumptions, the carbon price increases to $243 per metric ton in 2010.

- *Nuclear Power.* In the reference case, nuclear generation declines because 52 percent of the total nuclear capacity available in 1996 is retired by 2020. A number of units are retired before the end of their 40-year operating licenses, based on industry announcements and analysis of the age and operating costs of the units. In the carbon reduction cases, life extension of the plants can occur, if economical, and there is an increasing incentive to invest in nuclear plant refurbishment with higher carbon prices; however, these cases do not allow the construction of new nuclear power plants. A nuclear power sensitivity case examines the effects of allowing new plants to be constructed if they are economical. Because nuclear plants still are not competitive with fossil and renewable plants in the 1990+9% case, this sensitivity case is analyzed against the 1990-3% case. In addition to allowing new nuclear plants, the higher costs assumed in the reference case for the first few advanced nuclear plants are reduced in this case.

  Relative to the 1990-3% case, 1 gigawatt of new nuclear capacity is added by 2010 in the nuclear power sensitivity case, and 41 gigawatts, representing about 68 new plants of 600 megawatts each, are added by 2020. Because most of the impact from the new nuclear plants comes after the commitment period of 2008 through 2012, there is little impact on carbon prices and energy markets in 2010. By 2020, however, carbon prices are $199 per metric ton with the assumption of new nuclear plants, compared to $240 per metric ton in the 1990-3% case with the reference nuclear assumptions.

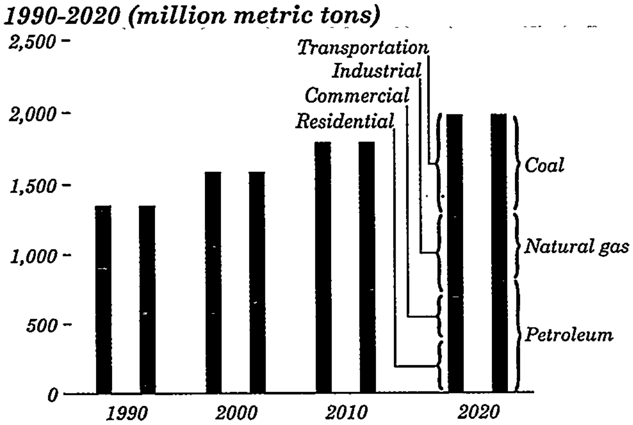
Carbon Emissions in *AEO99*

Reference Case

In the *AEO99* reference case, carbon emissions from energy consumption are expected to reach 1,585 million metric tons in 2000, 18 percent above the 1990 level of 1,346 million metric tons. The projected emissions continue to rise to 1,790 million metric tons in 2010 and 1,975 million metric tons in 2020, 33 percent and 47 percent above the 1990 levels, respectively (Figure 29). Total emissions increase at an average annual rate of 1.3 percent between 1997 and 2020, and per capita emissions also increase at an average rate of 0.4 percent. Throughout the projection period, carbon emissions rise, because continued economic growth and moderate increases in energy prices are expected to lead to increasing energy consumption. Emissions rise at a faster rate than total energy consumption, which increases at an average annual rate of 1.1 percent, for two primary reasons. First, approximately 51 percent of nuclear generating capacity, which is carbon free, is retired by 2020 and no new nuclear plants are constructed. Second, moderate increases in the price of natural gas and decreases in the price of coal lead to slow growth in renewables.

In 2020, electricity generation accounts for 38 percent of all carbon emissions, increasing from 36 percent in 1997. The increasing share of carbon emissions from generation results, in part, from the 1.4-percent annual growth rate in electricity consumption. Of the new capacity required to meet electricity demand growth and to replace the loss of nuclear capacity, about 9 percent is fueled with coal and 88 percent with natural gas.

Figure 29. U.S. carbon emissions by sector and fuel, 1990-2020 (million metric tons)



Energy consumption and carbon emissions for transportation grow the fastest of all the end-use sectors because of increased travel and the slow improvement in fuel efficiency in the reference case. Between 1997 and 2020, both transportation demand and emissions grow at an average annual rate of 1.7 percent, and in 2020 the transportation sector accounts for 35 percent of all carbon emissions. The average efficiency of the light-duty vehicle fleet—cars, light trucks, vans, and sport-utility vehicles—increases at an average annual rate of only 0.2 percent between 1997 and 2020. Over the same period, vehicle-miles traveled by light-duty vehicles increase by 1.6 percent a year, faster than the growth rate for the over-age-16 population (0.9 percent a year). Growth in both air and freight travel, at average rates of 3.8 percent and 1.8 percent a year, also contribute to the increase in emissions from the transportation sector.

Emissions from both the residential and commercial sectors grow by 1.2 percent a year, contributing 19 percent and 16 percent of carbon emissions in 2020 (including emissions from the generation of electricity used in each sector). Continued growth in energy service demand, particularly in electricity-using equipment and appliances, results in the emissions increases, offset somewhat by efficiency improvements in both sectors. Industrial sector emissions increase by only 0.9 percent a year through 2020 and account for 30 percent of the emissions in 2020 (including emissions from electricity generation for the sector). The relatively low growth rate results from efficiency improvements and a shift to less energy-intensive industries.

By fuel, petroleum products are the leading source of energy-related carbon emissions because of the continuing growth of the transportation sector, which is heavily dependent on petroleum. About 42 percent of all emissions, or 823 million metric tons of the total of 1,975 million metric tons in 2020, are from petroleum products, and about 81 percent of the petroleum emissions are from transportation uses.

Coal is the second leading source of carbon emissions at about 34 percent, or 676 million metric tons, in 2020. Coal has the highest carbon content of all the fossil fuels and remains the predominant source of electricity generation. By 2020, the share of coal-fired generation, excluding cogeneration, declines slightly from its 1997 level of 56 percent but still accounts for 52 percent of all generation. About 90 percent of coal emissions in 2020 result from electricity generation.

Natural gas consumption for both electricity generation and direct end uses grows the fastest of all the fossil fuels—at a rate of 1.7 percent a year through 2020. Natural gas has a relatively low carbon content relative to other fossil fuels (only about half that of coal), and thus carbon emissions from natural gas use are projected to be just 475 million metric tons in 2020, about 24 percent of the total.

Macroeconomic Growth

The assumed rate of economic growth has a strong impact on the projection of energy consumption and, therefore, carbon emissions. In *AEO99*, the high economic growth case includes higher growth in population, the labor force, and labor productivity, resulting in higher industrial output, lower inflation, and lower interest rates. As a result, GDP increases at an average rate of 2.6 percent a year from 1997 to 2020, compared with a growth rate of 2.1 percent a year in the reference case.

With higher macroeconomic growth, energy demand grows faster, as higher manufacturing output and higher income increase the demand for energy services. Total energy consumption in the high economic growth case is 129.4 quadrillion Btu in 2020, compared with 119.9 quadrillion Btu in the reference case. As a result of the higher consumption, carbon emissions are 2,124 million metric tons, or 8 percent, higher than the reference case level of 1,975 million metric tons in 2020.

Assumptions of lower growth in population, the labor force, and labor productivity result in an average annual growth rate of 1.5 percent in the low economic growth case through 2020. With lower economic growth, energy consumption in 2020 is reduced from 119.9 quadrillion Btu to 110.5 quadrillion Btu, and carbon emissions are 1,826 million metric tons, or 8 percent, lower than in the reference case.

Total energy intensity, measured as primary energy consumption per dollar of GDP, improves at a faster rate in the higher economic growth case, partially offsetting the changes in energy consumption caused by the higher growth assumptions. With more rapid growth in energy consumption, there is 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 decreases at a rate of 1.2 percent a year from 1997 through 2020, compared with 1.0 percent in the reference case and 0.8 percent in the low economic growth case.

Technology Improvement

The *AEO99* reference case includes 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 and transportation vehicles; 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 continued improvements in the efficiency of end-use and electricity generation technologies, total energy intensity in the reference case declines at an average annual rate of 1.0 percent between 1997 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 a year. Approximately half 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 1996, energy intensity was relatively flat.

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 of *AEO99* assumes no new efficiency standards. Only current standards or approved new standards with specified levels are included.

Technology improvements in energy-consuming equipment could reduce energy consumption and energy-related carbon emissions to levels below those in the reference case. Conversely, slower improvements could increase both consumption and emissions. *AEO99* presents a range of alternative cases that vary key assumptions about technology improvement and penetration.

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 included earlier years of introduction, lower costs, higher maximum market potential, and higher efficiencies than in the reference case. It is possible that further technology improvements could occur if there were a very aggressive research and development effort. For the electricity generation sector, the cost and efficiencies of advanced fossil-fired generating technologies were assumed to improve from reference case values [*47*].

The low technology case assumes that all future equipment choices are from the equipment and vehicles available in 1999, with new building shell and industrial plant efficiencies frozen at 1999 levels. New generating technologies are assumed not to improve over time. Aggregate efficiencies still improve over the forecast period as new equipment is chosen to replace older stock and the capital stock expands. Also, building shell efficiencies improve with price increases.

In the high technology case, with the high technology assumptions of all four end-use demand sectors and the electricity generation sector combined, aggregate energy intensity declines at an average of 1.3 percent a year from 1997 to 2020, compared with 1.0 percent a year in the reference case (Figure 30). In the 1999 technology case, the average decline is only 0.8 percent a year through 2020. Total energy consumption increases to 111.9 quadrillion Btu in 2020 in the high technology case, compared with 119.9 quadrillion Btu in the reference case (Figure 31), but increases to 126.6 quadrillion Btu in the 1999 technology case.

Figure 30. U.S. energy intensity in three cases, 1997-2020 (thousand Btu per dollar GDP)

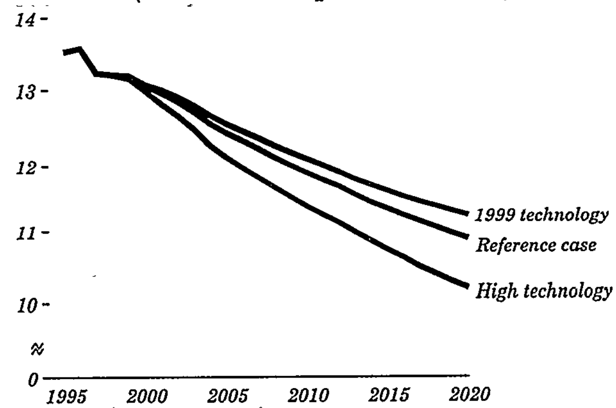
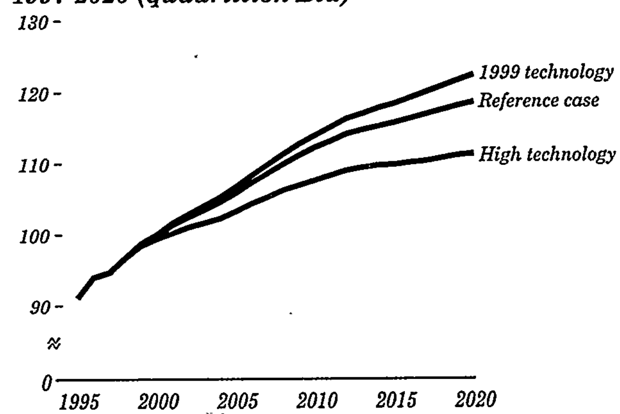
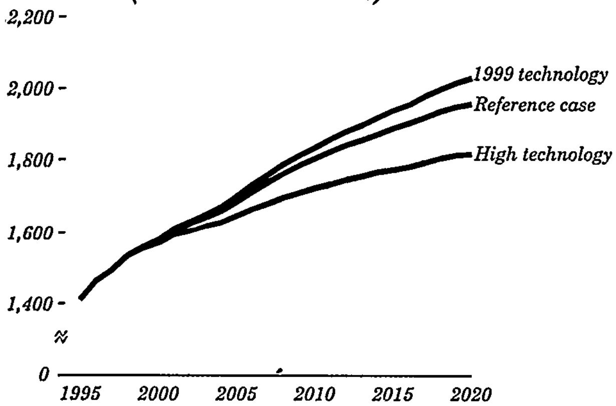


Figure 31. U.S. energy consumption in three cases, 1997-2020 (quadrillion Btu)



The lower energy consumption in the high technology case lowers carbon emissions from 1,975 million metric tons in the reference case in 2020 to 1,848 million metric tons (Figure 32). In the 1999 technology case, emissions increase to 2,105 million metric tons in 2020. About 30 percent, or 38 million metric tons, of the reduction in carbon emissions in the high technology case compared to the reference case results from lower electricity demand and generation. An additional 51 million metric tons of the reduction, or 40 percent, results from shifts to

Figure 32. U.S. carbon emissions in three cases, 1997-2020 (million metric tons)



more efficient or alternative-fueled vehicles in the transportation sector.

The high technology assumptions themselves do not guarantee acceptance and penetration in the market. Technologies must still be cost-effective as judged by the consumers, and penetration can 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 emissions, it is likely that either market policies (for example, higher energy prices) or non-market policies (for example, new standards) may be required.

Market Trends

The projections in *AEO99* 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.

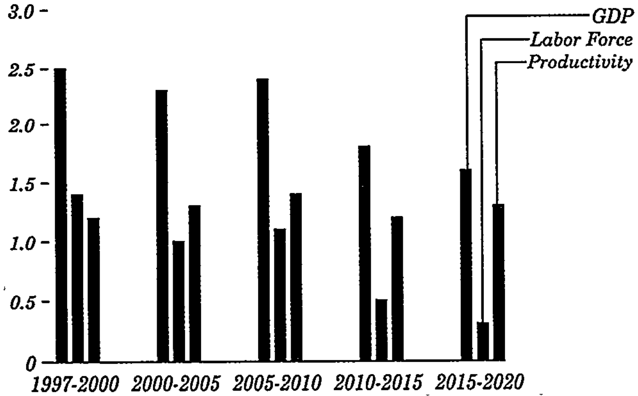
Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics 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 *AEO99* 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.

AEO99 Projects Strong Growth for U.S. Gross Domestic Product

Figure 33. Average annual real growth rates of economic factors, 1997-2020 (percent)

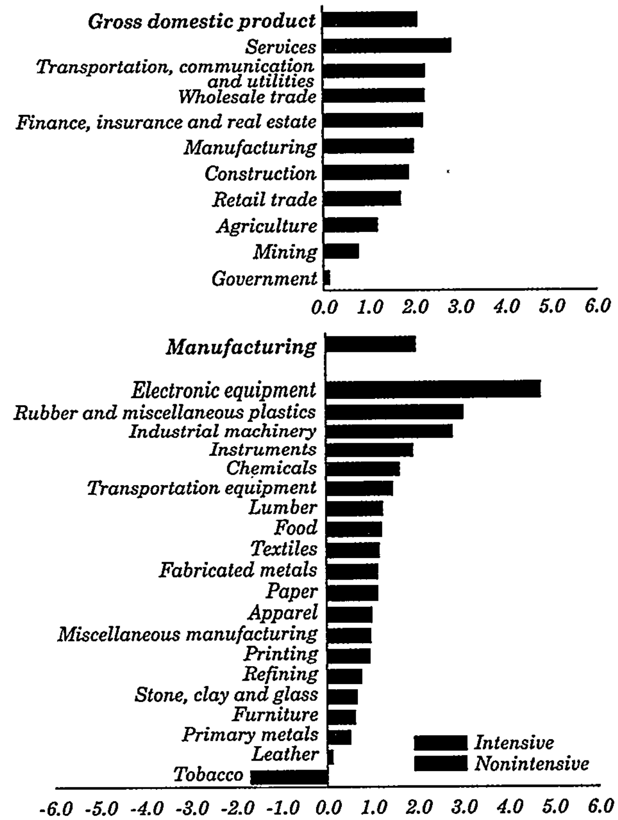


The output of the Nation's economy, measured by gross domestic product (GDP), is projected to increase by 2.1 percent a year between 1997 and 2020 (with GDP based on 1992 chain-weighted dollars) (Figure 33), slightly higher than the 1.8-percent growth projected in *AEO98* for the same period. The projected growth rate for the labor force is similar to last year's forecast through 2020; however, in the *AEO99* projection, productivity growth is 1.3 percent a year, up from 1.1 percent a year in *AEO98*.

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 increases in labor productivity moderate the effects of lower labor force growth. Total population growth remains fairly constant after 2000; the slowing growth in the size of the labor force results instead from the increasing size of the population over 65 years old after 2000. As more people retire from the work force, and as life expectancy rises, the labor force participation rate (labor force divided by adult population) declines. Thus, from 2010 to 2015, labor force growth slows to 0.5 percent, and from 2015 to 2020 it falls to 0.3 percent a year. Labor force productivity growth, however, remains above 1 percent a year throughout each of the 5-year periods. In addition, the labor force participation rate—the percentage of the population over 16 years of age actually holding or looking for employment—peaks in 2007 and then begins to decline as "baby boom" cohorts begin to retire.

Manufacturing Production Is Expected To Grow by 2 Percent a Year

Figure 34. Sectoral composition of GDP growth, 1997-2020 (percent per year)

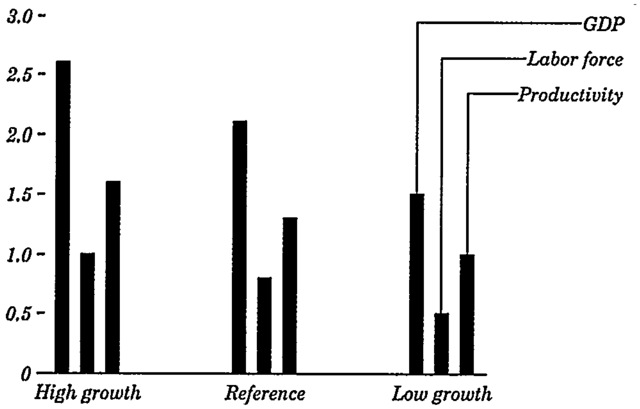


The projected growth rate for manufacturing production is 2.0 percent a year, slightly lower than the 2.1-percent annual growth projected for the aggregate economy. Energy-intensive industries, however, are projected to grow more slowly than non-energy-intensive industries (1.2 percent and 2.3 percent annual growth, respectively) [*48*], due in part to rising real energy prices.

The electronic equipment and industrial machinery sectors lead the expected growth in manufacturing, as semiconductors and computers find broader applications (Figure 34). 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 wholesale trade and services sectors than for the manufacturing sector, as in last year's forecast.

High and Low Growth Cases Show Effects of Economic Assumptions

Figure 35. Average annual real growth rates of economic factors in three cases, 1997-2020 (percent)



To reflect the uncertainty in forecasts of economic growth, *AEO99* includes high and low economic growth cases in addition to the reference case (Figure 35). The high and low growth cases show the effects of alternative growth assumptions on energy markets. The three economic growth cases are based on macroeconomic forecasts prepared by DRI/McGraw-Hill (DRI) [*49*]. The DRI forecast used in generating the *AEO99* reference case is the August 1998 trend growth scenario, adjusted to incorporate the world oil price assumptions used in the *AEO99* reference case. The *AEO99* high and low economic growth cases are based on the optimistic and pessimistic growth projections prepared by DRI in February 1998. With these changes incorporated, the DRI projections are used as the starting point for the macroeconomic forecasts in the National Energy Modeling System (NEMS) simulations for *AEO99*.

The high economic growth case incorporates higher growth rates for population, labor force, and labor productivity. With higher productivity gains, inflation and interest rates are lower than in the reference case, and economic output grows by 2.6 percent a year. GDP per capita grows by 1.6 percent a year, compared with 1.3 percent in the reference case. The low economic growth case assumes lower growth rates for population, labor force, and productivity, resulting in higher prices, higher interest rates, and lower industrial output growth. In the low growth case, economic output increases by 1.5 percent a year from 1997 through 2020, and growth in GDP per capita slows to 0.9 percent a year.

Long-Term Trend Indicates Slowing GDP Growth

Figure 36. Annual GDP growth rate for the preceding 20 years, 1970-2020 (percent)

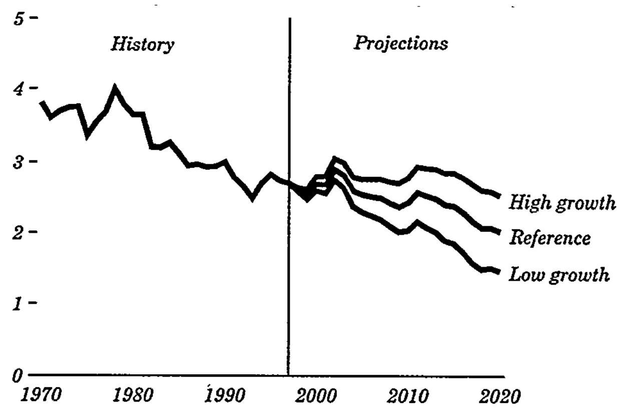
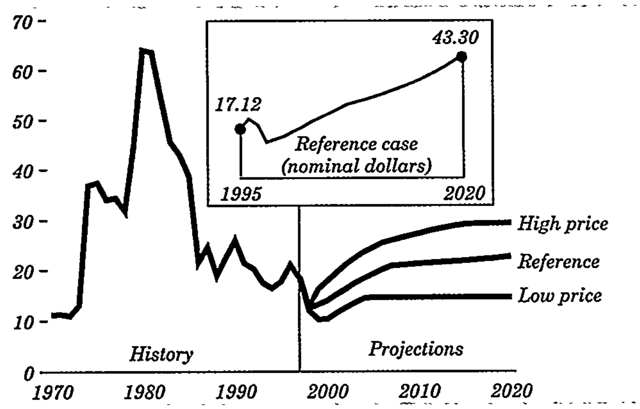


Figure 36 shows the trend in the moving 20-year annual growth rate for GDP, including projections for three *AEO99* cases. The value for each year is calculated as the annual growth rate over the preceding 20 years. The 20-year average shows major long-term trends in GDP growth by smoothing more volatile year-to-year changes (although the increase shown for 2000-2002 reflects the slow and negative growth of 1980-1982). The overall trend is downward, reflecting lower rates of capital accumulation during the 1970s and 1980s, lower labor force growth rates, and shifts in the demographic makeup of the population. In addition, 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 grows by 2.3 percent a year, while investment grows at a robust 3.0 percent. In the high growth case, growth in investment increases to 3.8 percent a 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 in the reference case. In the low growth case, annual growth in investment expenditures slows to 2.1 percent. With the labor force also growing more slowly, aggregate economic growth slows considerably.

Gradually Rising Oil Prices
Are Projected

Figure 37. World oil prices in three cases, 1970-2020 (1997 dollars per barrel)



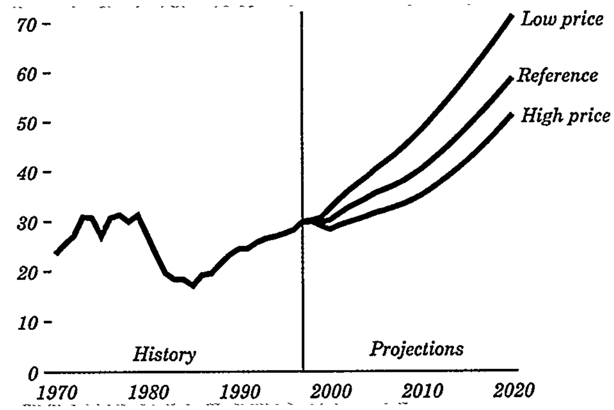
Just as the historical record shows substantial variability in world oil prices, there is considerable uncertainty about future prices. Three *AEO99* cases with different price paths allow an assessment of alternative views on the course of future oil prices (Figure 37). For the reference case, prices rise by about 0.9 percent a year, reaching $22.73 in constant 1997 dollars in 2020. In nominal dollars, the reference case price exceeds $43 in 2020. The low price case has prices rising, after the current price slump, to $14.57 by 2005 and remaining at about that level out to 2020. The high price case has a price rise of about 2.5 percent a year out to 2015 and then remains at $29.35 out to 2020. The leveling off at about $29.35 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 *AEO98* 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, reaching almost 47 million barrels per day by the turn of the century and increasing gradually thereafter to more than 55 million barrels per day by 2020.

Total worldwide demand for oil is expected to reach nearly 115 million barrels per day by 2020. Developing countries in Asia show the largest growth in demand, averaging almost 4 percent a year.

Outlook for World Oil Supplies
Is Optimistic

Figure 38. OPEC oil production in three cases, 1970-2020 (million barrels per day)



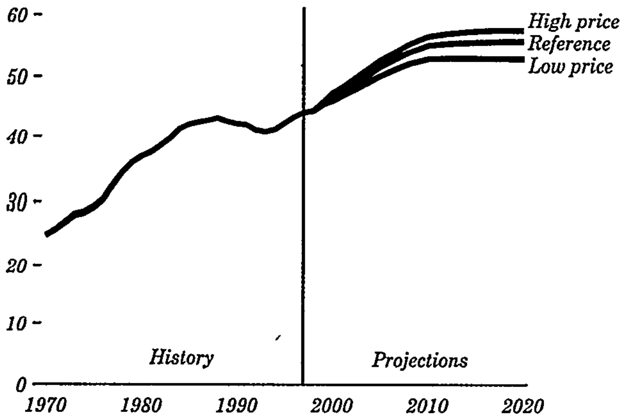
The three price cases are based on alternative assumptions about oil production levels in OPEC nations: higher production in the low price case and lower production in the high price case. With its vast store of readily accessible oil reserves, OPEC—primarily the Persian Gulf nations—is expected to be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

By 2000, OPEC supply in the reference case is over 30 million barrels per day, consistent with announced plans for OPEC capacity expansion [*50*]. By 2020, OPEC production is almost 59 million barrels per day (almost twice its 1997 production) in the reference case, over 51 million in the high case, and over 71 million in the low case (Figure 38). Worldwide demand for oil varies across the price cases in response to the price paths. Total world demand for oil ranges from 124.4 million barrels per day in the low price case to 109.1 in the high price case.

This variation 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 for the remainder of this decade. Recent discoveries offshore of Algeria and 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.

Continued Production Gains Are Seen for Non-OPEC Oil Suppliers

Figure 39. Non-OPEC oil production in three cases, 1970-2020 (million barrels per day)

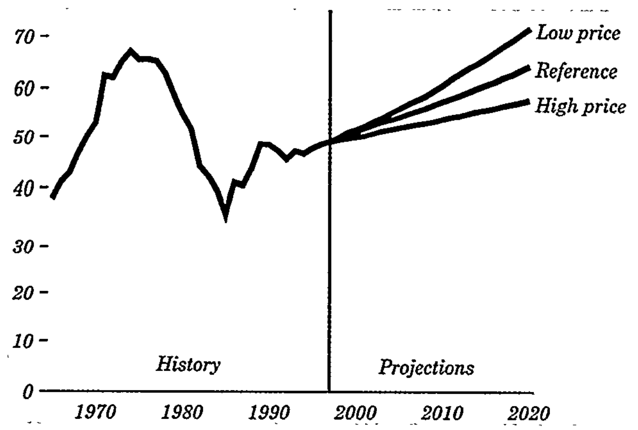


The growth and diversity in non-OPEC oil supply have shown surprising resilience even in the low price environment of this decade. Although OPEC producers will certainly benefit from the projected growth in oil demand, significant competition is expected from non-OPEC suppliers. Countries in the Organization 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 the next century. 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 *AEO99* reference case, non-OPEC supply is projected to reach almost 55 million barrels per day by 2010 and remain at about that level through 2020 (Figure 39). In the low oil price case, non-OPEC supply grows to less than 53 million barrels per day by 2020, whereas in the high oil price case it reaches more than 57 million barrels per day by the end of the forecast period.

Persian Gulf Share of World Oil Supply Increases in All the *AEO99* Cases

Figure 40. Persian Gulf share of worldwide oil exports, 1965-2020 (percent)

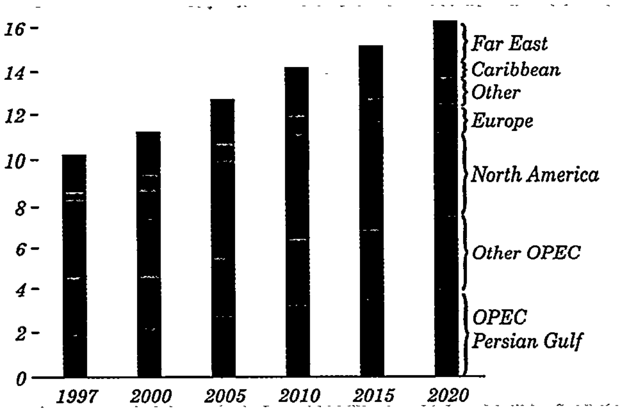


Considering the world market in oil exports, the historical peak for Persian Gulf exports (as a percent of world oil exports) occurred in 1974, when they made up more than two-thirds of the oil traded in world markets (Figure 40). The most recent historical low for Persian Gulf oil exports came in 1985 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. For the first time since the early 1980s, Persian Gulf producers are expected to account for more than 50 percent of worldwide trade. This is expected to occur before the end of this decade.

In the reference case, the Persian Gulf share of total exports is expected to exceed 51 percent shortly after the turn of the century and gradually increase to over 64 percent by the year 2020. In the *AEO99* low oil price case, the Persian Gulf share of worldwide petroleum exports is expected to reach almost 52 percent shortly after the turn of the century and steadily increase to almost 72 percent by 2020. While all Persian Gulf producers are expected to increase their oil production capacity significantly over the forecast period, both Saudi Arabia and Iraq are expected to more than double their current production capacity levels.

Crude Oil, Light Product Imports Are Expected To Increase

Figure 41. U.S. gross petroleum imports by source, 1997-2020 (million barrels per day)



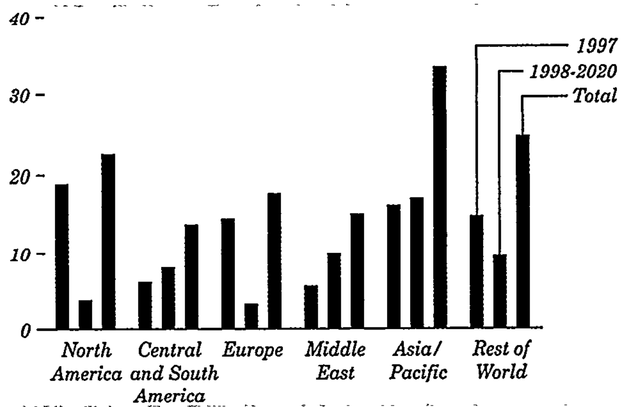
In the reference case, total U.S. gross oil imports increase from 10.2 million barrels per day in 1997 to 16.3 million in 2020 (Figure 41). Crude oil accounts for most of the increase in imports through 2000, whereas imports of petroleum products make up a larger share of the increase after 2000. Product imports increase more rapidly, as U.S. production stabilizes and U.S. refineries lack the capacity to process a larger quantity of imported crude oil.

By 2010, OPEC accounts for more than 45 percent of total projected U.S. petroleum imports. After 2010, the OPEC share increases gradually, to more than 46 percent in 2020. The Persian Gulf share of U.S. imports from OPEC increases from about 39 percent in 1997 to almost 50 percent in 2020. Crude oil imports from the North Sea increase slightly through 2010, then level off as North Sea production ebbs. Significant imports of petroleum from Canada and Mexico continue, and West Coast refiners are expected to import crude oil from the Far East to replace the modest volumes of Alaskan crude oil that will be exported.

Imports of light products are expected to more than double by 2020, to nearly 3.0 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.

Refining Capacity Is Projected To Grow Worldwide

Figure 42. Worldwide refining capacity by region, 1997 and 2020 (million barrels per day)



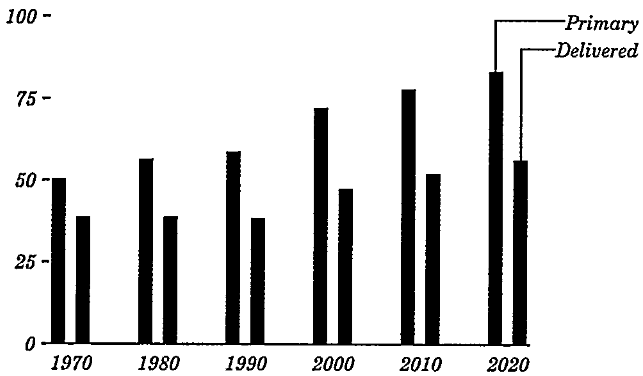
Worldwide crude oil distillation capacity was 76.1 million barrels per day at the beginning of 1997. To meet the growth in international oil demand in the reference case, worldwide refining capacity is expected to increase by more than two-thirds—to more than 127 million barrels per day—by 2020. Substantial growth in distillation capacity is expected in the Middle East, Central and South America, and the Asia/Pacific region (Figure 42).

The Asia/Pacific region has been the fastest growing refining center in the 1990s. It has recently passed Western Europe as the world's second largest refining center and, in terms of distillation capacity, is expected to surpass the United States by 2010. 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.

Primary and Delivered Energy Use
Show Similar Growth Rates

Figure 43. Primary and delivered energy consumption, excluding transportation use, 1970-2020 (quadrillion Btu)



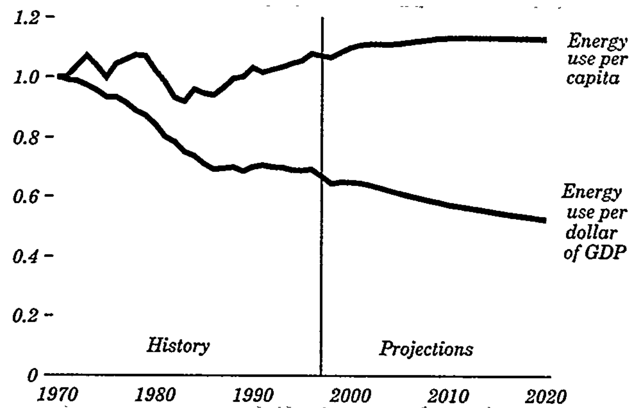
Net energy delivered to consumers represents only a part of total primary energy consumption. Primary consumption includes energy losses associated with the generation, transmission, and distribution of electricity, which are allocated to the end-use sectors (residential, commercial, and industrial) in proportion to each sector's share of electricity use [*51*].

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 total and delivered energy consumption (Figure 43). This trend is expected to stabilize over the forecast horizon, as more efficient generating technologies offset increased demand for electricity. Projected primary energy consumption and delivered energy consumption grow by 0.8 percent and 0.9 percent a 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 emissions, for example, are closely correlated with total energy consumption. In the development of carbon stabilization policies, growth rates for primary energy consumption may be more important than those for delivered energy.

Projected GDP Growth Exceeds
Growth in Energy Use

Figure 44. Energy use per capita and per dollar of gross domestic product, 1970-2020 (index, 1970 = 1)

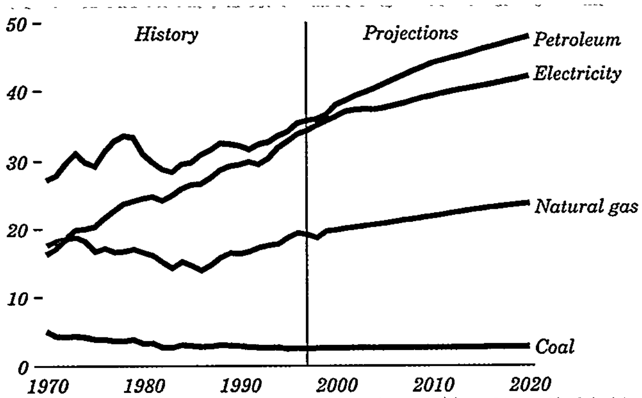


Energy intensity, both as measured by primary energy consumption per dollar of GDP and as measured on a per capita basis, declined between 1970 and the mid-1980s (Figure 44). While the overall GDP-based energy intensity of the economy is projected to continue declining between 1997 and 2020, the decline is not expected to be as rapid as it was in the earlier period, as a result of relatively stable projected energy prices and increased use of electricity-based energy services. As electricity claims a greater share of energy use, projected consumption per dollar of GDP declines at a slower rate, because electricity use contributes both end-use consumption and energy losses to total energy consumption. Between 1997 and 2020, GDP is estimated to increase by 61 percent, compared with a 27-percent increase in primary energy use.

In the *AEO99* forecast, the demand for energy services increases markedly over current levels. The average home in 2020 is expected to be 4 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 20 and 95 percent higher, respectively, than their current levels. Growth in demand for energy services notwithstanding, primary energy intensity on a per capita basis will remain essentially static through 2020, with efficiency improvements in many end-use energy applications making it possible to provide higher levels of service without significant increases in energy use per capita.

Transportation Petroleum Use Leads the Rise in Energy Consumption

Figure 45. Primary energy use by fuel, 1970-2020 (quadrillion Btu)



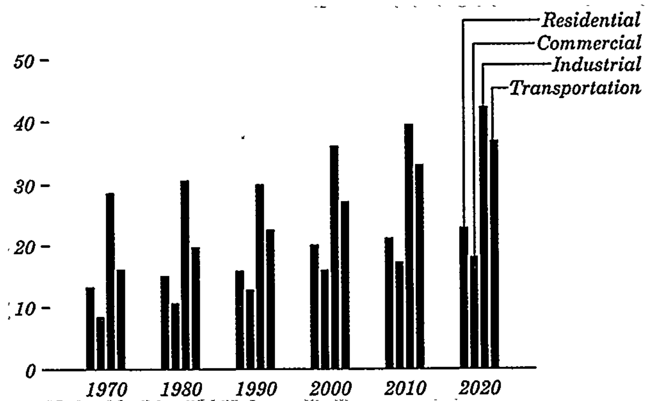
Petroleum products, mainly for transportation, claim the greatest share of primary energy consumption in the *AEO99* forecast (Figure 45). Growth in energy demand in the transportation sector, which averaged 2.0 percent a year during the 1970s, was diminished in the 1980s by rising fuel prices and by new Federal vehicle efficiency standards, which led to an unprecedented 2.1-percent annual increase in average vehicle fuel economy. In the *AEO99* forecast, fuel economy gains slow as a result of stable fuel prices and the absence of new legislative mandates. A growing population and increased travel per capita lead to 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 slower than the rapid growth seen in the 1970s. End-use demand for natural gas grows at a slightly slower rate than overall 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 19.9 percent of all end-use energy demand requirements in 2020.

End-use demand for renewable energy from sources such as wood, wood wastes, and ethanol increases by 1.2 percent a year. The use of geothermal and solar thermal energy in buildings increases by about 3.6 percent a year but does not exceed 1 percent of energy consumption for space and water heating.

Residential and Commercial Energy Use Is Expected To Increase Modestly

Figure 46. Primary energy use by sector, 1970-2020 (quadrillion Btu)



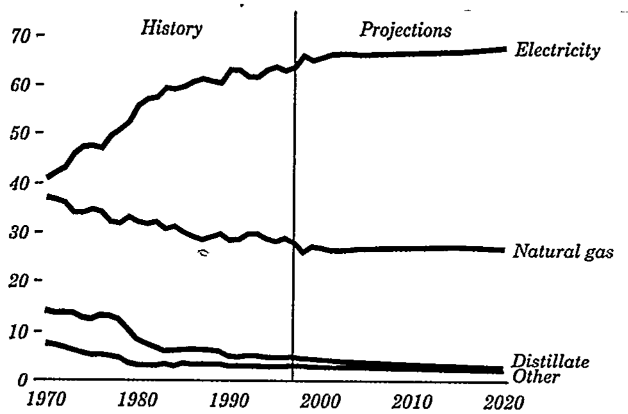
Primary energy use in the reference case is projected to reach 120 quadrillion Btu by 2020, 27 percent higher than the 1997 level. In the early 1980s, as energy prices rose, sectoral energy consumption grew relatively little (Figure 46). Between 1985 and 1997, however, stable energy prices contributed to a marked increase in sectoral energy consumption.

In the forecast, energy demand in the residential and commercial sectors grows at about the same rate as population. Demand for energy in the transportation sector grows more rapidly, driven by estimates 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 help bracket the uncertainty inherent in any long-term forecast, alternative assumptions were used to highlight the sensitivity of the *AEO99* forecast to different oil price and economic growth paths. At the consumer level, oil prices primarily affect the demand for transportation fuels. Oil use for transportation in the high world oil price case is 4.2 percent lower than in the low world oil price case in 2020, as consumer choices favor more fuel-efficient vehicles and a slightly reduced demand for travel services. Varying economic growth affects overall energy demand in each of the end-use sectors to a greater extent [*52*]. By 2020, high economic growth assumptions result in a 17-percent increase in total annual energy use over its projected level in the low growth case.

Electricity Dominates the Expected Increase in Residential Energy Use

Figure 47. Residential primary energy consumption by fuel, 1970-2020 (percent of total)



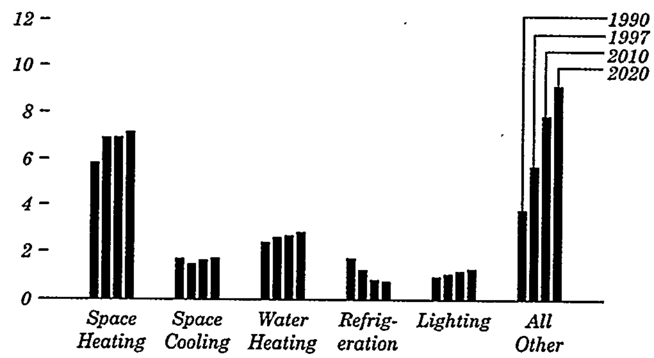
Residential energy consumption is projected to increase by more than 20 percent overall between 1997 and 2020. Most (87 percent) of the growth in total energy use is related to increased use of electricity. Sustained growth in housing in the South, where almost all new homes use central air conditioning, is an important component of the national trend, along with the penetration of consumer electronics, such as home office equipment and security systems (Figure 47).

While its share declines slightly, natural gas use in the residential sector is projected to grow by 0.6 percent a year through 2020. Natural gas prices to residential customers decline in the forecast and are lower than the prices of other fuels, such as heating oil. The number of homes heated by natural gas increases more than the number heated by electricity and oil. Distillate fuel and liquefied petroleum gas (LPG) use are projected to fall, with the number of homes using these 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 Improvements Could Slow the Growth in Energy Use for Heating

Figure 48. Residential primary energy consumption by end use, 1990, 1997, 2010, and 2020 (quadrillion Btu)



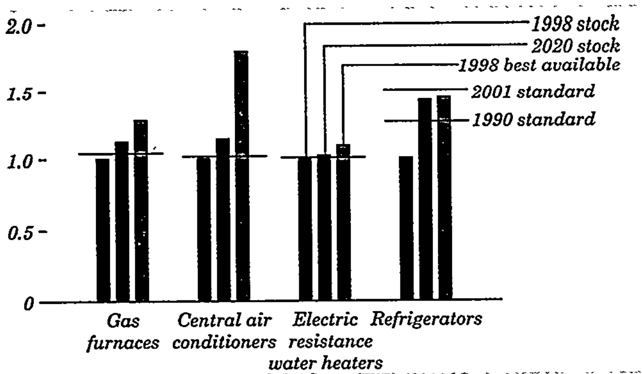
Energy use for space heating, the most energy-intensive end use in the residential sector, grew by 2.5 percent a year from 1990 to 1997 (Figure 48). Future growth should be slowed by higher equipment efficiency and tighter building codes. Building shell efficiency gains are projected to cut space heating demand in new homes by over 25 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 a year, and revised standards are expected to reduce consumption by another 30 percent by 2002. Energy use for refrigeration has declined by 4.4 percent annually since 1990 and is projected to decline by about 2.0 percent a 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 more than 6 percent a year since 1990 (Figure 48) and now accounts for 30 percent of residential 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 expected to exceed other components of residential demand by 2020.

Higher Efficiency, Lower Energy Intensity Are Expected for Appliances

Figure 49. Efficiency indicators for selected residential appliances, 1998 and 2020 (index, 1998 stock efficiency =1)

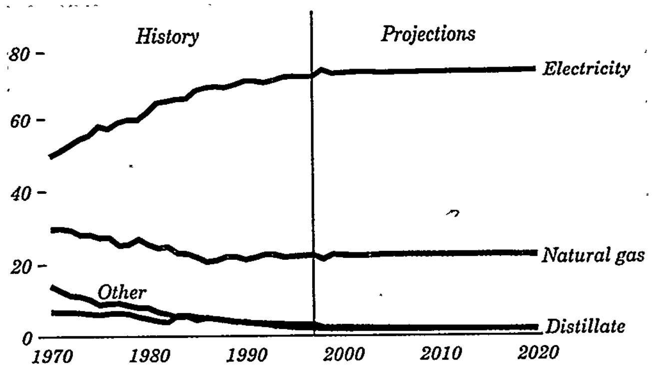


The *AEO99* reference case projects an increase in the stock efficiency of residential appliances, as stock turnover and technology advances in most end-use services combine to reduce residential energy intensity over time. For most appliances covered by the National Appliance Energy Conservation Act of 1987, the most recent Federal efficiency standards are higher than the 1998 stock, ensuring an increase in stock efficiency (Figure 49) 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 and water heaters are expected to be announced by March 1999, and several other product announcements are expected by spring 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 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.

Little Change Is Projected for Commercial Energy Fuel Mix

Figure 50. Commercial nonrenewable primary energy consumption by fuel, 1970-2020 (percent of total)

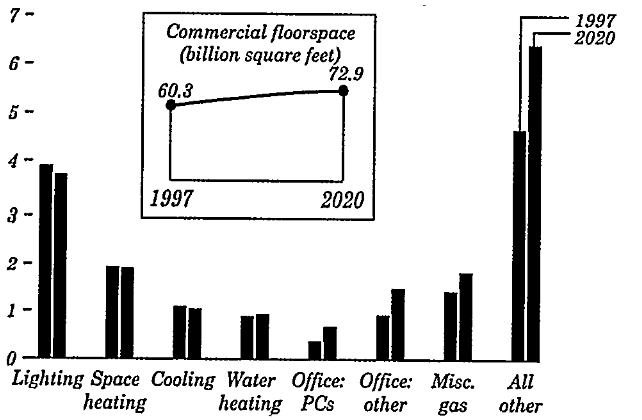


Projected energy use trends in the commercial sector show stable shares for all fuels, with growth in overall consumption slowing from its pace over the past two decades (Figure 50). Slow growth (0.7 percent a year) is expected in the commercial sector, for two reasons. Commercial floorspace is projected to grow by only 0.8 percent a year between 1997 and 2020, compared with an average of 1.5 percent a year over the past two decades. Lower growth in floorspace reflects the slowing population growth expected after 2000. Additionally, energy consumption per square foot is projected to decline by 0.1 percent a year, as a result of efficiency standards, voluntary government programs aimed at improving efficiency, and other technology improvements.

Electricity accounts for nearly three-fourths of commercial primary energy consumption throughout the forecast. Expected efficiency gains in electric equipment are offset by continuing penetration of new technologies and greater use of office equipment. Natural gas accounts for 22 percent of commercial energy consumption in 1997 and maintains that share throughout the forecast. Distillate fuel oil makes up only 3 percent of commercial demand in 1997, down from 6 percent in the years before deregulation of the natural gas industry. The fuel share projected for distillate drops to 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.

New Energy Uses Lead Projected Growth in Commercial Demand

Figure 51. Commercial primary energy consumption by end use, 1997 and 2020 (quadrillion Btu)

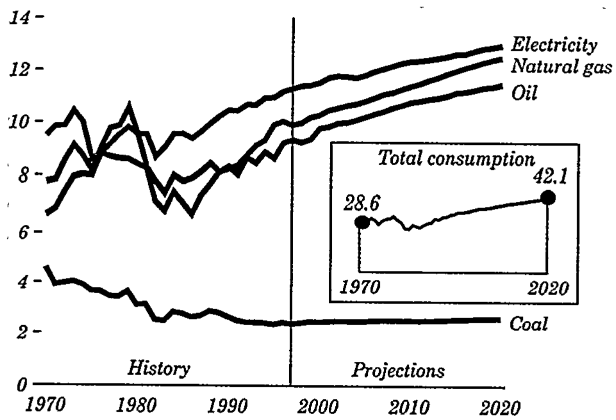


Through 2020, lighting remains the most important individual end use in the commercial sector [53]. Energy use for lighting declines slightly in the forecast as more energy-efficient lighting equipment and more efficient generating technologies are adopted. Efficiency also improves for space heating, space cooling, and water heating, moderating the growth in overall commercial sector energy demand. Increasing building shell efficiency, which affects the energy required for space heating and cooling, contributes to the trend (Figure 51).

The highest growth rates are expected for end uses that have not yet saturated the commercial market. Energy use for personal computers grows by 2.7 percent a year and for other office equipment, such as fax machines and copiers, by about 2.1 percent a year. The growth in electricity use for office equipment reflects a trend toward more powerful equipment, the response to a projected decline in real electricity prices, and an increase in the market for commercial electronic equipment. Natural gas use for such miscellaneous uses as cooking, district heating, and self-generated electricity is expected to grow by 1.1 percent a year. New telecommunications technologies and medical imaging equipment 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 as emerging technologies achieve greater market penetration.

Increasing Share of Natural Gas Use Is Projected for Industry

Figure 52. Industrial primary energy consumption by fuel, 1970-2020 (quadrillion Btu per year)

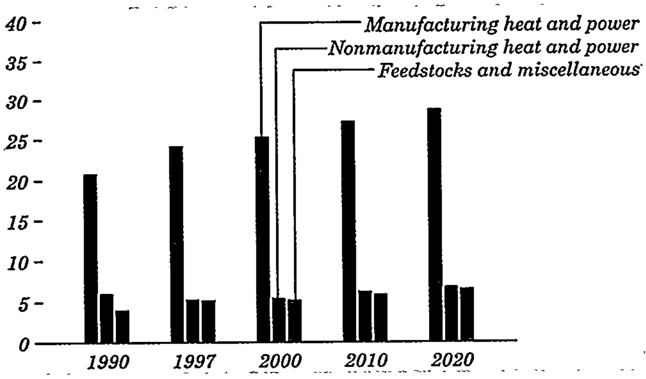


From 1970 to 1986, with demand for coking coal reduced by declines in steel production and natural gas use falling as a result of end-use restrictions and curtailments, electricity's share of industrial energy use increased from 23 percent to 35 percent. The natural gas share fell from 33 percent to 25 percent, and coal's share fell from 16 percent to 10 percent. After 1986, natural gas began to recover its share as end-use regulations were lifted and supplies became more certain and less costly. The *AEO99* projections of plentiful supplies and stable prices allow natural gas to increase its current share of industrial energy consumption.

Primary energy use in the industrial sector—which includes the agriculture, mining, and construction industries in addition to traditional manufacturing—increases by 0.8 percent a year in the forecast (Figure 52). 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 29.8 percent, as competition in the generation market keeps electricity prices low. Relatively low prices are also projected for natural gas, resulting in consumption that is 26.2 percent over its 1997 level by 2020. Industrial petroleum use grows by 23.2 percent over the same period. Coal use increases slowly, by 0.4 percent a year, as new steelmaking technologies continue to reduce demand for metallurgical coal, offsetting the modest growth in coal use for boiler fuel and as a substitute for coke in traditional steelmaking.

Manufacturing Heat and Power Dominate Industrial Energy Use

Figure 53. Industrial primary energy consumption by industry category, 1990-2020 (quadrillion Btu per year)



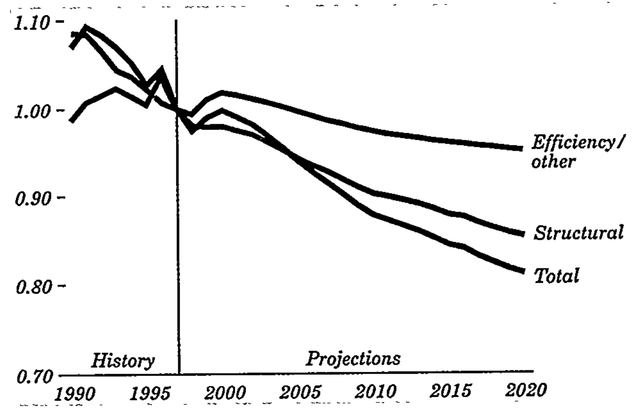
More than two-thirds of all the energy consumed in the industrial sector is used to provide heat and power for manufacturing; the remainder is approximately equally distributed among nonmanufacturing heat and power and consumption as feedstocks (raw materials) and other miscellaneous uses (Figure 53).

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 1997. The major fuels used in petroleum refineries are still gas, natural gas, and petroleum coke. In the chemical industry, natural gas accounts for two-thirds 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.

A major use of energy in the nonmanufacturing industries is for diesel-powered off-road equipment, such as mine excavation equipment, farm tractors, and bulldozers. The construction industry uses asphalt and road oil for paving and roofing. By 2020, nonmanufacturing output is projected to be 40.9 percent higher and delivered energy consumption (including asphalt and road oil) 38.3 percent higher than their 1997 levels. Total feedstock use is expected to increase by 19.8 percent. Natural gas is the fastest growing feedstock, increasing by 23.4 percent between 1997 and 2020.

Changing Industrial Output Leads the Decline in Energy Intensity

Figure 54. Industrial delivered energy intensity by component, 1990-2020 (index, 1997 = 1)

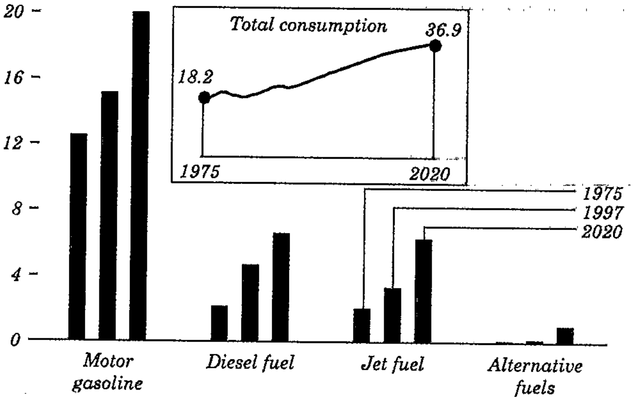


Changes in industrial energy intensity (consumption per unit of output) can be separated into two effects. One component reflects underlying increases in equipment and production efficiencies; the other arises from structural changes in the composition of manufacturing output. Since 1970, the use of more energy-efficient technologies, combined with relatively low growth in the energy-intensive industries, has moderated growth in industrial energy consumption. Thus, despite a 44 percent increase in industrial output, total energy use in the sector has grown by only 12 percent since 1977. These basic trends are expected to continue.

The share of total industrial output attributed to the energy-intensive industries falls from 23 percent to 19 percent from 1997 to 2020. Thus, even if no specific industry experienced a decline in intensity, aggregate industrial intensity would decline. Figure 54 shows projected changes in energy intensity due to structural effects and efficiency effects separately [*54*]. Over the forecast period, industrial delivered energy intensity drops by 19 percent, and the changing composition of industrial output alone results in approximately a 15-percent drop. Thus, more than two-thirds of the change in delivered energy intensity for the sector is attributable to structural shifts and the remainder to changes in energy intensity associated with increases in equipment and production efficiencies.

Low Prices Are Projected To Boost Gasoline Consumption

Figure 55. Transportation energy consumption by fuel, 1975, 1997, and 2020 (quadrillion Btu)



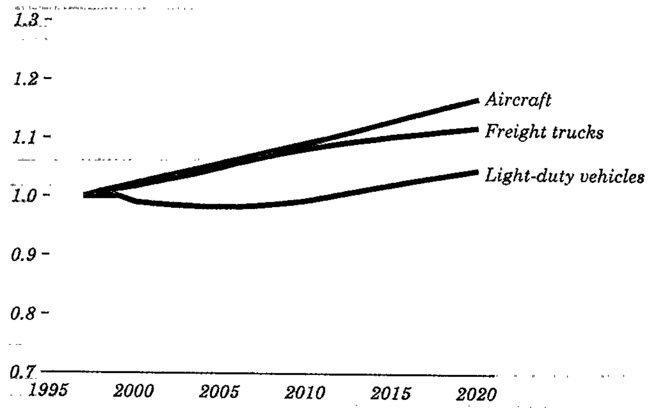
By 2020, total energy demand for transportation is expected to be 36.9 quadrillion Btu, compared with 25.0 quadrillion Btu in 1997 (Figure 55). Petroleum products dominate energy use in the sector. Motor gasoline use, increasing by 1.2 percent a year in the reference case, makes up more than half of transportation energy demand. Alternative fuels are projected to displace about 500,000 barrels of oil equivalent a day [*55*] by 2020 (about 5 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 sustained, however, by low projected gasoline prices and slower fuel efficiency gains in conventional light-duty vehicles (cars, vans, pickup trucks, and utility vehicles) than was achieved during the 1980s.

Assumed industrial output growth of 1.9 percent a year through 2020 leads to an increase in freight transport, with a corresponding increase in diesel use of 1.5 percent a year. Economic growth and low projected jet fuel prices yield a 3.8-percent annual increase in air travel, causing jet fuel use to increase by 2.8 percent a year.

In the forecast, energy prices directly affect the level of oil use through travel costs and average vehicle fuel efficiency. Most of the projected 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 1.1 percent a year, compared with 1.4 percent a year in the low oil price case.

Fuel Efficiency Grows, Despite Increasing Vehicle Horsepower

Figure 56. Transportation stock fuel efficiency by mode, 1997-2020 (index, 1997 = 1)



Projected fuel efficiency improves at a slower rate through 2020 than in the 1980s (Figure 56), with light-duty vehicle efficiency standards assumed to stay at current levels. Projected low fuel prices and higher personal income [*56*] increase the demand for larger, more powerful vehicles. Average horsepower for new cars in 2020 is 63 percent above the 1997 level (Table 3), but the use of advanced technologies and materials keeps new vehicle fuel economy from declining. New advanced technologies, such as gasoline fuel cells and direct fuel injection and electric hybrids for both gasoline and diesel engines, are projected to boost fuel economy levels gradually through 2020, by about 1 to 2 miles per gallon.

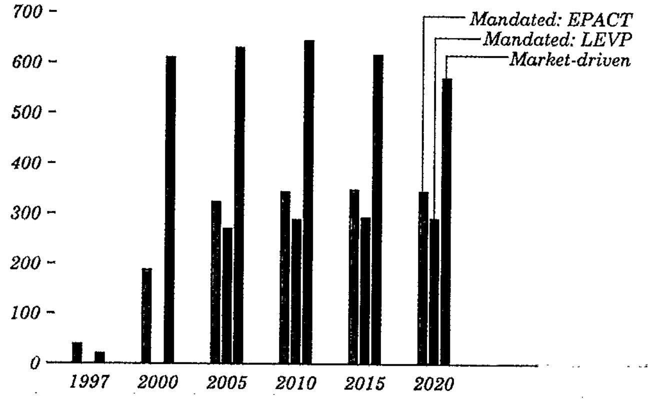
From 1990 to 1997, the horsepower of compact sport utility vehicles (medium light trucks) increased faster than that of standard sport utility vehicles (large light trucks)—3.0 percent vs. 2.6 percent a year. If it continues, this trend will lead to higher horsepower for medium than for large light trucks by 2020.

Table 3. 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*	*165*	*175*
Sales share	*0.60*	*0.28*	*0.12*	*0.50*	*0.38*	*0.12*
1997						
Horsepower	*139*	*167*	*187*	*156*	*185*	*196*
Sales share	*0.57*	*0.30*	*0.13*	*0.32*	*0.57*	*0.11*
2010						
Horsepower	*192*	*224*	*270*	*222*	*262*	*249*
Sales share	*0.58*	*0.29*	*0.14*	*0.34*	*0.50*	*0.16*
2020						
Horsepower	*232*	*263*	*307*	*275*	*307*	*291*
Sales share	*0.58*	*0.28*	*0.14*	*0.34*	*0.49*	*0.17*

Electric Vehicles Are Projected To Gain AFV Market Share

Figure 57. Alternative-fuel vehicle sales by type of demand, 1997-2020 (thousand vehicles sold)



Sales of alternative-fuel vehicles (AFVs) as a result of legislative mandates at the Federal level—under the Energy Policy Act of 1992 (EPACT)—and at the State level—under the Low Emission Vehicle Program (LEVP)—are expected to reach about 0.64 million units in 2020 (Figure 57). AFV acquisitions mandated for fleets under EPACT, predominantly fueled by compressed natural gas (CNG) or liquefied petroleum gas, represent the earliest legislated sales. Vehicles that use gaseous fuels continue to capture a large share of the AFV market through 2020 (Table 4).

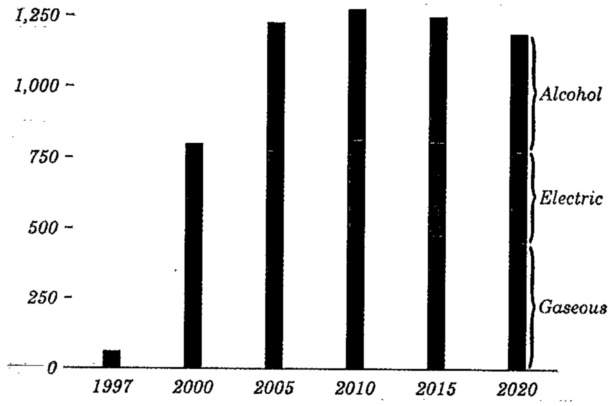
Implementation of LEVP regulations is assumed to begin in 2003 for California, Massachusetts, and New York. LEVP legislated sales are expected to total 292,000 units in 2020, boosting electric vehicles to about 25 percent of AFV sales. Market-driven sales [57] exceed mandated sales of AFVs by 2000 as a result of AFV corporate average fuel economy (CAFE) credits available to auto manufacturers under the Alternative Motor Fuels Act.

Table 4. Shares of the alternative-fuel light-duty vehicle market by technology type, 2020 (percent)

Technology	Market share	Technology	Market share
Dedicated internal combustion		*Flex fuel internal combustion*	
Alcohol	*11.0*	*Alcohol*	*23.0*
CNG	*17.1*	*CNG*	*4.1*
LPG	*13.6*	*LPG*	*2.5*
Electric	*24.8*	*Electric hybrid*	*2.4*
Fuel cell	*1.5*		

AFVs Are Projected at 8 Percent of All Vehicle Sales in 2020

Figure 58. Alternative-fuel light-duty vehicle sales by fuel type, 1997-2020 (thousand vehicles sold)



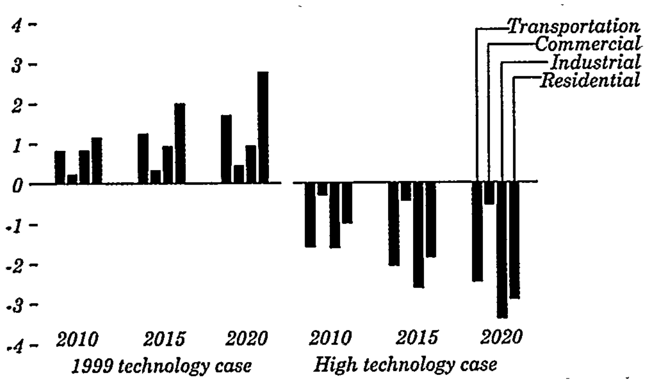
In the reference case, total AFV sales reach approximately 1.21 million units, or 8.1 percent of all vehicle sales, in 2020 (Figure 58). The use of light-duty AFVs is expected to reduce carbon emissions by 1 million metric tons of carbon by 2020. Vehicles that use gaseous fuels are already being sold by manufacturers at prices $3,000 to $4,000 above those for gasoline vehicles. Their limited range (about two-thirds that of gasoline vehicles) makes them good candidates for centrally fueled fleet applications. Because the large fuel tanks required to maintain vehicle range restrict both trunk and passenger space, the market potential for gaseous fuel AFVs for private use is limited to larger vehicles.

Electric vehicles are currently being developed by several automobile manufacturers, but large numbers of sales are not expected until LEVP mandates begin. Sales of dedicated electric vehicles—98 percent of which originate from LEVP mandates—are projected to reach nearly 299,000 units in 2020.

"Flex fuel" vehicles, which can use any combination of ethanol, methanol, and gasoline, are expected to make up 23 percent of AFV sales in 2020. The range, fuel efficiency, and performance of these vehicles are similar to those of conventional gasoline vehicles, and their incremental production cost is currently less than $500, although manufacturers are now selling them at cost to meet CAFE standards. Cellulosic ethanol is expected to displace corn-based ethanol by 2001, resulting in lower fuel costs for flex-fuel vehicles.

New Efficient Technologies Could Save Energy in All Sectors

Figure 59. Variation from reference case primary energy use by sector in two alternative technology cases, 2010, 2015, and 2020 (quadrillion Btu)



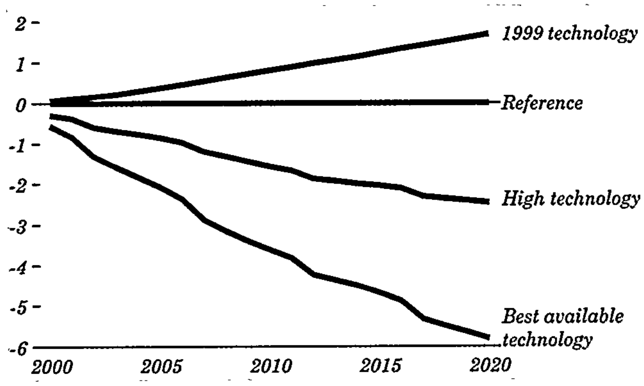
The availability and market penetration of new, more efficient technologies are uncertain. Alternative cases for each sector, based on a range of assumptions about technological progress, show the effects of the assumptions (Figure 59). The alternative cases assume that current equipment and building standards are met but do not include feedback effects on energy prices or on economic growth.

For the residential and commercial sectors, the 1999 technology case holds equipment and building shell efficiencies at 1999 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 1999 technology cases for the industrial and transportation sectors and the high technology case for the industrial sector use the same assumptions used for the buildings sector. The high technology case for the transportation sector includes reduced costs for advanced technologies and improved efficiencies, comparable to those assumed in a recent Department of Energy (DOE) interlaboratory study for air, rail, marine, and freight 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 [*58*].

Potential Efficiency Gains Are Significant for Residential Users

Figure 60. Variation from reference case primary residential energy use in three alternative cases, 2000-2020 (quadrillion Btu)



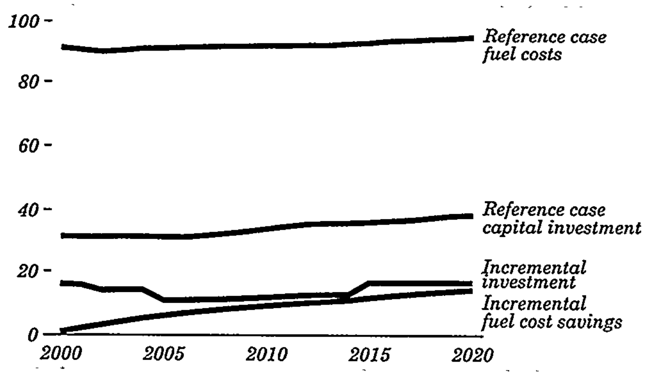
The *AEO99* reference case forecast includes the projected effects of several different policies aimed at increasing residential end-use efficiency. Examples include minimum efficiency standards and voluntary energy savings programs designed to promote energy efficiency through innovations in manufacturing, building, and mortgage financing. In the 1999 technology case, which assumes no further increases in the efficiency of equipment or building shells beyond that available in 1999, 7.4 percent more energy would be required in 2020 (Figure 60).

In the best available technology case, assuming that the most energy-efficient technology considered is always chosen regardless of cost, energy use is 25.4 percent lower than in the reference case in 2020, and household primary energy use is 30.5 percent lower than in the 1999 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 reach 10.8 percent in 2020; however, the savings are not as great as those in the best available technology case.

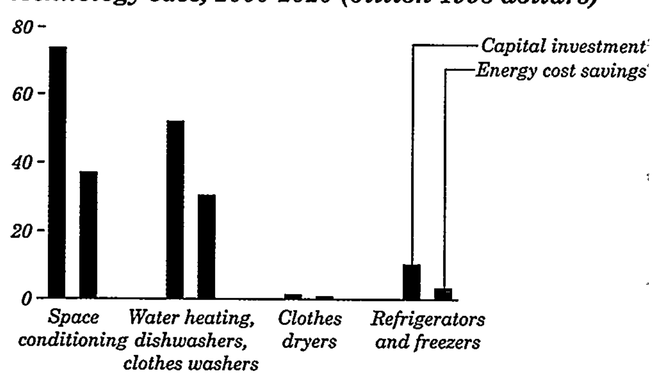
Investment Costs Could Outstrip Residential Energy Cost Savings

Figure 61. Cost and investment changes for selected residential appliances in the best available technology case, 2000-2020 (billion 1998 dollars)



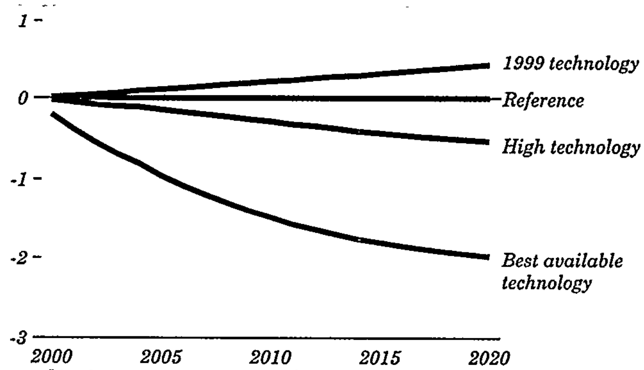
In the best available technology case, which requires the purchase of the most efficient equipment available, residential energy expenditures are lower but capital investment costs are higher (Figures 61 and 62). This case captures the effects of installing the most efficient (usually the most expensive) equipment at reference case turnover rates, regardless of economic considerations. An incremental investment of $137 billion [*59*] reduces residential delivered energy use by more than 22 quadrillion Btu—saving consumers more than $71 billion in energy expenditures—through 2020. 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 62. Present value of investment and savings for residential appliances in the best available technology case, 2000-2020 (billion 1998 dollars)



AEO99 Reference Case Includes Gains in Commercial Energy Efficiency

Figure 63. Variation from reference case primary commercial energy use in three alternative cases, 2000-2020 (quadrillion Btu)

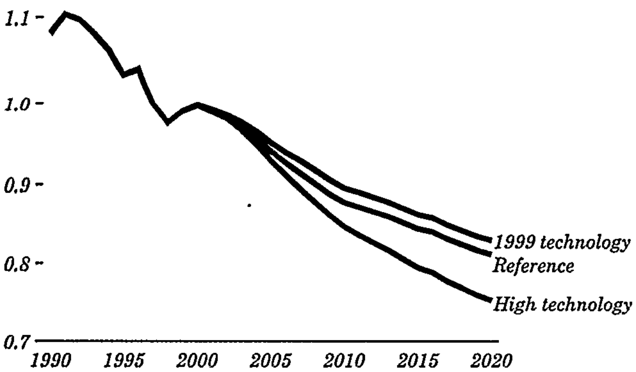


The *AEO99* reference case incorporates efficiency improvements for commercial equipment and building shells, contributing to a decline in commercial energy intensity of 0.1 percent a year over the forecast. The 1999 technology case assumes that future equipment and building shells will be no more efficient than those available in 1999. The high technology case assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment than in the reference case. In addition, building shells are assumed to improve at a faster rate then in the reference case. In comparison, the best available technology case assumes that only the most efficient technologies considered in *AEO99* will be chosen, regardless of cost, and that building shells will improve at the same rate assumed in the high technology case.

Energy use in the 1999 technology case is 2.3 percent higher than in the reference case by 2020 (Figure 63), with commercial primary energy intensity stable through 2020. In the high technology case there is an additional 3.0-percent energy savings in 2020, and primary energy intensity falls by 0.2 percent a year from 1997 to 2020. Allowing the purchase of only the most efficient equipment in the best available technology case yields energy use that is 11.0 percent lower than energy use in the reference case by 2020. Commercial primary energy intensity declines more rapidly in this case than in the high technology case, by 0.6 percent a year.

Trends in Energy Intensity Vary by 50 Percent in Alternative Cases

Figure 64. Industrial primary energy intensity in two alternative technology cases, 1990-2020 (index, 1997 = 1)



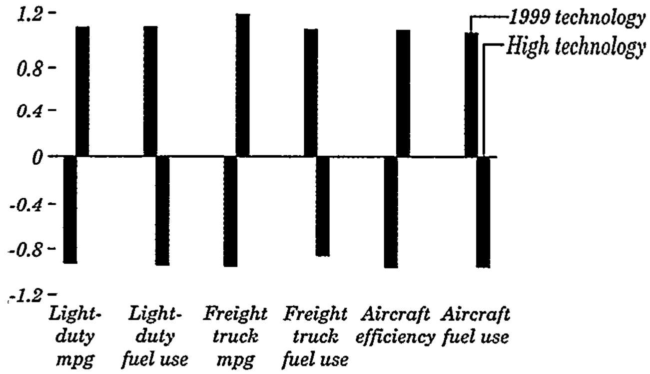
Projected efficiency gains in both energy-intensive and non-energy-intensive industries provide improvement in energy intensity. The growth in machinery and equipment production, driven primarily by investment and export-related demand, is a key factor: these less energy-intensive industries grow 48 percent faster than the industrial average (2.8 percent vs. 1.9 percent a year).

In the high technology case, 3.4 quadrillion Btu less energy is used in 2020 than for the same level of output in the reference case. Industrial primary energy intensity declines by 1.4 percent a year through 2020 in this case, compared with a 1.0-percent annual decline in the reference case (Figure 64). While the individual industry intensities decline about twice as rapidly in the high technology case as in the reference case, the aggregate intensity falls less rapidly, because the composition of industrial output is the same in the two cases.

In the 1999 technology case, industry consumes 0.9 quadrillion Btu more energy in 2020 than in the reference case. Energy efficiency remains at the level achieved in 1999 new plants, but average efficiency still improves as old plants are retired. Aggregate industrial energy intensity declines by 0.9 percent a year because of reduced efficiency gains and changes in industrial structure. The composition of industrial output accounts for 86 percent of the change in aggregate industrial energy intensity, compared with 77 percent in the reference case.

More Improvement in Fuel Efficiency Is Possible for Transportation Uses

Figure 65. Changes in key components of the transportation sector in two alternative cases, 2020 (percent change from reference case)



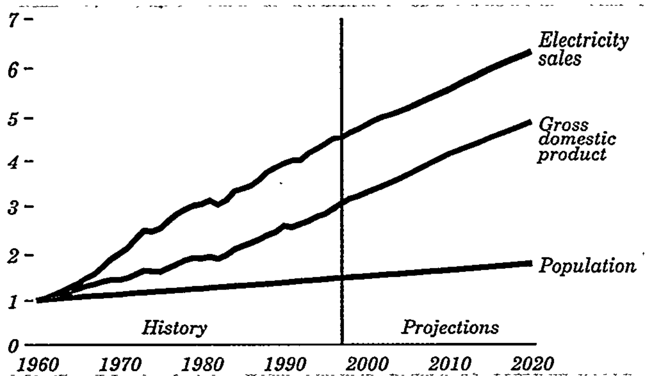
Two alternative cases are examined to bracket the potential impacts of technology improvements in the transportation sector. The 1999 technology case holds new fuel efficiencies for light-duty vehicles, freight trucks, and aircraft at 1999 levels throughout the forecast, resulting in average stock efficiencies for light-duty vehicles that are as much as 8.4 percent lower than those in the reference case in 2020. As a result, fuel use in 2020 is 2.8 quadrillion Btu (7.5 percent) higher than in the reference case (Figure 65). The increase in fuel use is attributable primarily to light-duty vehicles (55 percent of the total increase), followed by aircraft (17 percent) and freight trucks (16 percent).

The high technology case assumes cost and performance criteria provided by the DOE Office of Energy Efficiency and Renewable Energy and American Council for an Energy-Efficient Economy for light-duty vehicles, and from the efficiency case of the recent interlaboratory study [*60*] for air, freight, marine, and rail travel, including high-efficiency advanced light-duty diesel vehicles; electric, electric hybrid, and fuel cell light-duty vehicles with higher efficiencies and earlier introduction dates; advanced drag reduction, reduced vehicle weights, and advanced diesel engines for freight trucks, with shorter market penetration times and lower cost-effectiveness criteria; and aircraft with higher fuel efficiency. In the high technology case, total fuel consumption for the transportation sector is 2.9 quadrillion Btu (7.9 percent) lower than the reference case level in 2020.

Electricity Sales

Electricity Sales Growth Is Expected To Accompany GDP Growth

Figure 66. Population, gross domestic product, and electricity sales growth, 1960-2020 (index, 1960 = 1)



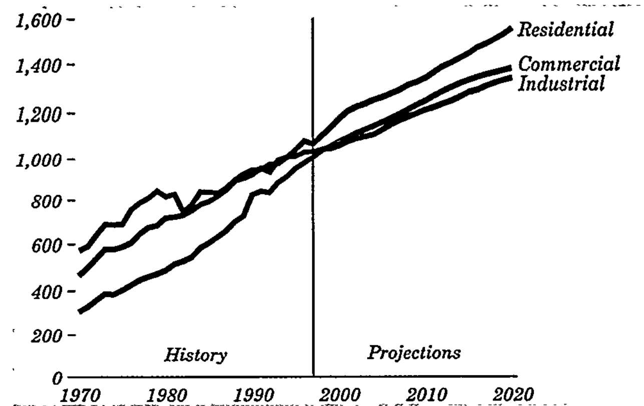
While generators and cogenerators try to adjust to the evolving structure of the electricity market, they are also faced with slower growth in demand than in the past. Historically, the demand for electricity has been related to economic growth. This positive relationship will continue, but the magnitude of the ratio is uncertain.

During the 1960s, electricity demand grew by more than 7 percent a year, nearly twice the rate of economic growth (Figure 66). 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. The same trend is expected to continue throughout the forecast, as retiring equipment is replaced with new, more efficient units.

Changing consumer markets could mitigate the slowing of electricity demand growth seen in these projections. New electric appliances are introduced frequently. Only a few years ago, no one foresaw the growth in home computers, facsimile machines, copiers, and security systems, all powered by electricity. If new uses of electricity are more substantial than currently expected, they could partially offset future efficiency gains.

Residential Consumption Leads Projected Electricity Sales Growth

Figure 67. Annual electricity sales by sector, 1970-2020 (billion kilowatthours)



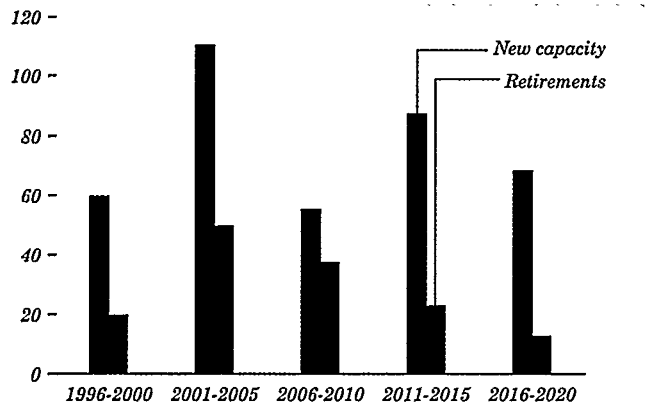
With the number of U.S. households projected to rise by 1.1 percent a year between 1997 and 2020, residential demand for electricity grows by 1.6 percent annually (Figure 67). Residential electricity demand changes as a function of the time of day, week, or year. During summer, residential demand peaks 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 will result in a need for more "peaking" capacity. Between 1997 and 2020, generating capacity from gas turbines and internal combustion engines is expected to more than triple.

Electricity demand in the commercial and industrial sectors grows by 1.4 and 1.1 percent a year, respectively, between 1997 and 2020. Annual commercial floorspace growth of 0.8 percent and industrial output growth of 1.9 percent drive the increase.

In addition to sectoral sales, cogenerators in 1997 produced 146 billion kilowatthours for their own use in industrial and commercial processes, such as petroleum refining and paper manufacturing. By 2020, these producers are expected to see only a slight decline in their share of total generation, increasing their own-use generation to 184 billion kilowatthours as demand for manufactured products increases.

Rising Demand, Plant Retirements Create a Need for New Generators

Figure 68. New generating capacity and retirements, 1996-2020 (gigawatts)



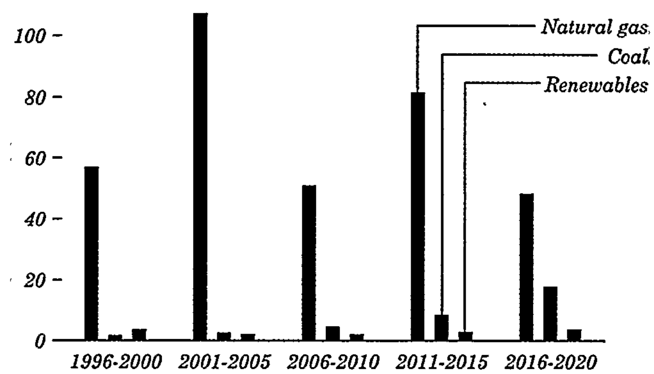
Despite slower demand growth, 363 gigawatts of new generating capacity will be needed by 2020 to meet growing demand and to replace retiring units. Between 1997 and 2020, 50 gigawatts (51 percent) of current nuclear capacity and 76 gigawatts (16 percent) of current fossil-steam capacity [*61*] are expected to be retired. Of the 155 gigawatts of new capacity needed after 2010 (Figure 68), 16 percent will replace retired nuclear capacity.

The reduction in baseload nuclear capacity has a marked impact on the electricity outlook after 2010: 44 percent of the new combined-cycle and 78 percent of the new coal capacity projected in the entire forecast are 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 to 38 percent for coal-steam units, with construction costs only about 37 percent those for coal-steam plants.

As older nuclear power plants age and their operating costs rise, more than one-half of currently operating nuclear capacity is expected to retire by 2020. More optimistic assumptions about operating lives and costs for nuclear units would reduce the need for new fossil-based capacity and reduce fossil fuel prices.

More Than a Thousand New Plants Could Be Needed by 2020

Figure 69. Electricity generation and cogeneration capacity additions by fuel type, 1996-2020 (gigawatts)

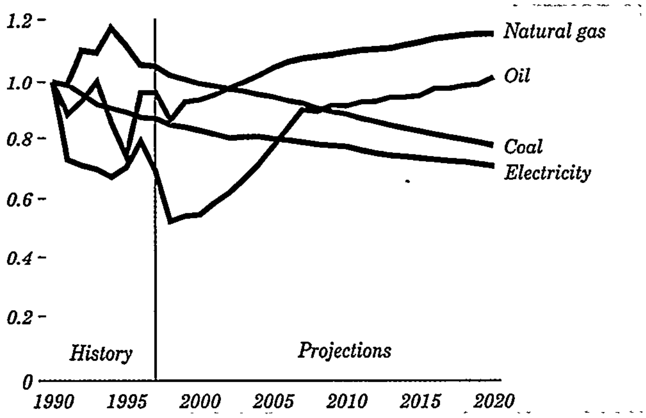


Before building new capacity, utilities are expected to use other options to meet demand growth—maintenance of existing plants, power imports from Canada and Mexico, and purchases from cogenerators. Even so, assuming an average plant capacity of 300 megawatts, a projected 1,210 new plants with a total of 363 gigawatts of capacity will be needed by 2020 to meet growing demand and to offset retirements. Of the new capacity, 88 percent is projected to be combined-cycle or combustion turbine technology fueled by natural gas or both oil and gas (Figure 69). Both technologies are designed primarily to supply peak and intermediate capacity, but combined-cycle technology can also be used to meet baseload requirements.

More than 32 gigawatts of new coal-fired capacity is projected to come on line between 1996 and 2020, accounting for almost 9 percent of all capacity expansion. Competition with low-cost gas-turbine-based technologies and the development of more efficient coal gasification systems has 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 the remaining 3 percent of capacity expansion by 2020—primarily, wind and biomass gasification units. Oil-fired steam plants, with higher fuel costs and lower efficiencies, account for very little of the new capacity in the forecast.

Projected Declines in Coal Prices Would Mean Cheaper Electricity

Figure 70. Fuel prices to electricity suppliers and electricity price, 1990-2020 (index, 1990 = 1)



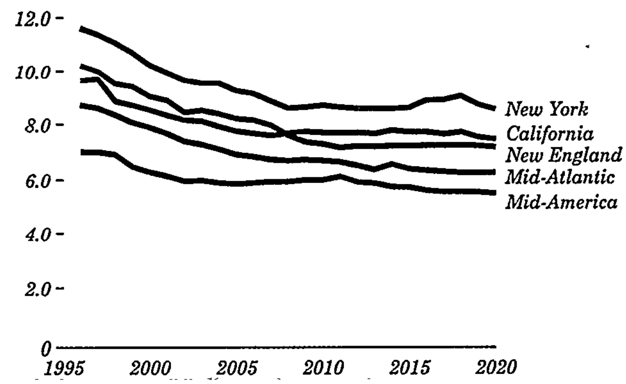
Between 1997 and 2020, the average price of electricity in real 1997 dollars is projected to decline by 0.9 percent a year as a result of competition among electricity suppliers (Figure 70). By sector, projected prices in 2020 are 16, 21, and 22 percent lower than 1997 prices for residential, commercial, and industrial customers.

The cost of producing electricity is a function of fuel costs, operating and maintenance costs, and the cost of capital. For existing plants, fuel costs typically represent $24 million annually or 79 percent of the total operational costs (fuel and operating and maintenance) for a 300-megawatt coal-fired plant and $31 million annually or 93 percent of the total operational costs for a gas-fired combined-cycle plant of the same size in 1997.

Natural gas prices to electricity suppliers rise by 0.8 percent a year in the forecast, from $2.76 per thousand cubic feet in 1997 to $3.31 in 2020. Gas-fired electricity generation increases by 211 percent, from 509 to 1,582 billion kilowatthours. Offsetting these increases are declining coal prices, declining capital expenditures, and improved efficiencies for new plants. Oil prices to utilities are expected to increase by 1.7 percent a year. As a result, oil-fired generation is expected to decline by more than 66 percent between 1997 and 2020. However, oil currently accounts for only 2.6 percent of total generation, and that share is expected to decline to 0.6 percent by 2020 as oil-fired steam generators are replaced by gas turbine technologies.

Retail Competition Is Expected To Lower Electricity Prices

Figure 71. Electricity prices in five regions in transition to competitive markets, 1997-2020 (1997 cents per kilowatthour)



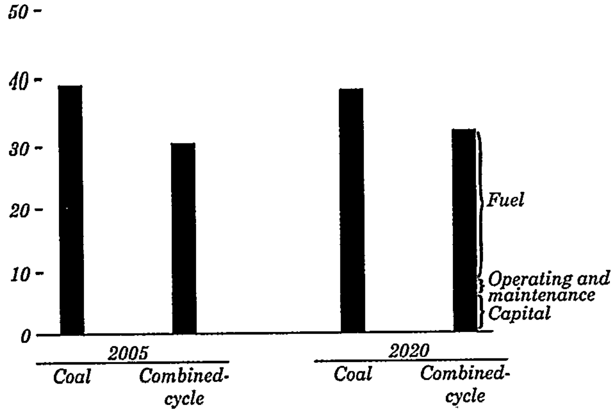
The reference case assumes a transition to competitive pricing in five regions—California, New York, New England, the Mid-Atlantic Area Council (consisting of Pennsylvania, Delaware, New Jersey and Maryland), and the Mid-America Interconnected Network (consisting of Illinois and parts of Wisconsin and Missouri). The 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. The region-wide 10-percent rate reduction required in California is represented. For the other regions it is assumed that competition will be phased in between 1999 and 2007, with fully competitive prices beginning in 2008. In all the competitively priced regions, the generation price (the price for the energy alone) is set by the marginal cost of generation. Transmission and distribution prices are assumed to remain regulated.

Prices in these regions fall rapidly in the early years of the projections, especially in the regions that have the highest prices today (Figure 71). From 1997 through 2005 the average price in the five regions declines by 2.6 percent a year. In addition, by 2020 the range of prices across the regions is expected to be much narrower than it is today. In 1997, the difference in electricity prices among the regions was 6.7 cents per kilowatthour, but by 2020 it is expected to narrow to 3.9 cents per kilowatthour.

New Gas-Fired Generators Could Be Less Expensive Than Coal Plants

Figure 72. Electricity generation costs, 2005 and 2020 (1997 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 levelized costs (Figure 72). The reference case assumes a capital recovery period of 20 years. In addition, the cost of capital is increased by 1 percentage point, to account for the competitive risk of siting new units.

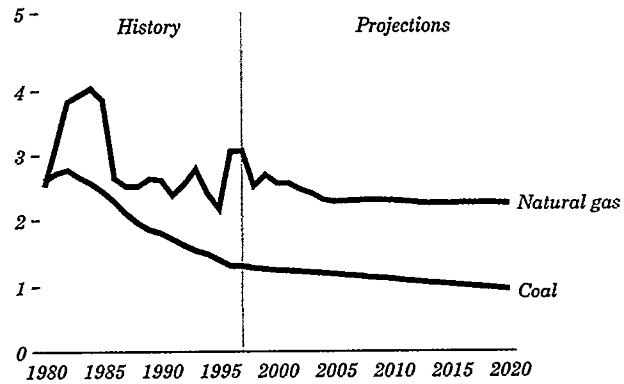
In the *AEO99* forecasts, the costs and performance characteristics for new plants improve over time, at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to refelct the optimism inherent in early project cost estimates. As project developers gain experience, the costs are assumed to decline rapidly. 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 5 to 18 percent between 1995 and 2020, depending on the technology (Table 5).

Table 5. Costs of producing electricity from new plants, 2005 and 2020

Item	2005 Conventional pulverized coal	2005 Advanced combined cycle	2020 Conventional pulverized coal	2020 Advanced combined cycle
	1997 mills per kilowatthour			
Capital	25.02	6.92	25.47	6.45
O&M	3.25	2.01	3.25	2.01
Fuel	10.96	21.64	9.75	24.03
Total	39.22	30.56	38.42	32.49
	Btu per kilowatthour			
Heat rate	9,253	6,639	9,087	6,350

Lower Generating Costs Are Projected for Both Coal and Gas Plants

Figure 73. Average fuel costs for coal- and gas-fired generating plants, 1980-2020 (1997 mills per kilowatthour)

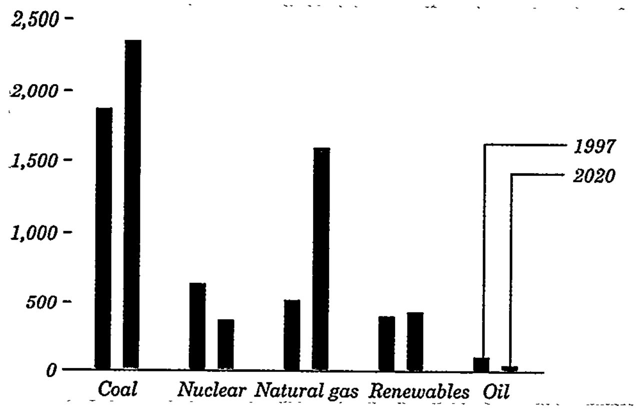


Since 1980, the per-kilowatthour fuel costs for gas-fired and, particularly, coal-fired power plants have fallen significantly (Figure 73). For coal plants, fuel prices have been declining since the early 1980s. For gas plants, fuel prices rose in the early 1980s but declined sharply in 1986. Generating costs for coal-fired plants decreased by 49 percent from 1980 to 1996, and the costs for gas-fired plants, even with the price increase that occurred in 1996, were still 24 percent lower than their peak in 1984.

The trend of declining costs for coal-fired plants is expected to continue as coal prices continue falling. In addition, nonfuel operations and maintenance costs are also expected to fall. In 1982, coal-fired steam plants used 250 employees per gigawatt of installed capacity, but utilities were able to reduce that number to 200 by 1995. Efforts to cut staff and reduce operating costs were prompted by the combination of technology improvements and competitive pressure. The amount by which utilities can continue to cut costs is uncertain, but many analysts agree that further reductions are possible. For gas-fired plants, per-kilowatthour generating costs are expected to fall early in the projections before leveling off. Although natural gas prices are expected to increase, the fuel costs per kilowatthour for gas-fired power plants are projected to remain steady as the efficiencies of new plants improve, offsetting the rise in fuel prices.

Coal-Fired Plants Are Projected To Dominate Electricity Generation

Figure 74. Electricity generation by fuel, 1997 and 2020 (billion kilowatthours)



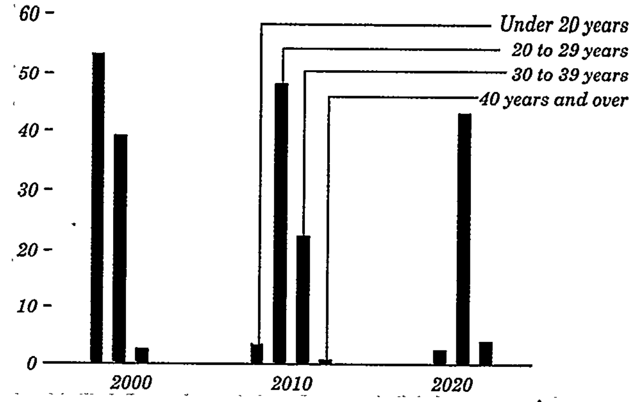
As they have since early in this century, coal-fired power plants are expected to remain the dominant source of electricity through 2020 (Figure 74). In 1997, coal accounted for 1,856 billion kilowatthours or 53 percent of total generation. Although coal-fired generation increases to 2,352 billion kilowatthours, increasing gas-fired generation reduces coal's share to 49 percent in 2020. 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 2000. Nevertheless, slow demand growth and the huge investment in existing plants will keep coal in its dominant position. By 2020, it is projected that 26 gigawatts of capacity will be retrofitted with scrubbers and 217 gigawatts with NO_x control technologies, to meet the requirements of the Clean Air Act Amendments of 1990 (CAAA90) and the Ozone Transport Rule (see "Legislation and Regulations," page 12).

The large investment in existing plants will also make nuclear power a growing source of electricity at least through 2000. Because the recent performance of nuclear power plants has improved substantially, nuclear generation is projected to increase until 2000, then decline as older units are retired.

In percentage terms, gas-fired generation increases the most, from 14 percent of the 1997 total to 33 percent in 2020. As a result, by 2003, natural gas overtakes nuclear power as the Nation's second-largest source of electricity. Generation from oil-fired plants remains fairly small throughout the forecast.

More Than Half of U.S. Nuclear Capacity Could Close by 2020

Figure 75. Operable nuclear power capacity by age of plant, 2000, 2010, and 2020 (megawatts)

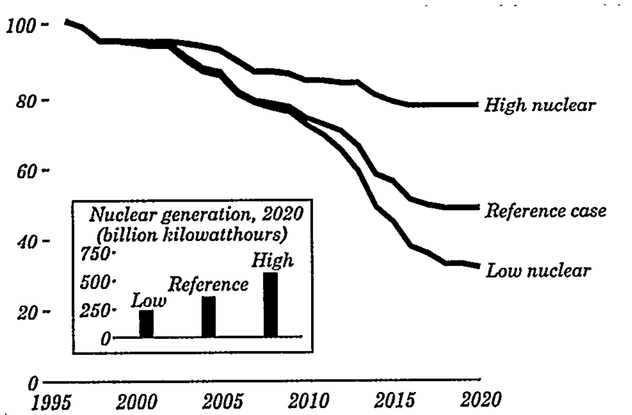


The nuclear power plants now in operation are aging, and many will reach the end of their operating licenses in the forecast period (Figure 75). In the reference case, 51 percent of current nuclear capacity is expected to be taken out of service by 2020. Some early retirements are included, based on the assumption that major capital investments will be needed after 30 years of operation and will be made only if they are more economical than building new capacity. In all, 27 nuclear units are projected to be retired early in the reference case. No new nuclear units are expected to become operable by 2020, because natural gas and coal-fired plants are projected to be more economical. By 2020, the nuclear share of total electricity generation is projected to fall to 7 percent from its current share of 18 percent.

Although some nuclear units are expected to be retired before the expiration of their 40-year operating licenses, others are expected to operate longer than their current license terms. The U.S. Nuclear Regulatory Commission has defined an application process for utilities to renew an existing license for 20 additional years. In 1998, two utilities—Baltimore Gas and Electric and Duke Power—submitted license renewal applications. The forecast assumes that license renewal will be chosen if a further capital investment to extend the operating life of a nuclear unit after 40 years is more economical than building new capacity. The reference case projects that six units with license expiration dates before 2020 will continue operating after license renewals.

Favorable Conditions Could Forestall Some Nuclear Retirements

Figure 76. Operable nuclear capacity in three cases, 1996-2020 (gigawatts)

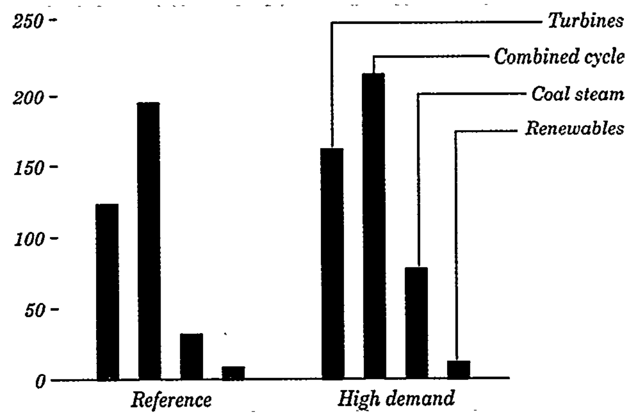


Two alternative cases—the high and low nuclear cases—show how nuclear plant retirement decisions affect the projections for capacity (Figure 76). The low nuclear case assumes that the capital expenditures required after 30 and 40 years of operation are higher than assumed in the reference case, leading to the retirement of 15 additional units by 2020. Higher costs could result from more severe degradation of the units or from waste disposal problems. The high nuclear case assumes that no additional capital expenditures will be required after 40 years and that more license renewals will be obtained by 2020. Conditions favoring license renewal could include performance improvements, a solution to the waste disposal problem, or stricter limits on emissions from fossil-fired generating facilities in response to environmental concerns.

In the low nuclear case, more than 60 new fossil-fired units (assuming an average size of 300 megawatts) would be built to replace additional retiring nuclear units. The new capacity would be split between coal-fired (30 percent), combined-cycle (28 percent), and combustion turbine (42 percent) units. The additional fossil-fueled capacity would produce 17 million metric tons of carbon emissions above those in the reference case in 2020. In the high nuclear case, 28 gigawatts of new fossil-fired capacity would not be needed, as compared with the reference case, and carbon emissions would be reduced by 11 million metric tons in 2010 and 31 million metric tons in 2020 (4 percent of total emissions by electricity generators).

Gas-Fired Capacity Additions Are Favored in the Projections

Figure 77. Cumulative new generating capacity by type in two cases, 1997-2020 (gigawatts)

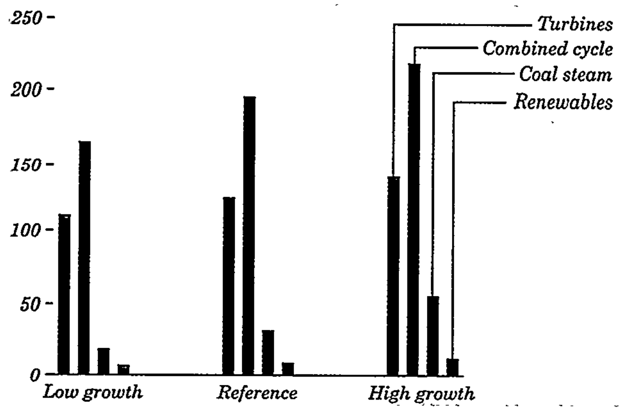


Electricity consumption grows in the forecast, but the rate of increase lags behind historical levels as a result of assumptions regarding efficiency improvements in end-use technologies, demand-side management programs, and population and economic growth. Deviations from these assumptions could result in substantial changes in electricity demand. For example, if electric vehicles enter the market faster than expected, the demand for electricity would also increase more rapidly. Lower electricity prices due to the effect of competitive markets could lead to increased consumption and less concern for conservation. In a high demand case, electricity demand is assumed to grow by 2.0 percent a year between 1997 and 2020, comparable to the annual growth rate of 2.2 percent between 1990 and 1997. In the reference case, electricity demand is projected to grow by 1.4 percent a year.

In the high demand case, 113 gigawatts more new generating capacity is built than in the reference case between 1997 and 2020—equivalent to 376 new 300-megawatt generating plants (Figure 77). The shares of coal- and gas-fired capacity additions are about the same—9 and 88 percent, respectively, in the reference case and 16 and 81 percent in the high demand case. Relative to the reference case, there is a 12-percent increase in coal consumption and a 17 percent increase in natural gas consumption in the high demand case, and carbon emissions from electricity generation are 96 million metric tons (13 percent) higher.

Stronger Economic Growth Would Require More Generating Capacity

Figure 78. Cumulative new generating capacity by type in three cases, 1997-2020 (gigawatts)



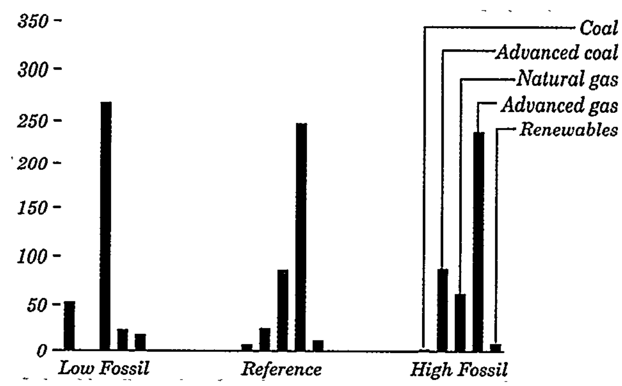
From 1997 to 2020, the annual average growth rate for GDP ranges between 2.6 and 1.5 percent in the high and low economic growth cases, respectively. The difference of a percentage point in the economic growth rate leads to a 17-percent change in electricity demand in 2020, with a corresponding difference of 124 gigawatts of new capacity required in the high and low economic growth cases. Utilities are expected to retire between 19 and 20 percent of their current generating capacity (equivalent to 460 to 505 300-megawatt generating plants) by 2020 as the result of increased operating costs for aging plants.

Most of the new capacity needed in the high economic growth case is expected to consist of natural-gas-fired plants—both turbine and combined-cycle units—which make up almost 60 percent of the projected new capacity in the high growth case. The stronger growth also stimulates additions of coal-fired plants, particularly in the later years, when higher natural gas prices make new coal-fired facilities more attractive economically (Figure 78).

Current construction costs for a typical 400-megawatt plant range from $400 per kilowatt for combined-cycle technologies to $1,079 per kilowatt for coal-steam technologies. These costs, combined with the difficulty of obtaining permits and developing new generating sites, make refurbishment of existing power plants a profitable option for utility resource planners. Between 1997 and 2020, utilities are expected to maintain most of their older coal-fired plants while retiring many of their older oil- and gas-fired generating plants.

Higher Costs for New Technologies Would Favor New Coal-Fired Capacity

Figure 79. Cumulative new electricity generating capacity by technology type in three cases, 1997-2020 (gigawatts)

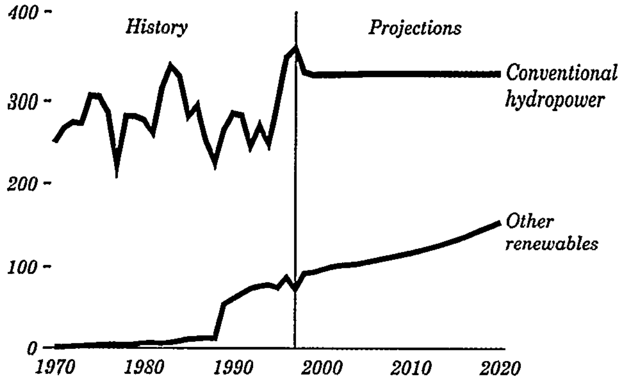


The *AEO99* reference case uses the cost and performance characteristics of generating technologies to select the mix and amounts of new generating capacity for each year in the forecast. Numerical values for the characteristics of different technologies are determined in consultation with industry and government specialists. In the high fossil fuel case, capital costs, operating costs, and 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 no advanced technologies will come on line during the projection period.

Because of their high initial capital costs, integrated coal gasification combined cycle (IGCC) units do not become competitive with gas technologies until late in the projections in the reference case. In the high fossil fuel case, which assumes lower initial capital costs and higher efficiencies for the IGCC technology, 88 gigawatts of IGCC capacity are projected. The low fossil fuel case, as compared with the reference case, projects 77 gigawatts less gas-fired capacity additions, 51 gigawatts more coal-fired capacity additions, and 6 gigawatts more renewable capacity additions between 1997 and 2020 (Figure 79).

Steady Growth Is Expected for Renewable Electricity Supply

Figure 80. Grid-connected electricity generation from renewable energy sources, 1970-2020 (billion kilowatthours)

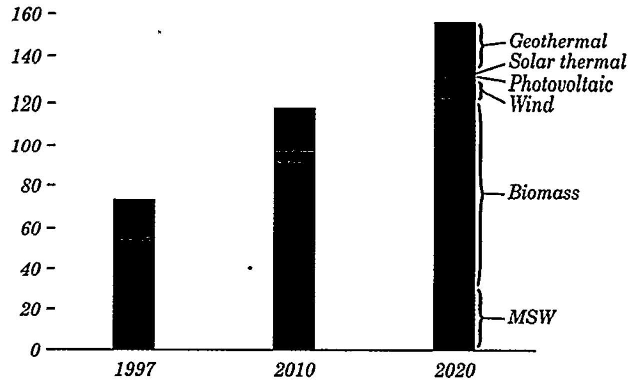


In the *AEO99* projections, expectations for renewables in the U.S. electricity supply are mixed. Targeted investment raises near-term projections, but in the long term renewables are at a disadvantage because of their higher costs, competition from fossil technologies, low fossil fuel prices, and the competitive marketplace. Total U.S. electricity generation from renewable resources increases from 430 billion kilowatthours in 1997 to 484 billion kilowatthours in 2020 (Figure 80). Most of the growth is attributed to biomass; geothermal, municipal solid waste, and wind generation also increase substantially. Overall, renewables are projected to make up a smaller share of U.S. electricity generation in 2020, declining from over 12 percent in 1997 to barely 10 percent in 2020.

Conventional hydroelectricity, which currently dominates U.S. renewable generation, is not expected to increase through 2020. Almost no new hydropower capacity is expected. As a result, after an excellent water year in 1997, hydroelectricity quickly slips from 357 billion kilowatthours (about 10 percent of U.S. electricity supply) to 329 billion kilowatthours a year (less than 7 percent) in 2020. Further, other water priorities—such as to enhance fish populations, for irrigation, or for recreation—could further reduce hydropower output.

Biomass Leads Projected Growth in Generation From Renewables

Figure 81. Nonhydroelectric renewable electricity generation by energy source, 1997, 2010, and 2020 (billion kilowatthours)

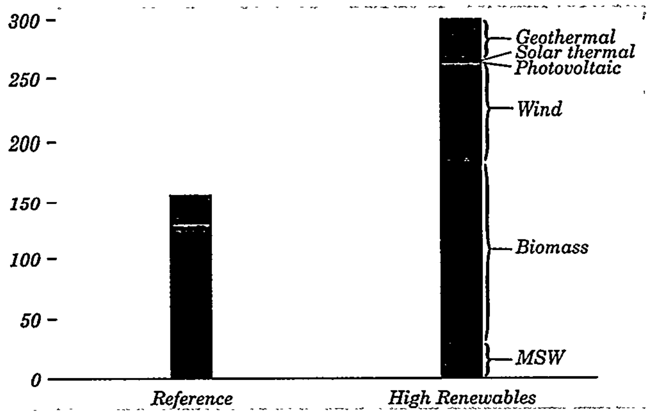


Renewables other than hydropower are projected to grow more substantially (Figure 81) as a result of near-term State and utility programs and the long-run demand for new capacity. Biomass use grows the most in the projections, to 91 billion kilowatthours in 2020, approaching 2 percent of U.S. generation. The increases reflect expected improvements in generating technologies, new energy crops, and growth of industries using wood byproducts for cogeneration. More efficient new units and retirements of less efficient older ones result in a 47-percent increase in geothermal generation through 2020. Generation from municipal solid waste grows to more than 30 billion kilowatthours, reflecting increased use of landfill gas and improved generating efficiency. Wind power also increases—extending from California to the Midwest, Texas, and the Northwest—helped in the near term by State and utility support programs. Overall, nonhydroelectric renewables increase from 2 percent of total generation in 1997 to more than 3 percent in 2020.

Solar thermal and photovoltaic technologies are not expected to become notable contributors to overall U.S. grid-connected electricity supply by 2020. Solar thermal technologies remain more costly than alternatives. Photovoltaics, while too costly for large-scale grid applications, are increasingly competitive for small, high-value niche markets, and the technology has attracted State and public interest as an environmentally attractive alternative. Off-grid applications and exports of photovoltaics are expected to continue robust growth.

Technology Improvements Could Increase Renewable Generation

Figure 82. Nonhydroelectric renewable electricity generation in two cases, 2020 (billion kilowatthours)

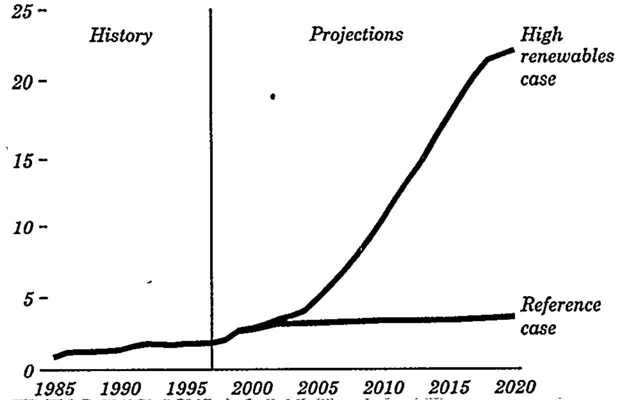


To examine more rapid improvements in renewable technologies, the high renewables case replaces the *AEO99* reference case assumptions for capital costs, operations and maintenance expenses, and capacity factors for nonhydroelectric renewables with more optimistic Department of Energy renewable energy assumptions, with no change in the assumptions for nuclear and fossil fuel technologies. The high renewables case also assumes that the yields for energy crops grown on pasture and crop land will be nearly 20 percent higher than expected in the reference case, and that the additional capacity effects of State RPS programs included in the reference case will extend beyond 2010, adding 97 megawatts of additional generating capacity by 2020.

The results of the high renewables case suggest that technology improvements would increase generation from some renewable sources (Figure 82) but would not alter the dominant role of fossil fuels in the U.S. fuel mix overall. Generation from nonhydroelectric renewables is projected at 299 billion kilowatthours in 2020, compared with 156 billion in the reference case. The increment in generation is mostly from wind, biomass, and geothermal resources, which displace coal and natural gas. Wind capacity in 2020 is over 22 gigawatts, compared with 3.6 gigawatts in the reference case (Figure 83). As a result, the share of total electricity generation from nonhydroelectric renewables increases to 6.2 percent, compared with 3.2 percent in the reference case, and carbon emissions in 2020 are reduced by 70 million tons, or 3.5 percent.

Lower Costs Could Boost Wind-Powered Generating Capacity

Figure 83. Wind-powered electricity generating capacity in two cases, 1985-2020 (gigawatts)

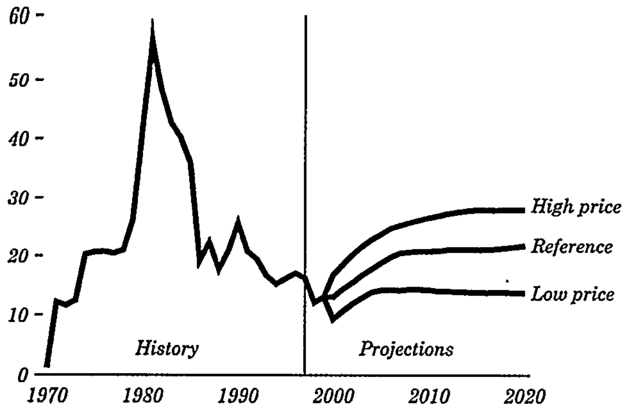


The *AEO99* projections show a growing number of State programs in support of renewable energy investment (see "Issues in Focus," page 22). The programs, reflecting both energy and environmental interests, are intended to spur private investment despite the increasingly competitive marketplace. Although the long-term implications of mandates, renewable portfolio standards (RPS), green power marketing, system benefits funds, and other State actions are not entirely clear, they are having the immediate effect of increasing renewable generating capacity. Whereas last year no quantifiable State RPS programs existed, *AEO99* projects 638 megawatts of new generating capacity as the result of RPS programs in Arizona, Connecticut, Massachusetts, and Nevada, as well as an additional 579 megawatts from a separate initiative in California.

Almost 64 percent of the known new capacity from mandates, State RPS programs, and the California initiative is from wind; biomass represents 14 percent, and other renewable energy technologies represent the rest in roughly equal shares (although solar thermal represents less than 3 percent). Most is expected to be in operation before 2005. Actual additions could well be greater, reflecting new capacity in States currently in the process of identifying winning technologies; the additional capacity effects should extend well beyond 2005.

Petroleum Use Grows, But Projected Prices Show Only Modest Increases

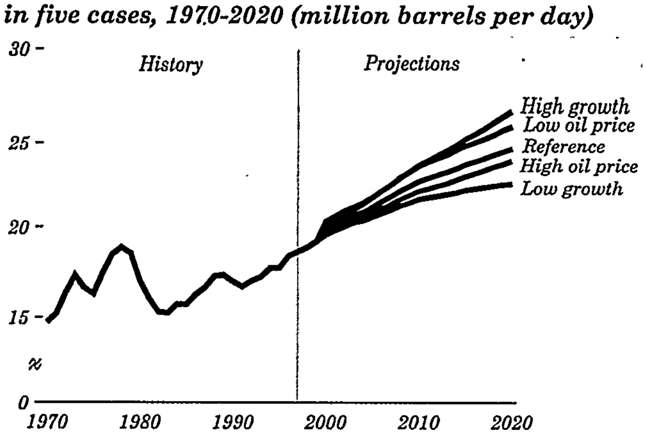
Figure 84. Lower 48 crude oil wellhead prices, 1970-2020 (1997 dollars per barrel)



Because domestic prices for crude oil are determined largely by the international market, the current decline in world oil prices causes wellhead prices for crude oil in the lower 48 States to drop considerably in 1998 in all cases, followed by an increase through the rest of the forecast, regaining 1997 levels in 2003 in the reference case. Wellhead prices are projected to fall by 0.7 percent a year from 1997 to 2020 in the low world oil price case, and to grow by 1.3 and 2.4 percent a year in the reference and high price cases, respectively (Figure 84).

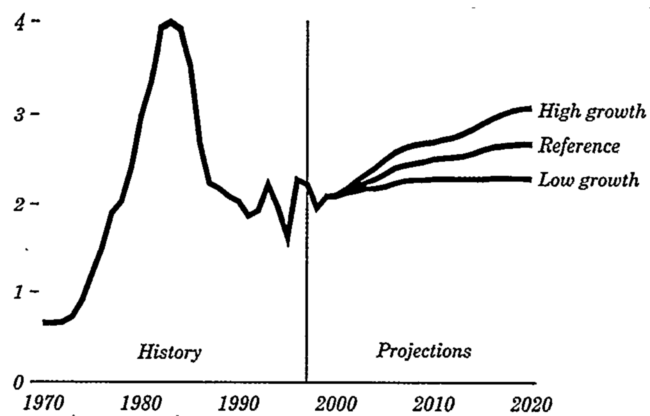
U.S. petroleum consumption continues to rise in all the *AEO99* cases (Figure 85). Total petroleum product supplied ranges from 22.5 million barrels per day in the low economic growth case to 26.8 million in the high growth case, as compared with 18.6 million in 1997.

Figure 85. U.S. petroleum consumption in five cases, 1970-2020 (million barrels per day)



Growing Demand Leads to Rising Natural Gas Prices

Figure 86. Lower 48 natural gas wellhead prices, 1970-2020 (1997 dollars per thousand cubic feet)



Wellhead prices for natural gas in the lower 48 States increase by 0.1, 0.8, and 1.4 percent a year in the low economic growth, reference, and high economic growth cases, respectively (Figure 86). The increases reflect rising demand for natural gas and its impact on the natural progression of the discovery process from larger and more profitable fields to smaller, less economical ones. Price increases also reflect more production from higher cost sources, such as unconventional gas recovery. Lower 48 unconventional gas production grows by 2.7 percent a year in the reference case, compared with 2.2-percent annual growth for conventional sources. Although the sources of production change, technically recoverable resources (Table 6) remain more than adequate overall to meet the production increases.

Demand for natural gas rises in all three cases. In the low economic growth case, the increase is gradual, and the price increases attributable to the rising demand are nearly overshadowed by the beneficial impacts of technological progress on the discovery process. In the reference and high growth cases, however, the impacts of technological progress only moderate the resulting price increases.

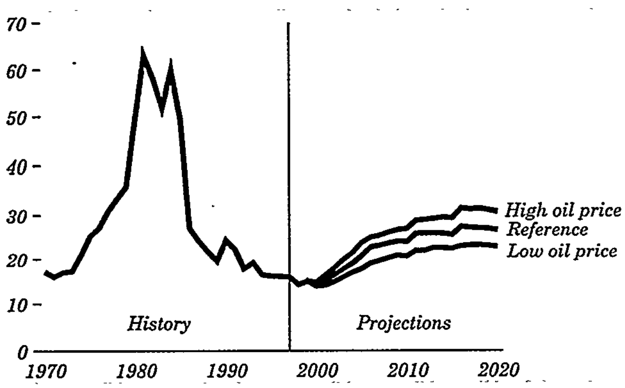
Table 6. Technically recoverable U.S. oil and gas resources as of January 1, 1997

Total U.S. resources	Crude oil (billion barrels)	Natural gas (trillion cubic feet)
Proved	23	166
Unproved	87	1,009
Total	110	1,176

Oil and Gas Reserve Additions

Increased Drilling Activity Is Expected in the *AEO99* Projections

Figure 87. Successful new lower 48 natural gas and oil wells in three cases, 1970-2020 (thousand successful wells)



Both exploratory and developmental drilling increase in the forecast. With rising prices and declining drilling costs, crude oil and natural gas well completions increase on average by 1.7 and 3.1 percent a year in the low and high oil price cases, respectively, compared with 2.4 percent in the reference case (Figure 87). Changes in world oil price assumptions have a more pronounced effect on projected oil drilling than on gas drilling (Table 7).

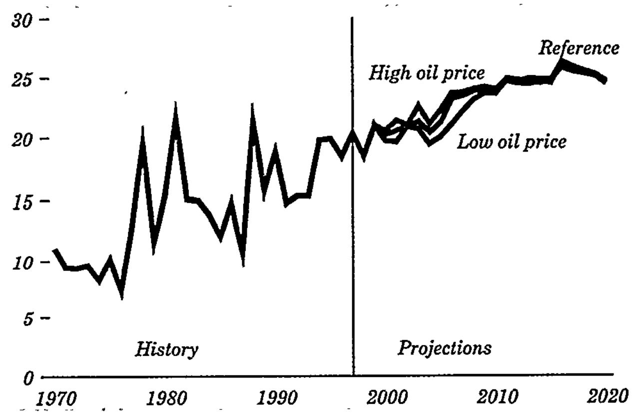
The productivity of natural gas drilling does not decline as much as that of oil drilling, in part because total recoverable gas resources are more abundant than oil resources. At the projected production levels, however, recoverable resources of conventional natural gas decline rapidly in some areas, particularly in the onshore Southwest and offshore Gulf of Mexico regions. In the final analysis, 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 [*62*].

Table 7. Natural gas and crude oil drilling in three cases, 1997-2020 (thousands of successful wells)

	1997	2000	2010	2020
Natural gas				
Low oil price case		*6.6*	*10.9*	*12.0*
Reference case	*8.0*	*6.9*	*11.2*	*12.2*
High oil price case		*7.2*	*11.3*	*12.2*
Crude oil				
Low oil price case		*7.1*	*9.5*	*10.7*
Reference case	*7.8*	*7.4*	*12.7*	*14.4*
High oil price case		*7.5*	*15.4*	*18.5*

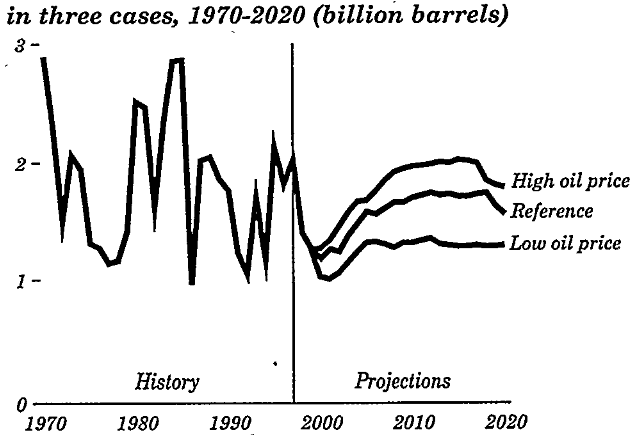
Oil Production Is Projected To Exceed Reserve Additions

Figure 88. Lower 48 natural gas reserve additions in three cases, 1970-2020 (trillion cubic feet)



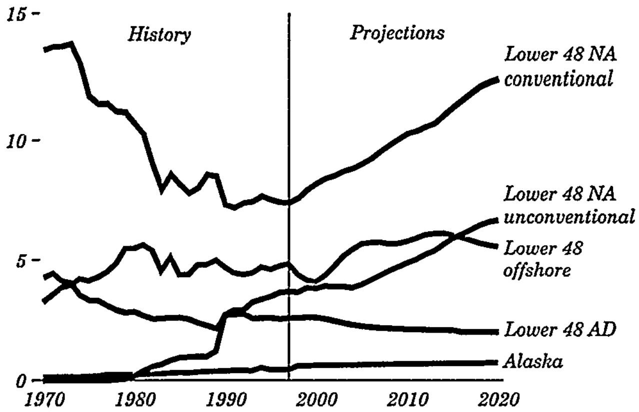
For most of the past two decades, lower 48 production of both oil and natural gas has exceeded reserve additions. The recent reversal of that pattern for natural gas is projected to continue through 2013, even with expected increases in demand, primarily for electricity generation. The relatively high levels of annual gas reserve additions through 2020 reflect increased drilling as a result of higher prices, as well as productivity gains from technological improvements comparable to those of recent years, affecting both exploration and development (Figure 88). Consequently, almost 60 percent of the lower 48 nonassociated natural gas resources expected to be technically recoverable from conventional sources are projected to be discovered by 2020. In contrast, despite varying patterns of lower 48 oil reserve additions (Figure 89), total lower 48 crude oil production exceeds total reserve additions over the forecast period in all cases.

Figure 89. Lower 48 crude oil reserve additions in three cases, 1970-2020 (billion barrels)



Most Natural Gas Production Is Expected From Conventional Sources

Figure 90. Natural gas production by source, 1970-2020 (trillion cubic feet)



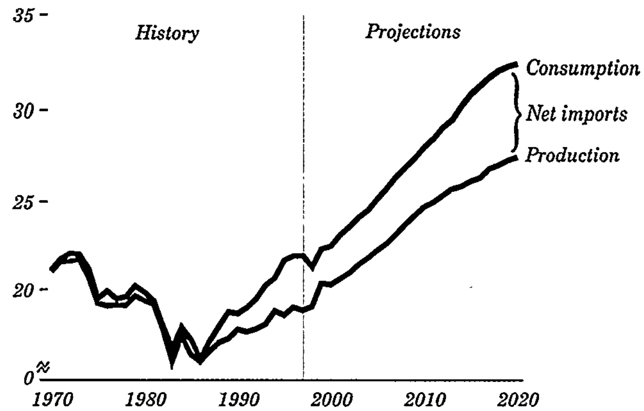
The continuing increase in domestic natural gas production in the forecast comes primarily from lower 48 onshore nonassociated (NA) sources (Figure 90). Conventional onshore production, which accounted for 39.2 percent of total U.S. domestic production in 1997, increases in share to 45.0 percent of the total in 2020. Unconventional sources also increase in share, and gas from offshore wells in the Gulf of Mexico contributes significantly to production. The innovative use of cost-saving technology and the expected mid-term continuation of recent huge finds, particularly in the deep waters of the Gulf of Mexico, support this projection.

Natural gas production from Alaska grows by 2.3 percent a year in the forecast. Currently, all production is either consumed in the State, reinjected, or exported to Japan as liquefied natural gas (LNG). Alaskan gas is not expected to be transported to the lower 48 States, because the projected lower 48 prices are not high enough in the forecast period to support the required transport system. Expected 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 marketed as LNG to Pacific Rim markets [*63*].

Production of associated/dissolved (AD) natural gas from lower 48 crude oil reservoirs generally declines, following the expected pattern of domestic crude oil production. AD gas accounts for 7.6 percent of total lower 48 production in 2020, compared with 13.9 percent in 1997.

Net Imports of Natural Gas Are Projected To Increase

Figure 91. Natural gas production, consumption, and imports, 1970-2020 (trillion cubic feet)



Net natural gas imports are expected to grow in the forecast (Figure 91) from 12.9 percent of total gas consumption in 1997 to 15.5 percent in 2020. Most of the increase is attributable to imports from Canada, which are projected to grow substantially as considerable new pipeline capacity comes on line. While most of the new capacity provides access to supplies from western Canada through the Midwest, new capacity is also expected to provide access to eastern supplies, including gas from Sable Island in the offshore Atlantic [*64*].

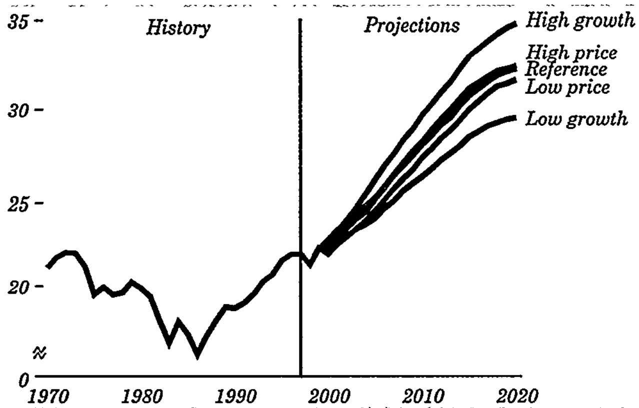
Mexico has a considerable natural gas resource base, but there is uncertainty as to whether its indigenous production can be increased sufficiently to satisfy rising demand. Since 1984, U.S. natural gas trade with Mexico has consisted primarily of exports. That trend is expected to continue throughout the forecast, with exports increasing as mandated conversion of power plants from heavy fuel oil to natural gas gains momentum, in compliance with Mexico's new environmental regulations.

LNG provides another source of gas imports; however, given the projected low natural gas prices in the lower 48 markets, LNG is not expected to grow beyond a regionally significant source of U.S. supply. LNG imports into Everett, Massachusetts, and Lake Charles, Louisiana, are projected to increase over the forecast, reaching a level of 0.29 trillion cubic feet in 2020, compared with 0.02 trillion cubic feet in 1997 [*65*].

Natural Gas Consumption

Natural Gas Use Grows Strongly in All the *AEO99* Cases

Figure 92. Natural gas consumption in five cases, 1970-2020 (trillion cubic feet)

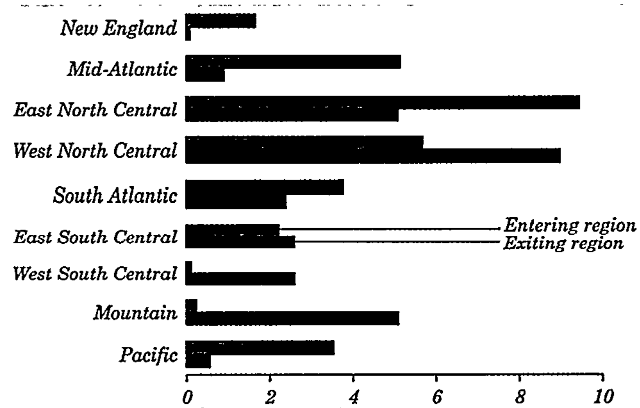


Natural gas consumption increases from 1997 to 2020 in all the *AEO99* cases (Figure 92). Domestic consumption ranges from 29.5 trillion cubic feet per year in the low economic growth case to 34.8 trillion in the high growth case in 2020, as compared with 22.0 trillion cubic feet in 1997. Growth is seen in all end-use sectors, with more than half of the growth resulting from rising demand for electricity, including industrial cogeneration.

Natural gas consumption in the electricity generation sector (excluding cogeneration) grows steadily throughout the forecast. In the reference case it nearly triples, from 3.3 trillion cubic feet a year in 1997 to 9.2 trillion cubic feet in 2020. Restructuring of the electric utility industry is expected to open up new opportunities for gas-fired generation. In addition, growth is spurred by increased utilization of existing gas-fired power plants in the forecast and the addition of new turbines and combined-cycle facilities, which are less capital-intensive than coal, nuclear, or renewable electricity generation plants. Although projected coal prices to the electricity generation sector fall throughout the forecast, the natural gas share of new capacity is nearly 10 times the coal share. Lower capital costs, projected improvements in gas turbine heat rates, and an assumed increase in the service life of gas-fired plants to 20 years make the overall cost of gas-generated electricity per kilowatthour competitive with the cost of electricity from new coal-burning generators.

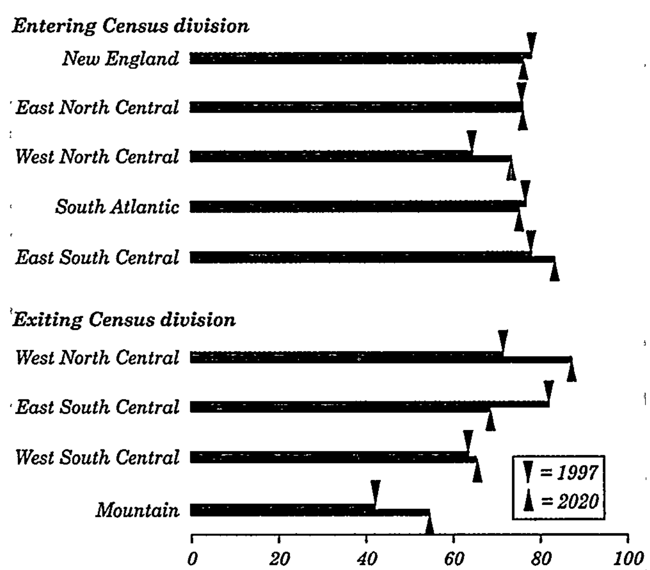
Rising Gas Demand Is Expected To Prompt Pipeline Expansions

Figure 93. Pipeline capacity expansion by Census division, 1997-2020 (billion cubic feet per day)



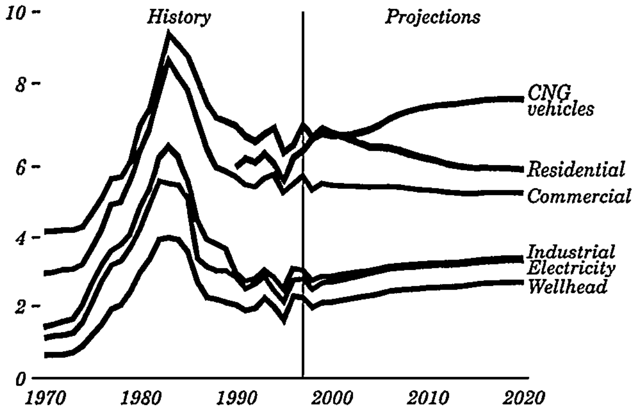
Demand for natural gas is projected to outstrip existing pipeline capacity. Expansion of interstate capacity (Figure 93) will be needed to provide access to new supplies and to serve expanding markets. Expansion is projected to proceed at a rate of 1.2 percent a year through the forecast. The greatest increases are projected along the corridors that move Canadian and Gulf Coast supplies to markets in the eastern half of the United States. Natural gas deliverability is also augmented by new storage capacity which is projected to increase in most regions over the forecast period. In several regions, growth in new pipeline construction is tempered by higher utilization of existing pipeline capacity (Figure 94).

Figure 94. Pipeline capacity utilization by Census division, 1997 and 2020 (percent)



Residential, Commercial Gas Prices Are Projected To Decline

Figure 95. Natural gas end-use prices by sector, 1970-2020 (1997 dollars per thousand cubic feet)



While consumer prices to the industrial, electricity, and transportation sectors generally increase throughout the forecast period, prices to the residential and commercial sectors decline (Figure 95). The decreases reflect declining distribution margins to these sectors due to anticipated efficiency improvements in an increasingly competitive market. In the industrial sector, a modest decrease in margins is overshadowed by an increase in wellhead prices, and the overall trend is a slight rise in prices. In the electricity generation sector, increases in pipeline margins and wellhead prices combine to yield an average 0.8-percent annual rise in end-use prices. The declines in the residential and commercial sectors overshadow the increases in other sectors, yielding a 0.3-percent drop in national average end-use prices.

Compared with their rise and decline over the 1970 1997 period, transmission and distribution revenues in the natural gas industry are relatively stable in the forecast, declining slightly through 2010, when they begin a gradual increase (Table 8). Declines in margins are balanced by higher volumes.

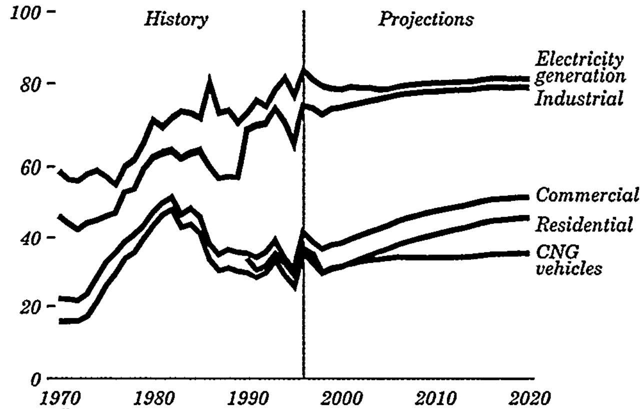
Table 8. Transmission and distribution revenues and margins, 1970-2020

	1970	1985	1997	2010	2015	2020
T&D revenues (billion 1997 dollars)	30.43	49.13	44.39	42.47	42.72	43.31
End-use consumption (trillion cubic feet)	19.02	15.81	20.02	25.49	28.06	29.39
Average margin (1997 dollars per thousand cubic feet)*	1.60	3.11	2.22	1.67	1.53	1.48

**Revenue divided by end-use consumption.*

Lower Distribution Costs Are Projected for Natural Gas

Figure 96. Wellhead share of natural gas end-use prices by sector, 1970-2020 (percent)



With distribution margins declining, the wellhead shares of end-use prices generally increase in the forecast (Figure 96). The greatest impact is in the residential and commercial markets, where most customers purchase gas through local distribution companies (LDCs). In the electricity generation sector, which has a relatively stable share, the majority of customers do not purchase from distributors.

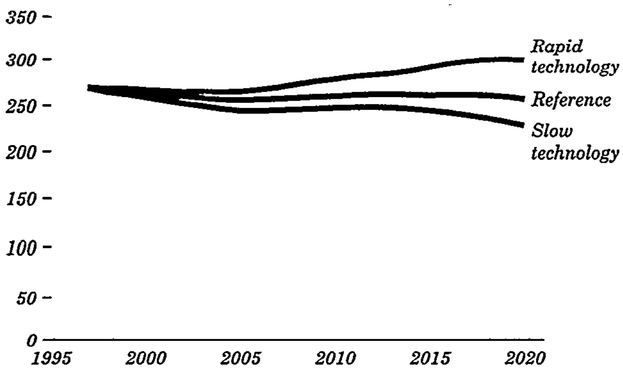
Changes have been seen historically in all components of end-use prices (Table 9). Pipeline margins decreased between 1985 and 1997 with industry restructuring. On average, modest decreases are projected to continue through the forecast period, despite the cost of interstate pipeline expansion. Although LDC margins in the residential and commercial sectors have seen little or no decrease since 1985, efficiency improvements and other impacts of restructuring are exerting downward pressure on distribution costs, and reduced margins are projected for these sectors.

Table 9. Components of residential and commercial natural gas end-use prices, 1985-2020 (1997 dollars per thousand cubic feet)

Price Component	1985	1997	2000	2010	2020
Wellhead price	3.56	2.23	2.10	2.52	2.68
Citygate price	5.32	3.59	3.34	3.66	3.75
Pipeline margin	1.76	1.36	1.24	1.14	1.07
LDC margin					
Residential	3.37	3.41	3.38	2.51	2.16
Commercial	2.49	2.20	2.13	1.66	1.49
End-use price					
Residential	8.69	7.00	6.72	6.17	5.91
Commercial	7.81	5.79	5.47	5.32	5.24

Technology Advances Could Boost Oil and Gas Reserve Additions

Figure 97. Lower 48 crude oil and natural gas end-of-year reserves in three cases, 1997-2020 (quadrillion Btu)



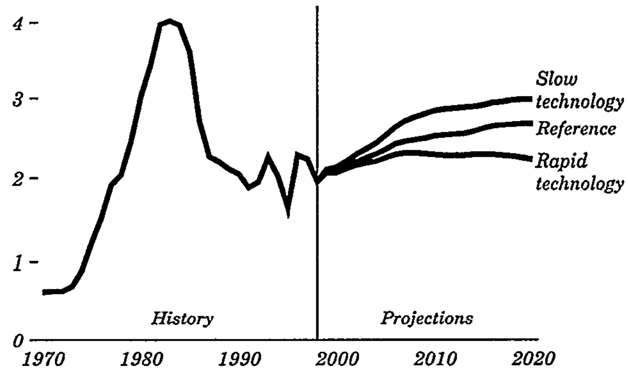
In the forecast, major advances in data acquisition, data processing, and the display and integration of seismic data with other geologic data—combined with lower cost computer power and experience gained with new techniques—continue to put downward pressure on costs while significantly improving finding 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 were used to 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 were increased and decreased by approximately 50 percent in the rapid and slow technology cases, which were run as fully integrated model runs. All other parameters in the model were kept at their reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about foreign natural gas trade.

Although gas reserves become a slightly larger share of the total in the reference case, total hydrocarbon reserve additions offset production, keeping total reserves essentially constant throughout the projection period (Figure 97). By 2020, reserves are 16.6 percent higher in the rapid technology case than in the reference case and 10.9 percent lower in the slow technology case.

Projected Gas Prices Strongly Depend on Technology Assumptions

Figure 98. Lower 48 natural gas wellhead prices in three cases, 1970-2020 (1997 dollars per thousand cubic feet)



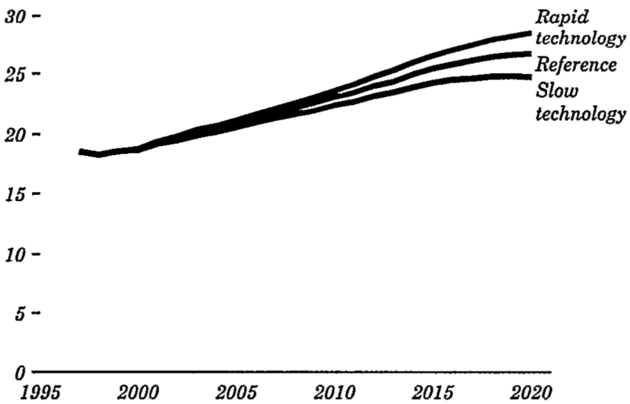
The natural gas price projections are highly sensitive to changes in the assumptions about technological progress (Figure 98). Lower 48 wellhead prices increase at an average annual rate of 1.3 percent in the slow technology case, compared with only 0.8 percent in the reference case, over the projection period. In the rapid technology case, average natural gas wellhead prices are higher than the 1997 level by at most 3.5 percent, and by 2020 they are back to the 1997 price of $2.23 per thousand cubic feet.

Through 2000, 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 11.6 percent higher (at $2.99 per thousand cubic feet) in the slow technology case and 16.8 percent lower (at $2.23 per thousand cubic feet) in the rapid technology case than in the reference case ($2.68 per thousand cubic feet).

Unlike natural gas, lower 48 average wellhead prices for crude oil do not vary significantly across the technology cases. In 2020, crude oil prices are 25 cents lower in the rapid technology case and 6 cents higher in the slow technology case than the reference case price of $21.73 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.

Technology Progress Could Boost Natural Gas Market Share

Figure 99. Lower 48 natural gas production in three cases, 1997-2020 (trillion cubic feet)



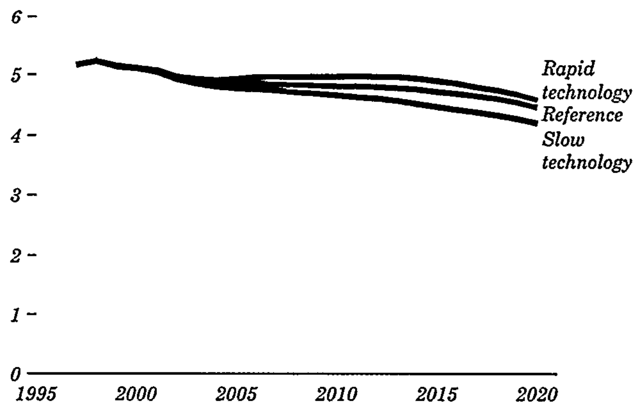
Changes in production in the alternative technology cases reflect the benefits of lower costs and higher finding rates for conventionally recoverable gas, as well as an array of technological enhancements for unconventional gas recovery. The changes in supply lead to price changes that affect new investment in all types of gas-fired technologies, especially in the industrial and electricity generation sectors. Rapid technology improvements yield benefits in the form of both lower prices and increased production to meet higher consumption requirements (Figure 99).

In the rapid technology case, the natural gas share of fossil fuel inputs to electricity generation facilities in 2020 is 24.6 percent, compared with 22.2 percent in the slow technology case. The higher level of gas consumption comes largely at the expense of coal. There is little additional displacement of petroleum products in the rapid technology case, because natural gas captures the bulk of the dual-fired boiler market in the reference case. In contrast, in the slow technology case, natural gas loses market share to both coal and petroleum products in the electricity generation sector.

Production from unconventional gas resources (tight sands, shales, and coalbeds) is particularly responsive to changes in the assumed levels of technological progress. In the rapid technology case, the unconventional gas share of total lower 48 natural gas production in 2020 is projected to be 33.5 percent, compared with 25.2 percent in the reference case and 19.3 percent in the slow technology case.

Oil Production Shows Less Change With Technology Assumptions

Figure 100. Lower 48 crude oil production in three cases, 1997-2020 (million barrels per day)



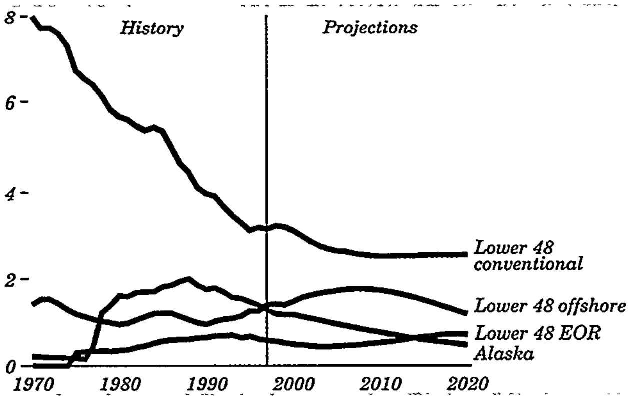
The projections for domestic oil production also are sensitive to changes in the technological progress assumptions (Figure 100). In comparison with the projected lower 48 production level of 4.5 million barrels per day in 2020 in the reference case, oil production increases to 5.2 million barrels per day in the rapid technology case and decreases to 4.6 million 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 range from a low of 11.7 million barrels per day in the rapid technology case to a high of 12.4 million barrels per day in the slow technology case.

Global trade in natural gas has not grown to the same extent as petroleum trade. Because opportunities for gas trade between the United States and countries outside North America are limited, changes in U.S. gas production are determined more by the market conditions in North America than by the international market.

Continued Decline Is Projected for Conventional Oil Production

Figure 101. Crude oil production by source, 1970-2020 (million barrels per day)



Projected domestic crude oil production continues its historic decline throughout the forecast (Figure 101), declining by 1.1 percent a year, from 6.5 million barrels per day in 1997 to 5.0 million barrels per day in 2020 [*66*]. Conventional onshore production in the lower 48 States, which accounted for 49.1 percent of total U.S. crude oil production in 1997, is also projected to decrease at an average annual rate of 0.9 percent over the forecast.

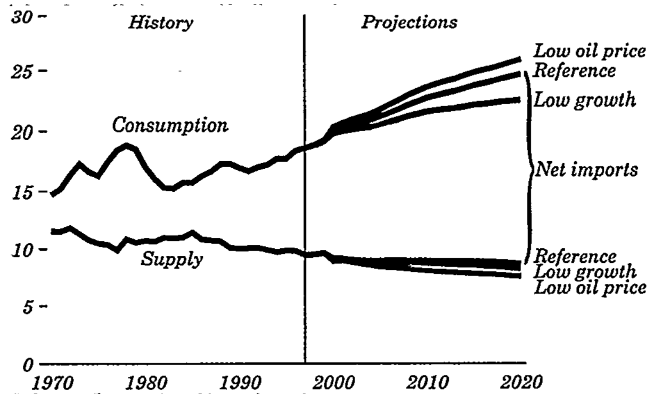
Crude oil production from Alaska is expected to decline at an average annual rate of 4.1 percent between 1997 and 2020. The overall decrease in Alaska's oil production results from a continuing decline in production from most of its oil fields and, in particular, from Prudhoe Bay, the largest producing field, which historically has accounted for more than 60 percent of total Alaskan production.

Offshore production generally increases in the forecast through 2008 and then drops below current levels in 2020, resulting in an overall decrease of 0.7 percent a year. Technological advances and lower costs for deep exploration and production in the Gulf of Mexico contribute to the increase in the early years of the forecast.

Production from enhanced oil recovery (EOR) [*67*], which becomes less profitable as oil prices fall, slows through 2003 and then increases along with world oil prices through the remainder of the forecast.

Declining Domestic Oil Supply Leads to Growing Imports

Figure 102. Petroleum supply, consumption, and imports, 1970-2020 (million barrels per day)



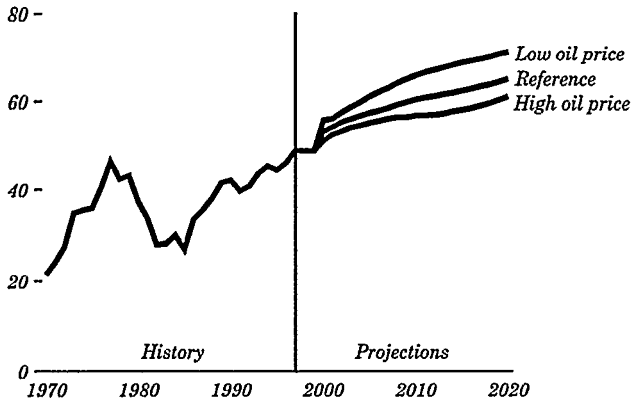
Domestic petroleum supply declines in all the *AEO99* cases (Figure 102), as U.S. crude oil production falls off. In the low price case, domestic supply drops from its 1997 level of 9.4 million barrels per day to 7.6 million barrels per day in 2020. In the high price case, domestic supply declines only slightly, to 9.3 million barrels per day in 2020.

The greatest variation in petroleum consumption levels is seen across the economic growth cases, with an increase of 8.2 million barrels per day over the 1997 level in the high growth case, compared with an increase of only 3.9 million barrels per day in the low growth case.

Additional petroleum imports will be needed to fill the widening gap between supply and consumption. The greatest gap between supply and consumption is seen 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 18.4 million barrels per day in the low oil price case—more than double the 1997 level of 9.2 million barrels per day—to a low of 14.3 million barrels per day in the low growth case. The value of petroleum imports in 2020 ranges from $99.7 billion in the low price case to $158.1 billion in the high price case. Total annual U.S. expenditures for petroleum imports, which reached a historical peak of $140 billion (in 1997 dollars) in 1980 [*68*], were $60.9 billion in 1997.

Imports Are Projected To Meet About Two-Thirds of U.S. Oil Demand

Figure 103. Share of U.S. petroleum consumption supplied by net imports, 1970-2020 (percent)



In 1997, net imports of petroleum climbed to a record 49 percent of domestic petroleum consumption. Continued dependence on petroleum imports is projected, reaching 65 percent in 2020 in the reference case (Figure 103). The corresponding import shares of total consumption in 2020 are 61 percent in the high oil price case and 71 percent in the low price case.

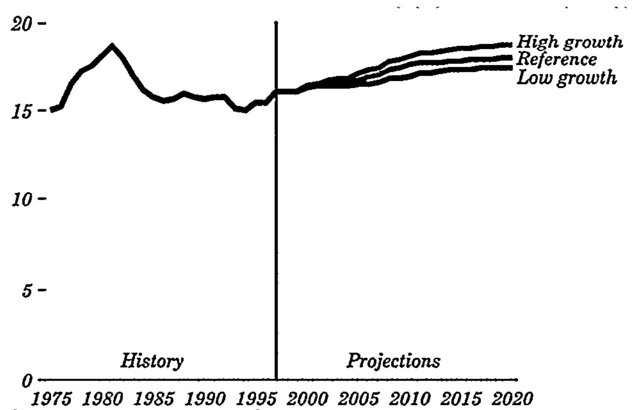
Although crude oil is expected to continue as the major component of petroleum imports, refined products represent a growing share. More imports will be needed as growth in demand for refined products exceeds the expansion of domestic refining capacity. Refined products make up 20 percent of net petroleum imports in 2020 in the low economic growth case and 29 percent in the high growth case, as compared with their 11-percent share in 1997 (Table 10).

Table 10. Petroleum consumption and net imports, 1997 and 2020 (million barrels per day)

Year and projection	Product supplied	Net imports	Net crude imports	Net product imports
1997	18.6	9.2	8.1	1.0
2020				
Reference	24.7	16.0	12.0	4.0
Low oil price	26.0	18.3	13.1	5.2
High oil price	24.0	14.6	11.5	3.1
Low growth	22.5	14.3	11.4	2.9
High growth	26.8	17.7	12.6	5.1

Modest Increases Are Projected for U.S. Refining Capacity

Figure 104. Domestic refining capacity, 1975-2020 (million barrels per day)



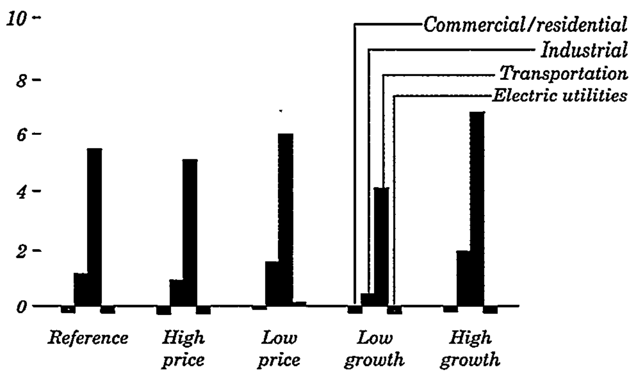
Falling demand for petroleum and the deregulation of the domestic refining industry in the 1980s led to 13 years of decline in U.S. refinery capacity [*69*]. That trend was broken in 1995 by a capacity increase of 0.5 million barrels per day over a 2-year period. Financial and legal considerations make 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 *AEO99* cases (Figure 104).

Distillation capacity is projected to grow from the 1997 level of 16.0 million barrels per day to 17.3 million in 2020 in the low economic growth case and 18.7 million in the high growth case, as refining capacity exceeds the 1981 peak of 18.6 million barrels per day. Refining capacity is projected to expand on the East, West, and Gulf coasts. Existing refineries will continue to be utilized intensively throughout the forecast, in a range from 93 to 96 percent of design capacity. In comparison, the 1997 utilization rate was 95 percent, well above the rates of the 1980s and early 1990s.

Domestic refineries will produce a slightly higher yield of heating oil and jet fuel in 2020 in response to growing demand for those products. In 2020, heating oil is projected to represent 9 percent of production and jet fuel 13 percent, compared with 7 percent and 9 percent, respectively, in 1997.

More Petroleum Use by Industry and for Transportation Is Projected

Figure 105. Change in petroleum consumption by sector in five cases, 1997-2020 (million barrels per day)



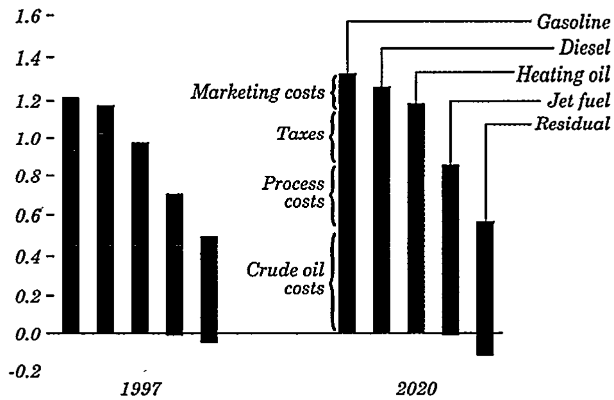
U.S. petroleum consumption is projected to increase by 6.0 million barrels per day between 1997 and 2020 in the reference case, 3.9 million in the low economic growth case, and 8.2 million in the high growth case (Figure 105). All the cases show growth in petroleum consumption in the transportation and industrial sectors and, with the exception of the low world oil price case, slight declines in residential, commercial, and electric utility oil use.

Most of the increase in petroleum consumption occurs in the transportation sector, which accounted for about 65 percent of U.S. petroleum use in 1997. That share grows to 69 percent in the low oil price case and 72 percent in the low economic growth case in 2020. Gasoline accounts for about 45 percent of the projected growth in total petroleum consumption, jet fuel 24 percent, diesel fuel 4 percent, and heating oil 9 percent. All these fuels are "light products," which are more difficult to produce than such heavier products as asphalt and residual fuel oil.

A shift in consumption patterns is expected within the transportation sector. Gasoline, which in 1997 represented 65 percent of the petroleum consumed for transportation, shrinks to a 61-percent share in 2020, as alternative fuels penetrate transportation markets. The jet fuel share rises from 13 percent in 1997 to 17 percent as air travel increases substantially. The share for diesel declines from 18 percent to 14 percent. With the emergence of biomass-based ethanol, the use of ethanol to boost octane or oxygen in gasoline increases from about 80,000 barrels per day in 1997 to 180,000 barrels per day in 2020.

Higher Processing Costs Are Expected for Gasoline and Jet Fuel

Figure 106. Components of refined product costs, 1997 and 2020 (1997 dollars per gallon)



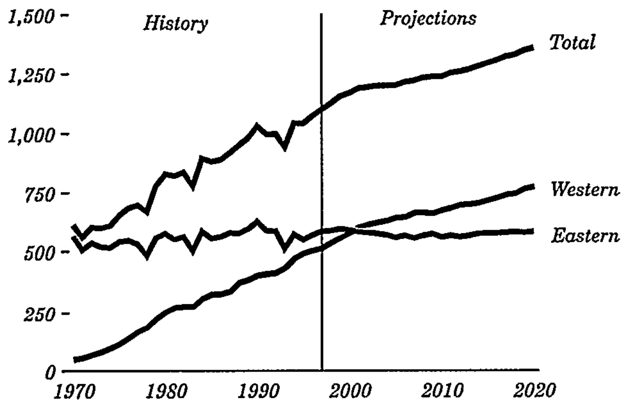
Refined product prices are determined by crude oil costs, refining process costs (including refiner profits), marketing costs, and taxes (Figure 106). In the *AEO99* projections, crude oil costs continue to make the greatest contribution to product prices, and marketing costs remain stable, but the contributions of processing costs and taxes change considerably.

The processing costs for gasoline and jet fuel increase by 6 cents and 7 cents per gallon, respectively, between 1997 and 2020. For the most part, the increases can be attributed to the growth in demand for these products. A small portion of the increases can be attributed to investments related to compliance with refinery emissions, health, and safety regulations, which add 1 to 3 cents per gallon to the processing costs of light products (gasoline, distillate, jet fuel, kerosene, and liquefied petroleum gases).

Whereas processing costs tend to increase refined product prices, assumptions about Federal taxes tend to slow the growth of motor fuels prices. In keeping with the *AEO99* assumption of current laws and legislation, Federal motor fuels taxes are assumed to remain at nominal 1997 levels throughout the forecast. 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 these assumptions is a decrease in Federal taxes between 1997 and 2020—9 cents per gallon for gasoline, 11 cents for diesel fuel, and 2 cents for jet fuel.

Continued Growth Is Projected for Coal Production from Western Mines

Figure 107. Coal production by region, 1970-2020 (million short tons)



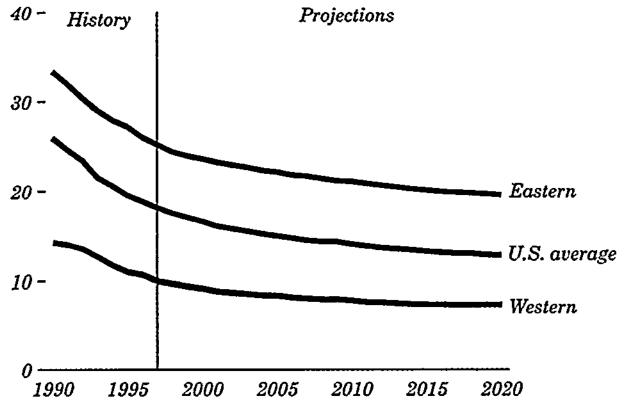
Continued improvements in mine productivity (averaging 6.2 percent a year since 1977) are projected to cause falling real mine prices throughout the forecast. Higher electricity demand and lower prices, in turn, yield increasing coal demand, but the demand is subject to a fixed sulfur emissions cap from CAAA90, which mandates 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 less sulfur emissions than the use of many types of higher sulfur eastern coal. As coal demand grows, 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 grows, there will still be a market for low-cost higher-sulfur coal throughout the forecast.

From 1997 to 2020, high- and medium-sulfur coal production rises from 654 to 662 million tons (0.1 percent a year), and low-sulfur coal production rises from 445 to 696 million tons (2.0 percent a year). As a result of the competition between low-sulfur coal and post-combustion sulfur removal, western coal production continues its historic growth, reaching 772 million tons in 2020 (Figure 107), but its annual growth rate falls from the 9.4 percent achieved between 1970 and 1997 to 1.8 percent in the forecast period.

Further Declines Are Seen for U.S. Minemouth Coal Prices

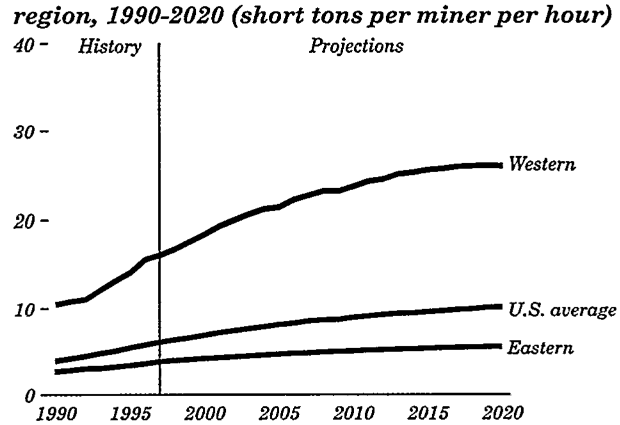
Figure 108. Average minemouth price of coal by region, 1990-2020 (1997 dollars per ton)



Minemouth coal prices declined by $4.97 per ton in 1997 dollars between 1970 and 1997, and they are projected to decline by 1.5 percent a year, or $5.40 per ton, between 1997 and 2020 (Figure 108). The price of coal delivered to electricity generators, which was essentially unchanged between 1970 and 1997, falls to $18.77 per ton in 2020—a 1.4-percent annual decline.

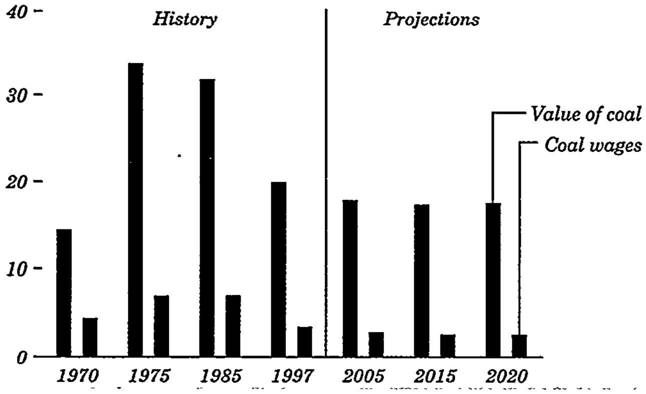
The mines of the Northern Great Plains, with thick seams and low overburden ratios, have had higher labor productivity than other coalfields, and their advantage is maintained throughout the forecast. Average U.S. labor productivity (Figure 109) follows the trend for eastern mines most closely, because eastern mining is more labor-intensive than western mining.

Figure 109. Coal mining labor productivity by region, 1990-2020 (short tons per miner per hour)



Additional Declines in Mine Labor Costs Are Projected

Figure 110. Labor cost component of minemouth coal prices, 1970-2020 (billion 1997 dollars)



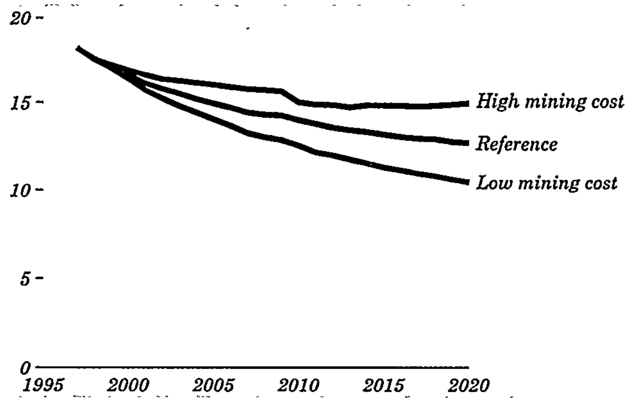
Gains in coal mine labor productivity result from technology improvements, economies of scale, and better mine design. At the national level, however, average labor productivity will also be influenced by changing regional production shares. Competition from very low sulfur, low-cost western and imported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

Eastern coalfields contain extensive reserves of higher sulfur coal in moderately thick seams suited to longwall mining. Maturing technologies for extracting and hauling high coal volumes in both surface and underground mining suggest 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 1997, the number of miners fell by 2.1 percent a year. With improvements continuing through 2020, a further decline of 1.3 percent a year in the number of miners is projected. The share of wages in minemouth coal prices [*70*], which fell from 31 percent to 17 percent between 1970 and 1997, is projected to decline to 15 percent by 2020 (Figure 110).

Even With Higher Cost Assumptions, Coal Prices Are Projected To Fall

Figure 111. Average minemouth coal prices in three cases, 1997-2020 (1997 dollars per ton)

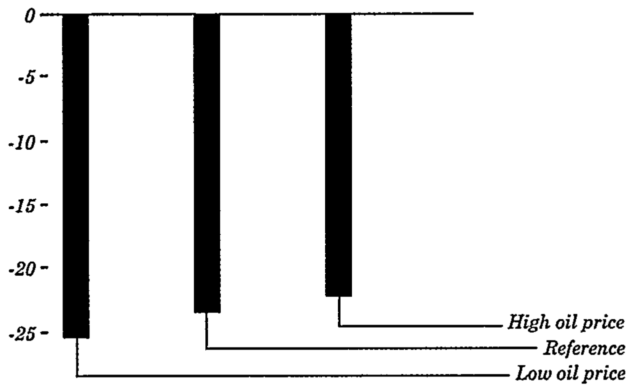


Alternative assumptions about future regional mining costs affect the market shares of eastern and western mines and the national average minemouth price of coal. In two alternative mining cost cases, demand for coal by electricity generators was allowed to respond to relative fuel prices, but coal demand from other sectors was held constant. Minemouth prices, delivered prices, and resultant regional coal production levels varied with changes in mining costs.

In the reference case projections, productivity increases by 2.3 percent a year through 2020, while wage rates are constant in 1997 dollars. The national minemouth coal price declines by 1.5 percent a year to $12.74 per ton in 2020 (Figure 111). In the low mining cost case, productivity increases by 3.8 percent a year, and real wages decline by 0.5 percent a year [*71*]. The average minemouth price falls by 2.4 percent a year to $10.42 per ton in 2020 (18.2 percent less than in the reference case). Eastern coal production is 17 million tons higher in the low 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 increases by only 1.2 percent a year, and real wages increase by 0.5 percent a year. The average minemouth price of coal falls by 0.8 percent a year to $14.94 per ton in 2020 (17.3 percent higher than in the reference case). Eastern production in 2020 is 52 million tons lower in the high labor cost case than in the reference case.

Lower Coal Transportation Costs Are Projected Through 2020

Figure 112. Percent change in coal transportation costs in three cases, 1997-2020

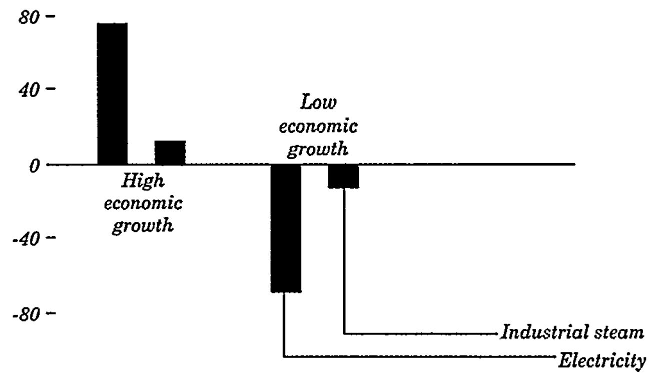


The competition between coal and other fuels, and among coalfields, is influenced by coal transportation costs. Changes in fuel costs affect transportation rates (Figure 112), but fuel efficiency also grows with other productivity improvements in the forecast. As a result, in the reference case, average coal transportation rates decline by 1.1 percent a year between 1997 and 2020. The most rapid declines have occurred on routes that originate in coalfields with 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.

Expansion of the national market for Powder River Basin coal slowed during 1996 and 1997 as a result of rail service problems after the Union Pacific-Southern Pacific railroad merger. Many Gulf Coast and Midwest consumers had problems maintaining coal stocks as the frequency and predictability of unit-train coal deliveries deteriorated. Improvements in the first two quarters of 1998 suggest that service efficiency is returning to pre-merger levels. Activities resulting from other mergers, such as the current integration of Conrail within Norfolk Southern and CSX, may cause similar short-term problems, but *AEO99* projects that rail rates for coal will continue their historic decline in real terms.

Slower Economic Growth Could Reduce Demand for Coal

Figure 113. Variation from reference case projection of coal demand in two alternative cases, 2020 (million short tons)



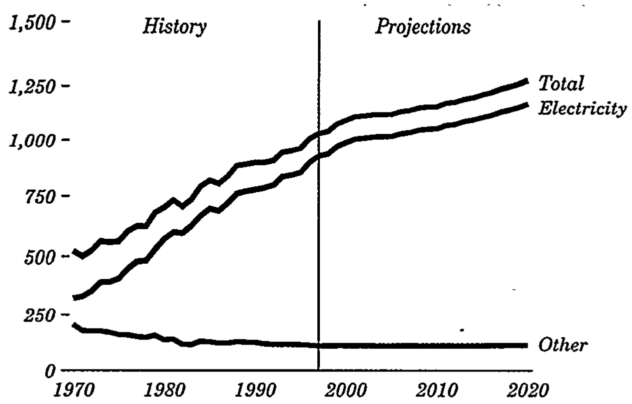
A strong correlation between economic growth and electricity use accounts for the variation in coal demand across the economic growth cases (Figure 113), with domestic coal consumption ranging from 1,195 to 1,363 million tons. Of the difference, coal use for electricity generation makes up 144 million tons. The difference in total coal production between the two economic growth cases is 166 million tons, of which 94 million tons (57 percent) is projected to be western production. Despite the fact that western coal must travel up to 2,000 miles to reach some of its markets, when its transportation costs are added to its low mine price and low sulfur allowance cost, it remains competitively priced in all regions except the Northeast.

Changes in world oil prices affect the costs of energy (both diesel fuel and electricity) for coal mining. In the high and low oil price cases, average minemouth coal prices are 0.2 percent higher and 0.6 percent lower, respectively, in 2020 than in the reference case. The low world oil price case projects 33 million tons less coal use in 2020 than in the high world oil price case as low oil prices encourage electricity generation from oil, while high oil prices encourage greater coal consumption. About 55 percent of the difference in production levels is western coal needed to meet the sulfur emissions cap. The higher coal consumption in the high oil price case is shared between the electricity generation and industrial steam coal sectors, with electricity taking 28 million tons (85 percent) of the difference and the industrial sector gaining the rest.

Coal Consumption

Electricity Generation Sets the Trend for U.S. Coal Consumption

Figure 114. Electricity and other coal consumption, 1970-2020 (million short tons per year)



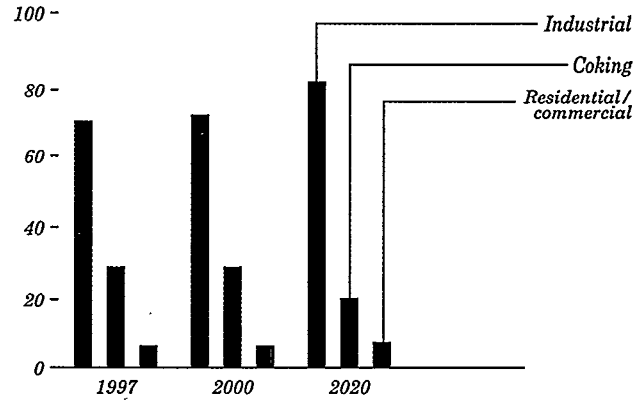
Domestic coal demand rises by 245 million tons in the forecast, from 1,030 million tons in 1997 to 1,275 million tons in 2020 (Figure 114), because of growth in coal use for electricity generation. Coal demand in other domestic end-use sectors increases by 3 million tons, as reduced coking coal consumption is offset by coal demand for industrial cogeneration.

Coal consumption for electricity generation (excluding industrial cogeneration) rises from 924 million tons in 1997 to 1,166 million tons in 2020, due to increased utilization of existing generation capacity and, in later years, additions of new capacity. The average utilization rate for coal-fired power plants increases from 67 to 79 percent between 1997 and 2020. Coal consumption (in tons) per kilowatthour of generation is higher for subbituminous and lignite coals than for bituminous coal. Thus, the shift to western coal increases the tonnage per kilowatthour of generation in midwestern and southeastern regions. In the East, generators shift from higher to lower sulfur Appalachian bituminous coals that contain more energy (Btu) per short ton.

Although coal maintains its fuel cost advantage over both oil and natural gas, gas-fired generation is the most economical choice for construction of new power generation units through 2010 when capital, operating, and fuel costs are considered. Between 2010 and 2020, rising natural gas costs and nuclear retirements are projected to cause increasing demand for coal-fired baseload capacity.

Industrial Coal Use Is Projected To Increase

Figure 115. Non-electricity coal consumption by sector, 1997, 2000, and 2020 (million short tons)



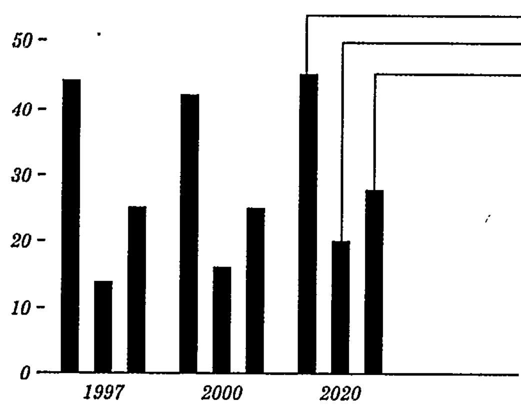
In the non-electricity sectors, an increase of 12 million tons in industrial steam coal consumption between 1997 and 2020 (0.7-percent annual growth) is offset by a decrease of 9 million tons in coking coal consumption (Figure 115). Increasing consumption of industrial steam coal results primarily from increased use of coal in the chemical and food-processing industries and from increased use of coal for cogeneration (the production of both electricity and usable heat for industrial processes).

The projected decline in domestic consumption of coking coal results from the 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 1.7 percent a year through 2020. Domestic production of coking coal is stabilized, in part, by sustained levels of export demand.

While total energy consumption in the residential and commercial sectors grows by 0.8 percent a year, most of the growth is captured by electricity and natural gas. Coal consumption in these sectors remains constant, accounting for less than 1 percent of total U.S. coal demand.

U.S. Coal Exports Rise Slowly in the *AEO99* Projections

Figure 116. U.S. coal exports by destination, 1997, 2000, and 2020 (million short tons)



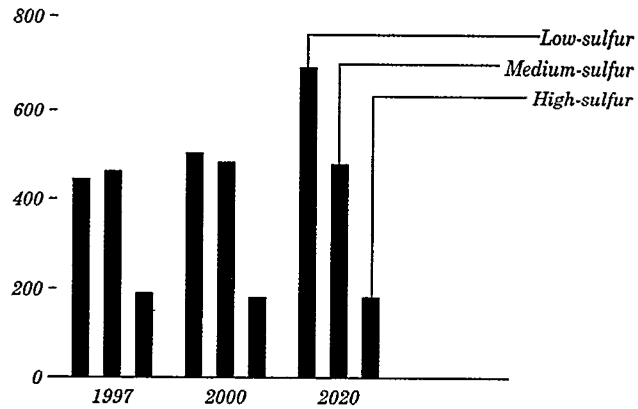
U.S. coal exports rise slowly in the forecast, from 84 million tons in 1997 to 93 million in 2020 (Figure 116), primarily as a result of higher demand for steam coal imports in Asia. Exports of metallurgical coal in 2020 are slightly lower than the 1997 level. Worldwide trade in metallurgical coal declines slightly, reflecting generally slow growth in steel production and improved process efficiency, but the U.S. market share remains essentially unchanged.

U.S. steam coal exports to Europe increase from 13 million tons in 1997 to 20 million in 2020 (1.9-percent annual growth). Europe's steam coal imports rise from 119 million tons in 1997 to 135 million tons in 2020 (0.5 percent a year), reflecting reduced subsidies for domestic coal production, as well as some new generating capacity. The *AEO99* forecast for European imports is lower than some that have been provided by the governments of the importing nations themselves, where environmental considerations, including emerging carbon emissions issues, limit fuel choices.

U.S. coal exports to Asia increase by 1.6 percent a year, from 14 million tons in 1997 to 20 million in 2020, as metallurgical exports fall by 1.5 percent and steam coal exports rise by 3.8 percent annually. Coal imports to Asia from all sources rise by 1.6 percent a year, from 274 million tons in 1997 to 394 million in 2020, as Pacific Rim nations without indigenous fossil fuel resources base electricity generation on imported coal. Most of the growth in Asian imports is projected to be supplied by Australia, South Africa, China, and Indonesia.

Low-Sulfur Coal Is Expected To Gain Market Share

Figure 117. Coal distribution by sulfur content, 1997, 2000, and 2020 (million short tons)



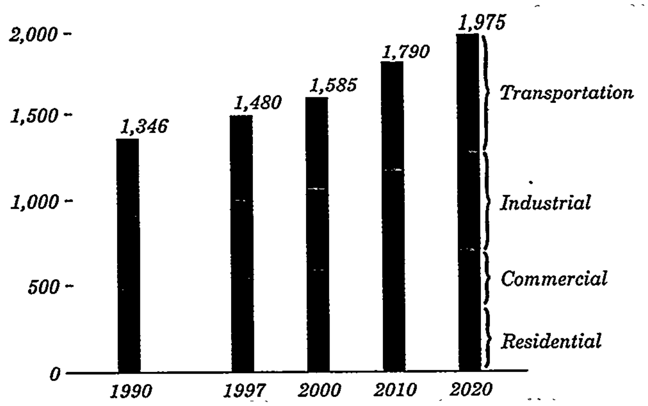
Phase 1 of CAAA90 required 261 coal-fired generators to reduce sulfur dioxide emissions to about 2.5 pounds per million Btu of fuel. Phase 2, which begins in 2000, tightens the annual emissions limits imposed on these large, higher-emitting plants and also sets restrictions on smaller, cleaner plants fired by coal, oil, and gas. The program affects existing utility units serving generators over 25 megawatts capacity and all new utility units [*72*].

Relatively modest capital investments have allowed many generators to 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. Excess allowances are 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). Fuel switching for regulatory compliance and cost savings is projected to reduce the composite sulfur content of all coal produced (Figure 117). National sulfur emissions from coal-fired generators have already declined by approximately 24 percent between 1990 and 1995 [*73*].

Coal users may incur additional costs in the future if environmental problems associated with nitrogen oxides, particulate emissions, and possibly CO_2 emissions from coal combustion are monetized and added to the costs of coal combustion. The most probable method would be a regulatory market mechanism like that established under CAAA90 to price sulfur emissions.

Without New Policies, Carbon Emissions Are Projected To Grow

Figure 118. Carbon emissions by sector, 1990-2020 (million metric tons per year)



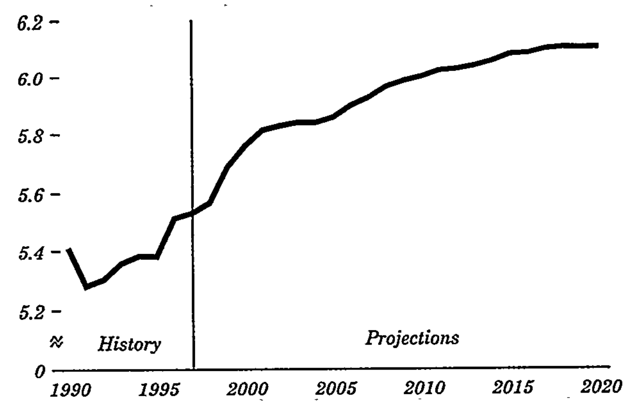
Carbon emissions from energy use are projected to increase by an average of 1.3 percent a year from 1997 to 2020, reaching 1,975 million metric tons (Figure 118). This projection is slightly higher than the *AEO98* projection of 1,956 million metric tons, due to higher energy consumption—particularly, coal for electricity generation and petroleum for transportation.

Increasing concentrations of carbon dioxide, methane, nitrous oxide, and other greenhouse gases may increase the Earth's temperature and affect the climate. The *AEO99* projections include analysis of the Climate Change Action Plan (CCAP), developed by the Clinton Administration in 1993 to stabilize U.S. greenhouse gas emissions by 2000 at 1990 levels. Carbon emissions from fuel combustion, the primary source of greenhouse gas emissions, were about 1,346 million metric tons in 1990. The analysis does not account for carbon-absorbing sinks, the 13 CCAP actions related to non-energy programs or gases other than carbon dioxide, nor any future mitigation actions that may be considered to meet the reductions proposed in the Kyoto Protocol.

Emissions in the 1990s have grown more rapidly than projected at the time CCAP was formulated, partly due to lower energy prices and higher economic growth than projected, which have led to higher energy demand. In addition, some CCAP programs have been curtailed. Additional carbon mitigation programs, technology improvements, or more rapid adoption of voluntary programs could result in lower emissions levels than projected here.

Increasing Use of Electricity Raises Per Capita Carbon Emissions

Figure 119. Carbon emissions per capita, 1990-2020 (metric tons per person)



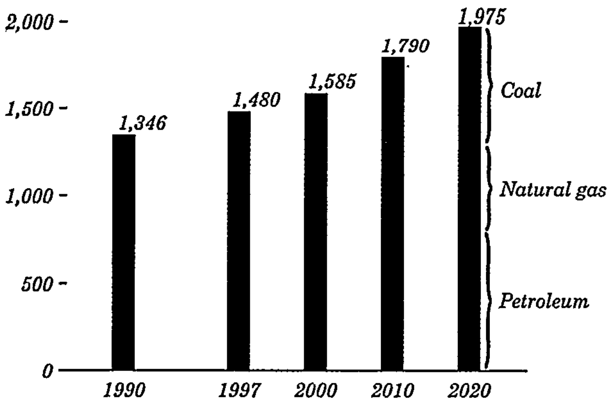
U.S. carbon emissions from energy use are projected to grow at an average annual rate of 1.3 percent; however, per capita emissions grow by only 0.4 percent a year (Figure 119). To stabilize or reduce total emissions, population growth would need to be offset by reductions in per capita emissions.

Emissions in the residential sector, including emissions from the generation of electricity used in the sector, are projected to increase by 1.2 percent a 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 emissions, which also increase by 1.2 percent a year—is likely to be moderated by slowing growth in floorspace, coupled with efficiency standards, voluntary efficiency programs, and technology improvements.

Transportation emissions grow at an average annual rate of 1.7 percent as a result of increases in vehicle-miles traveled and freight and air travel, combined with slow growth in the average light-duty fleet efficiency. Industrial emissions are projected to grow by only 0.9 percent a year, as shifts to less energy-intensive industries and efficiency gains moderate growth in energy use.

Petroleum Products Lead Growth in Carbon Emissions From Energy Use

Figure 120. Carbon emissions by fuel, 1990-2020 (million metric tons per year)



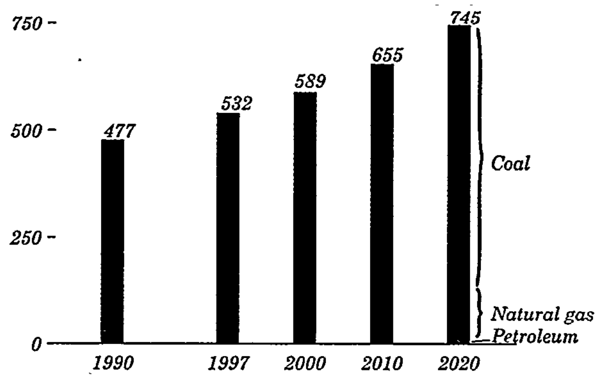
Petroleum products are the leading source of carbon emissions from energy use. In 2020, petroleum is projected to contribute 823 million metric tons of carbon to the total 1,975 million tons, a 42-percent share (Figure 120). About 81 percent (665 million metric tons) of the petroleum emissions result from transportation 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 emissions, projected to produce 676 million metric tons in 2020, or 34 percent of the total. The share declines from 36 percent in 1997 because coal consumption increases at a slower rate through 2020 than consumption of petroleum and natural gas, the sources of virtually all other energy-related carbon emissions. Most of the increases in coal emissions result from electricity generation. A slight increase in emissions from industrial steam coal use is partially offset by a decline in emissions from coking coal.

In 2020, natural gas use is projected to produce 475 million metric tons of carbon emissions, a 24-percent share. Of the fossil fuels, natural gas consumption and emissions increase most rapidly through 2020, at average annual rates of 1.7 percent; however, natural gas produces only half the carbon emissions of coal per unit of input. Average emissions from petroleum use are between those for coal and natural gas. The use of renewable fuels and nuclear generation, which emit little or no carbon, mitigates the growth of emissions.

Coal Accounts for Most U.S. Electricity-Related Carbon Emissions

Figure 121. Carbon emissions from electricity generation by fuel, 1990-2020 (million metric tons per year)



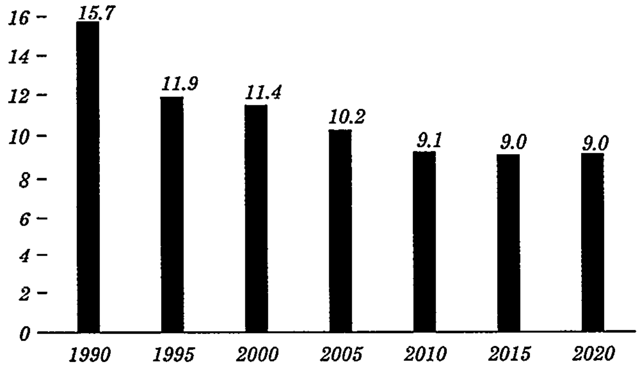
Electricity use is a major cause of carbon emissions. Although electricity produces no emissions at the point of use, its generation currently accounts for 36 percent of total carbon emissions, and that share is expected to increase to 38 percent in 2020. Coal, which accounts for about 52 percent of electricity generation in 2020 (excluding cogeneration), produces 81 percent of electricity-related carbon emissions (Figure 121). In 2020, natural gas accounts for 30 percent of electricity generation but only 18 percent of electricity-related carbon emissions.

Between 1997 and 2020, 50 gigawatts of nuclear capacity are expected to be retired, resulting in a 43-percent decline in nuclear generation. To compensate for the loss of nuclear capacity and meet rising demand, 345 gigawatts of new fossil-fueled capacity (excluding cogeneration) will be needed. Increased generation from fossil fuels will raise electricity-related carbon emissions by 213 million metric tons, or 40 percent, from 1997 levels. Generation from renewable technologies increases by 53 billion kilowatthours, or 12 percent, between 1997 and 2020 but is insufficient 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. Additional use of lower carbon fuels, reduced electricity demand growth, or improved technologies all could contribute to lower emissions than are projected here.

Sulfur Emissions Allowance Program Is Expected To Meet Its Goals

Figure 122. Sulfur dioxide emissions from electricity generation, 1990-2020 (million tons per year)



CAAA90 called for annual emissions of sulfur dioxide (SO_2) by electricity generators to be reduced to approximately 12 million short tons in 1996, 9.48 million tons between 2000 and 2009, and 8.95 million tons a year thereafter. More than 95 percent of the SO_2 produced by generators results from coal combustion, with the rest from residual oil.

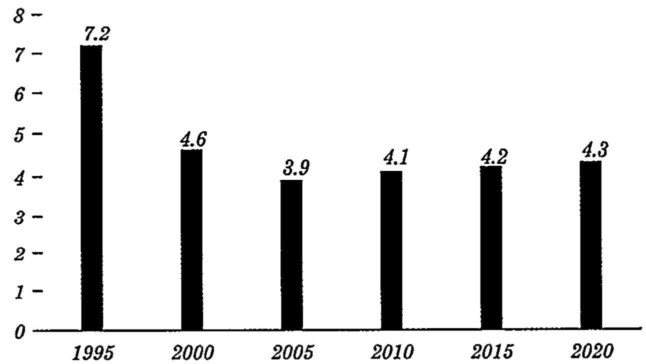
In Phase 1, 261 generating units at 110 plants were issued tradable emissions allowances permitting SO_2 emissions to reach a fixed amount per year—generally less than the plant's historical emissions. Allowances may also be banked for use in future years. Switching to lower sulfur, subbituminous coal was the option chosen by more than half of the generators. In Phase 2, beginning in 2000, emissions constraints on Phase 1 plants will be tightened, and limits will be set for the remaining 2,500 boilers at 1,000 plants. With allowance banking, emissions are expected to decline from 11.9 million tons in 1995 to 11.4 million in 2000 (Figure 122). Since allowance prices are projected to increase after 2000, it is expected that 26.4 gigawatts of capacity—about 88 300-megawatt plants—will be retrofitted with scrubbers to meet the Phase 2 goal (Table 11).

Table 11. Scrubber retrofits and allowance costs, 2000-2020

Forecast	2000	2005	2010	2015	2020
Cumulative retrofits from 1997 (gigawatts of capacity)	13.6	13.6	25.8	26.4	26.4
Allowance costs (1997 dollars per ton SO_2)	90	240	293	182	130

New Legislation Will Reduce Nitrogen Oxide Emissions

Figure 123. Nitrogen oxide emissions from electricity generation, 1995-2020 (million tons per year)



Nitrogen oxide (NO_x) emissions in the United States will fall significantly over the next 5 years as new legislation takes effect (Figure 123). First will be the second phase of the NO_x reduction program from CAAA90, which calls for NO_x reductions at electric power plants in two phases—the first in 1995 and the second in 2000. It is expected that the second phase of CAAA90 will result in NO_x reductions of 1.5 million tons between 1999 and 2000.

A second piece of legislation, the ozone transport rule (OTR), will take effect in 2003. After studying the ozone transport problem, the U.S. Environmental Protection Agency (EPA) issued the OTR in September 1997. The OTR sets caps on NO_x emissions in each of 22 midwestern and eastern States during the 5-month summer season (May through September). The EPA wants to establish a cap and trade program with tradable emission permits. Holders of the permits would be free to use them themselves or sell them to someone whose NO_x emission reduction options are more costly.

The OTR is expected lead to a total NO_x emissions reduction of 0.7 million tons between 2002 and 2003 as control technologies are installed on utility boilers. By 2020, 10 gigawatts of capacity is expected to be retrofitted with advanced combustion controls, selective noncatalytic reduction units (SNCR) are expected to be added to 96 gigawatts, and selective catalytic reduction units (SCR) are expected to be added to 111 gigawatts. The annualized cost is estimated to be \$2 billion, relative to about \$200 billion in annual consumer expenditures for electricity.

Forecast Comparisons

Three other organizations — DRI/McGraw-Hill (DRI), the WEFA Group (WEFA), and the Gas Research Institute (GRI) — also produce comprehensive energy projections with a time horizon similar to that of *AEO99*. The most recent projections from these organizations (DRI, April 1998; WEFA, 1998; GRI, August 1998) and others that concentrate on petroleum, natural gas, and international oil markets are compared with the *AEO99* projections in this section.

Economic Growth

Differences in long-run economic forecasts can be traced primarily to different views of the major supply-side determinants of growth: labor force and productivity change. Other forecasts are presented in Table 12. The WEFA forecast shows the highest economic growth compared to the *AEO99* and DRI reference cases, including higher growth rates for the labor force. The *AEO99* long-run forecast of economic growth is higher than the *AEO98* forecast by 0.2 percent, when compared on a similar basis, with a projected annual growth rate for GDP of 1.8 percent from 1997 to 2020.

Table 12. Forecasts of economic growth, 1997-2020

Forecast	Average annual percentage growth: Real GDP	Labor force	Productivity
AEO99			
Low growth	1.5	0.5	1.0
Reference	2.1	0.8	1.3
High growth	2.6	1.0	1.6
DRI			
Low	1.8	0.5	1.3
Reference	2.1	0.8	1.3
High	2.3	1.0	1.3
WEFA			
Low	1.9	0.9	1.0
Reference	2.3	1.1	1.2
High	2.6	1.3	1.3

In the 1998 *Economic Report of the President*, real GDP growth of 2.3 percent a year between 1997 and 2005 was projected. *AEO99* projects annual growth of 2.5 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 BT Alex Brown (BTAB)—are shown in Table 13 (IEA, 1996; PEL, February 1998; PIRA, October 1997; NRCan, April 1997; BTAB, September 1998). With the exception of IEA in 2005 and PEL, the range between the *AEO99* low and high world oil price cases spans the range of other published forecasts beyond 2005.

Table 13. Forecasts of world oil prices, 2000-2020

Forecast	1997 dollars per barrel: 2000	2005	2010	2015	2020
AEO99 reference	13.97	19.25	21.30	21.91	22.73
AEO99 high price	17.90	24.53	27.33	29.14	29.35
AEO99 low price	10.25	14.57	14.57	14.57	14.57
DRI	15.55	16.94	19.06	21.44	24.13
IEA1	18.49	27.19	27.19	NA	NA
IEA2	18.49	18.49	18.49	NA	NA
PEL	15.57	14.21	13.37	12.93	NA
PIRA	20.00	19.00	19.60	NA	NA
WEFA	18.27	19.04	19.75	20.52	21.32
GRI	17.16	16.86	16.81	17.02	NA
NRCan	20.76	20.76	20.76	20.76	20.76
BTAB	11.71	16.61	16.30	15.89	NA

NA = not available.

Total Energy Consumption

The *AEO99* 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 to those in *AEO99*. Electricity is expected to remain the fastest growing source of delivered energy (Table 14), although its rate of growth is down sharply from historical rates in each of the forecasts, because many traditional

Table 14. Forecasts of average annual growth rates for energy consumption (percent)

Energy use	History 1974-1984	History 1984-1996	Projections AEO99 (1997-2020)	Projections DRI (1997-2020)	Projections GRI (1997-2015)	Projections WEFA (1997-2020)
Petroleum*	-0.1	1.4	1.3	1.2	1.1	1.3
Natural gas*	-1.7	2.3	0.9	0.8	1.4	0.8
Coal*	-3.0	-1.5	0.4	-0.7	-0.4	0.2
Electricity	3.0	2.6	1.4	1.4	1.8	1.7
Delivered energy	-0.4	1.9	1.2	1.1	1.2	1.2
Electricity losses	2.5	2.0	0.6	0.7	1.0	0.9
Primary energy	0.2	2.0	1.1	1.0	1.2	1.1

*Excludes consumption by electric utilities.

uses of electricity (such as for air conditioning) approach saturation while average equipment efficiencies rise. Petroleum consumption grows at the same rate as in recent history. Consumption growth for the remaining fuels slows as a result of moderating economic growth, fuel switching, and increased end-use efficiency.

Residential and Commercial Sectors

Growth rates in energy demand for the residential and commercial sectors are expected to decrease by more than 60 percent from the rates between 1984 and 1996, largely because of projected lower growth in population, housing starts, commercial floorspace additions, and colder winter weather in 1996. 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 15). Natural gas use also grows but at lower rates, and petroleum use continues to fall.

Industrial Sector

In all the forecasts, the industrial sector shows slower growth in primary energy consumption than it did between 1984 and 1996 (Table 16). 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 in the industrial sector for different fuels between 1984 and 1996 reflect a shift from petroleum products and coal to a greater reliance on natural gas and electricity. Natural gas use grows more slowly than in recent history across the forecasts, 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.

Table 15. Forecasts of average annual growth in residential and commercial energy demand (percent)

Forecast	History 1984-1996	Projections AEO99 (1997-2020)	Projections DRI (1997-2020)	Projections GRI (1997-2015)	Projections WEFA (1997-2020)
Residential					
Petroleum	0.6	-1.2	-0.6	-1.2	-0.5
Natural gas	1.2	0.6	0.8	0.7	0.7
Electricity	2.8	1.6	1.1	1.7	1.9
Delivered energy	2.1	0.8	0.7	0.7	1.0
Electricity losses	2.2	0.8	0.3	0.9	1.1
Primary energy	2.1	0.8	0.5	0.8	1.1
Commercial					
Petroleum	-3.9	-1.3	-0.9	-2.9	-0.6
Natural gas	1.9	0.7	0.5	1.0	0.6
Electricity	3.3	1.4	1.4	1.6	1.6
Delivered energy	1.5	0.9	0.8	1.0	1.0
Electricity losses	2.7	0.6	0.7	0.8	0.8
Primary energy	2.1	0.7	0.8	0.9	0.9

Table 16. Forecasts of average annual growth in industrial energy demand (percent)

Forecast	History 1984-1996	Projections AEO99 (1997-2020)	Projections DRI (1997-2020)	Projections GRI (1997-2015)	Projections WEFA (1997-2020)
Petroleum	1.2	0.9	0.7	1.2	1.5
Natural gas	2.5	1.0	0.8	1.7	0.8
Coal	-1.3	0.4	0.2	0.0	0.0
Electricity	1.7	1.1	1.7	2.3	1.5
Delivered energy	2.1	1.0	0.8	1.4	1.1
Electricity losses	1.2	0.3	0.9	2.4	1.6
Primary energy	1.9	0.8	0.8	1.6	1.2

Transportation Sector

Overall fuel consumption in the transportation sector is expected to grow more slowly than in the recent past in each of the alternative forecasts (Table 17). All the forecasts anticipate continued rapid growth in air travel as well as significant increases in aircraft efficiency, while growth in light-duty vehicle travel slows considerably.

Table 17. Forecasts of average annual growth in transportation energy demand (percent)

	History		Projections			
Forecast	*1974-1984*	*1984-1995*	*AEO99 (1997-2020)*	*DRI (1997-2020)*	*GRI (1997-2015)*	*WEFA (1997-2020)*
			Consumption			
Motor gasoline	0.1	1.4	1.2	1.3	0.5	0.8
Diesel fuel	4.5	2.8	1.5	1.0	1.9	1.3
Jet fuel	1.9	2.4	2.8	2.4	2.3	3.0
Residual fuel	1.4	0.7	2.4	2.4	3.3	2.6
All energy	0.9	1.8	1.7	1.5	1.4	1.4
			Key indicators			
Car and light truck travel	2.8	2.8	1.6	2.1	1.4	NA
Air travel (revenue passenger-miles)	7.0	5.0	3.1	3.4	2.8	NA
Average new car fuel efficiency	4.5	0.5	0.6	0.5	0.9	NA
Gasoline prices	1.8	-3.1	0.3	0.5	-0.1	0.1

NA = not available.

Electricity

Comparison across forecasts shows slight variation in projected electricity sales (Table 18). Sales projections for 2020 range from 1,349 billion kilowatthours (DRI) to 1,635 billion kilowatthours (WEFA) for the residential sector, as compared with the *AEO99* reference case value of 1,557 billion kilowatthours. The forecasts for total electricity sales in 2020 range from 4,279 billion kilowatthours (DRI) to 4,581 billion kilowatthours (WEFA). All the projections for total electricity sales in 2020 fall within the range of the *AEO99* low and high economic growth cases (4,013 and 4,687 billion kilowatthours, respectively). Different assumptions governing 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.

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. *AEO99* also assumes that competitive pressures will grow and continue to push prices down until the later years of the projections. *AEO99* 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 *AEO99* mix of capacity among fuels is similar to those in the other forecasts, small differences in sectoral demands across the forecasts lead to significant changes in capacity mix. For example, 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 fuel cell technology than coal, oil, or gas steam capacity.

Table 18. Comparison of electricity forecasts (billion kilowatthours, except where noted)

Projection	AEO99 Reference	AEO99 Low economic growth	AEO99 High economic growth	Other forecasts WEFA	Other forecasts GRI	Other forecasts DRI
2015						
Average end-use price (1997 cents per kilowatthour)	5.8	5.4	6.3	5.76	5.30	5.40
Residential	7.3	6.7	7.9	7.10	6.90	6.80
Commercial	6.2	5.6	6.8	6.29	6.20	5.80
Industrial	3.8	3.5	4.1	3.82	3.10	3.80
Net energy for load	4,415	4,153	4,680	4,573	4,733	4,639
Coal	2,151	2,081	2,225	2,243	2,563	2,428
Oil	26	23	26	48	32	121
Natural gas	1,213	1,047	1,353	1,187	1,099	1,022
Nuclear	419	411	419	479	453	582
Hydroelectric/other [a]	400	394	412	351	407	444
Nonutility sales to grid [b]	180	170	189	223	168	NA
Net imports	27	27	27	42	39	38
Electricity sales	4,113	3,875	4,355	4,213	4,350	4,062
Residential	1,446	1,389	1,506	1,488	1,456	1,285
Commercial/other [c]	1,387	1,345	1,425	1,365	1,363	1,338
Industrial	1,280	1,141	1,423	1,360	1,532	1,440
Capability (gigawatts) [d,e]	977	927	1,028	937	881	972
Coal	326	320	336	356	372	403
Oil and gas	470	429	510	392	345	359
Nuclear	56	55	56	65	64	93
Hydroelectric/other [a]	124	123	126	124	123	117
2020						
Average end-use price (1997 cents per kilowatthour)	5.6	5.1	6.1	5.56	NA	5.30
Residential	7.1	6.4	7.7	6.84	NA	6.60
Commercial	6.0	5.3	6.6	6.04	NA	5.70
Industrial	3.6	3.3	4.0	3.70	NA	3.70
Net energy for load	4,661	4,289	5,037	4,974	NA	4,883
Coal	2,298	2,139	2,497	2,472	NA	2,638
Oil	24	20	25	49	NA	130
Natural gas	1,349	1,191	1,474	1,463	NA	1,084
Nuclear	359	342	373	372	NA	549
Hydroelectric/other [a]	419	406	444	351	NA	443
Nonutility sales to grid [b]	184	171	197	223	NA	NA
Net imports	27	27	27	44	NA	36
Electricity sales	4,345	4,013	4,687	4,581	NA	4,279
Residential	1,557	1,478	1,637	1,635	NA	1,349
Commercial/other [c]	1,448	1,389	1,505	1,479	NA	1,397
Industrial	1,339	1,146	1,544	1,467	NA	1,534
Capability (gigawatts) [d,e]	1,033	963	1,105	1,008	NA	1,013
Coal	343	328	366	389	NA	428
Oil and gas	514	465	557	446	NA	380
Nuclear	49	46	51	48	NA	87
Hydroelectric/other [a]	127	124	132	124	NA	117

[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 *AEO99*, 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 60 gigawatts.

Sources: *AEO99:* AEO99 National Energy Modeling System, runs AEO99B.D100198A (reference case), LMAC99.D100198A (low economic growth case), and HMAC99.D100198A (high economic growth case). **WEFA:** The WEFA Group, *U.S. Power Outlook* (1998). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand,* 1999 Edition (August 1998). **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook* (April 1998).

Natural Gas

The diversity among published forecasts of natural gas prices, production, consumption, and imports (Table 19) indicates 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. The forecasts for total natural gas consumption in 2015 vary from a high of 32.99 trillion cubic feet in the *AEO99* high economic growth case to a low of 28.43 trillion cubic feet in the low economic growth case. The variation in the 2020 projections is even greater, with the higher projection only 16 percent above the lower projection in 2015 but 22 percent above the lower projection in 2020. The high projection for 2020 is 34.81 trillion cubic feet in the *AEO99* high economic growth case, compared with a low of 28.58 trillion cubic feet in the DRI forecast.

The American Gas Association (AGA) forecast (July 1998) for growth in residential consumption relative to historical levels is significantly higher than the others, whereas the DRI and WEFA forecasts of growth in commercial consumption lag behind the rest, even by 2020. GRI is the most optimistic about the future of industrial consumption, in both absolute and percentage growth terms. By a large margin, all forecasters expect the greatest growth to be in the electricity generator sector, with WEFA leading the pack. The DRI growth rate for generator consumption of natural gas through 2020 is less than one-third of WEFA's forecast (although it should be noted that DRI includes cogenerators in this category).

The projections of average lower 48 natural gas wellhead prices in 2015 in the *AEO99* high economic growth and reference cases are higher than the other forecasts, with the lowest price across all forecasts coming from WEFA, at 15 percent below the *AEO99* reference case and 3 percent below the low economic growth case. By 2020 the wellhead price forecasts from DRI and WEFA fall within the range of the *AEO99* cases, with DRI above the *AEO99* reference case and WEFA below. Excluding the *AEO99* low economic growth case, the 2015 residential and commercial prices are highest for GRI and lowest for AGA, with a differential between the two of $0.79 and $0.97 (13 and 19 percent), respectively, for the two sectors (however, the AGA prices do not include some State and local taxes).

The industrial (and to a lesser extent the electricity generator) sectoral prices are difficult to compare in absolute terms because of differences in definitions across the forecasting groups. For 2015, the *AEO99* reference case, DRI, and WEFA forecast slight growth in industrial prices, GRI a slight decline, and AGA a more significant decline. From 2015 to 2020 the DRI forecast for the industrial price increases more significantly than the others, which show more moderate growth or a slight decline (in the *AEO99* low economic growth case).

There are significant differences in the projected growth rates for natural gas prices to electricity generators. GRI, WEFA, and AGA project a slight decline through 2015, whereas DRI projects slight growth and *AEO99* more significant growth, especially in the high economic growth case. Through 2020, the DRI forecast for gas prices to electricity generators rises more rapidly, coming close to the *AEO99* reference case forecast, with the WEFA and EIA forecasts showing only moderate or no growth.

Table 19. Comparison of natural gas forecasts (trillion cubic feet, except where noted)

Projection	AEO99			Other forecasts			
	Reference	Low economic growth	High economic growth	WEFA	GRI	DRI	AGA
2015							
Lower 48 wellhead price (1997 dollars per thousand cubic feet)	2.62	2.29	2.91	2.23	2.36[a]	2.52	2.31[a]
Dry gas production[b]	26.11	23.97	28.01	24.83	27.31	23.47	26.75
Net imports	4.78	4.54	5.07	5.14	3.51[c]	5.20	4.15
Consumption	30.81	28.43	32.99	30.12	31.28	28.51	30.99
Residential	5.61	5.31	5.90	5.70	5.66	5.79	6.23
Commercial[d]	3.86	3.73	3.97	3.51	3.91	3.55[e]	4.01
Industrial[d]	9.87	9.20	10.55	9.92	12.95	8.99[e]	10.84
Electricity generators[f]	8.42	7.33	9.34	8.52	7.19	7.55[d]	6.77
Other[g]	3.05	2.85	3.23	2.47	1.59[h]	2.64	3.14
End-use prices (1997 dollars per thousand cubic feet)							
Residential	5.95	5.78	6.11	6.21	6.71	6.61	5.92[i]
Commercial[d]	5.22	4.96	5.47	5.38	5.72	5.69	4.75[i]
Industrial[d]	3.32	2.95	3.65	3.58[j]	2.93	3.73[j]	2.76[i,k]
Electricity generators[f]	3.24	2.91	3.52	2.67	2.61	2.93	2.61[i]
2020							
Lower 48 wellhead price (1997 dollars per thousand cubic feet)	2.68	2.29	3.09	2.36	NA	2.82	NA
Dry gas production[b]	27.35	24.93	29.62	26.70	NA	23.33	NA
Net imports	5.02	4.69	5.26	5.31	NA	5.41	NA
Consumption	32.30	29.53	34.81	32.18	NA	28.58	NA
Residential	5.77	5.40	6.13	5.92	NA	6.00	NA
Commercial[d]	3.88	3.72	4.04	3.63	NA	3.53[e]	NA
Industrial[d]	10.24	9.30	11.17	10.15	NA	8.99[e]	NA
Electricity generators[f]	9.16	8.12	10.00	9.83	NA	7.40[d]	NA
Other[g]	3.24	3.00	3.48	2.65	NA	2.67	NA
End-use prices (1997 dollars per thousand cubic feet)							
Residential	5.91	5.72	6.14	6.13	NA	6.85	NA
Commercial[d]	5.24	4.93	5.56	5.33	NA	5.93	NA
Industrial[d]	3.40	2.93	3.87	3.68[j]	NA	4.01[j]	NA
Electricity generators[f]	3.31	2.90	3.71	2.76	NA	3.23	NA

[a]First purchase price or field acquisition price, because severance taxes and gathering charges are included.
[b]Does not include supplemental fuels.
[c]Includes supplemental fuels.
[d]Includes gas consumed in cogeneration.
[e]Does not include cogenerators.
[f]Includes independent power producers and does not include cogenerators.
[g]Includes lease and plant fuels and pipeline fuel.
[h]Includes only transportation use.
[i]Does not include certain State and local taxes levied on customers.
[j]On-system sales or system gas (i.e., does not include gas delivered for the account of others).
[k]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: ***AEO99***: AEO99 National Energy Modeling System, runs AEO99B.D100198A (reference case), LMAC99.D100198A (low economic growth case), and HMAC99.D100198A (high economic growth case). **WEFA:** The WEFA Group, *Natural Gas Outlook* (1998). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1999 Edition (August 1998). **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook* (April 1998). AGA: American Gas Association, *1998 AGA-TERA Base Case* (July 1998).

Petroleum

Projected prices for crude oil in the *AEO99* low and high oil price cases bound the 2010 and 2020 projections in five other petroleum forecasts (Table 20)—the *AEO99* reference case, WEFA, GRI, DRI, and the Independent Petroleum Association of America (IPAA) (April 1998). Comparisons with GRI and IPAA forecasts, which do not extend to 2020, apply only to 2010. The *AEO99* reference case oil price projection for 2010 is $1.55 above that of WEFA, $2.54 above that of DRI, and $3.80 above that of GRI. By 2020 the *AEO99* reference case oil price falls between the two other forecasts—$1.41 above WEFA and $0.95 below DRI.

The *AEO99* reference case projection for domestic oil production in 2010 falls between the WEFA and DRI projections but is 0.50 million barrels per day short of the GRI and IPAA projections. The GRI projection reflects natural gas liquids (NGL) production, which is higher than in any other case, while IPAA reflects the second highest production of both crude oil and NGL. As a result, the GRI and IPAA projections of total domestic production in 2010 are slightly higher than even the *AEO99* high oil price case. The *AEO99* reference case projection for 2020 is comparable to the DRI and WEFA forecasts. All three projections are bounded by the *AEO99* low and high oil price cases.

The three *AEO99* cases reflect relatively high projections for petroleum demand in 2010. The low oil price and reference case projections are higher than the four other cases, and the high oil price projection is higher than the IPAA, GRI, and WEFA forecasts. Demand growth in *AEO99* is relatively slow between 2010 and 2020, and by 2020 the *AEO99* projections are comparable to the DRI and WEFA forecasts.

Net petroleum imports in the *AEO99* reference and low price cases are well above the levels of the other forecasts. 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 *AEO99* low oil price case, followed by the reference case. For 2010 the import share of consumption ranges from 53 percent (IPAA) to 65 percent in the *AEO99* low oil price case. The low IPAA import share reflects stronger domestic production than in the other forecasts. The relatively high import share in the *AEO99* low oil price case reflects the lowest production and highest consumption projections.

For 2020 the import shares range from 61 percent in the WEFA and *AEO99* high oil price cases to 71 percent in the low price case. The WEFA and *AEO99* high oil price cases have the lowest import shares for different reasons; projected consumption is relatively high in the WEFA case, whereas production is high and demand is low in the *AEO99* high oil price case. Although the *AEO99* reference case and DRI have similar import shares at 65 and 64 percent, respectively, they have different import pictures. The *AEO99* reference case reflects net crude oil imports that are 1.96 million barrels per day higher than in the DRI forecast and petroleum product imports that are 1.61 million barrels per day lower than DRI. The different split between crude oil and product imports reflects a greater capacity for refining petroleum products in the *AEO99* reference case.

Table 20. Comparison of petroleum forecasts (million barrels per day, except where noted)

Projection	AEO99			Other forecasts			
	Reference	Low world oil price	High world oil price	WEFA	GRI	DRI	IPAA
2010							
World oil price (1997 dollars per barrel)	21.30	14.57	27.33	19.75	17.50[a]	18.76	NA
Crude oil and NGL production	7.74	7.07	8.22	7.63	8.24	7.99	8.26
Crude oil	5.59	4.96	6.06	5.44	5.56	5.69[b]	5.95
Natural gas liquids	2.15	2.11	2.16	2.19	2.68	2.30	2.31
Total net imports	13.70	15.46	12.62	12.06	NA	13.25	11.57
Crude oil	10.97	11.76	10.05	9.79	NA	9.92	NA
Petroleum products	2.73	3.70	2.57	2.27	NA	3.34	NA
Petroleum demand	22.69	23.60	22.13	21.83	21.46	22.15	21.98
Motor gasoline	10.01	10.20	9.77	8.74	8.72	10.03	9.46
Jet fuel	2.46	2.48	2.44	2.31	2.24	2.32	2.17
Distillate fuel	3.99	4.11	3.93	4.03	3.98	3.97	4.14
Residual fuel	0.72	1.08	0.66	0.93	1.07	0.98	0.95
Other	5.51	5.72	5.33	5.82	5.45	5.45	5.26
Import share of product supplied (percent)	60	65	57	55	NA	58	53
2020							
World oil price (1997 dollars per barrel)	22.73	14.57	29.35	21.32	NA	23.68	NA
Crude oil and NGL production	7.41	6.53	7.94	7.40	NA	7.42	NA
Crude oil	4.96	4.12	5.48	4.90	NA	5.18[b]	NA
Natural gas liquids	2.45	2.41	2.46	2.49	NA	2.24	NA
Total net imports	15.97	18.35	14.63	15.19	NA	15.61	NA
Crude oil	11.97	13.13	11.50	10.95	NA	10.01	NA
Petroleum products	4.00	5.22	3.13	4.24	NA	5.61	NA
Petroleum demand	24.66	25.95	23.96	24.80	NA	24.57	NA
Motor gasoline	10.69	11.01	10.40	9.61	NA	10.73	NA
Jet fuel	3.03	3.08	2.96	3.13	NA	2.76	NA
Distillate fuel	4.28	4.47	4.21	4.39	NA	4.19	NA
Residual fuel	0.83	1.24	0.78	1.04	NA	0.92	NA
Other	5.82	6.15	5.62	6.64	NA	5.97	NA
Import share of product supplied (percent)	65	71	61	61	NA	64	NA

[a]Composite of U.S. refiners' acquisition cost.
[b]Includes shale and other.
NA = Not available.
Sources: ***AEO99***: AEO99 National Energy Modeling System, runs AEO99B.D100198A (reference case), LWOP99.D100298B (low world oil price case), and HWOP99.D100298B (high world oil price case). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (1998). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1999 Edition (August 1998). **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook* (April 1998). IPAA: Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Run Report* (April 1998).

Coal

Coal forecasts by WEFA and DRI are similar to the *AEO99* projections (Table 21). Consumption by electricity generators in 2015 falls within the range spanned by the *AEO99* low economic growth, reference, and high economic growth cases (1,073 to 1,148 million tons). Coal consumption in 2015 at domestic coking plants is slightly higher in both the WEFA (26 million tons) and DRI (24 million tons) forecasts than in *AEO99* (21 to 22 million tons), reflecting the expectation that the replacement of coke-based steelmaking with electric arc technology, less coke-intensive methods with pulverized coal injection, and advanced non-coke-based methods will proceed more gradually than projected in *AEO99*. WEFA and DRI project industrial/other coal consumption in 2015 at values that tend toward the lower end of the *AEO99* range: 73 and 88 million tons, respectively. The *AEO99* range is from 77 through 86 to 94 million tons. The difference is largely attributable to differing views of consumption for cogeneration.

Total domestic demand ranges from 1,200 million tons (WEFA) to 1,247 million tons (DRI), whereas *AEO99* ranges from 1,172 to 1,263 million tons. The WEFA forecast has an optimistic outlook for net coal exports, showing 103 million tons, while DRI has 79 million tons and *AEO99* has 84 million tons in 2015. The difference stems from different views of the competitiveness of U.S. mines in a world market where competitors with low labor costs and undeveloped resources are further aided by the persistent strength of the dollar in international markets. Production forecasts follow from the differences in projected demand, with WEFA suggesting 1,300 million tons in 2015 and DRI 1,327 million tons. *AEO99* brackets these values by projecting 1,253 (low economic growth case), 1,294 (reference case) and 1,346 million tons (high economic growth case).

Although the coal production and consumption values are similar, WEFA forecasts minemouth and delivered prices that are about 6 to 10 cents per million Btu higher than those in *AEO99*, while DRI's delivered price (DRI does not forecast minemouth prices) is another 8 cents per million Btu above WEFA's. Coal's price advantage relative to natural gas at existing steam boilers may exceed 20 cents per million Btu, so that smaller price differences have little effect on the quantity demanded. The different price forecasts arise from different expectations of labor productivity improvements in mining and from the different market shares projected for the very low cost, low-sulfur coals of the Powder River Basin.

In 2020, WEFA and DRI project production totals that lie between those forecast for the reference and high economic growth cases in *AEO99*, stemming from a different view of total demand and interfuel competition. However, the entire range is bracketed by the *AEO99* high and low growth cases, with projected production of 1,281 and 1,447 million tons, respectively. WEFA and DRI again have slightly higher coking coal consumption, although their industrial consumption forecasts compare closely with the *AEO99* low growth and reference cases. Differences in net exports follow the pattern established in 2015, with *AEO99* and DRI projecting 86 and 80 million tons, respectively, and WEFA 119 million tons. Again, delivered prices are as much as 14 (WEFA) to 20 (DRI) cents per million Btu above the *AEO99* prices, but they have little effect on demand. Other than the differences in export tonnage and in minemouth and delivered prices, the *AEO99* values do not differ significantly from the WEFA and DRI forecasts.

The GRI / Hill & Associates coal forecast (March 1998) describes a different future, especially after 2005 [*74*]. Although the potential impact of U.S. implementation of the Kyoto Protocol on greenhouse gas emissions is specifically excluded, the authors incorporate the economic burdens that they project would be placed on coal consumption by full implementation of the proposals contained in the Clean Air Power Initiative, which would severely restrict emissions of particulates. The resulting forecast shows production growing as in the other forecasts until 2006. It declines to 957 million tons in 2015 (*AEO99* ranges from 1,253 to 1,346 million tons in 2015). By 2020, coal production has fallen to 938 million tons, while that in the other forecasts rises to between 1,281 and 1,447 million tons.

All elements of the GRI/Hill forecast are equally pessimistic. Net exports are projected at 59 million tons in 2015 and 56 million tons in 2020—about half the WEFA level. Domestic coking coal consumption falls to 19 million tons in 2015 and 16 million tons in

2020. And industrial coal consumption is only 67 million tons in 2015 and 65 million tons in 2020 (all sectors of domestic consumption are similarly depressed by the Clean Air Power Initiative).

These low consumption levels are reached in spite of low delivered prices to the electricity sector: 95 cents per million Btu in 2015 and 92 cents per million Btu in 2020. The other forecasts range from 96 cents (*AEO99* low growth case) to 114 cents (DRI) per million Btu in 2015, and from 90 to 110 cents per million Btu in 2020 (again, the *AEO99* low growth case and DRI). The implication is that even if efficient production, vigorous competition, and declining real transportation costs keep coal's delivered prices low and declining, the costs of compliance with the Clean Air Power Initiative will blunt its competitive edge.

Table 21. Comparison of coal forecasts (million short tons, except where noted)

Projection	*AEO99*			*Other forecasts*		
	Reference	*Low economic growth*	*High economic growth*	*WEFA*	*GRI/Hill*	*DRI*
			2015			
Production	*1,294*	*1,253*	*1,346*	*1,300*	*957*	*1,327*
Consumption by sector						
Electricity generation[a]	*1,103*	*1,073*	*1,148*	*1,100*	*801*	*1,136*
Coking plants	*22*	*22*	*21*	*26*	*19*	*24*
Industrial/other	*86*	*77*	*94*	*73*	*67*	*88*
Total	*1,211*	*1,172*	*1,263*	*1,200*	*887*	*1,247*
Net coal exports	*84*	*84*	*84*	*103*	*59*	*79*
Minemouth price						
(1997 dollars per short ton)	*13.21*	*12.98*	*13.39*	*15.13*	*NA*	*NA*
(1997 dollars per million Btu)	*0.63*	*0.62*	*0.64*	*0.70*	*NA*	*NA*
Average delivered price, electricity						
(1997 dollars per short ton)	*20.03*	*19.44*	*20.53*	*21.78*	*18.98*	*23.33*
(1997 dollars per million Btu)	*0.99*	*0.96*	*1.01*	*1.06*	*0.95*	*1.14*
			2020			
Production	*1,358*	*1,281*	*1,447*	*1,368*	*938*	*1,389*
Consumption by sector						
Electricity generation[a]	*1,166*	*1,098*	*1,242*	*1,199*	*789*	*1,196*
Coking plants	*20*	*20*	*19*	*24*	*16*	*21*
Industrial/other	*89*	*76*	*102*	*76*	*65*	*88*
Total	*1,275*	*1,195*	*1,363*	*1,299*	*870*	*1,305*
Net coal exports	*86*	*86*	*86*	*119*	*56*	*80*
Minemouth price						
(1997 dollars per short ton)	*12.74*	*12.47*	*12.89*	*14.95*	*NA*	*NA*
(1997 dollars per million Btu)	*0.62*	*0.60*	*0.62*	*0.69*	*NA*	*NA*
Average delivered price, electricity						
(1997 dollars per short ton)	*18.77*	*18.03*	*19.33*	*21.42*	*18.19*	*22.52*
(1997 dollars per million Btu)	*0.93*	*0.90*	*0.96*	*1.04*	*0.92*	*1.10*

[a] The DRI and *AEO99* forecasts for electricity generation include nonutility generators. Consumption by industrial cogenerators is included in industrial consumption. The WEFA values for electricity consumption have been adjusted by including consumption by nonutility generators (11.2 million tons in 2015 and 2020).

NA = Not available.

Btu = British thermal unit.

Sources: ***AEO99:*** AEO99 National Energy Modeling System, runs AEO99B.D100198A (reference case), LMAC99.D100198A (low economic growth case), and HMAC99.D100198A (high economic growth case). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (1998). **GRI/Hill:** Gas Research Institute, *Final Report, Coal Demand and Price Projections*, Vol. I, GRI-98/0053.1 (March 1998). **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook* (April 1998).

List of Acronyms

AD	Associated/dissolved natural gas
AEO98	*Annual Energy Outlook 1998*
AEO99	*Annual Energy Outlook 1999*
AFVs	Alternative-fuel vehicles
AGA	American Gas Association
API	American Petroleum Institute
BTAB	BT Alex Brown
CAAA90	Clean Air Act Amendments of 1990
CCAP	Climate Change Action Plan
CDM	Clean Development Mechanism
CFCs	Chlorofluorocarbons
CNG	Compressed natural gas
CO	Carbon monoxide
CO_2	Carbon dioxide
DOE	U.S. Department of Energy
DRI	DRI/McGraw-Hill
EIA	Energy Information Administration
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
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
HAPs	Hazardous air pollutants
HCFCs	Hydrochlorofluorocarbons
HFCs	Hydrofluorocarbons
IEA	International Energy Agency
IEO98	*International Energy Outlook 1998*
IGCC	Integrated coal gasification combined cycle
IMF	International Monetary Fund
INGAA	Interstate Natural Gas Association of America
IPAA	Independent Petroleum Association of America
IPCC	Intergovernmental Panel on Climate Change
LDCs	Local distribution companies
LEVP	Low Emission Vehicle Program
LEVs	Low emission vehicles
LNG	Liquefied natural gas
MACT	Maximum Achievable Control Technology
NAAQS	National Ambient Air Quality Standards
NEMS	National Energy Modeling System
NESHAPs	National emissions standards for hazardous air pollutants
NGL	Natural gas liquids
NGSA	Natural Gas Supply Association
NLEV	National Low Emissions Vehicle
NOPR	Notice of proposed rulemaking
NO_x	Nitrogen oxides
NPC	National Petroleum Council
NPRA	National Petrochemical and Refiners Association
NRCan	Natural Resources Canada
OCS	U.S. Outer Continental Shelf
OECD	Organization for Economic Cooperation and Development
OTAG	Ozone Transport Assessment Group
OTR	Ozone Transport Rule
PBF	Public benefit fund
PEL	Petroleum Economics, Ltd.
PFCs	Perfluorocarbons
PIRA	Petroleum Industry Research Associates, Inc.
PM	Particulate matter
ppm	Parts per million
QUICS	Qualifying industrial customer scheme
RECs	Regional Electricity Companies
RPS	Renewable portfolio standard
SCR	Selective catalytic reduction
SNCR	Selective noncatalytic reduction
SO_2	Sulfur dioxide
SPR	Strategic Petroleum Reserve
STEO	*Short-Term Energy Outlook*
ULEVs	Ultra-low emission vehicles
VOCs	Volatile organic compounds
WEFA	WEFA Group
ZEVs	Zero emission vehicles

Text Notes

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

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[*2*] Energy Information Administration, *Mitigating Greenhouse Gas Emissions: Voluntary Reporting*, DOE/EIA-0608(96) (Washington, DC, October 1997).

[*3*] For maps and information, see National Oceanic and Atmospheric Administration, web site www.sanctuaries.noaa.gov.

[*4*] For details, see Federal Energy Regulatory Commission, web site www.ferc.fed.us.

[*5*] U.S. Environmental Protection Agency, Office of Mobile Sources, *Tier 2 Report to Congress*, EPA-420-R-98-008 (Washington, DC, July 1998).

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[*6*] California Air Resource Board, *Proposed Regulations for Low Emission Vehicles and Clean Fuels*, Staff Report (August 13, 1990).

[*7*] NO_x emissions together with emissions of volatile organic compounds are major precursors to ozone formation.

[*8*] *Federal Register* 62 60318 (November 7, 1997).

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[*9*] Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998).

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[*10*] U.S. Environmental Protection Agency, 40 CFR Part 63, *Federal Register*, Vol. 63, No. 25 (February 6, 1998).

[*11*] *Clean Air Report*, Vol. 9, No. 19 (September 17, 1998), p. 26.

[*12*] U.S. Environmental Protection Agency, 40 CFR Part 63, *Federal Register*, Vol. 63, No. 176 (September 11, 1998).

[*13*] The status of State restructuring efforts is changing constantly. For an up-to-date summary of State efforts, see Energy Information Administration, web site www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev. html.

[*14*] Rhode Island began allowing some larger customers to choose their suppliers in 1997.

[*15*] California originally planned to open the market on January 1, 1998, but computer software problems delayed the opening.

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[*16*] For more discussion of the treatment of stranded costs, see Energy Information Administration, *The Changing Structure of the Electric Power Industry: Selected Issues, 1998*, DOE/EIA-0562(98) (Washington, DC, July 1998).

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[*17*] "NGSA: Return-on-Equity Fair Despite Protests by Pipelines," *Natural Gas Week* (March 9, 1998), p. 6.

[*18*] The *AEO99* assumptions about onshore undiscovered technically recoverable resources are based on the United States Geological Survey (USGS) report, *1995 National Assessment of United States Oil and Gas Resources*. For natural gas, the USGS resource estimates (as of January 1, 1994) vary from 207.1 trillion cubic feet at a 95-percent confidence interval to 329.1 trillion cubic feet at a 5-percent confidence interval, 20 percent below and 27 percent above, respectively, the mean estimate used in *AEO99* (258.7 trillion cubic feet). The *AEO99* offshore estimates are based on the Minerals Management Service (MMS) report, *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf*, with resource estimates as of January 1, 1995. The MMS estimates vary from 82.3 trillion cubic feet at a 95-percent confidence level to 110.3 trillion cubic feet at a 5-percent confidence level, 14 percent below and 15 percent above the mean estimate used in *AEO99* (95.7 trillion cubic feet). The ranges of the estimates indicate their uncertainty.

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

[*20*] Federal Energy Regulatory Commission, Office of Pipeline Regulation, Case Tracking System.

[*21*] Energy Information Administration, Office of Energy Markets and End Use.

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[*22*] U.S. Department of Energy, *Comprehensive Electricity Competition Plan* (Washington, DC, March 1998). See web site www.hr.doe.gov/electric/cecp.htm.

[*23*] U.S. Department of Energy, "Comprehensive Electricity Competition Act," web site www.doe.gov/ceca/ceca.htm.

[*24*] Note that the impacts of the existing State RPS programs are included in both the reference and the Federal RPS case.

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[*25*] Efficiency in the economic sense means that there are no wasted resources; that is, no additional consumption could occur without reducing something else.

[*26*] J.C. Bonbright, A.L. Danielsen, and D.R. Kamerschen, *Principles of Public Utility Rates*, Second Edition (Arlington, VA: Public Utility Reports, Inc., 1988), pp. 410-477.

[*27*] J. Surrey, ed., *The British Electricity Experiment* (Earthscan Publications, 1996), p. 196.

[*28*] Energy Information Administration, *Natural Gas Annual 1991*, DOE/EIA-0131(91) (Washington, DC, October 1992), pp. 44-45. It is likely that Figure 17 underestimates the margin between industrial and

other customers. An increasing number of options are available to industrial customers, and the data reflect only the subset that have not chosen to leave their local distribution companies.

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[29] J.C. Bonbright, A.L. Danielsen, and D.R. Kamerschen, *Principles of Public Utility Rates*, Second Edition (Arlington, VA: Public Utility Reports, Inc., 1988), p. 425.

[30] Such an approach was found to be economically optimal by Ramsey some 70 years ago. See F.P. Ramsey, "A Contribution to the Theory of Taxation," *Economic Journal* (March 1927).

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[31] U.S. Environmental Protection Agency, Office of Mobile Sources, *EPA Staff Paper on Gasoline Sulfur Issues*, EPA-420-R-98-005 (Washington, DC, May 1998).

[32] U.S. Environmental Protection Agency, Office of Mobile Sources, *EPA Staff Paper on Gasoline Sulfur Issues*, EPA-420-R-98-005 (Washington, DC, May 1998).

[33] The 23 States are Alabama, Florida, Georgia, Illinois, Indiana, Kentucky, Louisiana, Maine, Maryland, Michigan, Mississippi, Missouri, New Hampshire, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Vermont, Virginia, West Virginia, and Wisconsin.

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[34] Intergovernmental Panel on Climate Change, *Climate Change 1995: The Science of Climate Change* (Cambridge, UK: Cambridge University Press, 1996).

[35] President William J. Clinton and Vice President Albert Gore, Jr., *The Climate Change Action Plan* (Washington, DC, October 1993).

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[36] 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.

[37] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1997*, DOE/EIA-0573(97) (Washington, DC, October 1998).

[38] Energy Information Administration, *Mitigating Greenhouse Gas Emissions: Voluntary Reporting*, DOE/EIA-0608(96) (Washington, DC, October 1997).

[39] 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 Convention and did not commit to quantifiable emissions targets.

[40] The text of the Kyoto Protocol is available at web site www.unfccc.de.

[41] 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.

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[42] Energy Information Administration, *International Energy Outlook 1998*, DOE/EIA-0484(98) (Washington, DC, April 1998).

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[43] Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998).

[44] Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997).

[45] See U.S. Department of State, web site www.state.gov/www/global/oes/fs_kyoto_climate_980115.html.

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[46] **Buildings:** Energy Information Administration (EIA), *Technology Forecast Updates—Residential and Commercial Building Technologies*, Draft Report (Arthur D. Little, Inc., June 1998). **Industrial:** EIA, *Aggressive Technology Strategy for the NEMS Model* (Arthur D. Little, Inc., 1998). **Light-duty vehicle conventional technologies:** 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). **Light-duty alternative fuel technologies:** U.S. Department of Energy, Office of Transportation Technologies, *Program Analysis Methodology: Final Report—Quality Metrics 98 Revised* (Washington, DC, April 1997). **Freight trucks:** U.S. Department of Energy, Office of Transportation Technologies, *OHVT Technology Roadmap* (Washington, DC, October 1997); and conversations with Frank Stodolsky, Argonne National Laboratory, and Mr. Suski, American Trucking Association. **Air:** Conversations with Glenn M. Smith, National Aeronautics and Space Administration. **Fossil-fired generating technologies:** Table 45 from EIA, *Assumptions for the Annual Energy Outlook 1998*, web site www.eia.doe.gov/oiaf/aeo98/assumptions98/aeo98asu.pdf.

Renewable generating technologies: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Renewable Energy Technology Characterizations*, Draft Report, Vol. 1 (Washington, DC, February 1997), as updated in internal revisions, Summer 1997.

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[*47*] **Buildings:** Energy Information Administration (EIA), *Technology Forecast Updates—Residential and Commercial Building Technologies*, Draft Report (Arthur D. Little, Inc., June 1998). **Industrial:** EIA, *Aggressive Technology Strategy for the NEMS Model* (Arthur D. Little, Inc., 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 99* (December 1997); 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). **Fossil-fired generating technologies:** U.S. Department of Energy, Office of Fossil Energy.

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[*48*] Only portions of the national economic statistics have been converted to 1992 chain-weighted dollars. Because the national input-output matrix for manufacturing industries, which underlies the projections in Figure 34, is still available only in 1987 fixed-weight dollars, the growth rates shown in the figure are based on 1987 fixed-weight dollars. The use of fixed-weight dollars is not expected to affect the picture of relative growth rates shown in the figure.

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[*49*] DRI/McGraw-Hill, Simulation T250898, August 1998.

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[*50*] 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).

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[*51*] 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.

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[*52*] The high and low macroeconomic growth cases are linked to higher and lower population growth, respectively, which affects energy use in all sectors.

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[*53*] The definition of the commercial sector for *AEO99* is based on data from the 1995 Commercial Buildings Energy Consumption Survey (CBECS), specifically, Energy Information Administration, 1995 CBECS Micro-Data Files, February 17, 1998, see 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 *AEO99.* Further discussion of these factors is provided in the *commercial assumptions* section of Appendix G.

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[*54*] 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).

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[*55*] Estimated as consumption of alternative transportation fuels in crude oil Btu equivalence.

[*56*] 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.

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[*57*] Sales of alternative-fuel vehicles that are determined by market forces rather than by legislative mandates are defined here as market-driven AFV sales.

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[*58*] 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 99* (December 1997); 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).

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[*59*] Values for incremental investments and energy expenditure savings are discounted back to 1998 at a 7-percent real discount rate.

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[*60*] 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 99* (December 1997); 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).

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[*61*] Unless otherwise noted, the term "capacity" in the discussion of electricity generation indicates utility, nonutility, and cogenerator capacity.

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[*62*] 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. *AEO99* 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.

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[*63*] Substantial uncertainty surrounds the ultimate use of North Slope gas. However, projected low gas prices in the lower 48 markets justify the *AEO99* perspective that does not consider it a significant factor affecting domestic energy markets, especially natural gas markets.

[*64*] Thirteen projects are currently proposed to expand pipeline capacity from Canada into the United States between 1998 and 2000. Three are slated to provide access to Sable Island supplies. It is assumed that not all proposed projects will be built, but that some combination of currently proposed projects will add approximately 2 billion cubic feet per day of pipeline capacity to access western Canadian supplies and 0.4 billion cubic feet per day to access Sable Island supplies. For information about specific projects, see Energy Information Administration, "Natural Gas Pipeline and System Expansions," *Natural Gas Monthly,* DOE/EIA-0130(98/04) (Washington, DC, April 1998).

[*65*] Two additional LNG import facilities located at Cove Point, MD, and Elba Island, GA, both of which are currently idle, are not projected to be reopened in the reference case. While LNG imports in the forecast all come from Algeria, new potential sources of supply include Australia, Abu Dhabi, Trinidad and Tobago, and Norway.

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[*66*] 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.

[*67*] 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.

[*68*] Energy Information Administration, *Monthly Energy Review,* DOE/EIA-0035(96/03) (Washington, DC, March 1996), Table 1.6.

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[*69*] In the 1980s, falling consumption led to surplus refining capacity, which reduced the need for product imports. See Energy Information Administration, *The U.S. Petroleum Industry: Past as Prologue 1970-1992,* DOE/EIA-0572 (Washington, DC, September 1993), p. 47.

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[70] 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. Office workers are excluded from the calculation.

[71] 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.

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[72] U.S. Environmental Protection Agency, web site www. epa. gov/ acidrain/ overview. html (September 1997).

[73] U.S. Environmental Protection Agency, *National Air Pollutant Emission Trends, 1990-1996* (Washington, DC, 1998) Appendix A, National Emissions (1970-1996), Table A-4, p. A-19.

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[74] 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. GRI also publishes an annual multifuel energy forecast through 2015 with less coal detail, which differs from the one prepared by Hill & Associates (Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1999 Edition*, August 1998). In this projection, electricity sector coal consumption in 2015 is given as 24.5 quadrillion Btu and industrial /other consumption as 2.6 quadrillion Btu, for total domestic consumption of 27.1 quadrillion Btu (about 1,325 to 1,400 million tons). The delivered price in the electricity sector in this projection is 0.97 cents per million Btu in 1997 dollars.

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 (page 7): Tables A1, A19, A20, B1, B19, B20, C1, and C19.

Table 2. Summer season NO_x emissions budgets for 2003 and beyond (page 12): U.S. Environmental Protection Administration, "Supplemental Ozone Transport Rulemaking Regulatory Analysis" (April 7, 1998), Table D-1.

Table 3. New car and light truck horsepower ratings and market shares, 1990-2020 (page 55): **History:** U.S. Department of Transportation, National Highway Traffic Safety Administration. **Projections:** AEO99 National Energy Modeling System, run AEO99B. D100198A.

Table 4. Shares of the alternative-fuel light-duty vehicle market by technology type, 2020 (page 56): U.S. Department of Energy, Office of Policy, *Technical Report Fourteen: Market Potential and Impacts of Alternative Fuel Use in Light-Duty Vehicles: A 2000/2010 Analysis* (Draft, 1995). California Air Resources Board, "Proposed Regulations for Low-Emission Vehicles and Clean Fuels, Staff Report" (Sacramento, CA, August 13, 1990). U.S. Department of Commerce, Bureau of the Census, *Truck Inventory and Use Survey, 1992*, TC92-T-52 (Washington, DC, May 1995). Energy Information Administration, *Describing Current and Potential Markets for Alternative Fuel Vehicles*, DOE/EIA-0604 (Washington, DC, March 1996). Energy Information Administration, *Alternatives to Traditional Transportation Fuels 1996*, DOE/EIA-0585(96) (Washington, DC, December 1997). AEO99 National Energy Modeling System, run AEO99B.D100198A.

Table 5. Costs of producing electricity from new plants, 2005 and 2020 (page 63): AEO99 National Energy Modeling System, run AEO99B.D100198A.

Table 6. Technically recoverable U.S. oil and gas resources as of January 1, 1997 (page 69): Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 7. Natural gas and crude oil drilling in three cases, 1997-2020 (page 70): AEO99 National Energy Modeling System, runs AEO99B.D100198A, LWOP99. D100298B, and HWOP99.D100298B.

Table 8. Transmission and distribution revenues and margins, 1970-2020 (page 73): **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** AEO99 National Energy Modeling System, run AEO99B.D100198A. End-use consumption is net of pipeline and lease and plant fuels.

Table 9. Components of residential and commercial natural gas end-use prices, 1985-2020 (page 73): **History:** Energy Information Administration, *Annual Energy Review 1987*, DOE/EIA-0384(87) (Washington, DC, July 1988). **1997 and Projections:** AEO99 National Energy Modeling System, run AEO99B.D100198A. **Note:** End-use prices may not equal the sum of citygate prices and LDC margins due to independent rounding.

Table 10. Petroleum consumption and net imports, 1997 and 2020 (page 77): **1996:** Energy Information Administration, *Petroleum Supply Annual 1997*, DOE/EIA-0340(97)/1 (Washington, DC, June 1998). **Projections:** Tables A11, B11, and C11.

Table 11. Scrubber retrofits and allowance costs, 2000-2020 (page 86): AEO99 National Energy Modeling System, run AEO99B.D100198A.

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Table 12. Forecasts of economic growth, 1997-2020 (page 88): ***AEO99:*** Table B20. **DRI:** DRI/McGraw-Hill, simulations T250898, TO250898, and TP250898. **WEFA:** The WEFA Group, *U.S. Energy Outlook* (1998).

Table 13. Forecasts of world oil prices, 2000-2020 (page 88): ***AEO99:*** Tables A1 and C1. **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook* (April 1998). **IEA CC:** International Energy Agency, *World Energy Outlook, 1996*: Capacity Constraints Case. **IEA ES:** International Energy Agency, *World Energy Outlook, 1996*: Energy Savings Case. **PEL:** Petroleum Economics, Ltd., *Long Term Oil and Energy Outlook to 2015* (February 1998). **PIRA:** PIRA Energy Group, "Retainer Client Seminar" (October 1997). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (1998). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1999 Edition* (August 1998). **NRCan:** Natural Resources Canada, *Canada's Energy Outlook 1996-2020* (April 1997). **BT Alex Brown:** *The Oil Sector and the Global Economic Slowdown* (September 1998).

Table 14. Forecasts of average annual growth rates for energy consumption (page 89): ***AEO99:*** Table A2. **DRI:** DRI/McGraw Hill, *World Energy Service: U.S. Outlook* (April 1998). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1999 Edition* (August 1998). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (1998). **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 15. Forecasts of average annual growth in residential and commercial energy demand (page 89): ***AEO99:*** Table A2. **DRI:** DRI/McGraw Hill, *World Energy Service: U.S. Outlook* (April 1998). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1999 Edition* (August 1998). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (1998).

Table 16. Forecasts of average annual growth in industrial energy demand (page 89): ***AEO99:*** Table A2. **DRI:** DRI/McGraw Hill, *World Energy Service: U.S. Outlook* (April 1998). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1999 Edition* (August 1998). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (1998).

Table 17. Forecasts of average annual growth in transportation energy demand (page 90): ***AEO99:*** Table A2. **DRI:** DRI/McGraw Hill, *World Energy Service: U.S. Outlook* (April 1998). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1999 Edition* (August 1998). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (1998).

Table 18. Comparison of electricity forecasts (page 91): ***AEO99:*** AEO99 National Energy Modeling System, runs AEO99B.D100198A, LMAC99.D100198A, and HMAC99.D100198A. **WEFA:** The WEFA Group, *U.S. Power Outlook* (1998). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1999 Edition* (August 1998). **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook* (April 1998).

Table 19. Comparison of natural gas forecasts (page 93): ***AEO99:*** Tables B13 and B14. **WEFA:** The WEFA Group, *Natural Gas Outlook* (1998). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1999 Edition* (August 1998). **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook* (April 1998). **AGA:** American Gas Association, *1998 AGA-TERA Base Case* (July 1998).

Table 20. Comparison of petroleum forecasts (page 95): ***AEO99:*** Table C11. **WEFA:** The WEFA Group, *U.S. Energy Outlook* (1998). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1999 Edition* (August 1998). **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook* (April 1998). **IPAA:** Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Run Report* (April 1998).

Table 21. Comparison of coal forecasts (page 97): ***AEO99:*** Table B16. **WEFA:** The WEFA Group, *U.S. Energy Outlook* (1998). **GRI/Hill:** Gas Research Institute, *Final Report, Coal Demand and Price Projections*, Vol. I, GRI-98/0053.1 (March 1998), Table 4.3. **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook* (April 1998).

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, 1997-2020: *AEO98* and *AEO99* compared (page 2): ***AEO98*** **Projections:** Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997). ***AEO99*** **Projections:** Table A1.

Figure 2. Energy consumption by fuel, 1970-2020 (page 4): **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Tables A1 and A18. **Note:** Data for non-electric utility use of renewable energy were collected beginning in 1990.

Figure 3. Energy use per capita and per dollar of gross domestic product, 1970-2020 (page 4): **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Table A2.

Figure 4. Electricity generation by fuel, 1970-2020 (page 5): **History:** Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report"; Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington,

DC, July 1998); and Edison Electric Institute. **Projections:** Table A8.

Figure 5. Energy production by fuel, 1970-2020 (page 6): **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Tables A1 and A18. **Note:** Data for non-electric utility use of renewable energy were collected beginning in 1990.

Figure 6. Net energy imports by fuel, 1970-2020 (page 6): **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Table A1.

Figure 7. U.S. carbon emissions by sector and fuel, 1990-2020 (page 6): **History:** Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1997*, DOE/EIA-0573(97) (Washington, DC, October 1998). **Projections:** Table A19.

Figure 8. World oil price projections in the *AEO98* and *AEO99* reference cases, 1990-2020 (page 19): **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** ***AEO98***: Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98)(Washington, DC, December 1997). ***AEO99***: Table A1.

Figure 9. Oil demand projections for developing Asia in *AEO98* and *AEO99*, 1990-2020 (page 20): Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202(98/3Q) (Washington, DC, July 1998). **Projections:** ***AEO98***: Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98)(Washington, DC, December 1997). ***AEO99***: Table A21.

Figure 10. Projected annual growth in real U.S. exports, 1995-2003 (page 20): **History:** Bureau of Economic Analysis, U.S. Department of Commerce. **Projections:** AEO99 National Energy Modeling System, run AEO99B.D100198A.

Figure 11. Renewable electricity generation in two cases, 2020 (page 23): AEO99 National Energy Modeling System, runs AEO99B.D100198A and RPS99.D100698B.

Figure 12. Change in average U.S. electricity prices in the Federal RPS sensitivity case from the reference case, 2000-2020 (page 23): AEO99 National Energy Modeling System, runs AEO99B.D100198A and RPS99.D100698B.

Figure 13. Variation from reference case national electricity costs in the Federal RPS sensitivity case, 2005-2020 (page 24): AEO99 National Energy Modeling System, runs AEO99B.D100198A and RPS99.D100698B.

Figure 14. Projected U.S. electricity-related carbon emissions in two cases, 1996-2020 (page 24): AEO99 National Energy Modeling System, runs AEO99B.D100198A and RPS99.D100698B.

Figure 15. Percentage of time that different plant types set national marginal electricity prices, 2000, 2010, and 2020 (page 25): AEO99 National Energy Modeling System, run COMPETE.D100398A.

Figure 16. Real electricity prices in the United Kingdom after deregulation, 1988-1996 (page 26): United Kingdom Department of Trade and Industry, *Digest of the United Kingdom Energy Statistics 1996.*

Figure 17. Index of real U.S. natural gas transmission and distribution markups by end-use sector, 1985-1996 (page 26): Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998).

Figure 18. Actual 1997 electricity prices by sector and calculated prices with optimal pricing (page 27): AEO99 National Energy Modeling System, runs AEO99B.D100198A and COMPETE.D100398A.

Figure 19. Generation component of electricity prices by end-use sector, 1999-2020 (page 27): AEO99 National Energy Modeling System, run COMPETE.D100398A.

Figure 20. Electricity generation price duration curve for the New England region (page 28): AEO99 National Energy Modeling System, run COMPETE.D100398A.

Figure 21. U.S. industrial electricity prices under three fixed cost allocation options, 1999-2020 (page 28): AEO99 National Energy Modeling System, runs AEO99B.D100198A, COMPETE.D100398A, and CMP.D100598A.

Figure 22. U.S. electricity prices by end-use sector in the reference and full competition cases, 1999-2020 (page 28): **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** AEO99 National Energy Modeling System, run COMPETE.D100398A.

Figure 23. U.S. carbon emissions in seven Kyoto Protocol analysis cases, 1990-2020 (page 34): **History:** Energy Information Administration, Emissions of Greenhouse Gases in the United States 1997, DOE/EIA-0573(97) (Washington, DC, October 1998). **Projections:** Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998).

Figure 24. Carbon prices in six Kyoto Protocol analysis cases, 1996-2020 (page 35): Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998).

Figure 25. Projected fuel shares of U.S. energy consumption in two Kyoto Protocol analysis cases, 2010 (page 35): Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998).

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Appendixes

Appendix A

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 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Production								
Crude Oil and Lease Condensate	13.69	13.65	13.32	12.31	11.83	11.30	10.51	-1.1%
Natural Gas Plant Liquids	2.60	2.57	2.54	2.80	3.06	3.32	3.47	1.3%
Dry Natural Gas	19.32	19.47	19.82	22.17	24.44	26.84	28.12	1.6%
Coal	22.75	23.33	24.64	25.20	25.91	26.95	28.12	0.8%
Nuclear Power	7.20	6.71	7.04	6.73	5.91	4.47	3.83	-2.4%
Renewable Energy[1]	6.81	6.82	6.82	7.11	7.44	7.77	8.15	0.8%
Other[2]	1.28	0.66	0.53	0.57	0.57	0.62	0.65	-0.1%
Total	**73.66**	**73.22**	**74.71**	**76.89**	**79.16**	**81.28**	**82.85**	**0.5%**
Imports								
Crude Oil[3]	16.31	17.86	19.58	21.53	23.91	24.96	26.03	1.7%
Petroleum Products[4]	3.98	3.89	5.25	6.45	7.35	8.50	9.92	4.2%
Natural Gas	3.00	3.06	3.55	3.97	4.69	5.15	5.46	2.6%
Other Imports[5]	0.57	0.54	0.74	0.70	0.71	0.72	0.75	1.4%
Total	**23.85**	**25.34**	**29.12**	**32.65**	**36.66**	**39.33**	**42.15**	**2.2%**
Exports								
Petroleum[6]	2.04	2.09	2.04	2.05	2.11	2.02	2.00	-0.2%
Natural Gas	0.16	0.16	0.19	0.21	0.24	0.27	0.32	3.1%
Coal	2.37	2.19	2.14	2.21	2.27	2.31	2.36	0.3%
Total	**4.57**	**4.44**	**4.36**	**4.47**	**4.62**	**4.59**	**4.68**	**0.2%**
Discrepancy[7]	**0.68**	**-0.08**	**-0.25**	**-0.39**	**-0.37**	**-0.49**	**-0.44**	**N/A**
Consumption								
Petroleum Products[8]	36.03	36.49	38.95	41.25	44.22	46.20	48.08	1.2%
Natural Gas	22.59	22.59	23.17	25.89	28.79	31.64	33.17	1.7%
Coal	20.60	21.09	22.78	23.31	24.06	25.05	26.26	1.0%
Nuclear Power	7.20	6.71	7.04	6.73	5.91	4.47	3.83	-2.4%
Renewable Energy[1]	6.81	6.82	6.82	7.12	7.45	7.79	8.17	0.8%
Other[9]	0.39	0.33	0.46	0.39	0.39	0.38	0.39	0.7%
Total	**93.63**	**94.04**	**99.21**	**104.68**	**110.83**	**115.53**	**119.89**	**1.1%**
Net Imports - Petroleum	**18.25**	**19.65**	**22.79**	**25.93**	**29.16**	**31.44**	**33.95**	**2.4%**
Prices (1997 dollars per unit)								
World Oil Price (dollars per barrel)[10]	21.01	18.55	13.97	19.25	21.30	21.91	22.73	0.9%
Gas Wellhead Price (dollars per Mcf)[11]	2.28	2.23	2.10	2.35	2.52	2.62	2.68	0.8%
Coal Minemouth Price (dollars per ton)	18.85	18.14	16.59	14.93	14.00	13.21	12.74	-1.5%
Average Electric Price (cents per kilowatthour)	6.9	6.9	6.6	6.4	6.1	5.8	5.6	-0.9%

[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.
Kwh = Kilowatthour.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1996 and 1997 may differ from published data due to internal conversion factors.
Sources: 1996 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1996*, DOE/EIA-0131(96) (Washington, DC, September 1997). 1996 coal minemouth prices: EIA, *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997). Other 1996 values: EIA, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). 1997 natural gas values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(98/06) (Washington, DC, June 1998). 1997 coal minemouth price: *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, November 1998). Coal production and exports derived from: EIA, *Monthly Energy Review*, DOE/EIA-0035(98/08) (Washington, DC, August 1998). Other 1997 values: EIA, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Energy Consumption								
Residential								
Distillate Fuel	0.93	0.94	0.87	0.79	0.73	0.69	0.65	-1.6%
Kerosene	0.09	0.09	0.07	0.07	0.07	0.07	0.07	-1.4%
Liquefied Petroleum Gas	0.43	0.43	0.44	0.44	0.43	0.42	0.40	-0.3%
Petroleum Subtotal	1.44	1.47	1.38	1.29	1.23	1.18	1.12	-1.2%
Natural Gas	5.38	5.15	5.21	5.31	5.52	5.77	5.94	0.6%
Coal	0.06	0.06	0.06	0.05	0.05	0.05	0.05	-0.5%
Renewable Energy[1]	0.61	0.60	0.60	0.61	0.62	0.64	0.65	0.4%
Electricity	3.69	3.66	4.01	4.31	4.57	4.93	5.31	1.6%
Delivered Energy	**11.18**	**10.92**	**11.26**	**11.57**	**12.00**	**12.57**	**13.08**	**0.8%**
Electricity Related Losses	8.07	8.07	8.78	8.89	9.11	9.34	9.77	0.8%
Total	**19.25**	**18.99**	**20.04**	**20.47**	**21.11**	**21.91**	**22.85**	**0.8%**
Commercial								
Distillate Fuel	0.48	0.49	0.38	0.36	0.34	0.33	0.32	-1.9%
Residual Fuel	0.14	0.11	0.09	0.09	0.09	0.09	0.09	-0.8%
Kerosene	0.02	0.03	0.02	0.02	0.03	0.03	0.03	-0.2%
Liquefied Petroleum Gas	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.7%
Motor Gasoline[2]	0.02	0.03	0.03	0.03	0.03	0.02	0.02	-0.3%
Petroleum Subtotal	0.74	0.73	0.60	0.58	0.57	0.56	0.55	-1.3%
Natural Gas	3.24	3.37	3.55	3.68	3.84	3.97	4.00	0.7%
Coal	0.08	0.08	0.09	0.09	0.10	0.10	0.10	0.9%
Renewable Energy[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.0%
Electricity	3.35	3.44	3.69	3.97	4.26	4.54	4.72	1.4%
Delivered Energy	**7.42**	**7.63**	**7.92**	**8.32**	**8.77**	**9.18**	**9.37**	**0.9%**
Electricity Related Losses	7.31	7.59	8.07	8.19	8.48	8.60	8.68	0.6%
Total	**14.73**	**15.22**	**15.99**	**16.51**	**17.24**	**17.78**	**18.05**	**0.7%**
Industrial[4]								
Distillate Fuel	1.11	1.13	1.14	1.26	1.35	1.42	1.48	1.2%
Liquefied Petroleum Gas	2.14	2.14	2.15	2.30	2.45	2.58	2.69	1.0%
Petrochemical Feedstock	1.28	1.46	1.47	1.44	1.52	1.60	1.67	0.6%
Residual Fuel	0.30	0.28	0.29	0.32	0.33	0.35	0.36	1.1%
Motor Gasoline[2]	0.21	0.21	0.21	0.24	0.26	0.28	0.29	1.5%
Other Petroleum[5]	4.18	4.11	4.51	4.68	4.89	4.95	4.99	0.8%
Petroleum Subtotal	9.21	9.33	9.79	10.24	10.81	11.18	11.49	0.9%
Natural Gas[6]	10.06	9.92	10.31	10.85	11.43	12.02	12.52	1.0%
Metallurgical Coal	0.85	0.79	0.78	0.70	0.63	0.58	0.53	-1.7%
Steam Coal	1.57	1.56	1.56	1.61	1.67	1.73	1.80	0.6%
Net Coal Coke Imports	0.00	0.02	0.11	0.17	0.20	0.24	0.27	12.5%
Coal Subtotal	2.42	2.36	2.44	2.48	2.51	2.55	2.60	0.4%
Renewable Energy[7]	1.96	1.88	1.96	2.12	2.31	2.45	2.56	1.4%
Electricity	3.52	3.52	3.61	3.86	4.13	4.37	4.57	1.1%
Delivered Energy	**27.17**	**27.01**	**28.12**	**29.54**	**31.18**	**32.57**	**33.73**	**1.0%**
Electricity Related Losses	7.68	7.78	7.92	7.97	8.22	8.27	8.40	0.3%
Total	**34.85**	**34.79**	**36.03**	**37.51**	**39.41**	**40.84**	**42.14**	**0.8%**

Table A2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Transportation								
Distillate Fuel[8]	4.55	4.64	5.14	5.60	6.00	6.31	6.58	1.5%
Jet Fuel[9]	3.27	3.31	3.80	4.36	5.10	5.69	6.27	2.8%
Motor Gasoline[2]	14.88	15.08	16.08	17.51	18.70	19.31	19.94	1.2%
Residual Fuel	0.90	0.75	0.74	0.87	1.02	1.16	1.30	2.4%
Liquefied Petroleum Gas	0.04	0.04	0.06	0.12	0.18	0.20	0.22	7.7%
Other Petroleum[10]	0.23	0.29	0.30	0.32	0.34	0.35	0.36	1.0%
Petroleum Subtotal	23.88	24.10	26.12	28.77	31.33	33.03	34.68	1.6%
Pipeline Fuel Natural Gas	0.73	0.73	0.74	0.84	0.90	0.97	1.01	1.4%
Compressed Natural Gas	0.01	0.01	0.06	0.18	0.26	0.31	0.34	14.9%
Renewable Energy (E85)[11]	0.00	0.00	0.01	0.03	0.05	0.07	0.07	24.0%
M85[12]	0.00	0.00	0.02	0.05	0.08	0.10	0.11	21.8%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	0.06	0.06	0.06	0.10	0.15	0.19	0.22	5.9%
Delivered Energy	**24.68**	**24.91**	**27.01**	**29.98**	**32.77**	**34.65**	**36.44**	**1.7%**
Electricity Related Losses	0.13	0.13	0.14	0.22	0.30	0.36	0.41	5.1%
Total	**24.80**	**25.04**	**27.15**	**30.19**	**33.07**	**35.00**	**36.85**	**1.7%**
Delivered Energy Consumption for All Sectors								
Distillate Fuel	7.06	7.20	7.53	8.00	8.42	8.76	9.04	1.0%
Kerosene	0.15	0.15	0.13	0.13	0.13	0.13	0.13	-0.7%
Jet Fuel[9]	3.27	3.31	3.80	4.36	5.10	5.69	6.27	2.8%
Liquefied Petroleum Gas	2.68	2.69	2.73	2.94	3.15	3.29	3.40	1.0%
Motor Gasoline[2]	15.11	15.32	16.32	17.78	18.99	19.61	20.26	1.2%
Petrochemical Feedstock	1.28	1.46	1.47	1.44	1.52	1.60	1.67	0.6%
Residual Fuel	1.34	1.13	1.12	1.27	1.44	1.60	1.75	1.9%
Other Petroleum[13]	4.38	4.37	4.79	4.97	5.20	5.27	5.32	0.9%
Petroleum Subtotal	35.27	35.62	37.89	40.88	43.95	45.95	47.84	1.3%
Natural Gas[6]	19.43	19.19	19.87	20.86	21.95	23.03	23.81	0.9%
Metallurgical Coal	0.85	0.79	0.78	0.70	0.63	0.58	0.53	-1.7%
Steam Coal	1.71	1.69	1.70	1.75	1.82	1.88	1.95	0.6%
Net Coal Coke Imports	0.00	0.02	0.11	0.17	0.20	0.24	0.27	12.5%
Coal Subtotal	2.56	2.50	2.59	2.63	2.65	2.70	2.75	0.4%
Renewable Energy[14]	2.58	2.48	2.58	2.76	2.98	3.15	3.29	1.2%
M85[12]	0.00	0.00	0.02	0.05	0.08	0.10	0.11	21.8%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	10.61	10.68	11.37	12.23	13.11	14.03	14.82	1.4%
Delivered Energy	**70.45**	**70.47**	**74.31**	**79.41**	**84.72**	**88.96**	**92.62**	**1.2%**
Electricity Related Losses	23.18	23.57	24.90	25.27	26.11	26.57	27.27	0.6%
Total	**93.63**	**94.04**	**99.21**	**104.68**	**110.83**	**115.53**	**119.89**	**1.1%**
Electric Generators[15]								
Distillate Fuel	0.08	0.09	0.08	0.06	0.06	0.06	0.07	-1.4%
Residual Fuel	0.68	0.77	0.97	0.30	0.21	0.19	0.17	-6.4%
Petroleum Subtotal	0.77	0.87	1.06	0.37	0.28	0.25	0.24	-5.5%
Natural Gas	3.15	3.40	3.30	5.03	6.84	8.61	9.36	4.5%
Steam Coal	18.05	18.59	20.19	20.68	21.41	22.35	23.51	1.0%
Nuclear Power	7.20	6.71	7.04	6.73	5.91	4.47	3.83	-2.4%
Renewable Energy[16]	4.23	4.35	4.24	4.35	4.47	4.63	4.88	0.5%
Electricity Imports[17]	0.39	0.33	0.44	0.34	0.31	0.28	0.28	-0.7%
Total	**33.80**	**34.25**	**36.27**	**37.50**	**39.22**	**40.60**	**42.09**	**0.9%**

Table A2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Total Energy Consumption								
Distillate Fuel	7.15	7.29	7.62	8.06	8.49	8.82	9.10	1.0%
Kerosene	0.15	0.15	0.13	0.13	0.13	0.13	0.13	-0.7%
Jet Fuel[9]	3.27	3.31	3.80	4.36	5.10	5.69	6.27	2.8%
Liquefied Petroleum Gas	2.68	2.69	2.73	2.94	3.15	3.29	3.40	1.0%
Motor Gasoline[2]	15.11	15.32	16.32	17.78	18.99	19.61	20.26	1.2%
Petrochemical Feedstock	1.28	1.46	1.47	1.44	1.52	1.60	1.67	0.6%
Residual Fuel	2.02	1.91	2.10	1.58	1.65	1.79	1.92	0.0%
Other Petroleum[13]	4.38	4.37	4.79	4.97	5.20	5.27	5.32	0.9%
Petroleum Subtotal	36.03	36.49	38.95	41.25	44.22	46.20	48.08	1.2%
Natural Gas	22.59	22.59	23.17	25.89	28.79	31.64	33.17	1.7%
Metallurgical Coal	0.85	0.79	0.78	0.70	0.63	0.58	0.53	-1.7%
Steam Coal	19.75	20.29	21.89	22.43	23.23	24.23	25.45	1.0%
Net Coal Coke Imports	0.00	0.02	0.11	0.17	0.20	0.24	0.27	12.5%
Coal Subtotal	20.60	21.09	22.78	23.31	24.06	25.05	26.26	1.0%
Nuclear Power	7.20	6.71	7.04	6.73	5.91	4.47	3.83	-2.4%
Renewable Energy[18]	6.81	6.82	6.82	7.12	7.45	7.79	8.17	0.8%
M85[12]	0.00	0.00	0.02	0.05	0.08	0.10	0.11	21.8%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity Imports[17]	0.39	0.33	0.44	0.34	0.31	0.28	0.28	-0.7%
Total	93.63	94.04	99.21	104.68	110.83	115.53	119.88	1.1%
Energy Use and Related Statistics								
Delivered Energy Use	70.45	70.47	74.31	79.41	84.72	88.96	92.62	1.2%
Total Energy Use	93.63	94.04	99.21	104.68	110.83	115.53	119.88	1.1%
Population (millions)	265.76	268.19	275.18	286.54	298.31	310.75	323.36	0.8%
Gross Domestic Product (billion 1992 dollars)	6994.76	7269.76	7830.21	8769.30	9895.50	10800.49	11680.02	2.1%
Total Carbon Emissions (million metric tons)	1460.55	1479.60	1584.67	1677.73	1789.87	1890.06	1974.88	1.3%

[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.
[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.
[4]Fuel consumption includes consumption for cogeneration.
[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 for cogeneration, both for sale to the grid and for own use.
[8]Low sulfur diesel fuel.
[9]Includes naphtha and kerosene type.
[10]Includes aviation gas and lubricants.
[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 unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[14]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 and solar thermal hot water heaters.
[15]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.
[16]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.
[17]In 1997 approximately two-thirds of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions.
[18]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 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. Figures for 1996 and 1997 may differ from published data due to internal conversion factors. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1996 natural gas lease, plant, and pipeline fuel values: Energy Information Administration (EIA), *Natural Gas Annual 1996*, DOE/EIA-0131(96) (Washington, DC, September 1997). 1996 transportation sector compressed natural gas consumption: EIA, AEO99 National Energy Modeling System run AEO99B.D100198A. 1996 and 1997 electric utility fuel consumption: EIA, *Electric Power Annual 1997, Volume 1*, DOE/EIA-0348(97)/1 (Washington, DC, July 1998). 1996 and 1997 nonutility consumption estimates: Form EIA-867, "Annual Nonutility Power Producer Report." Other 1996 values derived from: EIA, *State Energy Data Report 1995*, DOE/EIA-0214(95) (Washington, DC, December 1997), and Office of Coal, Nuclear, Electric, and Alternative Fuels estimates. Other 1997 values: EIA, *Short-Term Energy Outlook, September 1998*. Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A3. Energy Prices by Sector and Source
(1997 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Residential	13.08	13.40	12.97	13.04	12.95	12.63	12.47	-0.3%
Primary Energy[1]	6.73	7.12	6.75	6.74	6.57	6.37	6.33	-0.5%
Petroleum Products[2]	8.60	8.42	7.80	9.04	9.36	9.49	9.67	0.6%
Distillate Fuel	7.18	7.00	6.46	7.45	7.75	7.82	7.79	0.5%
Liquefied Petroleum Gas	11.76	11.61	10.51	12.00	12.22	12.38	12.85	0.4%
Natural Gas	6.28	6.80	6.53	6.24	6.00	5.78	5.74	-0.7%
Electricity	24.91	24.85	23.30	22.78	22.45	21.50	20.68	-0.8%
Commercial	13.08	13.09	12.57	12.34	12.04	11.63	11.43	-0.6%
Primary Energy[1]	5.32	5.51	5.16	5.26	5.21	5.14	5.16	-0.3%
Petroleum Products[2]	5.62	5.46	4.79	5.80	6.10	6.22	6.40	0.7%
Distillate Fuel	5.35	4.93	4.24	5.21	5.49	5.61	5.69	0.6%
Residual Fuel	3.28	3.45	2.28	2.86	3.13	3.18	3.39	-0.1%
Natural Gas[3]	5.35	5.62	5.31	5.27	5.17	5.08	5.09	-0.4%
Electricity	22.50	22.32	21.08	20.11	19.28	18.25	17.59	-1.0%
Industrial[4]	5.48	5.42	4.67	5.12	5.22	5.21	5.28	-0.1%
Primary Energy	4.08	4.01	3.24	3.82	4.02	4.13	4.27	0.3%
Petroleum Products[2]	5.77	5.60	4.08	5.11	5.38	5.53	5.79	0.1%
Distillate Fuel	5.59	5.10	4.29	5.28	5.56	5.76	5.97	0.7%
Liquefied Petroleum Gas	8.12	8.38	5.26	6.60	6.67	6.85	7.33	-0.6%
Residual Fuel	3.11	2.90	1.84	2.42	2.72	2.73	2.89	-0.0%
Natural Gas[5]	2.99	2.96	2.77	2.99	3.14	3.23	3.30	0.5%
Metallurgical Coal	1.79	1.77	1.69	1.63	1.57	1.50	1.45	-0.9%
Steam Coal	1.44	1.44	1.37	1.31	1.26	1.20	1.14	-1.0%
Electricity	13.59	13.56	13.04	12.54	11.89	11.09	10.68	-1.0%
Transportation	8.89	8.60	7.54	8.63	9.00	9.00	9.00	0.2%
Primary Energy	8.87	8.58	7.52	8.61	8.98	8.97	8.97	0.2%
Petroleum Products[2]	8.88	8.58	7.52	8.61	8.98	8.97	8.97	0.2%
Distillate Fuel[6]	9.01	8.53	7.56	8.49	8.58	8.56	8.53	-0.0%
Jet Fuel[7]	5.60	5.20	4.13	5.36	5.74	5.96	6.31	0.8%
Motor Gasoline[8]	10.00	9.70	8.67	9.85	10.40	10.43	10.40	0.3%
Residual Fuel	2.82	3.09	1.33	2.19	2.58	2.60	2.82	-0.4%
Liquid Petroleum Gas[9]	12.58	12.00	11.70	13.04	13.06	12.99	13.20	0.4%
Natural Gas[10]	6.04	6.18	6.49	6.72	7.17	7.31	7.36	0.8%
E85[11]	16.10	16.27	14.61	16.83	17.53	17.68	17.78	0.4%
M85[12]	11.18	13.25	9.83	11.91	13.02	13.10	13.22	-0.0%
Electricity	16.11	16.30	15.81	15.10	14.55	13.67	13.04	-1.0%
Average End-Use Energy	8.80	8.72	7.93	8.48	8.62	8.53	8.52	-0.1%
Primary Energy	8.46	8.35	7.49	8.13	8.31	8.24	8.23	-0.1%
Electricity	20.35	20.26	19.28	18.62	18.00	17.10	16.50	-0.9%
Electric Generators[13]								
Fossil Fuel Average	1.55	1.54	1.44	1.52	1.57	1.61	1.61	0.2%
Petroleum Products	3.36	2.94	2.32	3.29	3.89	4.05	4.33	1.7%
Distillate Fuel	4.96	4.43	3.83	4.81	5.11	5.28	5.45	0.9%
Residual Fuel	3.16	2.76	2.19	2.97	3.52	3.63	3.90	1.5%
Natural Gas	2.70	2.70	2.62	2.94	3.08	3.17	3.24	0.8%
Steam Coal	1.31	1.27	1.19	1.14	1.06	0.99	0.93	-1.3%

Table A3. Energy Prices by Sector and Source (Continued)
(1997 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Average Price to All Users[14]								
Petroleum Products[2]	7.96	7.70	6.56	7.75	8.11	8.16	8.24	0.3%
Distillate Fuel	7.95	7.51	6.73	7.71	7.88	7.91	7.94	0.2%
Jet Fuel	5.60	5.20	4.13	5.36	5.74	5.96	6.31	0.8%
Liquefied Petroleum Gas	8.82	9.01	6.35	7.77	7.88	8.03	8.46	-0.3%
Motor Gasoline[8]	10.00	9.70	8.67	9.85	10.40	10.43	10.41	0.3%
Residual Fuel	3.01	2.95	1.84	2.43	2.76	2.76	2.96	0.0%
Natural Gas	4.18	4.32	4.12	4.10	4.06	4.02	4.05	-0.3%
Coal	1.29	1.28	1.21	1.15	1.08	1.01	0.95	-1.3%
E85[11]	16.10	16.27	14.61	16.83	17.53	17.68	17.78	0.4%
M85[12]	11.18	13.25	9.83	11.91	13.02	13.10	13.22	-0.0%
Electricity	20.35	20.26	19.28	18.62	18.00	17.10	16.50	-0.9%
Non-Renewable Energy Expenditures by Sector (Billion 1997 dollars)								
Residential	138.31	138.32	138.29	142.98	147.38	150.70	154.96	0.5%
Commercial	96.98	99.87	99.57	102.66	105.54	106.71	106.97	0.3%
Industrial	115.23	113.46	101.23	114.44	122.05	127.03	133.57	0.7%
Transportation	212.93	207.85	197.85	250.95	285.93	301.75	317.40	1.9%
Total Non-Renewable Expenditures	563.45	559.50	536.94	611.03	660.89	686.18	712.90	1.1%
Transportation Renewable Expenditures	0.01	0.01	0.15	0.51	0.90	1.15	1.32	24.4%
Total Expenditures	563.45	559.51	537.09	611.53	661.79	687.33	714.22	1.1%

[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: 1996 and 1997 figures may differ from published data due to internal rounding.
Sources: 1996 prices for gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1996. Online. http://www.eia.doe.gov/oil-gas/pmal/pmaframe.html (August 1, 1998).* 1997 prices for gasoline, distillate, and jet fuel are based on prices in various issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380 (97/03-98/04) (Washington, DC, 1997-98). 1996 and 1997 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditures Report: 1995,* DOE/EIA-0376(95) (Washington, DC, August, 1998). 1996 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Annual 1996,* DOE/EIA-0131(96) (Washington, DC, September 1997). 1996 electric generators natural gas delivered prices: Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 1996 and 1997 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1991.* 1997 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly,* DOE/EIA-0130(98/06) (Washington, DC, June 1998). Other 1997 natural gas delivered prices: EIA, AEO99 National Energy Modeling System run AEO99B.D100198A. Values for 1996 and 1997 coal prices have been estimated from EIA, *State Energy Price and Expenditures Report: 1995,* DOE/EIA-0376(95) (Washington, DC, August, 1998) by use of consumption quantities aggregated from EIA, *State Energy Data Report 1995* , DOE/EIA-0214(95) (Washington, DC, December 1997) and the *Coal Industry Annual 1997,* DOE/EIA-0584(97) (Washington, DC, November 1998). 1996 residential electricity prices derived from EIA, *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). 1996 and 1997 electricity prices for commercial, industrial, and transportation: EIA, AEO99 National Energy Modeling System run AEO99B.D100198A. **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A4. Residential Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Key Indicators								
Households (millions)								
Single-Family	69.34	70.18	72.80	76.89	81.13	85.30	89.35	1.1%
Multifamily	24.77	25.00	25.70	27.02	28.71	30.42	31.88	1.1%
Mobile Homes	5.98	6.13	6.52	7.05	7.64	8.24	8.79	1.6%
Total	**100.10**	**101.31**	**105.01**	**110.96**	**117.48**	**123.96**	**130.02**	**1.1%**
Average House Square Footage	**1649**	**1654**	**1669**	**1688**	**1703**	**1715**	**1727**	**0.2%**
Energy Intensity (million Btu consumed per household)								
Delivered Energy Consumption	111.73	107.80	107.25	104.28	102.14	101.38	100.58	-0.3%
Electricity Related Losses	80.58	79.65	83.58	80.15	77.52	75.34	75.16	-0.3%
Total Energy Consumption	192.31	187.45	190.82	184.43	179.66	176.72	175.74	-0.3%
Delivered Energy Consumption by Fuel								
Electricity								
Space Heating	0.46	0.44	0.45	0.47	0.47	0.49	0.51	0.7%
Space Cooling	0.48	0.46	0.50	0.52	0.55	0.58	0.60	1.2%
Water Heating	0.36	0.35	0.36	0.37	0.37	0.38	0.40	0.6%
Refrigeration	0.41	0.39	0.37	0.32	0.29	0.27	0.28	-1.5%
Cooking	0.13	0.13	0.14	0.14	0.15	0.16	0.17	1.2%
Clothes Dryers	0.19	0.19	0.20	0.21	0.22	0.24	0.25	1.3%
Freezers	0.13	0.12	0.11	0.08	0.07	0.07	0.07	-2.3%
Lighting	0.35	0.34	0.36	0.38	0.40	0.43	0.46	1.3%
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.04	0.04	1.3%
Dishwashers[1]	0.05	0.05	0.05	0.05	0.05	0.06	0.06	1.0%
Color Televisions	0.21	0.21	0.25	0.29	0.29	0.31	0.33	1.9%
Personal Computers	0.02	0.02	0.02	0.03	0.04	0.04	0.05	4.3%
Furnace Fans	0.09	0.09	0.10	0.11	0.12	0.13	0.14	2.0%
Other Uses[2]	0.78	0.83	1.08	1.32	1.52	1.74	1.95	3.8%
Delivered Energy	**3.69**	**3.66**	**4.01**	**4.31**	**4.57**	**4.93**	**5.31**	**1.6%**
Natural Gas								
Space Heating	3.77	3.58	3.61	3.67	3.80	3.96	4.07	0.6%
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.01	7.2%
Water Heating	1.31	1.27	1.29	1.31	1.38	1.45	1.50	0.7%
Cooking	0.16	0.16	0.16	0.17	0.17	0.18	0.19	0.8%
Clothes Dryers	0.05	0.05	0.05	0.05	0.06	0.06	0.06	1.2%
Other Uses[3]	0.09	0.09	0.10	0.10	0.11	0.11	0.12	1.2%
Delivered Energy	**5.38**	**5.15**	**5.21**	**5.31**	**5.52**	**5.77**	**5.94**	**0.6%**
Distillate								
Space Heating	0.83	0.84	0.77	0.69	0.64	0.60	0.57	-1.7%
Water Heating	0.10	0.10	0.09	0.09	0.09	0.09	0.09	-0.5%
Other Uses[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.1%
Delivered Energy	**0.93**	**0.94**	**0.87**	**0.79**	**0.73**	**0.69**	**0.65**	**-1.6%**
Liquefied Petroleum Gas								
Space Heating	0.32	0.32	0.32	0.32	0.31	0.30	0.28	-0.5%
Water Heating	0.07	0.07	0.08	0.08	0.08	0.08	0.07	0.2%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.0%
Other Uses[3]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	1.1%
Delivered Energy	**0.43**	**0.43**	**0.44**	**0.44**	**0.43**	**0.42**	**0.40**	**-0.3%**
Marketed Renewables (wood)[5]	0.61	0.60	0.60	0.61	0.62	0.64	0.65	0.4%
Other Fuels[6]	0.14	0.15	0.13	0.13	0.12	0.12	0.12	-1.0%

Table A4. Residential Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Delivered Energy Consumption by End-Use								
Space Heating	6.13	5.93	5.89	5.88	5.97	6.10	6.20	0.2%
Space Cooling	0.48	0.46	0.50	0.52	0.55	0.58	0.61	1.2%
Water Heating	1.84	1.79	1.82	1.85	1.91	2.00	2.06	0.6%
Refrigeration	0.41	0.39	0.37	0.32	0.29	0.27	0.28	-1.5%
Cooking	0.33	0.33	0.33	0.35	0.36	0.38	0.40	0.9%
Clothes Dryers	0.24	0.24	0.25	0.26	0.27	0.29	0.32	1.3%
Freezers	0.13	0.12	0.11	0.08	0.07	0.07	0.07	-2.3%
Lighting	0.35	0.34	0.36	0.38	0.40	0.43	0.46	1.3%
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.04	0.04	1.3%
Dishwashers	0.05	0.05	0.05	0.05	0.05	0.06	0.06	1.0%
Color Televisions	0.21	0.21	0.25	0.29	0.29	0.31	0.33	1.9%
Personal Computers	0.02	0.02	0.02	0.03	0.04	0.04	0.05	4.3%
Furnace Fans	0.09	0.09	0.10	0.11	0.12	0.13	0.14	2.0%
Other Uses[7]	0.89	0.93	1.19	1.43	1.63	1.86	2.08	3.5%
Delivered Energy	**11.18**	**10.92**	**11.26**	**11.57**	**12.00**	**12.57**	**13.08**	**0.8%**
Electricity Related Losses	**8.07**	**8.07**	**8.78**	**8.89**	**9.11**	**9.34**	**9.77**	**0.8%**
Total Energy Consumption by End-Use								
Space Heating	7.13	6.90	6.88	6.84	6.91	7.03	7.14	0.2%
Space Cooling	1.52	1.47	1.59	1.60	1.63	1.68	1.71	0.7%
Water Heating	2.63	2.57	2.61	2.60	2.65	2.73	2.80	0.4%
Refrigeration	1.32	1.26	1.17	0.97	0.85	0.79	0.78	-2.0%
Cooking	0.62	0.62	0.64	0.65	0.67	0.69	0.72	0.6%
Clothes Dryers	0.66	0.65	0.68	0.69	0.71	0.74	0.78	0.8%
Freezers	0.42	0.39	0.34	0.26	0.22	0.20	0.20	-2.9%
Lighting	1.10	1.09	1.14	1.17	1.20	1.25	1.30	0.8%
Clothes Washers	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.8%
Dishwashers	0.15	0.15	0.15	0.15	0.16	0.16	0.17	0.5%
Color Televisions	0.67	0.69	0.81	0.88	0.88	0.89	0.94	1.4%
Personal Computers	0.06	0.06	0.08	0.09	0.11	0.12	0.14	3.7%
Furnace Fans	0.28	0.28	0.31	0.32	0.35	0.37	0.40	1.4%
Other Uses[7]	2.60	2.77	3.56	4.15	4.65	5.15	5.65	3.2%
Total	**19.25**	**18.99**	**20.04**	**20.47**	**21.11**	**21.91**	**22.85**	**0.8%**
Non-Marketed Renewables								
Geothermal[8]	0.01	0.01	0.01	0.01	0.02	0.02	0.04	6.2%
Solar[9]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.4%
Total	**0.02**	**0.02**	**0.02**	**0.02**	**0.03**	**0.03**	**0.05**	**3.8%**

[1]Does not include electronic 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 1993.*
[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.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Source: 1996 and 1997: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A5. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Key Indicators								
Total Floor Space (billion square feet)								
Surviving	58.0	58.8	61.3	64.8	68.0	70.7	71.9	0.9%
New Additions	1.5	1.6	1.6	1.5	1.5	1.3	1.0	-2.0%
Total	**59.5**	**60.3**	**62.9**	**66.3**	**69.5**	**72.0**	**72.9**	**0.8%**
Energy Consumption Intensity (thousand Btu per square foot)								
Delivered Energy Consumption	124.6	126.5	126.0	125.6	126.2	127.5	128.5	0.1%
Electricity Related Losses	122.9	125.9	128.4	123.6	122.0	119.5	119.1	-0.2%
Total Energy Consumption	247.5	252.4	254.3	249.1	248.1	247.0	247.5	-0.1%
Delivered Energy Consumption by Fuel								
Electricity								
Space Heating	0.14	0.13	0.13	0.13	0.12	0.12	0.12	-0.5%
Space Cooling	0.34	0.34	0.35	0.35	0.35	0.36	0.36	0.3%
Water Heating	0.07	0.07	0.07	0.07	0.07	0.06	0.06	-0.5%
Ventilation	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.5%
Cooking	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.9%
Lighting	1.21	1.22	1.25	1.25	1.28	1.32	1.32	0.3%
Refrigeration	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.7%
Office Equipment (PC)	0.10	0.12	0.14	0.17	0.20	0.22	0.24	3.2%
Office Equipment (non-PC)	0.28	0.29	0.32	0.37	0.42	0.48	0.53	2.6%
Other Uses[1]	0.84	0.91	1.05	1.23	1.41	1.57	1.69	2.7%
Delivered Energy	**3.35**	**3.44**	**3.69**	**3.97**	**4.26**	**4.54**	**4.72**	**1.4%**
Natural Gas[2]								
Space Heating	1.36	1.31	1.31	1.33	1.37	1.41	1.40	0.3%
Space Cooling	0.01	0.01	0.02	0.02	0.03	0.03	0.03	2.9%
Water Heating	0.62	0.62	0.64	0.66	0.69	0.72	0.73	0.7%
Cooking	0.23	0.23	0.25	0.26	0.28	0.29	0.30	1.1%
Other Uses[3]	1.02	1.20	1.33	1.40	1.47	1.52	1.54	1.1%
Delivered Energy	**3.24**	**3.37**	**3.55**	**3.68**	**3.84**	**3.97**	**4.00**	**0.7%**
Distillate								
Space Heating	0.20	0.21	0.23	0.22	0.20	0.19	0.18	-0.6%
Water Heating	0.05	0.05	0.05	0.05	0.05	0.04	0.04	-0.8%
Other Uses[4]	0.23	0.23	0.10	0.09	0.09	0.10	0.09	-3.9%
Delivered Energy	**0.48**	**0.49**	**0.38**	**0.36**	**0.34**	**0.33**	**0.32**	**-1.9%**
Other Fuels[5]	**0.34**	**0.32**	**0.30**	**0.31**	**0.32**	**0.33**	**0.33**	**0.1%**
Marketed Renewable Fuels								
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.0%
Delivered Energy	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**1.0%**
Delivered Energy Consumption by End-Use								
Space Heating	1.70	1.65	1.67	1.68	1.70	1.72	1.70	0.1%
Space Cooling	0.36	0.35	0.37	0.37	0.38	0.39	0.39	0.4%
Water Heating	0.74	0.74	0.76	0.78	0.80	0.82	0.83	0.5%
Ventilation	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.5%
Cooking	0.25	0.25	0.27	0.28	0.30	0.31	0.32	1.0%
Lighting	1.21	1.22	1.25	1.25	1.28	1.32	1.32	0.3%
Refrigeration	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.7%
Office Equipment (PC)	0.10	0.12	0.14	0.17	0.20	0.22	0.24	3.2%
Office Equipment (non-PC)	0.28	0.29	0.32	0.37	0.42	0.48	0.53	2.6%
Other Uses[6]	2.44	2.67	2.79	3.04	3.30	3.53	3.65	1.4%
Delivered Energy	**7.42**	**7.63**	**7.92**	**8.32**	**8.77**	**9.18**	**9.37**	**0.9%**

Table A5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Electricity Related Losses	7.31	7.59	8.07	8.19	8.48	8.60	8.68	0.6%
Total Energy Consumption by End-Use								
Space Heating	1.99	1.94	1.95	1.94	1.95	1.95	1.91	-0.1%
Space Cooling	1.10	1.10	1.14	1.10	1.09	1.07	1.05	-0.2%
Water Heating	0.89	0.89	0.91	0.92	0.94	0.95	0.94	0.2%
Ventilation	0.52	0.53	0.54	0.54	0.55	0.54	0.53	-0.0%
Cooking	0.30	0.30	0.31	0.33	0.34	0.35	0.35	0.7%
Lighting	3.84	3.90	3.97	3.85	3.83	3.81	3.74	-0.2%
Refrigeration	0.57	0.58	0.60	0.60	0.60	0.60	0.60	0.1%
Office Equipment (PC)	0.33	0.37	0.46	0.54	0.58	0.63	0.68	2.7%
Office Equipment (non-PC)	0.89	0.93	1.02	1.13	1.26	1.38	1.49	2.1%
Other Uses[6]	4.28	4.68	5.09	5.58	6.11	6.51	6.76	1.6%
Total	**14.73**	**15.22**	**15.99**	**16.51**	**17.24**	**17.78**	**18.05**	**0.7%**
Non-Marketed Renewable Fuels								
Solar[7]	0.01	0.02	0.02	0.03	0.03	0.04	0.04	3.8%
Total	**0.01**	**0.02**	**0.02**	**0.03**	**0.03**	**0.04**	**0.04**	**3.8%**

[1]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, and medical equipment.
[2]Excludes estimated consumption from independent power producers.
[3]Includes miscellaneous uses, such as district services, pumps, emergency electric generators, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, district services, and emergency electric generators.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes primary energy displaced by solar thermal space heating and water heating.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Consumption values of 0.00 are value that round to 0.00 because they are less than 0.005.
Source: 1996 and 1997 Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). Projections: EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Key Indicators								
Value of Gross Output (billion 1987 dollars)								
Manufacturing	3045	3170	3305	3717	4224	4613	4986	2.0%
Nonmanufacturing	784	812	849	922	1013	1081	1145	1.5%
Total	**3829**	**3982**	**4153**	**4639**	**5237**	**5693**	**6131**	**1.9%**
Energy Prices (1997 dollars per million Btu)								
Electricity	13.59	13.56	13.04	12.54	11.89	11.09	10.68	-1.0%
Natural Gas	2.99	2.96	2.77	2.99	3.14	3.23	3.30	0.5%
Steam Coal	1.44	1.44	1.37	1.31	1.26	1.20	1.14	-1.0%
Residual Oil	3.11	2.90	1.84	2.42	2.72	2.73	2.89	-0.0%
Distillate Oil	5.59	5.10	4.29	5.28	5.56	5.76	5.97	0.7%
Liquefied Petroleum Gas	8.12	8.38	5.26	6.60	6.67	6.85	7.33	-0.6%
Motor Gasoline	9.98	9.69	8.68	9.87	10.42	10.47	10.46	0.3%
Metallurgical Coal	1.79	1.77	1.69	1.63	1.57	1.50	1.45	-0.9%
Energy Consumption								
Consumption[1]								
Purchased Electricity	3.52	3.52	3.61	3.86	4.13	4.37	4.57	1.1%
Natural Gas[2]	10.06	9.92	10.31	10.85	11.43	12.02	12.52	1.0%
Steam Coal	1.57	1.56	1.56	1.61	1.67	1.73	1.80	0.6%
Metallurgical Coal and Coke[3]	0.85	0.81	0.88	0.87	0.84	0.82	0.80	-0.0%
Residual Fuel	0.30	0.28	0.29	0.32	0.33	0.35	0.36	1.1%
Distillate	1.11	1.13	1.14	1.26	1.35	1.42	1.48	1.2%
Liquefied Petroleum Gas	2.14	2.14	2.15	2.30	2.45	2.58	2.69	1.0%
Petrochemical Feedstocks	1.28	1.46	1.47	1.44	1.52	1.60	1.67	0.6%
Other Petroleum[4]	4.39	4.33	4.73	4.92	5.16	5.23	5.29	0.9%
Renewables[5]	1.96	1.88	1.96	2.12	2.31	2.45	2.56	1.4%
Delivered Energy	**27.17**	**27.01**	**28.12**	**29.54**	**31.18**	**32.57**	**33.73**	**1.0%**
Electricity Related Losses	7.68	7.78	7.92	7.97	8.22	8.27	8.40	0.3%
Total	**34.85**	**34.79**	**36.03**	**37.51**	**39.41**	**40.84**	**42.14**	**0.8%**
Consumption per Unit of Output[1] (thousand Btu per 1987 dollars)								
Purchased Electricity	0.92	0.88	0.87	0.83	0.79	0.77	0.75	-0.7%
Natural Gas[2]	2.63	2.49	2.48	2.34	2.18	2.11	2.04	-0.9%
Steam Coal	0.41	0.39	0.38	0.35	0.32	0.30	0.29	-1.2%
Metallurgical Coal and Coke[3]	0.22	0.20	0.21	0.19	0.16	0.14	0.13	-1.9%
Residual Fuel	0.08	0.07	0.07	0.07	0.06	0.06	0.06	-0.8%
Distillate	0.29	0.28	0.28	0.27	0.26	0.25	0.24	-0.7%
Liquefied Petroleum Gas	0.56	0.54	0.52	0.50	0.47	0.45	0.44	-0.9%
Petrochemical Feedstocks	0.33	0.37	0.35	0.31	0.29	0.28	0.27	-1.3%
Other Petroleum[4]	1.15	1.09	1.14	1.06	0.98	0.92	0.86	-1.0%
Renewables[5]	0.51	0.47	0.47	0.46	0.44	0.43	0.42	-0.5%
Delivered Energy	**7.09**	**6.78**	**6.77**	**6.37**	**5.95**	**5.72**	**5.50**	**-0.9%**
Electricity Related Losses	2.01	1.95	1.91	1.72	1.57	1.45	1.37	-1.5%
Total	**9.10**	**8.74**	**8.68**	**8.09**	**7.52**	**7.17**	**6.87**	**-1.0%**

[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.
Sources: 1996 prices for gasoline and distillate are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1996.* Online. http:/www.eia.doe.gov/oil-gas/ pmal/pmaframe.html (August 1, 1998). 1997 prices for gasoline and distillate are based on prices in various issues of EIA, *Petroleum Marketing Monthly,* DOE/EIA-0380 (97/03-98/04) (Washington, DC, 1997-98). 1996 and 1997 coal prices: EIA, *Monthly Energy Review,* DOE/EIA-0035(98/08) (Washington, DC, August 1998). 1996 and 1997 electricity prices: EIA, AEO99 National Energy Modeling System run AEO99B.D100198A. Other 1996 values and other 1997 prices derived from EIA, *State Energy Data Report 1995* , DOE/EIA-0214(95) (Washington, DC, December 1997). Other 1997 values: EIA, *Short-Term Energy Outlook, September 1998.* Online. http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	Reference Case 1996	1997	2000	2005	2010	2015	2020	Annual Growth 1997-2020 (percent)
Key Indicators								
Level of Travel (billions)								
Light-Duty Vehicles <8,500 lbs. (VMT)	2203	2301	2388	2634	2887	3097	3303	1.6%
Commercial Light Trucks (VMT)[1]	68	69	74	82	90	97	104	1.8%
Freight Trucks >10,000 lbs. (VMT)	161	177	200	222	243	258	270	1.8%
Air (seat miles available)	1000	1049	1216	1479	1814	2127	2462	3.8%
Rail (ton miles traveled)	1311	1229	1305	1411	1519	1620	1719	1.5%
Marine (ton miles traveled)	747	757	779	826	879	928	964	1.1%
Energy Efficiency Indicators								
New Light-Duty Vehicle (miles per gallon)[2]	24.2	24.0	23.5	24.3	25.4	26.1	26.5	0.4%
New Car (miles per gallon)[2]	27.9	27.9	28.3	30.1	31.6	32.1	32.1	0.6%
New Light Truck (miles per gallon)[2]	20.2	20.2	19.4	19.9	20.7	21.5	22.0	0.4%
Light-Duty Fleet (miles per gallon)[3]	20.4	20.5	20.3	20.1	20.3	20.9	21.4	0.2%
New Commercial Light Truck (MPG)[1]	20.3	19.9	18.7	19.1	19.8	20.5	21.0	0.2%
Stock Commercial Light Truck (MPG)[1]	14.5	14.6	14.7	14.8	15.0	15.2	15.6	0.3%
Aircraft Efficiency (seat miles per gallon)	50.6	51.0	52.1	53.9	55.7	57.6	59.6	0.7%
Freight Truck Efficiency (miles per gallon)	5.2	5.6	5.7	5.9	6.1	6.2	6.3	0.5%
Rail Efficiency (ton miles per thousand Btu)	2.7	2.7	2.8	2.8	2.9	3.0	3.1	0.5%
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.4	2.4	2.5	2.5	2.6	2.7	2.7	0.5%
Energy Use by Mode (quadrillion Btu)								
Light-Duty Vehicles	13.75	13.94	15.03	16.72	18.10	18.85	19.60	1.5%
Commercial Light Trucks[1]	0.59	0.59	0.63	0.69	0.76	0.80	0.84	1.5%
Freight Trucks[4]	4.11	4.24	4.66	5.01	5.30	5.51	5.68	1.3%
Air	3.32	3.35	3.84	4.41	5.17	5.77	6.38	2.8%
Rail[5]	0.56	0.53	0.55	0.58	0.61	0.64	0.66	1.0%
Marine[6]	1.43	1.28	1.30	1.45	1.64	1.81	1.98	1.9%
Pipeline Fuel	0.73	0.73	0.74	0.84	0.90	0.97	1.01	1.4%
Other[7]	0.19	0.24	0.26	0.28	0.30	0.31	0.32	1.2%
Total	24.68	24.91	27.01	29.98	32.77	34.65	36.44	1.7%

[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 passenger rail.
[6]Includes military residual fuel use and recreation boats.
[7]Includes lubricants and aviation gasoline.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Lbs. = Pounds.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1996 pipeline fuel consumption: Energy Information Administration (EIA), *Natural Gas Annual 1996*, DOE/EIA-0131(96) (Washington, DC, September 1997). Other 1996 values: Federal Highway Administration, *Highway Statistics 1996* (Washington, DC, 1996); Oak Ridge National Laboratory, *Transportation Energy Data Book: 12, 13, 14, 15, 16, and 17*, (Oak Ridge, TN, August 1997); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance*, (Washington, DC, February 1997); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Dept. of Commerce, Bureau of the Census, "Truck Inventory and Use Survey", TC92-T-52, (Washington DC, May 1995); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives To Traditional Transportation Fuels 1996*, DOE/EIA-0585(96) (Washington, DC, December 1997); and EIA, *State Energy Data Report 1995*, DOE/EIA-0214(95) (Washington, DC, December 1997). 1997: U.S. Department of Transportation, Bureau of Transportation Statistics, *Air Carrier Statistics Monthly, December 1997/1996*, (Washington, DC, 1997); EIA, *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998); EIA, *Fuel Oil and Kerosene Sales 1997*, DOE/EIA-0535(97) (Washington, DC, August 1998); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A8. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Generation by Fuel Type								
Electric Generators[1]								
Coal	1745	1796	1931	1976	2046	2151	2298	1.1%
Petroleum	72	82	101	36	28	26	24	-5.2%
Natural Gas	278	299	338	649	919	1213	1349	6.8%
Nuclear Power	675	629	659	630	554	419	359	-2.4%
Pumped Storage	-2	-3	-1	-1	-1	-1	-1	-5.0%
Renewable Sources[2]	379	389	375	381	388	401	420	0.3%
Total	**3147**	**3192**	**3403**	**3672**	**3934**	**4208**	**4450**	**1.5%**
Non-Utility Generation for Own Use	10	10	10	9	9	9	9	-0.4%
Cogenerators[3]								
Coal	60	60	58	57	55	55	54	-0.4%
Petroleum	10	10	8	7	7	7	7	-1.3%
Natural Gas	209	210	210	214	221	230	233	0.4%
Other Gaseous Fuels[4]	4	4	5	5	5	5	5	1.2%
Renewable Sources[2]	41	41	48	52	57	60	63	1.9%
Other[5]	4	4	4	4	4	4	4	0.2%
Total	**328**	**328**	**334**	**340**	**350**	**362**	**367**	**0.5%**
Sales to Utilities	183	183	178	179	180	182	183	-0.0%
Generation for Own Use	145	146	156	161	169	180	184	1.0%
Net Imports[6]	**38**	**32**	**43**	**33**	**30**	**27**	**27**	**-0.7%**
Electricity Sales by Sector								
Residential	1082	1072	1175	1262	1341	1446	1557	1.6%
Commercial	981	1008	1081	1162	1247	1332	1383	1.4%
Industrial	1030	1033	1059	1130	1211	1280	1339	1.1%
Transportation	17	17	18	31	44	55	65	5.9%
Total	**3111**	**3130**	**3333**	**3585**	**3843**	**4113**	**4345**	**1.4%**
End-Use Prices (1997 cents per kilowatthour)[7]								
Residential	8.5	8.5	8.0	7.8	7.7	7.3	7.1	-0.8%
Commercial	7.7	7.6	7.2	6.9	6.6	6.2	6.0	-1.0%
Industrial	4.6	4.6	4.4	4.3	4.1	3.8	3.6	-1.0%
Transportation	5.5	5.6	5.4	5.2	5.0	4.7	4.4	-1.0%
All Sectors Average	**6.9**	**6.9**	**6.6**	**6.4**	**6.1**	**5.8**	**5.6**	**-0.9%**
Emissions (million short tons)								
Sulfur Dioxide	12.31	12.79	11.38	10.19	9.06	8.95	8.95	-1.5%
Nitrogen Oxide	5.88	5.89	4.62	3.90	4.06	4.21	4.29	-1.4%

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[2]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[3]Cogenerators produce electricity and other useful thermal energy. Includes sales to utilities and generation for own use.
[4]Other gaseous fuels include refinery and still gas.
[5]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[6]In 1997 approximately two-thirds of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions.
[7]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1996 and 1997 commercial and transportation sales derived from: Total transportation plus commercial sales come from Energy Information Administration (EIA), *State Energy Data Report 1995*, DOE/EIA-0214(95) (Washington, DC, December 1997), but individual sectors do not match because sales taken from commercial and placed in transportation, according to Oak Ridge National Laboratories, *Transportation Energy Data Book 17* (July 1996) which indicates the transportation value should be higher. 1996 and 1997 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: EIA, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). 1996 and 1997 residential electricity prices derived from EIA, *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **1996 and 1997 electricity prices for commercial, industrial, and transportation; emissions; and projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	Reference Case 1996	1997	2000	2005	2010	2015	2020	Annual Growth 1997-2020 (percent)
Electric Generators[2]								
Capability								
Coal Steam	304.7	304.7	305.4	305.2	308.9	316.2	333.0	0.4%
Other Fossil Steam[3]	137.8	138.7	138.4	101.6	80.2	79.5	75.7	-2.6%
Combined Cycle	15.4	16.4	27.1	88.7	126.0	175.9	211.5	11.8%
Combustion Turbine/Diesel	70.1	78.2	98.9	141.1	151.0	174.9	186.7	3.9%
Nuclear Power	100.7	99.0	94.8	87.4	74.2	56.4	48.9	-3.0%
Pumped Storage	19.6	19.6	21.5	21.5	21.5	21.5	21.5	0.4%
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4%
Renewable Sources[4]	87.7	87.9	89.7	91.1	92.1	93.9	96.7	0.4%
Total	**736.0**	**744.5**	**775.9**	**836.6**	**853.9**	**918.4**	**974.0**	**1.2%**
Cumulative Planned Additions[5]								
Coal Steam	0.1	0.1	0.9	1.4	1.4	1.4	1.4	12.6%
Other Fossil Steam[3]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	N/A
Combined Cycle	0.5	0.7	2.0	5.3	5.3	5.3	5.3	9.2%
Combustion Turbine/Diesel	1.1	1.5	6.7	18.6	18.6	18.6	18.6	11.7%
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	2.0	2.0	2.0	2.0	2.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.1%
Renewable Sources[4]	0.1	0.1	1.6	2.5	2.8	2.8	2.8	16.1%
Total	**1.7**	**2.5**	**13.3**	**29.8**	**30.1**	**30.2**	**30.2**	**11.5%**
Cumulative Unplanned Additions[5]								
Coal Steam	0.0	0.0	0.0	1.5	5.6	13.5	31.0	N/A
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combined Cycle	0.0	0.0	9.4	67.7	105.0	155.0	190.5	N/A
Combustion Turbine/Diesel	13.3	20.2	35.7	68.8	81.1	108.2	120.2	8.1%
Nuclear Power	0.0	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	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[4]	0.8	0.8	0.9	1.4	2.3	4.3	7.3	10.0%
Total	**14.1**	**21.0**	**46.0**	**139.4**	**194.0**	**281.0**	**348.9**	**13.0%**
Cumulative Total Additions	**15.8**	**23.5**	**59.3**	**169.2**	**224.2**	**311.1**	**379.0**	**12.9%**
Cumulative Retirements[6]	**12.7**	**14.8**	**19.4**	**68.7**	**105.7**	**128.3**	**140.6**	**10.3%**

Table A9. Electricity Generating Capability (Continued)
(Thousand Megawatts)

Net Summer Capability[1]	Reference Case 1996	1997	2000	2005	2010	2015	2020	Annual Growth 1997-2020 (percent)
Cogenerators[7]								
Capability								
Coal	9.4	9.4	9.8	9.8	9.9	9.9	10.0	0.3%
Petroleum	1.4	1.4	1.4	1.5	1.5	1.5	1.5	0.2%
Natural Gas	32.1	33.4	34.8	35.3	36.2	37.3	37.7	0.5%
Other Gaseous Fuels	0.6	0.6	0.9	0.9	0.9	0.9	0.9	1.5%
Renewable Sources[4]	6.8	6.9	7.5	7.8	8.2	8.5	8.8	1.1%
Other	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.9%
Total	**50.5**	**51.8**	**54.6**	**55.4**	**56.8**	**58.3**	**59.1**	**0.6%**
Cumulative Additions[5]	**18.9**	**20.2**	**23.0**	**23.8**	**25.1**	**26.7**	**27.4**	**1.3%**

[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]Cumulative additions after December 31, 1996. Non-zero utility planned additions in 1996 indicate units operational in 1996 but not supplying power to the grid.
[6]Cumulative total retirements from 1990.
[7]Nameplate capacity is reported for nonutilities on Form EIA-867, "Annual Nonutility Power Producer Report." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.
N/A = Not applicable.
Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO99. Net summer capacity is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recent data available as of July 1, 1998. Therefore, capacity estimates may differ from other Energy Information Administration sources.
Sources: 1996 and 1997 net summer capability at electric utilities and planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report." Net summer capability for nonutilities and cogeneration in 1996 and 1997 and planned additions estimated based on EIA, Form EIA-867, "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	Reference Case							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Interregional Electricity Trade								
Gross Domestic Firm Power Sales	173.4	190.3	167.9	152.3	148.6	148.6	148.6	-1.1%
Gross Domestic Economy Sales	65.2	87.6	78.5	78.3	67.2	78.4	83.9	-0.2%
Gross Domestic Trade	**238.6**	**277.9**	**246.4**	**230.7**	**215.8**	**227.0**	**232.5**	**-0.8%**
Gross Domestic Firm Power Sales (million 1997 dollars)	8148.5	8942.1	7890.5	7158.7	6983.5	6983.5	6983.5	-1.1%
Gross Domestic Economy Sales (million 1997 dollars)	1557.6	2186.7	1705.6	1848.6	1730.9	1843.5	1839.1	-0.7%
Gross Domestic Sales (million 1997 dollars)	**9706.1**	**11128.9**	**9596.0**	**9007.3**	**8714.5**	**8827.0**	**8822.6**	**-1.0%**
International Electricity Trade								
Firm Power Imports From Canada and Mexico[1]	26.1	23.9	36.0	19.3	19.3	19.3	19.3	-0.9%
Economy Imports From Canada and Mexico[1]	20.7	18.0	22.2	34.7	32.8	29.9	29.6	2.2%
Gross Imports From Canada and Mexico[1]	**46.8**	**42.0**	**58.1**	**54.0**	**52.2**	**49.2**	**49.0**	**0.7%**
Firm Power Exports To Canada and Mexico	2.8	4.7	8.9	14.1	14.1	14.1	14.1	4.9%
Economy Exports To Canada and Mexico	6.4	5.3	6.4	7.0	7.7	7.7	7.7	1.6%
Gross Exports To Canada and Mexico	**9.3**	**10.0**	**15.3**	**21.1**	**21.8**	**21.8**	**21.8**	**3.4%**

[1]Historically electric imports were primarily from renewable resources, principally hydroelectric.

Note: Totals may not equal sum of components due to independent rounding. 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: 1996 and 1997 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1996 and 1997 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 1996 and 1997 Firm/economy share: National Energy Board, *Annual Report 1993*. 1996 and 1997 Planned interregional and international firm power sales: DOE Form IE-411, "Coordinated Bulk Power Supply Program Report," April 1995. **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Crude Oil								
Domestic Crude Production[1]	6.47	6.45	6.29	5.82	5.59	5.34	4.96	-1.1%
Alaska	1.40	1.30	1.19	0.97	0.78	0.61	0.49	-4.1%
Lower 48 States	5.07	5.15	5.10	4.84	4.81	4.72	4.47	-0.6%
Net Imports	7.40	8.12	8.94	9.86	10.97	11.46	11.97	1.7%
Gross Imports	7.51	8.23	9.02	9.92	11.02	11.50	11.99	1.7%
Exports	0.11	0.11	0.08	0.06	0.04	0.03	0.02	-8.0%
Other Crude Supply[2]	0.33	0.09	0.00	0.00	0.00	0.00	0.00	N/A
Total Crude Supply	**13.87**	**14.57**	**15.23**	**15.68**	**16.56**	**16.80**	**16.94**	**0.7%**
Natural Gas Plant Liquids	**1.83**	**1.82**	**1.79**	**1.98**	**2.15**	**2.34**	**2.45**	**1.3%**
Other Inputs[3]	**0.37**	**0.28**	**0.28**	**0.29**	**0.31**	**0.35**	**0.36**	**1.2%**
Refinery Processing Gain[4]	**0.84**	**0.85**	**0.85**	**0.88**	**0.90**	**0.89**	**0.89**	**0.2%**
Net Product Imports[5]	**1.10**	**1.04**	**1.71**	**2.31**	**2.73**	**3.30**	**4.00**	**6.0%**
Gross Refined Product Imports[6]	1.55	1.52	2.14	2.72	3.12	3.59	4.26	4.6%
Unfinished Oil Imports	0.37	0.35	0.43	0.50	0.54	0.61	0.68	2.9%
Ether Imports	0.05	0.06	0.03	0.01	0.02	0.02	0.00	-14.4%
Exports	0.87	0.90	0.89	0.92	0.96	0.93	0.94	0.2%
Total Primary Supply[7]	**18.00**	**18.55**	**19.87**	**21.13**	**22.65**	**23.67**	**24.64**	**1.2%**
Refined Petroleum Products Supplied								
Motor Gasoline[8]	7.88	7.99	8.59	9.37	10.01	10.34	10.69	1.3%
Jet Fuel[9]	1.58	1.60	1.83	2.11	2.46	2.75	3.03	2.8%
Distillate Fuel[10]	3.36	3.43	3.58	3.79	3.99	4.15	4.28	1.0%
Residual Fuel	0.88	0.83	0.91	0.69	0.72	0.78	0.83	0.0%
Other[11]	4.68	4.77	4.99	5.21	5.51	5.68	5.82	0.9%
Total	**18.39**	**18.62**	**19.91**	**21.16**	**22.69**	**23.71**	**24.66**	**1.2%**
Refined Petroleum Products Supplied								
Residential and Commercial	1.17	1.18	1.08	1.03	0.99	0.96	0.92	-1.0%
Industrial[12]	4.87	4.92	5.14	5.39	5.70	5.90	6.07	0.9%
Transportation	12.02	12.14	13.23	14.59	15.88	16.73	17.56	1.6%
Electric Generators[13]	0.34	0.38	0.46	0.16	0.12	0.11	0.11	-5.4%
Total	**18.39**	**18.62**	**19.91**	**21.16**	**22.69**	**23.71**	**24.66**	**1.2%**
Discrepancy[14]	**-0.39**	**-0.07**	**-0.05**	**-0.04**	**-0.04**	**-0.03**	**-0.02**	**N/A**
World Oil Price (1997 dollars per barrel)[15]	**21.01**	**18.55**	**13.97**	**19.25**	**21.30**	**21.91**	**22.73**	**0.9%**
Import Share of Product Supplied	**0.46**	**0.49**	**0.53**	**0.57**	**0.60**	**0.62**	**0.65**	**1.2%**
Net Expenditures for Imported Crude Oil and Products (billion 1997 dollars)	**63.78**	**60.87**	**53.95**	**86.34**	**107.95**	**119.49**	**135.20**	**3.5%**
Domestic Refinery Distillation Capacity	**15.4**	**16.0**	**16.3**	**16.6**	**17.5**	**17.7**	**17.9**	**0.5%**
Capacity Utilization Rate (percent)	**94.0**	**95.0**	**93.6**	**94.3**	**95.1**	**95.1**	**95.2**	**0.0%**

[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.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1996 and 1997 expenditures for imported crude oil and petroleum products based on internal calculations. 1996 and 1997 product supplied data from Table A2. Other 1996 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1996*, DOE/EIA-0340(96/1) (Washington, DC. June 1997). Other 1997 data: EIA, *Petroleum Supply Annual 1997*, DOE/EIA-0340(97/1) (Washington, DC. June 1998). **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A12. Petroleum Product Prices

(1997 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference 1996	1997	2000	2005	2010	2015	2020	Annual Growth 1997-2020 (percent)
World Oil Price (1997 dollars per barrel)	21.01	18.55	13.97	19.25	21.30	21.91	22.73	0.9%
Delivered Sector Product Prices								
Residential								
Distillate Fuel	99.5	97.1	89.5	103.3	107.4	108.4	108.1	0.5%
Liquefied Petroleum Gas	101.5	100.2	90.7	103.6	105.4	106.9	110.9	0.4%
Commercial								
Distillate Fuel	74.2	68.4	58.8	72.2	76.2	77.8	78.9	0.6%
Residual Fuel	49.0	51.6	34.2	42.8	46.8	47.6	50.7	-0.1%
Residual Fuel (1997 dollars per barrel)	20.60	21.67	14.36	17.99	19.66	20.00	21.30	-0.1%
Industrial[1]								
Distillate Fuel	77.5	70.7	59.5	73.3	77.2	79.9	82.7	0.7%
Liquefied Petroleum Gas	70.0	72.4	45.4	57.0	57.6	59.1	63.2	-0.6%
Residual Fuel	46.5	43.4	27.5	36.2	40.7	40.8	43.2	-0.0%
Residual Fuel (1997 dollars per barrel)	19.53	18.21	11.56	15.20	17.10	17.14	18.15	-0.0%
Transportation								
Diesel Fuel (distillate)[2]	124.9	118.4	104.8	117.7	119.0	118.7	118.3	-0.0%
Jet Fuel[3]	75.6	70.2	55.8	72.4	77.6	80.4	85.1	0.8%
Motor Gasoline[4]	125.1	121.4	107.5	122.0	128.8	129.2	128.8	0.3%
Liquid Petroleum Gas	108.5	103.6	101.0	112.5	112.7	112.1	113.9	0.4%
Residual Fuel	42.3	46.2	19.9	32.9	38.6	38.8	42.2	-0.4%
Residual Fuel (1997 dollars per barrel)	17.75	19.40	8.34	13.80	16.20	16.32	17.74	-0.4%
E85	144.2	145.8	130.7	150.5	156.7	158.1	158.9	0.4%
M85	82.1	97.3	72.0	87.2	95.3	95.9	96.8	-0.0%
Electric Generators[5]								
Distillate Fuel	68.8	61.4	53.1	66.7	70.9	73.2	75.6	0.9%
Residual Fuel	47.4	41.3	32.8	44.5	52.7	54.4	58.4	1.5%
Residual Fuel (1997 dollars per barrel)	19.90	17.36	13.79	18.70	22.14	22.84	24.51	1.5%
Refined Petroleum Product Prices[6]								
Distillate Fuel	110.2	104.2	93.4	106.9	109.2	109.8	110.1	0.2%
Jet Fuel[3]	75.6	70.2	55.8	72.4	77.6	80.4	85.1	0.8%
Liquefied Petroleum Gas	76.1	77.7	54.8	67.1	68.0	69.3	73.0	-0.3%
Motor Gasoline[4]	125.1	121.4	107.5	122.0	128.8	129.2	128.8	0.3%
Residual Fuel	45.1	44.1	27.6	36.3	41.3	41.3	44.3	0.0%
Residual Fuel (1997 dollars per barrel)	18.93	18.53	11.57	15.26	17.33	17.35	18.59	0.0%
Average	104.8	101.2	86.8	101.7	106.3	106.7	107.5	0.3%

[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.

Sources: 1996 prices for gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1996.* Online. http:/www.eia.doe.gov/oil-gas/ pmal/pmaframe.html (August 1, 1998). 1997 prices for gasoline, distillate, and jet fuel are based on prices in various issues of EIA, *Petroleum Marketing Monthly,* DOE/EIA-0380 (97/03-98/04) (Washington, DC, 1997-98). 1996 and 1997 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1995,* DOE/EIA-0376(95) (Washington, DC, August, 1998). **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	Reference							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Production								
Dry Gas Production[1]	18.79	18.94	19.28	21.57	23.77	26.11	27.35	1.6%
Supplemental Natural Gas[2]	0.11	0.12	0.11	0.11	0.06	0.06	0.06	-2.9%
Net Imports	2.79	2.84	3.29	3.68	4.35	4.78	5.02	2.5%
Canada	2.83	2.84	3.22	3.47	4.15	4.61	4.91	2.4%
Mexico	-0.02	-0.02	-0.04	-0.06	-0.09	-0.12	-0.17	9.4%
Liquefied Natural Gas	-0.03	0.02	0.12	0.27	0.29	0.29	0.29	12.9%
Total Supply	**21.69**	**21.89**	**22.69**	**25.36**	**28.18**	**30.95**	**32.44**	**1.7%**
Consumption by Sector								
Residential	5.23	5.00	5.06	5.16	5.36	5.61	5.77	0.6%
Commercial	3.15	3.28	3.45	3.58	3.73	3.86	3.88	0.7%
Industrial[3]	8.53	8.40	8.73	9.04	9.46	9.87	10.24	0.9%
Electric Generators[4]	3.09	3.33	3.23	4.92	6.69	8.42	9.16	4.5%
Lease and Plant Fuel[5]	1.25	1.25	1.29	1.50	1.65	1.81	1.93	1.9%
Pipeline Fuel	0.71	0.71	0.72	0.82	0.87	0.94	0.98	1.4%
Transportation[6]	0.01	0.01	0.06	0.18	0.25	0.30	0.33	14.9%
Total	**21.97**	**21.98**	**22.54**	**25.19**	**28.02**	**30.81**	**32.30**	**1.7%**
Discrepancy[7]	**-0.29**	**-0.10**	**0.15**	**0.17**	**0.16**	**0.14**	**0.14**	**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, 1996 and 1997 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. Figures for 1996 and 1997 may differ from published data due to internal conversion factors.
Sources: 1996 supply values and consumption as lease, plant, and pipeline fuel: Energy Information Administration (EIA), *Natural Gas Annual 1996*, DOE/EIA-0131(96) (Washington, DC, September 1997). Other 1996 consumption derived from: EIA, *State Energy Data Report 1995*, DOE/EIA-0214(95) (Washington, DC, December 1997). 1997 supplemental natural gas: EIA, *Natural Gas Monthly*, DOE/EIA-0130(98/06) (Washington, DC, June 1998). 1997 imports and dry gas production derived from: EIA, *Natural Gas Annual 1996*, DOE/EIA-0131(96) (Washington, DC, September 1997). 1997 transportation sector consumption: EIA, AEO99 National Energy Modeling System run AEO99B.D100198A. Other 1997 consumption: EIA, *Short-Term Energy Outlook, September 1998*. Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO99 National Energy Modeling System run AEO99B.D100198A. **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A14. Natural Gas Prices, Margins, and Revenues
(1997 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	Reference							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Source Price								
Average Lower 48 Wellhead Price[1]	2.28	2.23	2.10	2.35	2.52	2.62	2.68	0.8%
Average Import Price	2.00	2.15	2.19	2.36	2.48	2.55	2.68	1.0%
Average[2]	**2.24**	**2.22**	**2.11**	**2.35**	**2.51**	**2.60**	**2.68**	**0.8%**
Delivered Prices								
Residential	6.47	7.00	6.72	6.42	6.17	5.95	5.91	-0.7%
Commercial	5.51	5.79	5.47	5.42	5.32	5.22	5.24	-0.4%
Industrial[3]	3.08	3.04	2.85	3.08	3.23	3.32	3.40	0.5%
Electric Generators[4]	2.76	2.76	2.68	3.00	3.15	3.24	3.31	0.8%
Transportation[5]	6.21	6.36	6.68	6.92	7.37	7.52	7.57	0.8%
Average[6]	**4.30**	**4.44**	**4.23**	**4.22**	**4.18**	**4.13**	**4.16**	**-0.3%**
Transmission and Distribution Margins[7]								
Residential	4.23	4.78	4.60	4.07	3.66	3.35	3.23	-1.7%
Commercial	3.27	3.57	3.36	3.07	2.81	2.62	2.56	-1.4%
Industrial[3]	0.84	0.82	0.74	0.73	0.72	0.72	0.72	-0.6%
Electric Generators[4]	0.52	0.54	0.57	0.65	0.64	0.63	0.63	0.7%
Transportation[5]	3.97	4.15	4.57	4.56	4.86	4.92	4.89	0.7%
Average[6]	**2.06**	**2.22**	**2.12**	**1.86**	**1.67**	**1.53**	**1.48**	**-1.7%**
Transmission and Distribution Revenue (billion 1997 dollars)								
Residential	22.11	23.92	23.30	20.98	19.64	18.76	18.65	-1.1%
Commercial	10.31	11.70	11.57	10.98	10.50	10.10	9.93	-0.7%
Industrial[3]	7.16	6.92	6.45	6.57	6.82	7.06	7.33	0.3%
Electric Generators[4]	1.60	1.80	1.84	3.21	4.28	5.31	5.76	5.2%
Transportation[5]	0.04	0.06	0.27	0.80	1.22	1.48	1.64	15.7%
Total	**41.21**	**44.39**	**43.44**	**42.53**	**42.47**	**42.72**	**43.31**	**-0.1%**

[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.
Sources: 1996 residential, commercial, and transportation delivered prices; average lower 48 wellhead price; and average import price: Energy Information Administration (EIA), *Natural Gas Annual 1996*, DOE/EIA-0131(96) (Washington, DC, September 1997). 1996 electric generators delivered price: Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants". 1996 and 1997 industrial delivered prices based on EIA, *Manufacturing Energy Consumption Survey 1991*. 1997 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(98/06) (Washington, DC, June 1998). Other 1996 values, other 1997 values, and projections: EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A15. Oil and Gas Supply

Production and Supply	Reference							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Crude Oil								
Lower 48 Average Wellhead Price[1] **(1997 dollars per barrel)**	17.03	16.25	13.02	18.80	20.80	21.05	21.73	1.3%
Production (million barrels per day)[2]								
U.S. Total	6.47	6.45	6.29	5.82	5.59	5.34	4.96	-1.1%
Lower 48 Onshore	3.81	3.75	3.62	3.11	3.07	3.21	3.28	-0.6%
Conventional	3.20	3.17	3.13	2.66	2.54	2.56	2.57	-0.9%
Enhanced Oil Recovery	0.61	0.58	0.49	0.45	0.53	0.66	0.71	0.9%
Lower 48 Offshore	1.26	1.40	1.48	1.73	1.74	1.51	1.19	-0.7%
Alaska	1.40	1.30	1.19	0.97	0.78	0.61	0.49	-4.1%
Lower 48 End of Year Reserves (billion barrels)[2]	18.14	18.28	16.47	14.44	13.80	13.70	13.70	-1.2%
Natural Gas								
Lower 48 Average Wellhead Price[1] **(1997 dollars per thousand cubic feet)**	2.28	2.23	2.10	2.35	2.52	2.62	2.68	0.8%
Production (trillion cubic feet)[3]								
U.S. Total	18.79	18.94	19.28	21.57	23.77	26.11	27.35	1.6%
Lower 48 Onshore	12.84	12.88	13.77	14.31	16.36	18.47	20.24	2.0%
Associated-Dissolved[4]	1.75	1.77	1.75	1.32	1.19	1.19	1.21	-1.7%
Non-Associated	11.09	11.11	12.03	12.99	15.18	17.28	19.04	2.4%
Conventional	7.44	7.43	8.21	9.01	10.27	11.30	12.32	2.2%
Unconventional	3.64	3.68	3.82	3.97	4.90	5.97	6.72	2.7%
Lower 48 Offshore	5.51	5.62	4.89	6.61	6.73	6.94	6.38	0.6%
Associated-Dissolved[4]	0.78	0.80	0.84	0.92	0.93	0.89	0.81	0.1%
Non-Associated	4.73	4.82	4.05	5.69	5.80	6.05	5.57	0.6%
Alaska	0.44	0.44	0.62	0.65	0.68	0.71	0.73	2.3%
Lower 48 End of Year Reserves (trillion cubic feet)	156.30	158.13	162.45	166.77	174.29	175.73	172.03	0.4%
Supplemental Gas Supplies (trillion cubic ft.)[5]	0.12	0.12	0.11	0.11	0.05	0.05	0.05	-3.7%
Total Lower 48 Wells (thousands)	22.59	27.02	19.86	27.00	31.54	33.66	35.62	1.2%

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Market 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.
Ft. = feet.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1996 and 1997 may differ from published data due to internal conversion factors.

Sources: 1996 lower 48 onshore, lower 48 offshore, Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 1996,* DOE/EIA-0340(96/1) (Washington, DC. June 1997). 1996 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* DOE/EIA-0216(96) (Washington, DC, December 1997). 1996 natural gas lower 48 average wellhead price and total natural gas production: EIA, *Natural Gas Annual 1996,* DOE/EIA-0131(96) (Washington, DC, September 1997). 1997 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 1997,* DOE/EIA-0340(97/1) (Washington, DC. June 1998). 1997 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly,* DOE/EIA-0130(98/06) (Washington, DC, June 1998). Other 1996 and 1997 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Production[1]								
Appalachia	461	477	483	482	482	479	466	-0.1%
Interior	173	171	169	129	127	146	164	-0.2%
West	439	451	516	589	627	670	728	2.1%
East of the Mississippi	573	589	593	561	563	580	586	0.0%
West of the Mississippi	500	511	575	640	672	714	772	1.8%
Total	**1073**	**1099**	**1168**	**1200**	**1236**	**1294**	**1358**	**0.9%**
Net Imports								
Imports	7	7	7	8	8	8	8	0.2%
Exports	90	84	84	87	90	91	93	0.5%
Total	**-83**	**-76**	**-76**	**-80**	**-82**	**-84**	**-86**	**0.5%**
Total Supply[2]	**989**	**1023**	**1092**	**1121**	**1154**	**1211**	**1272**	**1.0%**
Consumption by Sector								
Residential and Commercial	6	6	6	6	7	7	7	0.4%
Industrial[3]	71	70	72	74	77	79	82	0.7%
Coke Plants	32	29	29	26	24	22	20	-1.7%
Electric Generators[4]	897	924	985	1014	1050	1103	1166	1.0%
Total	**1006**	**1030**	**1092**	**1120**	**1156**	**1211**	**1275**	**0.9%**
Discrepancy and Stock Change[5]	**-15**	**-7**	**-0**	**1**	**-3**	**0**	**-3**	**N/A**
Average Minemouth Price								
(1997 dollars per short ton)	18.85	18.14	16.59	14.93	14.00	13.21	12.74	-1.5%
(1997 dollars per million Btu)	0.89	0.85	0.79	0.71	0.67	0.63	0.62	-1.4%
Delivered Prices (1997 dollars per short ton)[6]								
Industrial	32.90	32.41	29.86	28.53	27.40	26.15	24.96	-1.1%
Coke Plants	48.24	47.36	45.37	43.61	41.98	40.16	38.74	-0.9%
Electric Generators								
(1997 dollars per short ton)	26.96	26.16	24.47	23.21	21.66	20.03	18.77	-1.4%
(1997 dollars per million Btu)	1.31	1.27	1.19	1.14	1.06	0.99	0.93	-1.3%
Average	**28.05**	**27.20**	**25.39**	**24.04**	**22.46**	**20.80**	**19.49**	**-1.4%**
Exports[7]	41.54	40.55	38.32	36.58	35.15	33.38	31.90	-1.0%

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 7.9 million tons in 1994, 8.5 million tons in 1995, 8.9 million tons in 1996, 9.4 million tons in 1997, and are projected to reach 10.0 million tons in 1998, and 10.6 million tons in 1999.
[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.
Sources: 1996: Energy Information Administration (EIA), *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997). 1997 data derived from: EIA, *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, November 1998). **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A17. Renewable Energy Generating Capability and Generation
(Thousand Megawatts, Unless Otherwise Noted)

Capacity and Generation	Reference							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Electric Generators[1] (excluding cogenerators)								
Net Summer Capability								
Conventional Hydropower	77.45	77.60	78.14	78.45	78.51	78.51	78.51	0.1%
Geothermal[2]	3.00	3.00	3.06	3.08	3.16	3.25	3.52	0.7%
Municipal Solid Waste[3]	3.41	3.41	3.56	3.76	4.01	4.17	4.27	1.0%
Wood and Other Biomass[4]	1.64	1.66	1.76	1.97	2.33	3.61	5.61	5.4%
Solar Thermal	0.35	0.35	0.37	0.42	0.44	0.48	0.52	1.7%
Solar Photovoltaic	0.01	0.01	0.04	0.14	0.30	0.46	0.64	18.7%
Wind	1.88	1.88	2.80	3.24	3.39	3.41	3.61	2.9%
Total	**87.74**	**87.92**	**89.73**	**91.05**	**92.14**	**93.89**	**96.68**	**0.4%**
Generation (billion kilowatthours)								
Conventional Hydropower	340.66	350.62	322.30	323.16	323.42	323.50	323.58	-0.3%
Geothermal[2]	15.43	15.67	14.71	16.23	17.86	19.69	22.99	1.7%
Municipal Solid Waste[3]	14.24	14.30	23.35	24.78	26.49	27.65	28.34	3.0%
Wood and Other Biomass[4]	4.26	4.21	8.13	9.40	11.97	20.90	34.89	9.6%
Solar Thermal	0.90	0.90	0.95	1.11	1.19	1.31	1.44	2.0%
Solar Photovoltaic	0.00	0.00	0.09	0.33	0.71	1.12	1.56	31.2%
Wind	3.41	3.41	6.11	7.24	7.69	7.76	8.44	4.0%
Total	**378.90**	**389.11**	**375.63**	**382.26**	**389.33**	**401.92**	**421.24**	**0.3%**
Cogenerators[5]								
Net Summer Capability								
Conventional Hydropower[6]	0.94	0.93	0.93	0.93	0.93	0.93	0.93	-0.0%
Municipal Solid Waste	0.46	0.46	0.48	0.48	0.48	0.49	0.49	0.2%
Biomass	5.45	5.45	6.11	6.40	6.77	7.13	7.39	1.3%
Total	**6.85**	**6.85**	**7.52**	**7.82**	**8.19**	**8.55**	**8.81**	**1.1%**
Generation (billion kilowatthours)								
Conventional Hydropower[6]	6.16	6.16	4.90	4.90	4.90	4.90	4.90	-1.0%
Municipal Solid Waste	1.80	1.80	2.27	2.30	2.32	2.34	2.34	1.1%
Biomass	32.69	32.69	41.24	44.89	49.59	53.17	55.82	2.4%
Total	**40.65**	**40.65**	**48.42**	**52.10**	**56.81**	**60.41**	**63.06**	**1.9%**

[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]Represents own-use industrial hydroelectric power.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO99. Net summer capability is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recently available as of July 1,1998. Additional retirements are also determined on the basis of the size and age of the units. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: 1996 and 1997 electric utility capability: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report." 1996 and 1997 nonutility and cogenerator capability: EIA, Form EIA-867, "Annual Nonutility Power Producer Report." 1996 and 1997 generation: EIA, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A18. Renewable Energy, Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	Reference							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Marketed Renewable Energy[2]								
Residential	0.61	0.60	0.60	0.61	0.62	0.64	0.65	0.4%
Wood	0.61	0.60	0.60	0.61	0.62	0.64	0.65	0.4%
Commercial[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.0%
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.0%
Industrial[4]	1.96	1.88	1.96	2.12	2.31	2.45	2.56	1.4%
Conventional Hydroelectric	0.03	0.03	0.03	0.03	0.03	0.03	0.03	N/A
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Biomass	1.93	1.84	1.93	2.08	2.27	2.41	2.52	1.4%
Transportation	0.07	0.10	0.14	0.15	0.20	0.25	0.28	4.7%
Ethanol used in E85[5]	0.00	0.00	0.01	0.02	0.04	0.05	0.06	N/A
Ethanol used in Gasoline Blending	0.07	0.10	0.13	0.13	0.16	0.20	0.22	3.6%
Electric Generators[6]	4.23	4.35	4.24	4.36	4.48	4.64	4.90	0.5%
Conventional Hydroelectric	3.50	3.60	3.31	3.32	3.32	3.33	3.33	-0.3%
Geothermal	0.42	0.43	0.41	0.47	0.52	0.59	0.69	2.1%
Municipal Solid Waste	0.23	0.23	0.37	0.40	0.42	0.44	0.45	3.0%
Biomass	0.04	0.04	0.07	0.08	0.11	0.19	0.31	9.6%
Solar Thermal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	2.0%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.01	0.01	0.02	31.2%
Wind	0.04	0.04	0.06	0.07	0.08	0.08	0.09	4.0%
Total Marketed Renewable Energy	6.89	6.92	6.95	7.24	7.61	7.99	8.38	0.8%
Non-Marketed Renewable Energy[7] Selected Consumption								
Residential	0.02	0.02	0.02	0.02	0.03	0.03	0.05	3.8%
Solar Hot Water Heating	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.4%
Geothermal Heat Pumps	0.01	0.01	0.01	0.01	0.02	0.02	0.04	6.2%
Commercial	0.01	0.02	0.02	0.03	0.03	0.04	0.04	3.8%
Solar Thermal	0.01	0.02	0.02	0.03	0.03	0.04	0.04	3.8%

[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]Value is less than 0.005 quadrillion Btu per year and rounds to zero.
[4]Includes all electricity production by industrial and other cogenerators for the grid and for own use.
[5]Excludes motor gasoline component of E85.
[6]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.
[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.
Notes: Totals may not equal sum of components due to independent rounding.
Sources: 1996 and 1997 ethanol: Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). 1996 and 1997 electric generators: EIA, Form EIA-860, "Annual Electric Generator Report," and EIA, Form EIA-867, "Annual Nonutility Power Producer Report." Other 1996 and 1997: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A19. Carbon Emissions by Sector and Source
(Million Metric Tons per Year)

Sector and Source	Reference							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Residential								
Petroleum	27.3	27.8	26.0	24.2	23.0	22.0	21.0	-1.2%
Natural Gas	77.5	74.1	75.0	76.5	79.5	83.1	85.6	0.6%
Coal	1.4	1.4	1.5	1.4	1.3	1.3	1.3	-0.5%
Electricity	178.6	182.3	207.5	215.5	228.6	247.9	267.2	1.7%
Total	**284.8**	**285.6**	**310.0**	**317.6**	**332.5**	**354.3**	**375.0**	**1.2%**
Commercial								
Petroleum	14.6	14.4	11.7	11.3	11.1	11.0	10.6	-1.3%
Natural Gas	46.7	48.6	51.1	53.0	55.3	57.1	57.6	0.7%
Coal	2.1	2.1	2.3	2.4	2.5	2.6	2.6	0.9%
Electricity	161.8	171.5	190.9	198.5	212.8	228.3	237.3	1.4%
Total	**225.3**	**236.6**	**255.9**	**265.2**	**281.7**	**299.0**	**308.1**	**1.2%**
Industrial[1]								
Petroleum	103.7	105.8	108.3	112.6	117.4	120.0	121.4	0.6%
Natural Gas[2]	144.0	142.2	145.6	153.7	161.9	170.4	177.4	1.0%
Coal	59.8	58.5	61.9	62.9	63.5	64.6	65.9	0.5%
Electricity	170.0	175.6	187.2	193.0	206.5	219.5	229.8	1.2%
Total	**477.6**	**482.1**	**503.0**	**522.1**	**549.4**	**574.5**	**594.5**	**0.9%**
Transportation								
Petroleum[3]	459.5	461.9	500.7	552.0	600.8	632.9	664.7	1.6%
Natural Gas[4]	10.6	10.5	11.5	14.7	16.7	18.4	19.5	2.7%
Other[5]	0.0	0.0	0.3	0.9	1.4	1.7	1.9	N/A
Electricity	2.8	2.9	3.2	5.2	7.6	9.4	11.2	6.0%
Total[3]	**472.8**	**475.3**	**515.8**	**572.8**	**626.3**	**662.3**	**697.3**	**1.7%**
Total Carbon Emissions by Delivered Fuel								
Petroleum[3]	605.2	609.9	646.7	700.1	752.4	785.9	817.7	1.3%
Natural Gas	278.8	275.4	283.2	297.8	313.4	328.9	340.0	0.9%
Coal	63.4	62.0	65.6	66.6	67.4	68.4	69.8	0.5%
Other[5]	0.0	0.0	0.3	0.9	1.4	1.7	1.9	N/A
Electricity	513.2	532.4	588.8	612.3	655.4	705.1	745.5	1.5%
Total[3]	**1460.6**	**1479.6**	**1584.7**	**1677.7**	**1789.9**	**1890.1**	**1974.9**	**1.3%**
Electric Generators[6]								
Petroleum	15.4	17.6	22.4	7.7	5.8	5.3	4.9	-5.4%
Natural Gas	40.3	43.8	47.5	72.4	98.5	124.0	134.8	5.0%
Coal	457.5	471.0	518.9	532.2	551.1	575.9	605.8	1.1%
Total	**513.2**	**532.4**	**588.8**	**612.3**	**655.4**	**705.1**	**745.5**	**1.5%**
Total Carbon Emissions by Primary Fuel[7]								
Petroleum[3]	620.6	627.5	669.1	707.8	758.1	791.1	822.6	1.2%
Natural Gas	319.1	319.1	330.7	370.2	411.9	452.9	474.8	1.7%
Coal	520.9	533.0	584.5	598.8	618.5	644.4	675.6	1.0%
Other[5]	0.0	0.0	0.3	0.9	1.4	1.7	1.9	N/A
Total[3]	**1460.6**	**1479.6**	**1584.7**	**1677.7**	**1789.9**	**1890.1**	**1974.9**	**1.3%**
Carbon Emissions (tons per person)	**5.5**	**5.5**	**5.8**	**5.9**	**6.0**	**6.1**	**6.1**	**0.4%**

[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 emissions. In the years from 1989 through 1996, international bunker fuels accounted for 22 to 24 million metric tons of carbon 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.
[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.
Sources: Carbon coefficients from Energy Information Administration, (EIA) *Emissions of Greenhouse Gases in the United States 1997*, DOE/EIA-0573(97) (Washington, DC, October 1998). 1996 consumption estimates derived from EIA, *State Energy Data Report 1995*, DOE/EIA-0214(95) (Washington, DC, December 1997). 1997 consumption estimates based on: EIA, *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). Projections: EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A20. Macroeconomic Indicators
(Billion 1992 Chain-Weighted, Dollars Unless Otherwise Noted)

Indicators	Reference 1996	1997	2000	2005	2010	2015	2020	Annual Growth 1997-2020 (percent)
GDP Chain-Type Price Index (1992=1.000)	1.095	1.116	1.172	1.310	1.487	1.742	2.126	2.8%
Real Gross Domestic Product	6995	7270	7830	8769	9896	10800	11680	2.1%
Real Consumption	4752	4914	5395	5977	6754	7521	8347	2.3%
Real Investment	1084	1206	1384	1628	1925	2149	2401	3.0%
Real Government Spending	1268	1285	1341	1445	1588	1680	1764	1.4%
Real Exports	860	970	1085	1597	2257	2858	3460	5.7%
Real Imports	971	1106	1403	1905	2704	3655	4903	6.7%
Real Disposable Personal Income	5043	5183	5622	6311	7170	8006	8905	2.4%
Index of Manufacturing Gross Output (Index 1987=1.000)	1.305	1.359	1.416	1.593	1.810	1.977	2.137	2.0%
AA Utility Bond Rate (percent)	7.57	7.54	6.11	6.28	6.17	6.82	7.62	N/A
Real Yield on Government 10 Year Bonds (percent)	4.99	4.94	3.90	3.77	3.20	3.13	3.01	N/A
Real Utility Bond Rate (percent)	5.38	5.53	4.45	4.10	3.48	3.48	3.37	N/A
Energy Intensity (thousand Btu per 1992 dollar of GDP)								
Delivered Energy	10.08	9.70	9.50	9.06	8.57	8.24	7.94	-0.9%
Total Energy	13.39	12.94	12.68	11.94	11.21	10.70	10.27	-1.0%
Consumer Price Index (1982-84=1.00)	1.57	1.61	1.72	1.98	2.28	2.68	3.23	3.1%
Unemployment Rate (percent)	5.41	4.95	4.95	5.85	5.36	5.43	5.32	N/A
Unit Sales of Light-Duty Vehicles (million)	15.10	15.08	15.39	15.40	16.50	16.81	16.74	0.5%
Millions of People								
Population with Armed Forces Overseas	265.8	268.2	275.2	286.5	298.3	310.7	323.4	0.8%
Population (aged 16 and over)	204.2	206.3	212.8	223.5	235.0	245.4	255.1	0.9%
Employment, Non-Agriculture	118.7	121.4	126.9	134.2	143.5	149.4	154.0	1.0%
Employment, Manufacturing	18.5	18.5	18.1	17.5	17.2	16.2	15.1	-0.9%
Labor Force	133.9	136.3	141.9	149.2	157.2	161.3	163.5	0.8%

GDP = Gross domestic product.
Btu = British thermal unit.
N/A = Not applicable.
Sources: 1996 and 1997: Data Resources Incorporated (DRI), DRI Trend0898. **Projections:** Energy Information Administration, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table A21. International Petroleum Supply and Disposition Summary

(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
World Oil Price (1997 dollars per barrel)[1]	21.01	18.55	13.97	19.25	21.30	21.91	22.73	0.9%
Production[2]								
OECD								
U.S. (50 states)	9.34	9.34	9.23	8.96	8.99	8.94	8.70	-0.3%
Canada	2.47	2.59	2.84	3.19	3.31	3.35	3.38	1.2%
Mexico	3.31	3.44	3.65	3.92	3.97	3.95	3.87	0.5%
OECD Europe[3]	7.00	7.02	8.07	8.22	7.47	6.75	6.26	-0.5%
Other OECD	0.78	0.83	0.88	0.91	0.91	0.87	0.80	-0.1%
Total OECD	**22.90**	**23.21**	**24.66**	**25.20**	**24.66**	**23.86**	**23.00**	**-0.0%**
Developing Countries								
Other South & Central America	3.26	3.40	4.02	4.45	4.77	4.90	4.97	1.7%
Pacific Rim	2.09	2.17	2.36	2.87	3.16	3.23	3.25	1.8%
OPEC	28.20	29.85	30.27	35.60	40.35	48.70	58.81	3.0%
Other Developing Countries	4.54	4.58	4.87	5.78	6.33	6.82	7.32	2.1%
Total Developing Countries	**38.08**	**39.99**	**41.52**	**48.69**	**54.60**	**63.65**	**74.36**	**2.7%**
Eurasia								
Former Soviet Union	7.08	7.13	7.39	9.41	12.03	12.62	13.18	2.7%
Eastern Europe	0.26	0.25	0.30	0.35	0.42	0.44	0.42	2.2%
China	3.13	3.20	3.30	3.42	3.56	3.60	3.46	0.3%
Total Eurasia	**10.48**	**10.58**	**10.99**	**13.18**	**16.02**	**16.65**	**17.06**	**2.1%**
Total Production	**71.47**	**73.78**	**77.17**	**87.06**	**95.28**	**104.17**	**114.41**	**1.9%**
Consumption								
OECD								
U.S. (50 states)	18.31	18.62	19.94	21.15	22.69	23.71	24.67	1.2%
U.S. Territories	0.26	0.20	0.20	0.37	0.38	0.42	0.47	3.8%
Canada	1.80	1.86	2.06	2.12	2.19	2.32	2.48	1.3%
Mexico	1.90	1.91	2.09	2.46	2.78	3.02	3.26	2.4%
Japan	5.86	5.71	5.67	7.07	7.21	7.58	8.02	1.5%
Australia and New Zealand	0.93	0.95	1.00	1.12	1.21	1.25	1.30	1.4%
OECD Europe[3]	14.27	14.43	14.96	15.34	15.50	15.59	15.69	0.4%
Total OECD	**43.33**	**43.68**	**45.93**	**49.62**	**51.97**	**53.89**	**55.88**	**1.1%**
Developing Countries								
Other South and Central America	3.54	3.77	4.37	5.67	6.64	7.71	8.97	3.8%
Pacific Rim	4.55	4.77	4.75	6.35	7.38	8.74	10.38	3.4%
OPEC	5.39	5.56	5.69	6.30	7.06	7.91	8.86	2.0%
Other Developing Countries	5.35	5.50	5.76	7.36	8.20	9.14	10.24	2.7%
Total Developing Countries	**18.84**	**19.60**	**20.57**	**25.68**	**29.28**	**33.51**	**38.45**	**3.0%**

Table A21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Eurasia								
Former Soviet Union	4.38	4.43	4.98	5.16	5.96	6.71	7.47	2.3%
Eastern Europe	1.13	1.37	1.53	1.62	1.90	2.24	2.65	2.9%
China	3.55	3.88	4.47	5.28	6.47	8.12	10.26	4.3%
Total Eurasia	**9.05**	**9.68**	**10.97**	**12.06**	**14.33**	**17.07**	**20.38**	**3.3%**
Total Consumption	**71.22**	**72.96**	**77.47**	**87.36**	**95.58**	**104.47**	**114.71**	**2.0%**
Non-OPEC Production	43.27	43.94	46.90	51.47	54.93	55.46	55.60	1.0%
Net Eurasia Exports	1.42	0.91	0.02	1.12	1.69	-0.41	-3.32	N/A
OPEC Market Share	0.39	0.40	0.39	0.41	0.42	0.47	0.51	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.
N/A = Not applicable.
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, Slovak Republic, the Former Soviet Union, and the Former Yugoslavia.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1996 and 1997 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Appendix B

Economic Growth Case Comparisons

Table B1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1997	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	13.65	11.75	11.83	11.93	11.15	11.30	11.47	10.31	10.51	10.71
Natural Gas Plant Liquids	2.57	2.87	3.06	3.24	3.06	3.32	3.57	3.17	3.47	3.76
Dry Natural Gas	19.47	22.89	24.44	25.97	24.64	26.84	28.80	25.63	28.12	30.45
Coal	23.33	25.41	25.91	26.54	26.04	26.95	28.03	26.49	28.12	29.98
Nuclear Power	6.71	5.88	5.91	5.91	4.38	4.47	4.47	3.65	3.83	3.98
Renewable Energy[1]	6.82	7.24	7.44	7.69	7.43	7.77	8.19	7.64	8.15	8.79
Other[2]	0.66	0.51	0.57	0.60	0.57	0.62	0.73	0.50	0.65	0.79
Total	73.22	76.54	79.16	81.88	77.28	81.28	85.26	77.39	82.85	88.46
Imports										
Crude Oil[3]	17.86	22.76	23.91	24.85	24.01	24.96	26.14	24.81	26.03	27.39
Petroleum Products[4]	3.89	6.67	7.35	8.07	6.78	8.50	9.77	7.58	9.92	12.16
Natural Gas	3.06	4.50	4.69	4.84	4.91	5.15	5.45	5.11	5.46	5.70
Other Imports[5]	0.54	0.66	0.71	0.76	0.66	0.72	0.78	0.66	0.75	0.84
Total	25.34	34.60	36.66	38.53	36.36	39.33	42.15	38.16	42.15	46.09
Exports										
Petroleum[6]	2.09	2.01	2.11	2.16	1.90	2.02	2.08	1.86	2.00	2.10
Natural Gas	0.16	0.24	0.24	0.24	0.27	0.27	0.27	0.32	0.32	0.32
Coal	2.19	2.27	2.27	2.27	2.31	2.31	2.31	2.36	2.36	2.36
Total	4.44	4.52	4.62	4.67	4.47	4.59	4.65	4.54	4.68	4.78
Discrepancy[7]	-0.08	-0.45	-0.37	-0.44	-0.43	-0.49	-0.42	-0.54	-0.44	-0.40
Consumption										
Petroleum Products[8]	36.49	42.16	44.22	46.14	43.20	46.20	49.17	43.98	48.08	52.26
Natural Gas	22.59	27.05	28.79	30.47	29.20	31.64	33.88	30.33	33.17	35.74
Coal	21.09	23.44	24.06	24.66	24.14	25.05	26.22	24.48	26.26	28.17
Nuclear Power	6.71	5.88	5.91	5.91	4.38	4.47	4.47	3.65	3.83	3.98
Renewable Energy[1]	6.82	7.25	7.45	7.70	7.44	7.79	8.21	7.65	8.17	8.80
Other[9]	0.33	0.39	0.39	0.41	0.37	0.38	0.39	0.38	0.39	0.40
Total	94.04	106.17	110.83	115.29	108.73	115.53	122.34	110.47	119.89	129.36
Net Imports - Petroleum	19.65	27.42	29.16	30.77	28.89	31.44	33.84	30.53	33.95	37.44
Prices (1997 dollars per unit)										
World Oil Price (dollars per barrel)[10]	18.55	20.70	21.30	21.90	21.07	21.91	22.75	21.66	22.73	23.81
Gas Wellhead Price (dollars per Mcf)[11]	2.23	2.29	2.52	2.71	2.29	2.62	2.91	2.29	2.68	3.09
Coal Minemouth Price (dollars per ton)	18.14	13.88	14.00	14.16	12.98	13.21	13.39	12.47	12.74	12.89
Average Electric Price (cents per kwh)	6.9	5.7	6.1	6.5	5.4	5.8	6.3	5.1	5.6	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 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. Figures for 1997 may differ from published data due to internal conversion factors.

Sources: 1997 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(98/06) (Washington, DC, June 1998). 1997 coal minemouth price: *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, November 1998). Coal production and exports derived from: EIA, *Monthly Energy Review*, DOE/EIA-0035(98/08) (Washington, DC, August 1998). Other 1997 values: EIA, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998) **Projections:** EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A , AEO99B.D100198A, and HMAC99.D100198A.

Table B2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1997	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
Energy Consumption										
Residential										
Distillate Fuel	0.94	0.73	0.73	0.74	0.69	0.69	0.70	0.65	0.65	0.66
Kerosene	0.09	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.07	0.07
Liquefied Petroleum Gas	0.43	0.42	0.43	0.44	0.41	0.42	0.43	0.39	0.40	0.42
Petroleum Subtotal	1.47	1.21	1.23	1.25	1.16	1.18	1.20	1.11	1.12	1.14
Natural Gas	5.15	5.31	5.52	5.74	5.47	5.77	6.07	5.56	5.94	6.31
Coal	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.60	0.60	0.62	0.64	0.61	0.64	0.66	0.62	0.65	0.68
Electricity	3.66	4.44	4.57	4.72	4.74	4.93	5.14	5.04	5.31	5.59
Delivered Energy	**10.92**	**11.62**	**12.00**	**12.39**	**12.03**	**12.57**	**13.12**	**12.38**	**13.08**	**13.77**
Electricity Related Losses	8.07	8.93	9.11	9.27	9.12	9.34	9.58	9.43	9.77	10.09
Total	**18.99**	**20.55**	**21.11**	**21.66**	**21.14**	**21.91**	**22.70**	**21.81**	**22.85**	**23.86**
Commercial										
Distillate Fuel	0.49	0.34	0.34	0.35	0.33	0.33	0.34	0.31	0.32	0.32
Residual Fuel	0.11	0.09	0.09	0.10	0.09	0.09	0.10	0.09	0.09	0.10
Kerosene	0.03	0.02	0.03	0.03	0.02	0.03	0.03	0.02	0.03	0.03
Liquefied Petroleum Gas	0.08	0.08	0.09	0.09	0.08	0.09	0.09	0.08	0.09	0.09
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Petroleum Subtotal	0.73	0.56	0.57	0.58	0.55	0.56	0.58	0.53	0.55	0.57
Natural Gas	3.37	3.75	3.84	3.92	3.84	3.97	4.09	3.82	4.00	4.15
Coal	0.08	0.09	0.10	0.10	0.10	0.10	0.10	0.09	0.10	0.11
Renewable Energy[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	3.44	4.19	4.26	4.33	4.41	4.54	4.67	4.53	4.72	4.90
Delivered Energy	**7.63**	**8.60**	**8.77**	**8.93**	**8.90**	**9.18**	**9.44**	**8.97**	**9.37**	**9.73**
Electricity Related Losses	7.59	8.41	8.48	8.50	8.49	8.60	8.70	8.46	8.68	8.85
Total	**15.22**	**17.01**	**17.24**	**17.44**	**17.39**	**17.78**	**18.14**	**17.44**	**18.05**	**18.58**
Industrial[4]										
Distillate Fuel	1.13	1.27	1.35	1.43	1.31	1.42	1.54	1.33	1.48	1.64
Liquefied Petroleum Gas	2.14	2.25	2.45	2.65	2.29	2.58	2.89	2.29	2.69	3.13
Petrochemical Feedstock	1.46	1.40	1.52	1.64	1.42	1.60	1.78	1.42	1.67	1.93
Residual Fuel	0.28	0.30	0.33	0.36	0.31	0.35	0.39	0.30	0.36	0.41
Motor Gasoline[2]	0.21	0.25	0.26	0.28	0.25	0.28	0.30	0.26	0.29	0.33
Other Petroleum[5]	4.11	4.62	4.89	5.15	4.59	4.95	5.31	4.54	4.99	5.50
Petroleum Subtotal	9.33	10.08	10.81	11.51	10.17	11.18	12.21	10.15	11.49	12.94
Natural Gas[6]	9.92	10.88	11.43	11.96	11.20	12.02	12.82	11.40	12.52	13.60
Metallurgical Coal	0.79	0.64	0.63	0.63	0.58	0.58	0.57	0.54	0.53	0.52
Steam Coal	1.56	1.56	1.67	1.79	1.54	1.73	1.91	1.54	1.80	2.07
Net Coal Coke Imports	0.02	0.16	0.20	0.24	0.18	0.24	0.31	0.18	0.27	0.36
Coal Subtotal	2.36	2.35	2.51	2.66	2.30	2.55	2.79	2.25	2.60	2.95
Renewable Energy[7]	1.88	2.12	2.31	2.49	2.17	2.45	2.73	2.19	2.56	2.94
Electricity	3.52	3.81	4.13	4.46	3.89	4.37	4.86	3.91	4.57	5.27
Delivered Energy	**27.01**	**29.24**	**31.18**	**33.08**	**29.74**	**32.57**	**35.41**	**29.90**	**33.73**	**37.70**
Electricity Related Losses	7.78	7.65	8.22	8.76	7.49	8.27	9.06	7.31	8.40	9.51
Total	**34.79**	**36.89**	**39.41**	**41.84**	**37.23**	**40.84**	**44.46**	**37.21**	**42.14**	**47.22**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1997	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[8]	4.64	5.70	6.00	6.28	5.86	6.31	6.76	5.96	6.58	7.22
Jet Fuel[9]	3.31	4.79	5.10	5.40	5.21	5.69	6.18	5.60	6.27	6.98
Motor Gasoline[2]	15.08	18.09	18.70	19.27	18.41	19.31	20.19	18.69	19.94	21.16
Residual Fuel	0.75	0.99	1.02	1.05	1.11	1.16	1.20	1.22	1.30	1.37
Liquefied Petroleum Gas	0.04	0.17	0.18	0.19	0.19	0.20	0.22	0.20	0.22	0.25
Other Petroleum[10]	0.29	0.32	0.34	0.36	0.33	0.35	0.38	0.32	0.36	0.40
Petroleum Subtotal	24.10	30.06	31.33	32.54	31.10	33.03	34.94	32.00	34.68	37.37
Pipeline Fuel Natural Gas	0.73	0.86	0.90	0.94	0.91	0.97	1.03	0.93	1.01	1.09
Compressed Natural Gas	0.01	0.24	0.26	0.27	0.29	0.31	0.33	0.31	0.34	0.38
Renewable Energy (E85)[11]	0.00	0.05	0.05	0.05	0.06	0.07	0.07	0.06	0.07	0.08
M85[12]	0.00	0.07	0.08	0.08	0.09	0.10	0.10	0.09	0.11	0.12
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	0.15	0.15	0.16	0.18	0.19	0.20	0.21	0.22	0.24
Delivered Energy	24.91	31.43	32.77	34.05	32.62	34.65	36.67	33.61	36.44	39.28
Electricity Related Losses	0.13	0.29	0.30	0.31	0.34	0.36	0.37	0.40	0.41	0.43
Total	25.04	31.72	33.07	34.36	32.96	35.00	37.04	34.01	36.85	39.70
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.20	8.03	8.42	8.79	8.18	8.76	9.33	8.25	9.04	9.84
Kerosene	0.15	0.13	0.13	0.13	0.12	0.13	0.13	0.12	0.13	0.13
Jet Fuel[9]	3.31	4.79	5.10	5.40	5.21	5.69	6.18	5.60	6.27	6.98
Liquefied Petroleum Gas	2.69	2.91	3.15	3.36	2.97	3.29	3.63	2.97	3.40	3.89
Motor Gasoline[2]	15.32	18.36	18.99	19.58	18.69	19.61	20.52	18.98	20.26	21.51
Petrochemical Feedstock	1.46	1.40	1.52	1.64	1.42	1.60	1.78	1.42	1.67	1.93
Residual Fuel	1.13	1.38	1.44	1.50	1.50	1.60	1.69	1.61	1.75	1.87
Other Petroleum[13]	4.37	4.91	5.20	5.48	4.88	5.27	5.66	4.83	5.32	5.86
Petroleum Subtotal	35.62	41.92	43.95	45.88	42.98	45.95	48.92	43.78	47.84	52.01
Natural Gas[6]	19.19	21.04	21.95	22.83	21.70	23.03	24.34	22.03	23.81	25.52
Metallurgical Coal	0.79	0.64	0.63	0.63	0.58	0.58	0.57	0.54	0.53	0.52
Steam Coal	1.69	1.70	1.82	1.94	1.69	1.88	2.07	1.68	1.95	2.22
Net Coal Coke Imports	0.02	0.16	0.20	0.24	0.18	0.24	0.31	0.18	0.27	0.36
Coal Subtotal	2.50	2.50	2.65	2.81	2.45	2.70	2.95	2.40	2.75	3.11
Renewable Energy[14]	2.48	2.77	2.98	3.19	2.84	3.15	3.47	2.87	3.29	3.71
M85[12]	0.00	0.07	0.08	0.08	0.09	0.10	0.10	0.09	0.11	0.12
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	10.68	12.58	13.11	13.66	13.22	14.03	14.86	13.69	14.82	15.99
Delivered Energy	70.47	80.88	84.72	88.46	83.28	88.96	94.63	84.87	92.62	100.48
Electricity Related Losses	23.57	25.29	26.11	26.84	25.44	26.57	27.70	25.61	27.27	28.88
Total	94.04	106.17	110.83	115.29	108.73	115.53	122.34	110.47	119.89	129.36
Electric Generators[15]										
Distillate Fuel	0.09	0.06	0.06	0.06	0.06	0.06	0.07	0.06	0.07	0.07
Residual Fuel	0.77	0.18	0.21	0.19	0.16	0.19	0.18	0.14	0.17	0.17
Petroleum Subtotal	0.87	0.25	0.28	0.26	0.22	0.25	0.25	0.20	0.24	0.24
Natural Gas	3.40	6.01	6.84	7.64	7.50	8.61	9.55	8.30	9.36	10.22
Steam Coal	18.59	20.95	21.41	21.85	21.69	22.35	23.27	22.08	23.51	25.07
Nuclear Power	6.71	5.88	5.91	5.91	4.38	4.47	4.47	3.65	3.83	3.98
Renewable Energy[16]	4.35	4.48	4.47	4.51	4.60	4.63	4.74	4.78	4.88	5.09
Electricity Imports[17]	0.33	0.31	0.31	0.33	0.28	0.28	0.28	0.28	0.28	0.28
Total	34.25	37.88	39.22	40.49	38.67	40.60	42.56	39.30	42.09	44.87

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1997	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	7.29	8.10	8.49	8.85	8.25	8.82	9.39	8.31	9.10	9.91
Kerosene	0.15	0.13	0.13	0.13	0.12	0.13	0.13	0.12	0.13	0.13
Jet Fuel[9]	3.31	4.79	5.10	5.40	5.21	5.69	6.18	5.60	6.27	6.98
Liquefied Petroleum Gas	2.69	2.91	3.15	3.36	2.97	3.29	3.63	2.97	3.40	3.89
Motor Gasoline[2]	15.32	18.36	18.99	19.58	18.69	19.61	20.52	18.98	20.26	21.51
Petrochemical Feedstock	1.46	1.40	1.52	1.64	1.42	1.60	1.78	1.42	1.67	1.93
Residual Fuel	1.91	1.57	1.65	1.69	1.66	1.79	1.87	1.75	1.92	2.04
Other Petroleum[13]	4.37	4.91	5.20	5.48	4.88	5.27	5.66	4.83	5.32	5.86
Petroleum Subtotal	36.49	42.16	44.22	46.14	43.20	46.20	49.17	43.98	48.08	52.25
Natural Gas	22.59	27.05	28.79	30.47	29.20	31.64	33.88	30.33	33.17	35.74
Metallurgical Coal	0.79	0.64	0.63	0.63	0.58	0.58	0.57	0.54	0.53	0.52
Steam Coal	20.29	22.65	23.23	23.79	23.37	24.23	25.34	23.76	25.45	27.29
Net Coal Coke Imports	0.02	0.16	0.20	0.24	0.18	0.24	0.31	0.18	0.27	0.36
Coal Subtotal	21.09	23.44	24.06	24.66	24.14	25.05	26.22	24.48	26.26	28.17
Nuclear Power	6.71	5.88	5.91	5.91	4.38	4.47	4.47	3.65	3.83	3.98
Renewable Energy[18]	6.82	7.25	7.45	7.70	7.44	7.79	8.21	7.65	8.17	8.80
M85[12]	0.00	0.07	0.08	0.08	0.09	0.10	0.10	0.09	0.11	0.12
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports[17]	0.33	0.31	0.31	0.33	0.28	0.28	0.28	0.28	0.28	0.28
Total	94.04	106.17	110.83	115.29	108.73	115.53	122.34	110.47	119.88	129.35
Energy Use and Related Statistics										
Delivered Energy Use	70.47	80.88	84.72	88.46	83.28	88.96	94.63	84.87	92.62	100.48
Total Energy Use	94.04	106.17	110.83	115.29	108.73	115.53	122.34	110.47	119.88	129.35
Population (millions)	268.19	290.23	298.31	305.69	299.19	310.75	321.32	308.36	323.36	337.08
Gross Domestic Product (billion 1992 dollars)	7269.76	9184.11	9895.50	10593.38	9755.00	10800.49	11841.51	10256.30	11680.02	13106.40
Total Carbon Emissions (million metric tons)	1479.60	1717.82	1789.87	1858.34	1784.92	1890.06	1996.65	1826.28	1974.88	2124.39

[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.
[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.
[4]Fuel consumption includes consumption for cogeneration.
[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 & wood waste, municipal solid waste, & other biomass; includes for cogeneration, both sales to the grid & for own use.
[8]Low sulfur diesel fuel.
[9]Includes naphtha and kerosene type.
[10]Includes aviation gas and lubricants.
[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 unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[14]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 and solar thermal hot water heaters.
[15]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.
[16]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.
[17]In 1997 approximately two-thirds of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions.
[18]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 and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1997 may differ from published data due to internal conversion factors. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1997 electric utility fuel consumption: Energy Information Administration (EIA), *Electric Power Annual 1997, Volume 1*, DOE/EIA-0348(97)/1 (Washington, DC, July 1998). 1997 nonutility consumption estimates: Form EIA-867, "Annual Nonutility Power Producer Report." Other 1997 values: EIA, *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **Projections:** EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A.

Table B3. Energy Prices by Sector and Source
(1997 Dollars per Million Btu)

Sector and Source	1997	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	13.40	12.31	12.95	13.49	11.78	12.63	13.37	11.51	12.47	13.35
Primary Energy[1]	7.12	6.46	6.57	6.67	6.18	6.37	6.53	6.12	6.33	6.55
Petroleum Products[2]	8.42	9.19	9.36	9.58	9.06	9.49	9.72	9.16	9.67	9.98
Distillate Fuel	7.00	7.63	7.75	7.89	7.53	7.82	7.99	7.53	7.79	8.04
Liquefied Petroleum Gas	11.61	12.04	12.22	12.52	11.76	12.38	12.61	11.98	12.85	13.17
Natural Gas	6.80	5.89	6.00	6.09	5.61	5.78	5.94	5.56	5.74	5.96
Electricity	24.85	20.95	22.45	23.65	19.67	21.50	23.10	18.68	20.68	22.48
Commercial	13.09	11.25	12.04	12.68	10.62	11.63	12.52	10.20	11.43	12.48
Primary Energy[1]	5.51	5.04	5.21	5.37	4.87	5.14	5.36	4.86	5.16	5.46
Petroleum Products[2]	5.46	5.96	6.10	6.28	5.87	6.22	6.43	5.97	6.40	6.67
Distillate Fuel	4.93	5.37	5.49	5.67	5.29	5.61	5.82	5.33	5.69	5.95
Residual Fuel	3.45	3.03	3.13	3.22	3.05	3.18	3.31	3.22	3.39	3.57
Natural Gas[3]	5.62	4.99	5.17	5.33	4.82	5.08	5.31	4.79	5.09	5.40
Electricity	22.32	17.79	19.28	20.46	16.45	18.25	19.84	15.45	17.59	19.40
Industrial[4]	5.42	4.91	5.22	5.52	4.73	5.21	5.59	4.69	5.28	5.77
Primary Energy	4.01	3.82	4.02	4.23	3.76	4.13	4.38	3.82	4.27	4.63
Petroleum Products[2]	5.60	5.23	5.38	5.60	5.12	5.53	5.75	5.27	5.79	6.09
Distillate Fuel	5.10	5.44	5.56	5.80	5.38	5.76	6.04	5.49	5.97	6.25
Liquefied Petroleum Gas	8.38	6.50	6.67	6.99	6.20	6.85	7.08	6.41	7.33	7.62
Residual Fuel	2.90	2.62	2.72	2.83	2.58	2.73	2.86	2.70	2.89	3.15
Natural Gas[5]	2.96	2.88	3.14	3.37	2.86	3.23	3.55	2.85	3.30	3.76
Metallurgical Coal	1.77	1.55	1.57	1.58	1.47	1.50	1.53	1.40	1.45	1.48
Steam Coal	1.44	1.24	1.26	1.27	1.16	1.20	1.23	1.10	1.14	1.18
Electricity	13.56	11.10	11.89	12.52	10.14	11.09	11.96	9.54	10.68	11.63
Transportation	8.60	8.60	9.00	9.35	8.37	9.00	9.41	8.20	9.00	9.48
Primary Energy	8.58	8.57	8.98	9.32	8.34	8.97	9.38	8.18	8.97	9.45
Petroleum Products[2]	8.58	8.58	8.98	9.32	8.34	8.97	9.38	8.17	8.97	9.44
Distillate Fuel[6]	8.53	8.16	8.58	9.07	7.83	8.56	9.11	7.63	8.53	9.10
Jet Fuel[7]	5.20	5.49	5.74	5.99	5.44	5.96	6.28	5.58	6.31	6.75
Motor Gasoline[8]	9.70	9.92	10.40	10.77	9.73	10.43	10.87	9.53	10.40	10.91
Residual Fuel	3.09	2.48	2.58	2.70	2.50	2.60	2.73	2.60	2.82	3.02
Liquid Petroleum Gas[9]	12.00	12.65	13.06	13.56	12.11	12.99	13.48	12.08	13.20	13.80
Natural Gas[10]	6.18	6.61	7.17	7.65	6.59	7.31	7.95	6.54	7.36	8.12
E85[11]	16.27	17.10	17.53	18.13	16.89	17.68	18.37	17.11	17.78	18.60
M85[12]	13.25	12.35	13.02	13.37	12.53	13.10	13.59	12.54	13.22	13.81
Electricity	16.30	13.63	14.55	15.21	12.63	13.67	14.53	11.95	13.04	13.87
Average End-Use Energy	8.72	8.20	8.62	8.97	7.92	8.53	8.98	7.78	8.52	9.05
Primary Energy	8.35	7.91	8.31	8.65	7.65	8.24	8.67	7.51	8.23	8.75
Electricity	20.26	16.84	18.00	18.91	15.70	17.10	18.32	14.90	16.50	17.83
Electric Generators[13]										
Fossil Fuel Average	1.54	1.47	1.57	1.67	1.47	1.61	1.74	1.45	1.61	1.75
Petroleum Products	2.94	3.86	3.89	4.14	3.96	4.05	4.29	4.16	4.33	4.67
Distillate Fuel	4.43	4.99	5.11	5.33	4.94	5.28	5.52	5.03	5.45	5.72
Residual Fuel	2.76	3.48	3.52	3.74	3.59	3.63	3.82	3.78	3.90	4.23
Natural Gas	2.70	2.85	3.08	3.28	2.85	3.17	3.45	2.84	3.24	3.63
Steam Coal	1.27	1.05	1.06	1.08	0.96	0.99	1.01	0.90	0.93	0.96

Table B3. Energy Prices by Sector and Source (Continued)
(1997 Dollars per Million Btu)

Sector and Source	1997	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
Average Price to All Users[14]										
Petroleum Products[2]	7.70	7.81	8.11	8.41	7.62	8.16	8.49	7.55	8.24	8.64
Distillate Fuel	7.51	7.54	7.88	8.28	7.30	7.91	8.38	7.17	7.94	8.43
Jet Fuel	5.20	5.49	5.74	5.99	5.44	5.96	6.28	5.58	6.31	6.75
Liquefied Petroleum Gas	9.01	7.74	7.88	8.17	7.43	8.03	8.21	7.63	8.46	8.70
Motor Gasoline[8]	9.70	9.92	10.40	10.77	9.73	10.43	10.87	9.54	10.41	10.91
Residual Fuel	2.95	2.66	2.76	2.87	2.65	2.76	2.89	2.74	2.96	3.17
Natural Gas	4.32	3.88	4.06	4.23	3.75	4.02	4.27	3.70	4.05	4.41
Coal	1.28	1.06	1.08	1.09	0.98	1.01	1.03	0.91	0.95	0.98
E85[11]	16.27	17.10	17.53	18.13	16.89	17.68	18.37	17.11	17.78	18.60
M85[12]	13.25	12.35	13.02	13.37	12.53	13.10	13.59	12.54	13.22	13.81
Electricity	20.26	16.84	18.00	18.91	15.70	17.10	18.32	14.90	16.50	17.83
Non-Renewable Energy Expenditures by Sector (Billion 1997 dollars)										
Residential	138.32	135.59	147.38	158.48	134.48	150.70	166.46	135.39	154.96	174.69
Commercial	99.87	96.66	105.54	113.26	94.44	106.71	118.15	91.51	106.97	121.40
Industrial	113.46	106.96	122.05	137.73	104.36	127.03	149.49	103.65	133.57	164.96
Transportation	207.85	261.95	285.93	308.52	264.24	301.75	333.94	266.82	317.40	360.20
Total Non-Renewable Expenditures	559.50	601.16	660.89	717.99	597.53	686.18	768.04	597.37	712.90	821.25
Transportation Renewable Expenditures	0.01	0.80	0.90	0.99	0.97	1.15	1.31	1.08	1.32	1.54
Total Expenditures	559.51	601.97	661.79	718.97	598.51	687.33	769.35	598.44	714.22	822.79

[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: 1997 figures may differ from published data due to internal rounding.
Sources: 1997 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 (97/03-98/04) (Washington, DC, 1997-98). 1997 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditures Report: 1995,* DOE/EIA-0376(95) (Washington, DC, August, 1998). 1997 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1991.* 1997 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly,* DOE/EIA-0130(98/06) (Washington, DC, June 1998). Other 1997 natural gas delivered prices: EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A , AEO99B.D100198A, and HMAC99.D100198A. Values for 1997 coal prices have been estimated from EIA, *State Energy Price and Expenditures Report: 1995,* DOE/EIA-0376(95) (Washington, DC, August, 1998) by use of consumption quantities aggregated from EIA, *State Energy Data Report 1995*, DOE/EIA-0214(95) (Washington, DC, December 1997) and the *Coal Industry Annual 1997,* DOE/EIA-0584(97) (Washington, DC, November 1998). 1997 electricity prices for commercial, industrial, and transportation: EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A , AEO99B.D100198A, and HMAC99.D100198A. **Projections:** EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A , AEO99B.D100198A, and HMAC99.D100198A.

Table B4. Residential Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1997	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	70.18	77.85	81.13	84.44	80.56	85.30	90.09	83.12	89.35	95.69
Multifamily	25.00	27.27	28.71	30.16	28.31	30.42	32.53	29.14	31.88	34.63
Mobile Homes	6.13	7.32	7.64	7.93	7.85	8.24	8.59	8.35	8.79	9.19
Total	**101.31**	**112.45**	**117.48**	**122.53**	**116.72**	**123.96**	**131.21**	**120.61**	**130.02**	**139.51**
Average House Square Footage	**1654**	**1696**	**1703**	**1709**	**1707**	**1715**	**1723**	**1717**	**1727**	**1737**
Energy Intensity (million Btu consumed per household)										
Delivered Energy Consumption	107.80	103.32	102.14	101.12	103.05	101.38	99.97	102.64	100.58	98.73
Electricity Related Losses	79.65	79.45	77.52	75.61	78.11	75.34	73.01	78.20	75.16	72.32
Total Energy Consumption	187.45	182.78	179.66	176.73	181.16	176.72	172.98	180.85	175.74	171.05
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.44	0.46	0.47	0.49	0.48	0.49	0.51	0.49	0.51	0.54
Space Cooling	0.46	0.53	0.55	0.57	0.55	0.58	0.61	0.57	0.60	0.64
Water Heating	0.35	0.37	0.37	0.38	0.38	0.38	0.39	0.39	0.40	0.41
Refrigeration	0.39	0.27	0.29	0.30	0.26	0.27	0.29	0.26	0.28	0.30
Cooking	0.13	0.15	0.15	0.16	0.15	0.16	0.17	0.16	0.17	0.19
Clothes Dryers	0.19	0.21	0.22	0.23	0.23	0.24	0.25	0.24	0.25	0.27
Freezers	0.12	0.07	0.07	0.08	0.07	0.07	0.07	0.07	0.07	0.08
Lighting	0.34	0.39	0.40	0.41	0.42	0.43	0.45	0.44	0.46	0.48
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.03	0.04	0.04
Dishwashers[1]	0.05	0.05	0.05	0.06	0.05	0.06	0.06	0.05	0.06	0.07
Color Televisions	0.21	0.29	0.29	0.30	0.30	0.31	0.32	0.32	0.33	0.35
Personal Computers	0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05
Furnace Fans	0.09	0.11	0.12	0.12	0.12	0.13	0.14	0.13	0.14	0.15
Other Uses[2]	0.83	1.48	1.52	1.56	1.67	1.74	1.81	1.85	1.95	2.04
Delivered Energy	**3.66**	**4.44**	**4.57**	**4.72**	**4.74**	**4.93**	**5.14**	**5.04**	**5.31**	**5.59**
Natural Gas										
Space Heating	3.58	3.65	3.80	3.96	3.75	3.96	4.17	3.81	4.07	4.32
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.01	0.01
Water Heating	1.27	1.32	1.38	1.43	1.38	1.45	1.52	1.40	1.50	1.59
Cooking	0.16	0.17	0.17	0.18	0.17	0.18	0.19	0.18	0.19	0.20
Clothes Dryers	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.07
Other Uses[3]	0.09	0.10	0.11	0.11	0.11	0.11	0.12	0.11	0.12	0.13
Delivered Energy	**5.15**	**5.31**	**5.52**	**5.74**	**5.47**	**5.77**	**6.07**	**5.56**	**5.94**	**6.31**
Distillate										
Space Heating	0.84	0.64	0.64	0.64	0.60	0.60	0.61	0.56	0.57	0.57
Water Heating	0.10	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
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	**0.94**	**0.73**	**0.73**	**0.74**	**0.69**	**0.69**	**0.70**	**0.65**	**0.65**	**0.66**
Liquefied Petroleum Gas										
Space Heating	0.32	0.30	0.31	0.31	0.29	0.30	0.31	0.28	0.28	0.29
Water Heating	0.07	0.08	0.08	0.08	0.07	0.08	0.08	0.07	0.07	0.08
Cooking	0.03	0.03	0.03	0.04	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	**0.43**	**0.42**	**0.43**	**0.44**	**0.41**	**0.42**	**0.43**	**0.39**	**0.40**	**0.42**
Marketed Renewables (wood)[5]	0.60	0.60	0.62	0.64	0.61	0.64	0.66	0.62	0.65	0.68
Other Fuels[6]	0.15	0.12	0.12	0.12	0.12	0.12	0.12	0.11	0.12	0.12

Table B4. Residential Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1997	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	5.93	5.78	5.97	6.16	5.84	6.10	6.37	5.87	6.20	6.52
Space Cooling	0.46	0.53	0.55	0.57	0.55	0.58	0.61	0.57	0.61	0.64
Water Heating	1.79	1.86	1.91	1.97	1.92	2.00	2.08	1.96	2.06	2.17
Refrigeration	0.39	0.27	0.29	0.30	0.26	0.27	0.29	0.26	0.28	0.30
Cooking	0.33	0.35	0.36	0.38	0.36	0.38	0.40	0.37	0.40	0.42
Clothes Dryers	0.24	0.27	0.27	0.28	0.28	0.29	0.31	0.30	0.32	0.33
Freezers	0.12	0.07	0.07	0.08	0.07	0.07	0.07	0.07	0.07	0.08
Lighting	0.34	0.39	0.40	0.41	0.42	0.43	0.45	0.44	0.46	0.48
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.03	0.04	0.04
Dishwashers	0.05	0.05	0.05	0.06	0.05	0.06	0.06	0.05	0.06	0.07
Color Televisions	0.21	0.29	0.29	0.30	0.30	0.31	0.32	0.32	0.33	0.35
Personal Computers	0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05
Furnace Fans	0.09	0.11	0.12	0.12	0.12	0.13	0.14	0.13	0.14	0.15
Other Uses[7]	0.93	1.59	1.63	1.68	1.79	1.86	1.94	1.98	2.08	2.18
Delivered Energy	10.92	11.62	12.00	12.39	12.03	12.57	13.12	12.38	13.08	13.77
Electricity Related Losses	8.07	8.93	9.11	9.27	9.12	9.34	9.58	9.43	9.77	10.09
Total Energy Consumption by End-Use										
Space Heating	6.90	6.71	6.91	7.12	6.76	7.03	7.32	6.79	7.14	7.49
Space Cooling	1.47	1.59	1.63	1.68	1.61	1.68	1.74	1.63	1.71	1.79
Water Heating	2.57	2.59	2.65	2.71	2.64	2.73	2.81	2.69	2.80	2.91
Refrigeration	1.26	0.82	0.85	0.88	0.75	0.79	0.83	0.73	0.78	0.83
Cooking	0.62	0.64	0.67	0.69	0.65	0.69	0.72	0.67	0.72	0.76
Clothes Dryers	0.65	0.69	0.71	0.73	0.72	0.74	0.76	0.75	0.78	0.81
Freezers	0.39	0.21	0.22	0.23	0.19	0.20	0.21	0.19	0.20	0.21
Lighting	1.09	1.18	1.20	1.23	1.22	1.25	1.28	1.26	1.30	1.35
Clothes Washers	0.09	0.10	0.10	0.10	0.10	0.10	0.11	0.10	0.11	0.11
Dishwashers	0.15	0.15	0.16	0.17	0.15	0.16	0.18	0.16	0.17	0.19
Color Televisions	0.69	0.87	0.88	0.90	0.86	0.89	0.91	0.91	0.94	0.97
Personal Computers	0.06	0.11	0.11	0.11	0.12	0.12	0.12	0.14	0.14	0.15
Furnace Fans	0.28	0.33	0.35	0.36	0.35	0.37	0.39	0.37	0.40	0.42
Other Uses[7]	2.77	4.56	4.65	4.75	5.01	5.15	5.30	5.44	5.65	5.86
Total	18.99	20.55	21.11	21.66	21.14	21.91	22.70	21.81	22.85	23.86
Non-Marketed Renewables										
Geothermal[8]	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.03	0.04	0.04
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	0.02	0.03	0.03	0.03	0.03	0.03	0.04	0.05	0.05

[1]Does not include electronic 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 1993.*
[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.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1997: Energy Information Administration (EIA) *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **Projections:** EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A , AEO99B.D100198A, and HMAC99.D100198A.

Table B5. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1997	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										
Total Floor Space (billion square feet)										
Surviving	58.8	66.0	68.0	69.9	67.8	70.7	73.6	67.9	71.9	75.8
New Additions	1.6	1.3	1.5	1.7	1.1	1.3	1.5	0.8	1.0	1.2
Total	60.3	67.3	69.5	71.5	68.8	72.0	75.1	68.7	72.9	77.0
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	126.5	127.7	126.2	124.9	129.3	127.5	125.8	130.6	128.5	126.3
Electricity Related Losses	125.9	125.0	122.0	118.9	123.4	119.5	115.9	123.2	119.1	114.9
Total Energy Consumption	252.4	252.7	248.1	243.7	252.7	247.0	241.7	253.8	247.5	241.3
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.13	0.12	0.12	0.13	0.12	0.12	0.12	0.11	0.12	0.12
Space Cooling	0.34	0.35	0.35	0.36	0.35	0.36	0.37	0.35	0.36	0.37
Water Heating	0.07	0.07	0.07	0.07	0.06	0.06	0.07	0.06	0.06	0.06
Ventilation	0.17	0.18	0.18	0.19	0.18	0.19	0.19	0.18	0.19	0.19
Cooking	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Lighting	1.22	1.27	1.28	1.30	1.29	1.32	1.34	1.27	1.32	1.35
Refrigeration	0.18	0.19	0.20	0.21	0.20	0.21	0.22	0.20	0.21	0.23
Office Equipment (PC)	0.12	0.19	0.20	0.20	0.21	0.22	0.22	0.23	0.24	0.25
Office Equipment (non-PC)	0.29	0.41	0.42	0.43	0.46	0.48	0.49	0.50	0.53	0.55
Other Uses[1]	0.91	1.38	1.41	1.44	1.53	1.57	1.62	1.61	1.69	1.76
Delivered Energy	3.44	4.19	4.26	4.33	4.41	4.54	4.67	4.53	4.72	4.90
Natural Gas[2]										
Space Heating	1.31	1.35	1.37	1.40	1.37	1.41	1.44	1.35	1.40	1.45
Space Cooling	0.01	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Water Heating	0.62	0.67	0.69	0.71	0.68	0.72	0.75	0.68	0.73	0.77
Cooking	0.23	0.27	0.28	0.29	0.28	0.29	0.31	0.28	0.30	0.31
Other Uses[3]	1.20	1.44	1.47	1.49	1.49	1.52	1.56	1.48	1.54	1.59
Delivered Energy	3.37	3.75	3.84	3.92	3.84	3.97	4.09	3.82	4.00	4.15
Distillate										
Space Heating	0.21	0.20	0.20	0.20	0.19	0.19	0.19	0.18	0.18	0.18
Water Heating	0.05	0.05	0.05	0.05	0.04	0.04	0.05	0.04	0.04	0.04
Other Uses[4]	0.23	0.09	0.09	0.09	0.09	0.10	0.10	0.09	0.09	0.10
Delivered Energy	0.49	0.34	0.34	0.35	0.33	0.33	0.34	0.31	0.32	0.32
Other Fuels[5]	0.32	0.32	0.32	0.33	0.32	0.33	0.34	0.31	0.33	0.35
Marketed Renewable Fuels										
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy Consumption by End-Use										
Space Heating	1.65	1.67	1.70	1.73	1.67	1.72	1.76	1.64	1.70	1.76
Space Cooling	0.35	0.37	0.38	0.39	0.38	0.39	0.40	0.37	0.39	0.40
Water Heating	0.74	0.78	0.80	0.83	0.79	0.82	0.86	0.78	0.83	0.88
Ventilation	0.17	0.18	0.18	0.19	0.18	0.19	0.19	0.18	0.19	0.19
Cooking	0.25	0.29	0.30	0.31	0.30	0.31	0.33	0.30	0.32	0.33
Lighting	1.22	1.27	1.28	1.30	1.29	1.32	1.34	1.27	1.32	1.35
Refrigeration	0.18	0.19	0.20	0.21	0.20	0.21	0.22	0.20	0.21	0.23
Office Equipment (PC)	0.12	0.19	0.20	0.20	0.21	0.22	0.22	0.23	0.24	0.25
Office Equipment (non-PC)	0.29	0.41	0.42	0.43	0.46	0.48	0.49	0.50	0.53	0.55
Other Uses[6]	2.67	3.24	3.30	3.36	3.43	3.53	3.63	3.51	3.65	3.79
Delivered Energy	7.63	8.60	8.77	8.93	8.90	9.18	9.44	8.97	9.37	9.73

Table B5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1997	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	7.59	8.41	8.48	8.50	8.49	8.60	8.70	8.46	8.68	8.85
Total Energy Consumption by End-Use										
Space Heating	1.94	1.92	1.95	1.98	1.90	1.95	1.99	1.84	1.91	1.97
Space Cooling	1.10	1.08	1.09	1.09	1.05	1.07	1.09	1.02	1.05	1.08
Water Heating	0.89	0.91	0.94	0.96	0.91	0.95	0.98	0.90	0.94	0.99
Ventilation	0.53	0.54	0.55	0.55	0.53	0.54	0.54	0.51	0.53	0.54
Cooking	0.30	0.33	0.34	0.35	0.33	0.35	0.36	0.33	0.35	0.37
Lighting	3.90	3.81	3.83	3.84	3.77	3.81	3.84	3.66	3.74	3.79
Refrigeration	0.58	0.58	0.60	0.62	0.58	0.60	0.63	0.56	0.60	0.64
Office Equipment (PC)	0.37	0.58	0.58	0.59	0.61	0.63	0.64	0.65	0.68	0.70
Office Equipment (non-PC)	0.93	1.24	1.26	1.27	1.35	1.38	1.41	1.44	1.49	1.54
Other Uses[6]	4.68	6.01	6.11	6.19	6.36	6.51	6.65	6.53	6.76	6.96
Total	15.22	17.01	17.24	17.44	17.39	17.78	18.14	17.44	18.05	18.58
Non-Marketed Renewable Fuels										
Solar[7]	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Total	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04

[1]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, and medical equipment.
[2]Excludes estimated consumption from independent power producers.
[3]Includes miscellaneous uses, such as district services, pumps, emergency electric generators, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, district services, and emergency electric generators.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes primary energy displaced by solar thermal space heating and water heating.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1997 Energy Information Administration, *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **Projections:** EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A , AEO99B.D100198A, and HMAC99.D100198A.

Table B6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1997	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 1987 dollars)										
Manufacturing	3170	3917	4224	4538	4166	4613	5096	4356	4986	5690
Nonmanufacturing	812	935	1013	1096	974	1081	1192	1008	1145	1289
Total	3982	4852	5237	5634	5141	5693	6288	5363	6131	6978
Energy Prices (1997 dollars per million Btu)										
Electricity	13.56	11.10	11.89	12.52	10.14	11.09	11.96	9.54	10.68	11.63
Natural Gas	2.96	2.88	3.14	3.37	2.86	3.23	3.55	2.85	3.30	3.76
Steam Coal	1.44	1.24	1.26	1.27	1.16	1.20	1.23	1.10	1.14	1.18
Residual Oil	2.90	2.62	2.72	2.83	2.58	2.73	2.86	2.70	2.89	3.15
Distillate Oil	5.10	5.44	5.56	5.80	5.38	5.76	6.04	5.49	5.97	6.25
Liquefied Petroleum Gas	8.38	6.50	6.67	6.99	6.20	6.85	7.08	6.41	7.33	7.62
Motor Gasoline	9.69	9.94	10.42	10.80	9.75	10.47	10.91	9.57	10.46	10.97
Metallurgical Coal	1.77	1.55	1.57	1.58	1.47	1.50	1.53	1.40	1.45	1.48
Energy Consumption										
Consumption[1]										
Purchased Electricity	3.52	3.81	4.13	4.46	3.89	4.37	4.86	3.91	4.57	5.27
Natural Gas[2]	9.92	10.88	11.43	11.96	11.20	12.02	12.82	11.40	12.52	13.60
Steam Coal	1.56	1.56	1.67	1.79	1.54	1.73	1.91	1.54	1.80	2.07
Metallurgical Coal and Coke[3]	0.81	0.80	0.84	0.87	0.76	0.82	0.88	0.72	0.80	0.88
Residual Fuel	0.28	0.30	0.33	0.36	0.31	0.35	0.39	0.30	0.36	0.41
Distillate	1.13	1.27	1.35	1.43	1.31	1.42	1.54	1.33	1.48	1.64
Liquefied Petroleum Gas	2.14	2.25	2.45	2.65	2.29	2.58	2.89	2.29	2.69	3.13
Petrochemical Feedstocks	1.46	1.40	1.52	1.64	1.42	1.60	1.78	1.42	1.67	1.93
Other Petroleum[4]	4.33	4.87	5.16	5.43	4.85	5.23	5.62	4.80	5.29	5.82
Renewables[5]	1.88	2.12	2.31	2.49	2.17	2.45	2.73	2.19	2.56	2.94
Delivered Energy	27.01	29.24	31.18	33.08	29.74	32.57	35.41	29.90	33.73	37.70
Electricity Related Losses	7.78	7.65	8.22	8.76	7.49	8.27	9.06	7.31	8.40	9.51
Total	34.79	36.89	39.41	41.84	37.23	40.84	44.46	37.21	42.14	47.21
Consumption per Unit of Output[1] (thousand Btu per 1987 dollars)										
Purchased Electricity	0.88	0.78	0.79	0.79	0.76	0.77	0.77	0.73	0.75	0.75
Natural Gas[2]	2.49	2.24	2.18	2.12	2.18	2.11	2.04	2.13	2.04	1.95
Steam Coal	0.39	0.32	0.32	0.32	0.30	0.30	0.30	0.29	0.29	0.30
Metallurgical Coal and Coke[3]	0.20	0.16	0.16	0.15	0.15	0.14	0.14	0.13	0.13	0.13
Residual Fuel	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Distillate	0.28	0.26	0.26	0.25	0.25	0.25	0.24	0.25	0.24	0.23
Liquefied Petroleum Gas	0.54	0.46	0.47	0.47	0.45	0.45	0.46	0.43	0.44	0.45
Petrochemical Feedstocks	0.37	0.29	0.29	0.29	0.28	0.28	0.28	0.26	0.27	0.28
Other Petroleum[4]	1.09	1.00	0.98	0.96	0.94	0.92	0.89	0.90	0.86	0.83
Renewables[5]	0.47	0.44	0.44	0.44	0.42	0.43	0.43	0.41	0.42	0.42
Delivered Energy	6.78	6.03	5.95	5.87	5.78	5.72	5.63	5.57	5.50	5.40
Electricity Related Losses	1.95	1.58	1.57	1.55	1.46	1.45	1.44	1.36	1.37	1.36
Total	8.74	7.60	7.52	7.43	7.24	7.17	7.07	6.94	6.87	6.77

[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.
Sources: 1997 prices for gasoline and distillate are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly,* DOE/EIA-0380 (97/03-98/04) (Washington, DC, 1997-98). 1997 coal prices: EIA, *Monthly Energy Review,* DOE/EIA-0035(98/08) (Washington, DC, August 1998). 1997 electricity prices: EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A. Other 1997 prices derived from EIA, *State Energy Data Report 1995*, DOE/EIA-0214(95) (Washington, DC, December 1997). Other 1997 values: EIA, *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **Projections:** EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A.

Table B7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	1997	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										
Level of Travel (billions)										
Light-Duty Vehicles <8,500 lbs. (VMT)	2301	2778	2887	2993	2933	3097	3257	3076	3303	3520
Commercial Light Trucks (VMT)[1]	69	86	90	95	91	97	104	95	104	114
Freight Trucks >10,000 lbs. (VMT)	177	229	243	257	237	258	279	240	270	301
Air (seat miles available)	1049	1689	1814	1935	1922	2127	2331	2154	2462	2765
Rail (ton miles traveled)	1229	1462	1519	1574	1526	1620	1718	1571	1719	1874
Marine (ton miles traveled)	757	837	879	917	862	928	985	875	964	1045
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)	24.0	25.4	25.4	25.5	26.1	26.1	26.0	26.5	26.5	26.4
New Car (miles per gallon)[2]	27.9	31.7	31.6	31.7	32.1	32.1	31.9	32.2	32.1	31.8
New Light Truck (miles per gallon)[2]	20.2	20.7	20.7	20.8	21.4	21.5	21.4	22.0	22.0	21.9
Light-Duty Fleet (miles per gallon)[3]	20.5	20.4	20.3	20.3	20.9	20.9	20.9	21.5	21.4	21.4
New Commercial Light Truck (MPG)[1]	19.9	19.8	19.8	19.8	20.5	20.5	20.4	21.0	21.0	20.9
Stock Commercial Light Truck (MPG)[1]	14.6	15.0	15.0	15.0	15.3	15.2	15.2	15.6	15.6	15.5
Aircraft Efficiency (seat miles per gallon)	51.0	55.5	55.7	55.8	57.1	57.6	57.9	58.8	59.6	59.9
Freight Truck Efficiency (miles per gallon)	5.6	6.1	6.1	6.1	6.2	6.2	6.2	6.2	6.3	6.3
Rail Efficiency (ton miles per thousand Btu)	2.7	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.1
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.4	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.7
Energy Use by Mode (quadrillion Btu)										
Light-Duty Vehicles	13.94	17.50	18.10	18.66	17.96	18.85	19.73	18.34	19.60	20.81
Commercial Light Trucks[1]	0.59	0.72	0.76	0.79	0.74	0.80	0.86	0.76	0.84	0.92
Freight Trucks[4]	4.24	5.03	5.30	5.56	5.10	5.51	5.91	5.12	5.68	6.25
Air	3.35	4.85	5.17	5.47	5.29	5.77	6.27	5.70	6.38	7.09
Rail[5]	0.53	0.59	0.61	0.63	0.61	0.64	0.67	0.61	0.66	0.71
Marine[6]	1.28	1.60	1.64	1.69	1.74	1.81	1.88	1.88	1.98	2.09
Pipeline Fuel	0.73	0.86	0.90	0.94	0.91	0.97	1.03	0.93	1.01	1.09
Other[7]	0.24	0.28	0.30	0.32	0.28	0.31	0.34	0.28	0.32	0.36
Total	24.91	31.43	32.77	34.05	32.62	34.65	36.67	33.61	36.44	39.28

[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 passenger rail.
[6]Includes military residual fuel use and recreation boats.
[7]Includes lubricants and aviation gasoline.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Lbs. = Pounds.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1997: U.S. Department of Transportation, Bureau of Transportation Statistics, *Air Carrier Traffic Statistics Monthly, December 1997/1996*, (Washington, DC, 1997); Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1998*. Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998); EIA, *Fuel Oil and Kerosene Sales 1997*, DOE/EIA-0535(97) (Washington, DC, August 1998); and United States Department of Defense, Defense Fuel Supply Center. Projections: EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A , AEO99B.D100198A, and HMAC99.D100198A.

Table B8. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1997	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
Generation by Fuel Type										
Electric Generators[1]										
Coal	1796	2002	2046	2092	2081	2151	2255	2139	2298	2497
Petroleum	82	25	28	26	23	26	26	20	24	25
Natural Gas	299	804	919	1040	1047	1213	1353	1191	1349	1474
Nuclear Power	629	551	554	554	411	419	419	342	359	373
Pumped Storage	-3	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[2]	389	388	388	393	395	401	413	407	420	445
Total	3192	3769	3934	4103	3956	4208	4464	4099	4450	4813
Non-Utility Generation for Own Use	10	9	9	9	9	9	9	9	9	9
Cogenerators[3]										
Coal	60	55	55	55	54	55	55	54	54	55
Petroleum	10	7	7	7	7	7	7	7	7	7
Natural Gas	210	219	221	223	227	230	234	228	233	238
Other Gaseous Fuels[4]	4	5	5	5	5	5	5	5	5	5
Renewable Sources[2]	41	52	57	61	53	60	67	53	63	72
Other[5]	4	4	4	4	4	4	4	4	4	4
Total	328	343	350	357	351	362	373	352	367	382
Sales to Utilities	183	180	180	181	181	182	184	181	183	185
Generation for Own Use	146	163	169	175	170	180	189	171	184	197
Net Imports[6]	32	30	30	32	27	27	27	27	27	27
Electricity Sales by Sector										
Residential	1072	1303	1341	1382	1389	1446	1506	1478	1557	1637
Commercial	1008	1227	1247	1269	1293	1332	1367	1327	1383	1436
Industrial	1033	1116	1211	1306	1141	1280	1423	1146	1339	1544
Transportation	17	43	44	46	52	55	58	62	65	69
Total	3130	3688	3843	4003	3875	4113	4355	4013	4345	4687
End-Use Prices (1997 cents per kilowatthour)[7]										
Residential	8.5	7.1	7.7	8.1	6.7	7.3	7.9	6.4	7.1	7.7
Commercial	7.6	6.1	6.6	7.0	5.6	6.2	6.8	5.3	6.0	6.6
Industrial	4.6	3.8	4.1	4.3	3.5	3.8	4.1	3.3	3.6	4.0
Transportation	5.6	4.7	5.0	5.2	4.3	4.7	5.0	4.1	4.4	4.7
All Sectors Average	6.9	5.7	6.1	6.5	5.4	5.8	6.3	5.1	5.6	6.1
Emissions (million short tons)										
Sulfur Dioxide	12.7	9.07	9.06	9.12	9.01	8.95	8.95	8.94	8.95	8.95
Nitrogen Oxide	5.8	3.95	4.06	4.14	4.08	4.21	4.33	4.10	4.29	4.40

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[2]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[3]Cogenerators produce electricity and other useful thermal energy. Includes sales to utilities and generation for own use.
[4]Other gaseous fuels include refinery and still gas.
[5]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[6]In 1997 approximately two-thirds of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions.
[7]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1997 commercial and transportation sales derived from: Total transportation plus commercial sales come from Energy Information Administration (EIA), *State Energy Data Report 1995*, DOE/EIA-0214(95) (Washington, DC, December 1997), but individual sectors do not match because sales taken from commercial and placed in transportation, according to Oak Ridge National Laboratories, *Transportation Energy Data Book 17* (August 1997) which indicates the transportation value should be higher. 1997 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: EIA, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). 1997 residential electricity prices derived from EIA, *Short-Term Energy Outlook, September 1998*. Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **1997 electricity prices for commercial, industrial, and transportation; emissions; and projections:** EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A.

Table B9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	1997	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	304.7	305.6	308.9	311.5	309.9	316.2	325.4	318.1	333.0	356.0
Other Fossil Steam[3]	138.7	76.5	80.2	78.8	73.5	79.5	78.3	70.9	75.7	78.1
Combined Cycle	16.4	112.2	126.0	146.3	152.9	175.9	199.9	182.8	211.5	234.0
Combustion Turbine/Diesel	78.2	144.3	151.0	163.5	163.6	174.9	191.2	172.2	186.7	203.4
Nuclear Power	99.0	73.4	74.2	74.2	55.3	56.4	56.4	46.1	48.9	50.8
Pumped Storage	19.6	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
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]	87.9	92.0	92.1	92.7	93.1	93.9	95.5	94.8	96.7	100.2
Total	744.5	825.6	853.9	888.5	869.9	918.4	968.2	906.4	974.0	1044.0
Cumulative Planned Additions[5]										
Coal Steam	0.1	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Other Fossil Steam[3]	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combined Cycle	0.7	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Combustion Turbine/Diesel	1.5	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6
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	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
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]	0.1	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Total	2.5	30.1	30.1	30.1	30.2	30.2	30.2	30.2	30.2	30.2
Cumulative Unplanned Additions[5]										
Coal Steam	0.0	4.0	5.6	8.9	8.9	13.5	23.4	17.7	31.0	54.6
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	91.2	105.0	125.3	132.0	155.0	179.0	161.8	190.5	213.0
Combustion Turbine/Diesel	20.2	73.6	81.1	96.0	96.6	108.2	125.0	106.8	120.2	137.5
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]	0.8	2.2	2.3	2.9	3.5	4.3	6.0	5.5	7.3	10.8
Total	21.0	171.0	194.0	233.2	241.0	281.0	333.4	291.8	348.9	415.9
Cumulative Total Additions	23.5	201.2	224.2	263.4	271.1	311.1	363.5	322.0	379.0	446.0
Cumulative Retirements[6]	14.8	111.6	105.7	110.8	137.3	128.3	131.4	151.6	140.6	138.1

Economic Growth Case Comparisons

Table B9. Electricity Generating Capability (Continued)
(Thousand Megawatts)

Net Summer Capability[1]	1997	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
Cogenerators[7]										
Capability										
Coal	9.4	9.7	9.9	10.0	9.7	9.9	10.1	9.7	10.0	10.3
Petroleum	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Natural Gas	33.4	35.9	36.2	36.6	36.8	37.3	38.0	36.9	37.7	38.7
Other Gaseous Fuels	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Renewable Sources[4]	6.9	7.7	8.2	8.7	7.8	8.5	9.3	7.8	8.8	9.8
Other	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	51.8	55.8	56.8	57.8	56.8	58.3	60.0	56.8	59.1	61.3
Cumulative Additions[5]	20.2	24.2	25.1	26.2	25.1	26.7	28.4	25.2	27.4	29.7

[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]Cumulative additions after December 31, 1996.
[6]Cumulative total retirements from 1990.
[7]Nameplate capacity is reported for nonutilities on Form EIA-867, "Annual Nonutility Power Producer Report." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO99. Net summer capacity is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recent data available as of July 1, 1998. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: 1997 net summer capability at electric utilities and planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report." Net summer capability for nonutilities and cogeneration in 1997 and planned additions estimated based on EIA, Form EIA-867, "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A.

Table B10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1997	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 Sales	190.3	148.6	148.6	148.6	148.6	148.6	148.6	148.6	148.6	148.6
Gross Domestic Economy Sales	87.6	68.2	67.2	71.7	69.6	78.4	80.7	77.8	83.9	79.2
Gross Domestic Trade	277.9	216.8	215.8	220.3	218.2	227.0	229.3	226.5	232.5	227.9
Gross Domestic Firm Power Sales (million 1997 dollars)	8942.1	6983.5	6983.5	6983.5	6983.5	6983.5	6983.5	6983.5	6983.5	6983.5
Gross Domestic Economy Sales (million 1997 dollars)	2186.7	1568.3	1730.9	1911.4	1522.3	1843.5	2065.0	1608.3	1839.1	1945.2
Gross Domestic Sales (million 1997 dollars)	11128.9	8551.8	8714.5	8894.9	8505.8	8827.0	9048.6	8591.8	8822.6	8928.8
International Electricity Trade										
Firm Power Imports From Canada and Mexico[1]	23.9	19.3	19.3	20.5	19.3	19.3	19.3	19.3	19.3	19.3
Economy Imports From Canada and Mexico[1]	18.0	32.9	32.8	32.8	29.9	29.9	29.8	29.7	29.6	29.7
Gross Imports From Canada and Mexico[1]	42.0	52.2	52.2	53.3	49.3	49.2	49.2	49.1	49.0	49.0
Firm Power Exports To Canada and Mexico	4.7	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1
Economy Exports To Canada and Mexico	5.3	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	10.0	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8

[1]Historically electric imports were primarily from renewable resources, principally hydroelectric.

Note: Totals may not equal sum of components due to independent rounding. 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: 1997 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1997 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 1997 Firm/economy share: National Energy Board, *Annual Report 1993.* 1997 Planned interregional and international firm power sales: DOE Form IE-411, "Coordinated Bulk Power Supply Program Report," April 1995. **Projections:** EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A.

Table B11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1997	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]	6.45	5.55	5.59	5.64	5.26	5.34	5.42	4.87	4.96	5.06
Alaska	1.30	0.77	0.78	0.78	0.61	0.61	0.62	0.49	0.49	0.50
Lower 48 States	5.15	4.78	4.81	4.86	4.65	4.72	4.80	4.38	4.47	4.56
Net Imports	8.12	10.44	10.97	11.40	11.03	11.46	12.01	11.42	11.97	12.59
Gross Imports	8.23	10.49	11.02	11.45	11.06	11.50	12.04	11.43	11.99	12.61
Exports	0.11	0.04	0.04	0.05	0.03	0.03	0.04	0.01	0.02	0.02
Other Crude Supply[2]	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	14.57	15.99	16.56	17.04	16.30	16.80	17.42	16.29	16.94	17.65
Natural Gas Plant Liquids	1.82	2.02	2.15	2.28	2.16	2.34	2.51	2.23	2.45	2.65
Other Inputs[3]	0.28	0.27	0.31	0.34	0.32	0.35	0.43	0.26	0.36	0.47
Refinery Processing Gain[4]	0.85	0.89	0.90	0.91	0.88	0.89	0.90	0.88	0.89	0.91
Net Product Imports[5]	1.04	2.41	2.73	3.08	2.48	3.30	3.94	2.86	4.00	5.11
Gross Refined Product Imports[6]	1.52	2.83	3.12	3.45	2.95	3.59	4.21	3.36	4.26	5.19
Unfinished Oil Imports	0.35	0.49	0.54	0.56	0.41	0.61	0.64	0.38	0.68	0.87
Ether Imports	0.06	0.01	0.02	0.05	0.00	0.02	0.05	0.00	0.00	0.04
Exports	0.90	0.92	0.96	0.98	0.88	0.93	0.96	0.88	0.94	0.99
Total Primary Supply[7]	18.55	21.59	22.65	23.64	22.13	23.67	25.21	22.52	24.64	26.80
Refined Petroleum Product Supplied										
Motor Gasoline[8]	7.99	9.68	10.01	10.32	9.86	10.34	10.83	10.01	10.69	11.35
Jet Fuel[9]	1.60	2.31	2.46	2.61	2.52	2.75	2.99	2.71	3.03	3.37
Distillate Fuel[10]	3.43	3.81	3.99	4.16	3.88	4.15	4.42	3.91	4.28	4.66
Residual Fuel	0.83	0.68	0.72	0.74	0.73	0.78	0.82	0.76	0.83	0.89
Other[11]	4.77	5.14	5.51	5.85	5.18	5.68	6.20	5.15	5.82	6.56
Total	18.62	21.63	22.69	23.69	22.16	23.71	25.25	22.54	24.66	26.83
Refined Petroleum Products Supplied										
Residential and Commercial	1.18	0.97	0.99	1.01	0.94	0.96	0.98	0.91	0.92	0.95
Industrial[12]	4.92	5.30	5.70	6.07	5.35	5.90	6.46	5.34	6.07	6.87
Transportation	12.14	15.24	15.88	16.49	15.76	16.73	17.69	16.21	17.56	18.91
Electric Generators[13]	0.38	0.11	0.12	0.11	0.10	0.11	0.11	0.09	0.11	0.11
Total	18.62	21.63	22.69	23.69	22.16	23.71	25.25	22.54	24.66	26.83
Discrepancy[14]	-0.07	-0.04	-0.04	-0.05	-0.03	-0.03	-0.04	-0.02	-0.02	-0.04
World Oil Price (1997 dollars per barrel)[15]	18.55	20.70	21.30	21.90	21.07	21.91	22.75	21.66	22.73	23.81
Import Share of Product Supplied	0.49	0.59	0.60	0.61	0.61	0.62	0.63	0.63	0.65	0.66
Net Expenditures for Imported Crude Oil and Products (billion 1997 dollars)	60.87	98.22	107.95	117.53	104.41	119.49	134.46	114.21	135.20	158.00
Domestic Refinery Distillation Capacity	16.0	16.8	17.5	18.0	17.2	17.7	18.5	17.3	17.9	18.7
Capacity Utilization Rate (percent)	95.0	95.2	95.1	95.0	95.1	95.1	95.1	94.6	95.2	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.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1997 expenditures for imported crude oil and petroleum products based on internal calculations. 1997 product supplied data from table B2. Other 1997 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1997*, DOE/EIA-0340(97/1) (Washington, DC. June 1998). Projections: EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A.

Table B12. Petroleum Product Prices
(1997 Cents per Gallon Unless Otherwise Noted)

Sector and Fuel	1997	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 (1997 dollars per barrel)	18.55	20.70	21.30	21.90	21.07	21.91	22.75	21.66	22.73	23.81
Delivered Sector Product Prices										
Residential										
Distillate Fuel	97.1	105.8	107.4	109.4	104.4	108.4	110.8	104.4	108.1	111.6
Liquefied Petroleum Gas	100.2	103.9	105.4	108.1	101.5	106.9	108.9	103.4	110.9	113.6
Commercial										
Distillate Fuel	68.4	74.5	76.2	78.6	73.3	77.8	80.8	73.9	78.9	82.5
Residual Fuel	51.6	45.4	46.8	48.3	45.6	47.6	49.6	48.1	50.7	53.5
Residual Fuel (1997 dollars per barrel)	21.67	19.06	19.66	20.27	19.17	20.00	20.84	20.22	21.30	22.46
Industrial[1]										
Distillate Fuel	70.7	75.5	77.2	80.4	74.7	79.9	83.8	76.1	82.7	86.7
Liquefied Petroleum Gas	72.4	56.1	57.6	60.4	53.5	59.1	61.1	55.3	63.2	65.8
Residual Fuel	43.4	39.3	40.7	42.3	38.6	40.8	42.9	40.4	43.2	47.1
Residual Fuel (1997 dollars per barrel)	18.21	16.49	17.10	17.76	16.21	17.14	18.00	16.98	18.15	19.80
Transportation										
Diesel Fuel (distillate)[2]	118.4	113.1	119.0	125.8	108.6	118.7	126.3	105.8	118.3	126.2
Jet Fuel[3]	70.2	74.1	77.6	80.8	73.5	80.4	84.8	75.3	85.1	91.2
Motor Gasoline[4]	121.4	122.9	128.8	133.4	120.5	129.2	134.6	118.1	128.8	135.1
Liquefied Petroleum Gas	103.6	109.1	112.7	117.0	104.5	112.1	116.4	104.3	113.9	119.1
Residual Fuel	46.2	37.2	38.6	40.3	37.4	38.8	40.8	38.9	42.2	45.2
Residual Fuel (1997 dollars per barrel)	19.40	15.61	16.20	16.94	15.69	16.32	17.14	16.33	17.74	18.99
E85	145.8	152.9	156.7	162.1	151.0	158.1	164.2	152.9	158.9	166.2
M85	97.3	90.4	95.3	97.9	91.7	95.9	99.5	91.8	96.8	101.1
Electric Generators[5]										
Distillate Fuel	61.4	69.2	70.9	73.9	68.4	73.2	76.6	69.8	75.6	79.3
Residual Fuel	41.3	52.1	52.7	56.0	53.7	54.4	57.2	56.6	58.4	63.3
Residual Fuel (1997 dollars per barrel)	17.36	21.87	22.14	23.50	22.56	22.84	24.03	23.77	24.51	26.58
Refined Petroleum Product Prices[6]										
Distillate Fuel	104.2	104.6	109.2	114.9	101.2	109.8	116.2	99.5	110.1	117.0
Jet Fuel[3]	70.2	74.1	77.6	80.8	73.5	80.4	84.8	75.3	85.1	91.2
Liquefied Petroleum Gas	77.7	66.8	68.0	70.5	64.1	69.3	70.9	65.8	73.0	75.1
Motor Gasoline[4]	121.4	122.9	128.8	133.4	120.5	129.2	134.6	118.1	128.8	135.1
Residual Fuel	44.1	39.8	41.3	43.0	39.6	41.3	43.3	41.0	44.3	47.5
Residual Fuel (1997 dollars per barrel)	18.53	16.72	17.33	18.05	16.64	17.35	18.18	17.22	18.59	19.94
Average	101.2	102.2	106.3	110.2	99.6	106.7	111.1	98.4	107.5	112.7

[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.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption. Includes small power producers and exempt wholesale generators.

Sources: 1997 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 (97/03-98/04) (Washington, DC, 1997-98). 1997 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1995*, DOE/EIA-0376(95) (Washington, DC, August, 1998). **Projections:** EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A.

Table B13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1997	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
Production										
Dry Gas Production[1]	18.94	22.26	23.77	25.26	23.97	26.11	28.01	24.93	27.35	29.62
Supplemental Natural Gas[2]	0.12	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	2.84	4.17	4.35	4.50	4.54	4.78	5.07	4.69	5.02	5.26
Canada	2.84	3.97	4.15	4.30	4.37	4.61	4.85	4.57	4.91	5.10
Mexico	-0.02	-0.09	-0.09	-0.09	-0.12	-0.12	-0.12	-0.17	-0.17	-0.17
Liquefied Natural Gas	0.02	0.29	0.29	0.29	0.29	0.29	0.33	0.29	0.29	0.33
Total Supply	21.89	26.50	28.18	29.82	28.58	30.95	33.14	29.67	32.44	34.94
Consumption by Sector										
Residential	5.00	5.16	5.36	5.57	5.31	5.61	5.90	5.40	5.77	6.13
Commercial	3.28	3.65	3.73	3.81	3.73	3.86	3.97	3.72	3.88	4.04
Industrial[3]	8.40	9.01	9.46	9.90	9.20	9.87	10.55	9.30	10.24	11.17
Electric Generators[4]	3.33	5.88	6.69	7.47	7.33	8.42	9.34	8.12	9.16	10.00
Lease and Plant Fuel[5]	1.25	1.57	1.65	1.72	1.69	1.81	1.91	1.79	1.93	2.05
Pipeline Fuel	0.71	0.83	0.87	0.92	0.88	0.94	1.00	0.91	0.98	1.06
Transportation[6]	0.01	0.24	0.25	0.26	0.28	0.30	0.32	0.30	0.33	0.37
Total	21.98	26.33	28.02	29.67	28.43	30.81	32.99	29.53	32.30	34.81
Discrepancy[7]	-0.10	0.16	0.16	0.16	0.15	0.14	0.15	0.14	0.14	0.13

[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, 1997 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1997 may differ from published data due to internal conversion factors.
Sources: 1997 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(98/06) (Washington, DC, June 1998). 1997 imports and dry gas production derived from: EIA, *Natural Gas Annual 1996*, DOE/EIA-0131(96) (Washington, DC, September 1997). 1997 transportation sector consumption: EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A. Other 1997 consumption: EIA, *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A. **Projections:** EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A.

Table B14. Natural Gas Prices, Margins, and Revenue
(1997 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1997	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]	2.23	2.29	2.52	2.71	2.29	2.62	2.91	2.29	2.68	3.09
Average Import Price	2.15	2.35	2.48	2.60	2.41	2.55	2.72	2.47	2.68	2.88
Average[2]	2.22	2.30	2.51	2.70	2.31	2.60	2.88	2.32	2.68	3.06
Delivered Prices										
Residential	7.00	6.06	6.17	6.27	5.78	5.95	6.11	5.72	5.91	6.14
Commercial	5.79	5.14	5.32	5.49	4.96	5.22	5.47	4.93	5.24	5.56
Industrial[3]	3.04	2.96	3.23	3.47	2.95	3.32	3.65	2.93	3.40	3.87
Electric Generators[4]	2.76	2.91	3.15	3.35	2.91	3.24	3.52	2.90	3.31	3.71
Transportation[5]	6.36	6.80	7.37	7.87	6.79	7.52	8.18	6.73	7.57	8.36
Average[6]	4.44	3.99	4.18	4.34	3.85	4.13	4.39	3.81	4.16	4.53
Transmission and Distribution Margins[7]										
Residential	4.78	3.76	3.66	3.57	3.47	3.35	3.24	3.41	3.23	3.08
Commercial	3.57	2.84	2.81	2.79	2.65	2.62	2.59	2.62	2.56	2.50
Industrial[3]	0.82	0.66	0.72	0.77	0.64	0.72	0.78	0.61	0.72	0.81
Electric Generators[4]	0.54	0.61	0.64	0.66	0.60	0.63	0.65	0.59	0.63	0.65
Transportation[5]	4.15	4.50	4.86	5.18	4.47	4.92	5.30	4.41	4.89	5.30
Average[6]	2.22	1.69	1.67	1.65	1.54	1.53	1.51	1.49	1.48	1.47
Transmission and Distribution Revenue (billion 1997 dollars)										
Residential	23.92	19.39	19.64	19.90	18.42	18.76	19.10	18.41	18.65	18.89
Commercial	11.70	10.36	10.50	10.64	9.88	10.10	10.30	9.72	9.93	10.11
Industrial[3]	6.92	5.94	6.82	7.66	5.85	7.06	8.19	5.69	7.33	9.05
Electric Generators[4]	1.80	3.58	4.28	4.91	4.38	5.31	6.06	4.77	5.76	6.53
Transportation[5]	0.06	1.07	1.22	1.37	1.25	1.48	1.72	1.33	1.64	1.95
Total	44.39	40.34	42.47	44.47	39.77	42.72	45.36	39.91	43.31	46.54

[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.
Sources: 1997 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1991.* 1997 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly,* DOE/EIA-0130(98/06) (Washington, DC, June 1998). Other 1997 values, and projections: EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A.

Economic Growth Case Comparisons

Table B15. Oil and Gas Supply

Production and Supply	1997	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] (1997 dollars per barrel)	16.25	20.18	20.80	21.59	20.09	21.05	22.11	20.47	21.73	22.85
Production (million barrels per day)[2]										
U.S. Total	6.45	5.55	5.59	5.64	5.26	5.34	5.42	4.87	4.96	5.06
Lower 48 Onshore	3.75	3.04	3.07	3.10	3.16	3.21	3.27	3.20	3.28	3.35
Conventional	3.17	2.53	2.54	2.56	2.53	2.56	2.58	2.54	2.57	2.58
Enhanced Oil Recovery	0.58	0.52	0.53	0.54	0.63	0.66	0.69	0.66	0.71	0.76
Lower 48 Offshore	1.40	1.73	1.74	1.76	1.50	1.51	1.53	1.18	1.19	1.22
Alaska	1.30	0.77	0.78	0.78	0.61	0.61	0.62	0.49	0.49	0.50
Lower 48 End of Year Reserves (billion barrels)[2]	18.28	13.68	13.80	13.94	13.45	13.70	13.97	13.30	13.70	14.07
Natural Gas										
Lower 48 Average Wellhead Price[1] (1997 dollars per thousand cubic feet)	2.23	2.29	2.52	2.71	2.29	2.62	2.91	2.29	2.68	3.09
Production (trillion cubic feet)[3]										
U.S. Total	18.94	22.26	23.77	25.27	23.97	26.11	28.01	24.93	27.35	29.62
Lower 48 Onshore	12.88	14.94	16.36	17.83	16.63	18.47	19.97	18.22	20.24	21.94
Associated-Dissolved[4]	1.77	1.18	1.19	1.19	1.18	1.19	1.20	1.19	1.21	1.21
Non-Associated	11.11	13.75	15.18	16.64	15.45	17.28	18.78	17.03	19.04	20.73
Conventional	7.43	9.65	10.27	10.62	10.69	11.30	11.81	11.72	12.32	12.88
Unconventional	3.68	4.10	4.90	6.02	4.76	5.97	6.96	5.31	6.72	7.84
Lower 48 Offshore	5.62	6.65	6.73	6.75	6.64	6.94	7.33	5.98	6.38	6.94
Associated-Dissolved[4]	0.80	0.93	0.93	0.93	0.88	0.89	0.89	0.81	0.81	0.82
Non-Associated	4.82	5.72	5.80	5.81	5.75	6.05	6.43	5.17	5.57	6.12
Alaska	0.44	0.68	0.68	0.69	0.70	0.71	0.72	0.72	0.73	0.74
Lower 48 End of Year Reserves (trillion cubic feet)	158.13	166.66	174.29	187.88	164.97	175.73	188.80	157.40	172.03	181.19
Supplemental Gas Supplies (trillion cubic feet)[5]	0.12	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Total Lower 48 Wells (thousands)	27.02	29.18	31.54	35.83	30.77	33.66	36.36	31.78	35.62	39.36

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Market 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.

Ft. = feet.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1997 may differ from published data due to internal conversion factors.

Sources: 1997 lower 48 onshore, lower 48 offshore, Alaska crude oil production: Energy Information Administration (EIA), EIA, *Petroleum Supply Annual 1997,* DOE/EIA-0340(97/1) (Washington, DC. June 1998). 1997 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly,* DOE/EIA-0130(98/06) (Washington, DC, June 1998). Other 1997 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A.

Table B16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1997	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
Production[1]										
Appalachia	477	479	482	496	453	479	495	444	466	497
Interior	171	120	127	127	150	146	154	147	164	168
West	451	613	627	642	649	670	697	689	728	782
East of the Mississippi	589	554	563	579	560	580	604	548	586	620
West of the Mississippi	511	657	672	686	693	714	742	733	772	827
Total	1099	1211	1236	1264	1253	1294	1346	1281	1358	1447
Net Imports										
Imports	7	8	8	8	8	8	8	8	8	8
Exports	84	90	90	90	91	91	91	93	93	93
Total	-76	-82	-82	-82	-84	-84	-84	-86	-86	-86
Total Supply[2]	1023	1129	1154	1182	1169	1211	1262	1195	1272	1362
Consumption by Sector										
Residential and Commercial	6	6	7	7	6	7	7	6	7	7
Industrial[3]	70	71	77	82	71	79	87	70	82	95
Coke Plants	29	24	24	23	22	22	21	20	20	19
Electric Generators[4]	924	1027	1050	1070	1073	1103	1148	1098	1166	1242
Total	1030	1128	1156	1182	1172	1211	1263	1195	1275	1363
Discrepancy and Stock Change[5]	-7	1	-3	1	-3	0	-1	0	-3	-1
Average Minemouth Price										
(1997 dollars per short ton)	18.14	13.88	14.00	14.16	12.98	13.21	13.39	12.47	12.74	12.89
(1997 dollars per million Btu)	0.85	0.66	0.67	0.67	0.62	0.63	0.64	0.60	0.62	0.62
Delivered Prices (1997 dollars per short ton)[6]										
Industrial	32.41	26.92	27.40	27.84	25.41	26.15	26.83	24.05	24.96	25.86
Coke Plants	47.36	41.51	41.98	42.33	39.29	40.16	41.00	37.57	38.74	39.61
Electric Generators										
(1997 dollars per short ton)	26.16	21.33	21.66	22.00	19.44	20.03	20.53	18.03	18.77	19.33
(1997 dollars per million Btu)	1.27	1.05	1.06	1.08	0.96	0.99	1.01	0.90	0.93	0.96
Average	27.20	22.11	22.46	22.81	20.17	20.80	21.32	18.71	19.49	20.08
Exports[7]	40.55	34.75	35.15	35.51	32.55	33.38	34.10	30.89	31.90	32.71

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 7.9 million tons in 1994, 8.5 million tons in 1995, 8.9 million tons in 1996, 9.4 million tons in 1997, and are projected to reach 10.0 million tons in 1998 and 10.6 million tons in 1999.
[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.
Sources: 1997 data derived from: Energy Information Administration (EIA), *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, November 1998). **Projections:** EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A.

Table B17. Renewable Energy Generating Capability and Generation
(Thousand Megawatts, Unless Otherwise Noted)

Capacity and Generation	1997	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	77.60	78.51	78.51	78.51	78.51	78.51	78.51	78.51	78.51	78.51
Geothermal[2]	3.00	3.25	3.16	3.16	3.33	3.25	3.22	3.67	3.52	3.40
Municipal Solid Waste[3]	3.41	3.97	4.01	4.05	4.11	4.17	4.31	4.16	4.27	4.47
Wood and Other Biomass[4]	1.66	2.18	2.33	2.88	2.77	3.61	5.13	3.70	5.61	9.03
Solar Thermal	0.35	0.44	0.44	0.44	0.48	0.48	0.48	0.52	0.52	0.52
Solar Photovoltaic	0.01	0.30	0.30	0.30	0.46	0.46	0.46	0.64	0.64	0.64
Wind	1.88	3.39	3.39	3.39	3.42	3.41	3.41	3.63	3.61	3.59
Total	87.92	92.04	92.14	92.74	93.08	93.89	95.52	94.83	96.68	100.15
Generation (billion kilowatthours)										
Conventional Hydropower	350.62	323.38	323.42	323.46	323.43	323.50	323.57	323.48	323.58	323.68
Geothermal[2]	15.67	18.53	17.86	17.88	20.30	19.69	19.49	24.09	22.99	22.07
Municipal Solid Waste[3]	14.30	26.26	26.49	26.83	27.18	27.65	28.61	27.57	28.34	29.77
Wood and Other Biomass[4]	4.21	10.87	11.97	15.82	15.03	20.90	31.54	21.56	34.89	58.81
Solar Thermal	0.90	1.19	1.19	1.19	1.31	1.31	1.31	1.44	1.44	1.44
Solar Photovoltaic	0.00	0.71	0.71	0.71	1.12	1.12	1.12	1.56	1.56	1.56
Wind	3.41	7.69	7.69	7.69	7.81	7.76	7.78	8.47	8.44	8.37
Total	389.11	388.63	389.33	393.58	396.17	401.92	413.41	408.17	421.24	445.70
Cogenerators[5]										
Net Summer Capability										
Conventional Hydropower[6]	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
Municipal Solid Waste	0.46	0.48	0.48	0.49	0.48	0.49	0.49	0.48	0.49	0.49
Biomass	5.45	6.28	6.77	7.25	6.37	7.13	7.84	6.37	7.39	8.36
Total	6.85	7.70	8.19	8.67	7.78	8.55	9.26	7.79	8.81	9.78
Generation (billion kilowatthours)										
Conventional Hydropower[6]	6.16	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.90
Municipal Solid Waste	1.80	2.32	2.32	2.33	2.32	2.34	2.35	2.32	2.34	2.35
Biomass	32.69	44.83	49.59	54.01	45.98	53.17	59.76	46.22	55.82	64.78
Total	40.65	52.05	56.81	61.24	53.21	60.41	67.01	53.45	63.06	72.04

[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]Represents own-use industrial hydroelectric power.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO99. Net summer capability is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recently available as of July 1, 1998. Additional retirements are also determined on the basis of the size and age of the units. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: 1997 electric utility capability: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report." 1997 nonutility and cogenerator capability: EIA, Form EIA-867, "Annual Nonutility Power Producer Report." 1997 generation: EIA, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A.

Table B18. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1997	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	0.60	0.60	0.62	0.64	0.61	0.64	0.66	0.62	0.65	0.68
Wood	0.60	0.60	0.62	0.64	0.61	0.64	0.66	0.62	0.65	0.68
Commercial[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[4]	1.88	2.12	2.31	2.49	2.17	2.45	2.73	2.19	2.56	2.94
Conventional Hydroelectric	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	1.84	2.08	2.27	2.46	2.14	2.41	2.70	2.15	2.52	2.91
Transportation	0.10	0.14	0.20	0.24	0.20	0.25	0.37	0.13	0.28	0.42
Ethanol used in E85[5]	0.00	0.04	0.04	0.04	0.05	0.05	0.06	0.05	0.06	0.07
Ethanol used in Gasoline Blending	0.10	0.11	0.16	0.20	0.15	0.20	0.31	0.08	0.22	0.36
Electric Generators[6]	4.35	4.48	4.48	4.52	4.61	4.64	4.75	4.80	4.90	5.10
Conventional Hydroelectric	3.60	3.32	3.32	3.33	3.32	3.33	3.33	3.33	3.33	3.33
Geothermal	0.43	0.54	0.52	0.52	0.61	0.59	0.58	0.72	0.69	0.66
Municipal Solid Waste	0.23	0.42	0.42	0.43	0.43	0.44	0.46	0.44	0.45	0.48
Biomass	0.04	0.10	0.11	0.14	0.13	0.19	0.28	0.19	0.31	0.52
Solar Thermal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar Photovoltaic	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02
Wind	0.04	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09
Total Marketed Renewable Energy	6.92	7.35	7.61	7.90	7.59	7.99	8.51	7.73	8.38	9.16
Non-Marketed Renewable Energy[7] Selected Consumption										
Residential	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.04	0.05	0.05
Solar Hot Water Heating	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Geothermal Heat Pumps	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.03	0.04	0.04
Commercial	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Solar Thermal	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04

[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]Value is less than 0.005 quadrillion Btu per year and rounds to zero.
[4]Includes all electricity production by industrial and other cogenerators for the grid and for own use.
[5]Excludes motor gasoline component of E85.
[6]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.
[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.
Notes: Totals may not equal sum of components due to independent rounding.
Sources: 1997 ethanol: EIA, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). 1997 electric generators: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report," and EIA, Form EIA-867, "Annual Nonutility Power Producer Report." Other 1997: EIA, Office of Integrated Analysis and Forecasting. Projections: EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A.

Economic Growth Case Comparisons

Table B19. Carbon Emissions by Sector and Source
(Million Metric Tons per Year)

Sector and Source	1997	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
Residential										
Petroleum	27.8	22.7	23.0	23.3	21.7	22.0	22.3	20.7	21.0	21.4
Natural Gas	74.1	76.4	79.5	82.6	78.8	83.1	87.4	80.1	85.6	90.9
Coal	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Electricity	182.3	222.9	228.6	234.1	240.5	247.9	256.6	255.3	267.2	278.8
Total	285.6	323.4	332.5	341.3	342.3	354.3	367.7	357.4	375.0	392.3
Commercial										
Petroleum	14.4	10.9	11.1	11.3	10.7	11.0	11.3	10.3	10.6	11.0
Natural Gas	48.6	54.1	55.3	56.5	55.3	57.1	58.9	55.1	57.6	59.8
Coal	2.1	2.4	2.5	2.6	2.5	2.6	2.7	2.4	2.6	2.7
Electricity	171.5	209.9	212.8	214.8	224.0	228.3	233.0	229.0	237.3	244.6
Total	236.6	277.3	281.7	285.2	292.5	299.0	305.9	296.8	308.1	318.2
Industrial[1]										
Petroleum	105.8	110.5	117.4	123.6	110.7	120.0	129.3	109.4	121.4	134.8
Natural Gas[2]	142.2	154.3	161.9	169.4	158.8	170.4	181.6	161.8	177.4	192.6
Coal	58.5	59.6	63.5	67.4	58.4	64.6	70.8	57.1	65.9	74.9
Electricity	175.6	191.0	206.5	221.2	197.7	219.5	242.6	197.9	229.8	263.0
Total	482.1	515.4	549.4	581.7	525.7	574.5	624.3	526.2	594.5	665.2
Transportation										
Petroleum[3]	461.9	577.4	600.8	623.4	596.8	632.9	667.5	615.6	664.7	713.7
Natural Gas[4]	10.5	15.9	16.7	17.5	17.2	18.4	19.6	17.9	19.5	21.1
Other[5]	0.0	1.3	1.4	1.4	1.5	1.7	1.8	1.6	1.9	2.1
Electricity	2.9	7.3	7.6	7.8	9.1	9.4	9.9	10.7	11.2	11.8
Total[3]	475.3	601.8	626.3	650.1	624.5	662.3	698.7	645.9	697.3	748.7
Total Carbon Emissions by Delivered Fuel										
Petroleum[3]	609.9	721.4	752.4	781.7	739.9	785.9	830.4	756.0	817.7	880.9
Natural Gas	275.4	300.6	313.4	326.0	310.1	328.9	347.5	314.8	340.0	364.3
Coal	62.0	63.4	67.4	71.3	62.2	68.4	74.8	60.9	69.8	78.9
Other[5]	0.0	1.3	1.4	1.4	1.5	1.7	1.8	1.6	1.9	2.1
Electricity	532.4	631.1	655.4	677.9	671.3	705.1	742.2	693.0	745.5	798.2
Total[3]	1479.6	1717.8	1789.9	1858.3	1784.9	1890.1	1996.7	1826.3	1974.9	2124.4
Electric Generatorsl[6]										
Petroleum	17.6	5.2	5.8	5.4	4.6	5.3	5.2	4.1	4.9	5.0
Natural Gas	43.8	86.6	98.5	110.0	107.9	124.0	137.5	119.5	134.8	147.2
Coal	471.0	539.4	551.1	562.6	558.7	575.9	599.5	569.3	605.8	646.1
Total	532.4	631.1	655.4	677.9	671.3	705.1	742.2	693.0	745.5	798.2
Total Carbon Emissions by Primary Fuel[7]										
Petroleum[3]	627.5	726.6	758.1	787.0	744.5	791.1	835.6	760.2	822.6	885.8
Natural Gas	319.1	387.2	411.9	436.0	418.0	452.9	484.9	434.3	474.8	511.5
Coal	533.0	602.7	618.5	633.9	620.9	644.4	674.3	630.2	675.6	725.0
Other[5]	0.0	1.3	1.4	1.4	1.5	1.7	1.8	1.6	1.9	2.1
Total[3]	1479.6	1717.8	1789.9	1858.3	1784.9	1890.1	1996.7	1826.3	1974.9	2124.4
Carbon Emissions (tons per person)	5.5	5.9	6.0	6.1	6.0	6.1	6.2	5.9	6.1	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 emissions. In the years from 1989 through 1996, international bunker fuels account for 22 to 24 million metric ton of carbon 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.
[7]Emissions from electric power generator are distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Carbon coefficients from Energy Information Administration, (EIA) *Emissions of Greenhouse Gases in the United States 1997*, DOE/EIA-0573(97) (Washington, DC, October 1998). 1997 consumption estimates based on: EIA, *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998).
Projections: EIA, AEO99 National Energy Modeling System run LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A.

Table B20. Macroeconomic Indicators
(Billion 1992 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	1997	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										
(1992=1.000)	1.116	1.882	1.487	1.256	2.441	1.742	1.373	3.289	2.126	1.564
Real Gross Domestic Product	7270	9184	9896	10593	9755	10800	11842	10256	11680	13106
Real Consumption	4914	6400	6754	7106	6974	7521	8070	7569	8347	9124
Real Investment	1206	1682	1925	2169	1814	2149	2487	1956	2401	2853
Real Government Spending	1285	1513	1588	1663	1569	1680	1791	1612	1764	1915
Real Exports	970	2055	2257	2458	2500	2858	3217	2895	3460	4023
Real Imports	1106	2607	2704	2826	3470	3655	3878	4567	4903	5264
Real Disposable Personal Income	5183	6766	7170	7577	7388	8006	8633	8030	8905	9770
Index of Manufacturing Gross Output										
(Index 1987=1.000)	1.359	1.679	1.810	1.945	1.786	1.977	2.184	1.867	2.137	2.439
AA Utility Bond Rate (percent)	7.54	8.29	6.17	4.61	8.99	6.82	5.24	9.82	7.62	5.94
Real Yield on Government 10 Year Bonds										
(percent)	4.94	3.12	3.20	3.22	3.09	3.13	3.10	2.97	3.01	2.92
Real Utility Bond Rate (percent)	5.53	3.52	3.48	3.39	3.51	3.48	3.32	3.46	3.37	3.12
Energy Intensity										
(thousand Btu per 1992 dollar of GDP)										
Delivered Energy	9.70	8.81	8.57	8.36	8.54	8.24	8.00	8.28	7.94	7.67
Total Energy	12.94	11.57	11.21	10.89	11.15	10.70	10.34	10.78	10.27	9.88
Consumer Price Index (1982-84=1.00)	1.61	2.89	2.28	1.93	3.74	2.68	2.11	4.98	3.23	2.39
Unemployment Rate (percent)	4.95	5.86	5.36	4.96	5.82	5.43	5.06	5.59	5.32	4.95
Unit Sales of Light-Duty Vehicles (million)	15.08	15.50	16.50	17.47	15.24	16.81	18.40	14.48	16.74	18.97
Millions of People										
Population with Armed Forces Overseas	268.2	290.2	298.3	305.7	299.2	310.7	321.3	308.4	323.4	337.1
Population (aged 16 and over)	206.3	229.2	235.0	2405	237.0	245.4	253.2	244.0	255.1	265.4
Employment, Non-Agriculture	121.4	138.2	143.5	149.0	142.1	149.4	157.2	144.6	154.0	164.5
Employment, Manufacturing	18.5	16.3	17.2	18.0	15.1	16.2	17.3	13.8	15.1	16.4
Labor Force	136.3	152.0	157.2	162.2	153.9	161.3	168.2	154.0	163.5	172.5

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 1997: Data Resources Incorporated (DRI), DRI Trend0898. **Projections:** Energy Information Administration, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A.

Economic Growth Case Comparisons

Table B21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1997	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 (1997 dollars per barrel)[1]	18.55	20.70	21.30	21.90	21.07	21.91	22.75	21.66	22.73	23.81
Production[2]										
OECD										
U.S. (50 states)	9.34	8.79	8.99	9.18	8.57	8.94	9.30	8.26	8.70	9.13
Canada	2.59	3.31	3.31	3.31	3.35	3.35	3.35	3.38	3.38	3.38
Mexico	3.44	3.97	3.97	3.97	3.95	3.95	3.95	3.87	3.87	3.87
OECD Europe[3]	7.02	7.47	7.47	7.47	6.75	6.75	6.75	6.26	6.26	6.26
Other OECD	0.83	0.91	0.91	0.91	0.87	0.87	0.87	0.80	0.80	0.80
Total OECD	23.21	24.46	24.66	24.85	23.49	23.86	24.22	22.56	23.00	23.44
Developing Countries										
Other South & Central America	3.40	4.77	4.77	4.77	4.90	4.90	4.90	4.97	4.97	4.97
Pacific Rim	2.17	3.16	3.16	3.16	3.23	3.23	3.23	3.25	3.25	3.25
OPEC	29.85	39.48	40.35	41.16	47.51	48.70	49.89	57.13	58.81	60.54
Other Developing Countries	4.58	6.33	6.33	6.33	6.82	6.82	6.82	7.32	7.32	7.32
Total Developing Countries	39.99	53.73	54.60	55.41	62.46	63.65	64.84	72.67	74.36	76.09
Eurasia										
Former Soviet Union	7.13	12.03	12.03	12.03	12.62	12.62	12.62	13.18	13.18	13.18
Eastern Europe	0.25	0.42	0.42	0.42	0.44	0.44	0.44	0.42	0.42	0.42
China	3.20	3.56	3.56	3.56	3.60	3.60	3.60	3.46	3.46	3.46
Total Eurasia	10.58	16.02	16.02	16.02	16.65	16.65	16.65	17.06	17.06	17.06
Total Production	73.78	94.20	95.28	96.27	102.60	104.17	105.71	112.29	114.41	116.58
Consumption										
OECD										
U.S. (50 states)	18.62	21.62	22.69	23.69	22.14	23.71	25.25	22.54	24.67	26.83
U.S. Territories	0.20	0.38	0.38	0.38	0.42	0.42	0.42	0.47	0.47	0.47
Canada	1.86	2.19	2.19	2.19	2.32	2.32	2.32	2.48	2.48	2.48
Mexico	1.91	2.78	2.78	2.78	3.02	3.02	3.02	3.26	3.26	3.26
Japan	5.71	7.21	7.21	7.21	7.58	7.58	7.58	8.02	8.02	8.02
Australia and New Zealand	0.95	1.21	1.21	1.21	1.25	1.25	1.25	1.30	1.30	1.30
OECD Europe[3]	14.43	15.50	15.50	15.50	15.59	15.59	15.59	15.69	15.69	15.69
Total OECD	43.68	50.90	51.97	52.97	52.32	53.89	55.43	53.76	55.88	58.05
Developing Countries										
Other South and Central America	3.77	6.64	6.64	6.64	7.71	7.71	7.71	8.97	8.97	8.97
Pacific Rim	4.77	7.38	7.38	7.38	8.74	8.74	8.74	10.38	10.38	10.38
OPEC	5.56	7.06	7.06	7.06	7.91	7.91	7.91	8.86	8.86	8.86
Other Developing Countries	5.50	8.20	8.20	8.20	9.14	9.14	9.14	10.24	10.24	10.24
Total Developing Countries	19.60	29.28	29.28	29.28	33.51	33.51	33.51	38.45	38.45	38.45

Table B21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1997	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
Eurasia										
Former Soviet Union	4.43	5.96	5.96	5.96	6.71	6.71	6.71	7.47	7.47	7.47
Eastern Europe	1.37	1.90	1.90	1.90	2.24	2.24	2.24	2.65	2.65	2.65
China	3.88	6.47	6.47	6.47	8.12	8.12	8.12	10.26	10.26	10.26
Total Eurasia	9.68	14.33	14.33	14.33	17.07	17.07	17.07	20.38	20.38	20.38
Total Consumption	72.96	94.50	95.58	96.57	102.90	104.47	106.01	112.59	114.71	116.88
Non-OPEC Production	43.94	54.73	54.93	55.12	55.09	55.46	55.82	55.16	55.60	56.04
Net Eurasia Exports	0.91	1.69	1.69	1.69	-0.41	-0.41	-0.41	-3.32	-3.32	-3.32
OPEC Market Share	0.40	0.42	0.42	0.43	0.46	0.47	0.47	0.51	0.51	0.52

[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, Slovak Republic, the Former Soviet Union, and the Former Yugoslavia.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1997 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **Projections:** EIA, AEO99 National Energy Modeling System runs LMAC99.D100198A, AEO99B.D100198A, and HMAC99.D100198A.

Appendix C

Oil Price Case Comparisons

Table C1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1997	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										
Crude Oil and Lease Condensate	13.65	10.50	11.83	12.84	9.56	11.30	12.48	8.73	10.51	11.60
Natural Gas Plant Liquids	2.57	2.99	3.06	3.07	3.24	3.32	3.36	3.42	3.47	3.49
Dry Natural Gas	19.47	23.90	24.44	24.55	26.16	26.84	27.19	27.64	28.12	28.24
Coal	23.33	26.08	25.91	26.05	26.82	26.95	27.04	27.65	28.12	28.34
Nuclear Power	6.71	5.88	5.91	5.91	4.39	4.47	4.47	3.75	3.83	3.92
Renewable Energy[1]	6.82	7.42	7.44	7.49	7.73	7.77	7.83	8.09	8.15	8.23
Other[2]	0.66	0.48	0.57	0.60	0.52	0.62	0.68	0.56	0.65	0.75
Total	73.22	77.25	79.16	80.51	78.42	81.28	83.06	79.83	82.85	84.57
Imports										
Crude Oil[3]	17.86	25.56	23.91	21.96	27.33	24.96	23.67	28.52	26.03	25.05
Petroleum Products[4]	3.89	9.12	7.35	6.95	10.58	8.50	6.94	12.19	9.92	8.11
Natural Gas	3.06	4.49	4.69	4.71	5.01	5.15	5.17	5.33	5.46	5.46
Other Imports[5]	0.54	0.71	0.71	0.73	0.72	0.72	0.75	0.74	0.75	0.78
Total	25.34	39.88	36.66	34.35	43.65	39.33	36.53	46.79	42.15	39.40
Exports										
Petroleum[6]	2.09	2.09	2.11	1.97	2.14	2.02	1.97	2.08	2.00	1.95
Natural Gas	0.16	0.24	0.24	0.24	0.27	0.27	0.27	0.32	0.32	0.32
Coal	2.19	2.27	2.27	2.27	2.31	2.31	2.31	2.36	2.36	2.36
Total	4.44	4.60	4.62	4.48	4.72	4.59	4.54	4.76	4.68	4.63
Discrepancy[7]	-0.08	-0.52	-0.37	-0.37	-0.55	-0.49	-0.37	-0.63	-0.44	-0.34
Consumption										
Petroleum Products[8]	36.49	46.08	44.22	43.11	48.53	46.20	44.82	50.69	48.08	46.70
Natural Gas	22.59	28.05	28.79	28.93	30.81	31.64	32.04	32.56	33.17	33.30
Coal	21.09	24.18	24.06	24.14	24.95	25.05	25.10	25.73	26.26	26.43
Nuclear Power	6.71	5.88	5.91	5.91	4.39	4.47	4.47	3.75	3.83	3.92
Renewable Energy[1]	6.82	7.43	7.45	7.50	7.74	7.79	7.84	8.10	8.17	8.24
Other[9]	0.33	0.39	0.39	0.41	0.38	0.38	0.40	0.40	0.39	0.41
Total	94.04	112.02	110.83	110.00	116.81	115.53	114.67	121.23	119.89	119.00
Net Imports - Petroleum	19.65	32.59	29.16	26.93	35.77	31.44	28.64	38.64	33.95	31.20
Prices (1997 dollars per unit)										
World Oil Price (dollars per barrel)[10]	18.55	14.57	21.30	27.33	14.57	21.91	29.14	14.57	22.73	29.35
Gas Wellhead Price (dollars per Mcf)[11]	2.23	2.48	2.52	2.52	2.58	2.62	2.64	2.62	2.68	2.70
Coal Minemouth Price (dollars per ton)	18.14	14.06	14.00	14.15	13.29	13.21	13.22	12.66	12.74	12.76
Average Electric Price (cents per kwh)	6.9	6.1	6.1	6.1	5.8	5.8	5.8	5.6	5.6	5.6

[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. Figures for 1997 may differ from published data due to internal conversion factors.
Sources: 1997 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(98/06) (Washington, DC, June 1998). 1997 coal minemouth price: *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, November 1998). Coal production and exports derived from: EIA, *Monthly Energy Review*, DOE/EIA-0035(98/08) (Washington, DC, August 1998). Other 1997 values: EIA, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998) **Projections:** EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Table C2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1997	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	0.94	0.78	0.73	0.69	0.75	0.69	0.65	0.72	0.65	0.61
Kerosene	0.09	0.07	0.07	0.07	0.07	0.07	0.06	0.07	0.07	0.06
Liquefied Petroleum Gas	0.43	0.47	0.43	0.40	0.47	0.42	0.38	0.47	0.40	0.37
Petroleum Subtotal	1.47	1.33	1.23	1.16	1.29	1.18	1.09	1.26	1.12	1.04
Natural Gas	5.15	5.50	5.52	5.54	5.74	5.77	5.79	5.91	5.94	5.97
Coal	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.60	0.62	0.62	0.62	0.64	0.64	0.64	0.65	0.65	0.65
Electricity	3.66	4.58	4.57	4.58	4.93	4.93	4.94	5.31	5.31	5.32
Delivered Energy	**10.92**	**12.08**	**12.00**	**11.95**	**12.65**	**12.57**	**12.51**	**13.18**	**13.08**	**13.02**
Electricity Related Losses	8.07	9.31	9.11	9.11	9.54	9.34	9.34	9.95	9.77	9.78
Total	**18.99**	**21.39**	**21.11**	**21.06**	**22.19**	**21.91**	**21.85**	**23.12**	**22.85**	**22.81**
Commercial										
Distillate Fuel	0.49	0.42	0.34	0.30	0.42	0.33	0.29	0.41	0.32	0.28
Residual Fuel	0.11	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Kerosene	0.03	0.03	0.03	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.08	0.09	0.09	0.08	0.09	0.09	0.09	0.09	0.09	0.09
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Petroleum Subtotal	0.73	0.65	0.57	0.53	0.66	0.56	0.52	0.65	0.55	0.50
Natural Gas	3.37	3.81	3.84	3.85	3.93	3.97	3.98	3.95	4.00	4.00
Coal	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	3.44	4.26	4.26	4.26	4.54	4.54	4.55	4.72	4.72	4.72
Delivered Energy	**7.63**	**8.82**	**8.77**	**8.74**	**9.23**	**9.18**	**9.14**	**9.42**	**9.37**	**9.33**
Electricity Related Losses	7.59	8.67	8.48	8.48	8.79	8.60	8.60	8.85	8.68	8.69
Total	**15.22**	**17.50**	**17.24**	**17.21**	**18.02**	**17.78**	**17.75**	**18.27**	**18.05**	**18.02**
Industrial[4]										
Distillate Fuel	1.13	1.39	1.35	1.32	1.47	1.42	1.39	1.54	1.48	1.45
Liquefied Petroleum Gas	2.14	2.51	2.45	2.41	2.67	2.58	2.54	2.79	2.69	2.65
Petrochemical Feedstock	1.46	1.53	1.52	1.52	1.60	1.60	1.60	1.68	1.67	1.67
Residual Fuel	0.28	0.50	0.33	0.27	0.53	0.35	0.27	0.54	0.36	0.27
Motor Gasoline[2]	0.21	0.26	0.26	0.26	0.28	0.28	0.28	0.30	0.29	0.29
Other Petroleum[5]	4.11	5.18	4.89	4.66	5.28	4.95	4.61	5.41	4.99	4.68
Petroleum Subtotal	9.33	11.38	10.81	10.44	11.84	11.18	10.68	12.25	11.49	11.03
Natural Gas[6]	9.92	10.91	11.43	11.63	11.39	12.02	12.41	11.80	12.52	12.88
Metallurgical Coal	0.79	0.64	0.63	0.62	0.59	0.58	0.57	0.54	0.53	0.52
Steam Coal	1.56	1.64	1.67	1.68	1.66	1.73	1.76	1.70	1.80	1.83
Net Coal Coke Imports	0.02	0.21	0.20	0.20	0.24	0.24	0.25	0.26	0.27	0.28
Coal Subtotal	2.36	2.49	2.51	2.50	2.50	2.55	2.58	2.50	2.60	2.63
Renewable Energy[7]	1.88	2.29	2.31	2.34	2.42	2.45	2.49	2.52	2.56	2.60
Electricity	3.52	4.15	4.13	4.11	4.39	4.37	4.36	4.58	4.57	4.56
Delivered Energy	**27.01**	**31.22**	**31.18**	**31.02**	**32.54**	**32.57**	**32.51**	**33.65**	**33.73**	**33.68**
Electricity Related Losses	7.78	8.45	8.22	8.18	8.48	8.27	8.24	8.58	8.40	8.39
Total	**34.79**	**39.67**	**39.41**	**39.21**	**41.02**	**40.84**	**40.75**	**42.24**	**42.14**	**42.07**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1997	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[8]	4.64	6.01	6.00	5.98	6.34	6.31	6.28	6.63	6.58	6.54
Jet Fuel[9]	3.31	5.13	5.10	5.04	5.75	5.69	5.60	6.37	6.27	6.13
Motor Gasoline[2]	15.08	19.04	18.70	18.24	19.79	19.31	18.77	20.54	19.94	19.40
Residual Fuel	0.75	1.02	1.02	1.02	1.15	1.16	1.16	1.29	1.30	1.30
Liquefied Petroleum Gas	0.04	0.18	0.18	0.17	0.21	0.20	0.20	0.23	0.22	0.22
Other Petroleum[10]	0.29	0.34	0.34	0.34	0.35	0.35	0.35	0.36	0.36	0.36
Petroleum Subtotal	24.10	31.72	31.33	30.80	33.60	33.03	32.36	35.42	34.68	33.95
Pipeline Fuel Natural Gas	0.73	0.88	0.90	0.90	0.94	0.97	0.97	0.99	1.01	1.01
Compressed Natural Gas	0.01	0.26	0.26	0.26	0.31	0.31	0.31	0.34	0.34	0.34
Renewable Energy (E85)[11]	0.00	0.05	0.05	0.05	0.07	0.07	0.06	0.08	0.07	0.07
M85[12]	0.00	0.08	0.08	0.07	0.10	0.10	0.09	0.12	0.11	0.10
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	0.15	0.15	0.15	0.19	0.19	0.18	0.22	0.22	0.22
Delivered Energy	24.91	33.15	32.77	32.23	35.21	34.65	33.98	37.17	36.44	35.70
Electricity Related Losses	0.13	0.31	0.30	0.30	0.37	0.36	0.35	0.42	0.41	0.40
Total	25.04	33.46	33.07	32.52	35.58	35.00	34.33	37.60	36.85	36.10
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.20	8.61	8.42	8.29	8.99	8.76	8.60	9.30	9.04	8.88
Kerosene	0.15	0.13	0.13	0.12	0.13	0.13	0.12	0.13	0.13	0.12
Jet Fuel[9]	3.31	5.13	5.10	5.04	5.75	5.69	5.60	6.37	6.27	6.13
Liquefied Petroleum Gas	2.69	3.25	3.15	3.06	3.44	3.29	3.21	3.57	3.40	3.32
Motor Gasoline[2]	15.32	19.33	18.99	18.53	20.09	19.61	19.07	20.86	20.26	19.71
Petrochemical Feedstock	1.46	1.53	1.52	1.52	1.60	1.60	1.60	1.68	1.67	1.67
Residual Fuel	1.13	1.61	1.44	1.38	1.78	1.60	1.52	1.93	1.75	1.67
Other Petroleum[13]	4.37	5.49	5.20	4.97	5.60	5.27	4.93	5.74	5.32	5.00
Petroleum Subtotal	35.62	45.08	43.95	42.92	47.39	45.95	44.64	49.58	47.84	46.51
Natural Gas[6]	19.19	21.37	21.95	22.18	22.32	23.03	23.46	22.99	23.81	24.18
Metallurgical Coal	0.79	0.64	0.63	0.62	0.59	0.58	0.57	0.54	0.53	0.52
Steam Coal	1.69	1.78	1.82	1.83	1.81	1.88	1.92	1.85	1.95	1.98
Net Coal Coke Imports	0.02	0.21	0.20	0.20	0.24	0.24	0.25	0.26	0.27	0.28
Coal Subtotal	2.50	2.63	2.65	2.65	2.65	2.70	2.73	2.65	2.75	2.78
Renewable Energy[14]	2.48	2.97	2.98	3.01	3.13	3.15	3.19	3.25	3.29	3.33
M85[12]	0.00	0.08	0.08	0.07	0.10	0.10	0.09	0.12	0.11	0.10
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	10.68	13.15	13.11	13.10	14.05	14.03	14.03	14.84	14.82	14.82
Delivered Energy	70.47	85.28	84.72	83.93	89.63	88.96	88.14	93.43	92.62	91.73
Electricity Related Losses	23.57	26.74	26.11	26.07	27.18	26.57	26.54	27.80	27.27	27.26
Total	94.04	112.02	110.83	110.00	116.81	115.53	114.67	121.23	119.89	119.00
Electric Generators[15]										
Distillate Fuel	0.09	0.13	0.06	0.06	0.18	0.06	0.06	0.21	0.07	0.06
Residual Fuel	0.77	0.87	0.21	0.13	0.96	0.19	0.12	0.91	0.17	0.12
Petroleum Subtotal	0.87	1.00	0.28	0.20	1.14	0.25	0.18	1.12	0.24	0.18
Natural Gas	3.40	6.68	6.84	6.75	8.49	8.61	8.58	9.57	9.36	9.12
Steam Coal	18.59	21.54	21.41	21.48	22.31	22.35	22.37	23.07	23.51	23.65
Nuclear Power	6.71	5.88	5.91	5.91	4.39	4.47	4.47	3.75	3.83	3.92
Renewable Energy[16]	4.35	4.47	4.47	4.49	4.61	4.63	4.65	4.85	4.88	4.91
Electricity Imports[17]	0.33	0.31	0.31	0.34	0.28	0.28	0.31	0.28	0.28	0.31
Total	34.25	39.89	39.22	39.17	41.23	40.60	40.57	42.64	42.09	42.08

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1997	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
Total Energy Consumption										
Distillate Fuel	7.29	8.74	8.49	8.35	9.17	8.82	8.67	9.51	9.10	8.94
Kerosene	0.15	0.13	0.13	0.12	0.13	0.13	0.12	0.13	0.13	0.12
Jet Fuel[9]	3.31	5.13	5.10	5.04	5.75	5.69	5.60	6.37	6.27	6.13
Liquefied Petroleum Gas	2.69	3.25	3.15	3.06	3.44	3.29	3.21	3.57	3.40	3.32
Motor Gasoline[2]	15.32	19.33	18.99	18.53	20.09	19.61	19.07	20.86	20.26	19.71
Petrochemical Feedstock	1.46	1.53	1.52	1.52	1.60	1.60	1.60	1.68	1.67	1.67
Residual Fuel	1.91	2.48	1.65	1.51	2.74	1.79	1.63	2.84	1.92	1.78
Other Petroleum[13]	4.37	5.49	5.20	4.97	5.60	5.27	4.93	5.74	5.32	5.00
Petroleum Subtotal	36.49	46.08	44.22	43.11	48.53	46.20	44.82	50.70	48.08	46.69
Natural Gas	22.59	28.05	28.79	28.93	30.81	31.64	32.04	32.56	33.17	33.30
Metallurgical Coal	0.79	0.64	0.63	0.62	0.59	0.58	0.57	0.54	0.53	0.52
Steam Coal	20.29	23.33	23.23	23.31	24.12	24.23	24.29	24.92	25.45	25.63
Net Coal Coke Imports	0.02	0.21	0.20	0.20	0.24	0.24	0.25	0.26	0.27	0.28
Coal Subtotal	21.09	24.18	24.06	24.14	24.95	25.05	25.10	25.73	26.26	26.43
Nuclear Power	6.71	5.88	5.91	5.91	4.39	4.47	4.47	3.75	3.83	3.92
Renewable Energy[18]	6.82	7.43	7.45	7.50	7.74	7.79	7.84	8.10	8.17	8.24
M85[12]	0.00	0.08	0.08	0.07	0.10	0.10	0.09	0.12	0.11	0.10
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports[17]	0.33	0.31	0.31	0.34	0.28	0.28	0.31	0.28	0.28	0.31
Total	94.04	112.02	110.83	110.00	116.81	115.53	114.67	121.23	119.88	118.98
Energy Use and Related Statistics										
Delivered Energy Use	70.47	85.28	84.72	83.93	89.63	88.96	88.14	93.43	92.62	91.73
Total Energy Use	94.04	112.02	110.83	110.00	116.81	115.53	114.67	121.23	119.88	118.98
Population (millions)	268.19	298.31	298.31	298.31	310.75	310.75	310.75	323.36	323.36	323.36
Gross Domestic Product (billion 1992 dollars)	7269.76	9895.98	9895.50	9895.98	10802.19	10800.49	10802.19	11680.22	11680.02	11680.22
Total Carbon Emissions (million metric tons)	1479.60	1820.91	1789.87	1771.68	1923.63	1890.06	1869.35	2006.25	1974.88	1952.63

[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.
[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.
[4]Fuel consumption includes consumption for cogeneration.
[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 & wood waste, municipal solid waste, & other biomass; includes for cogeneration, both sales to the grid & for own use.
[8]Low sulfur diesel fuel.
[9]Includes naphtha and kerosene type.
[10]Includes aviation gas and lubricants.
[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 unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[14]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 and solar thermal hot water heaters.
[15]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.
[16]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.
[17]In 1997 approximately two-thirds of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions.
[18]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 and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1997 may differ from published data due to internal conversion factors. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1997 electric utility fuel consumption: Energy Information Administration (EIA), *Electric Power Annual 1997, Volume 1,* DOE/EIA-0348(97)/1 (Washington, DC, July 1998). 1997 nonutility consumption estimates: Form EIA-867, "Annual Nonutility Power Producer Report." Other 1997 values: EIA, *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **Projections:** EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Table C3. Energy Prices by Sector and Source
(1997 Dollars per Million Btu)

Sector and Source	1997	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	13.40	12.71	12.95	13.09	12.40	12.63	12.76	12.23	12.47	12.57
Primary Energy[1]	7.12	6.35	6.57	6.75	6.15	6.37	6.55	6.09	6.33	6.47
Petroleum Products[2]	8.42	8.18	9.36	10.54	8.13	9.49	10.74	8.18	9.67	10.80
Distillate Fuel	7.00	6.60	7.75	8.81	6.56	7.82	8.99	6.50	7.79	8.88
Liquefied Petroleum Gas	11.61	10.91	12.22	13.68	10.73	12.38	13.81	10.87	12.85	14.10
Natural Gas	6.80	5.96	6.00	6.01	5.74	5.78	5.80	5.69	5.74	5.76
Electricity	24.85	22.28	22.45	22.42	21.40	21.50	21.47	20.57	20.68	20.66
Commercial	13.09	11.84	12.04	12.10	11.47	11.63	11.70	11.23	11.43	11.48
Primary Energy[1]	5.51	5.01	5.21	5.35	4.92	5.14	5.29	4.92	5.16	5.29
Petroleum Products[2]	5.46	4.86	6.10	7.26	4.81	6.22	7.48	4.86	6.40	7.52
Distillate Fuel	4.93	4.34	5.49	6.57	4.32	5.61	6.79	4.34	5.69	6.74
Residual Fuel	3.45	2.17	3.13	4.01	2.06	3.18	4.26	2.12	3.39	4.37
Natural Gas[3]	5.62	5.12	5.17	5.19	5.03	5.08	5.10	5.03	5.09	5.11
Electricity	22.32	19.14	19.28	19.19	18.23	18.25	18.17	17.50	17.59	17.51
Industrial[4]	5.42	4.73	5.22	5.67	4.65	5.21	5.66	4.66	5.28	5.67
Primary Energy	4.01	3.44	4.02	4.55	3.45	4.13	4.66	3.53	4.27	4.74
Petroleum Products[2]	5.60	4.13	5.38	6.59	4.08	5.53	6.78	4.18	5.79	6.88
Distillate Fuel	5.10	4.44	5.56	6.68	4.47	5.76	6.95	4.57	5.97	6.98
Liquefied Petroleum Gas	8.38	5.48	6.67	8.17	5.29	6.85	8.22	5.45	7.33	8.47
Residual Fuel	2.90	1.52	2.72	3.58	1.42	2.73	3.77	1.48	2.89	3.82
Natural Gas[5]	2.96	3.10	3.14	3.16	3.19	3.23	3.25	3.24	3.30	3.33
Metallurgical Coal	1.77	1.55	1.57	1.57	1.49	1.50	1.51	1.43	1.45	1.45
Steam Coal	1.47	1.24	1.26	1.27	1.18	1.20	1.21	1.13	1.14	1.15
Electricity	13.56	11.85	11.89	11.83	11.13	11.09	11.04	10.66	10.68	10.63
Transportation	8.60	7.56	9.00	10.13	7.37	9.00	10.11	7.26	9.00	10.07
Primary Energy	8.58	7.53	8.98	10.11	7.34	8.97	10.10	7.22	8.97	10.05
Petroleum Products[2]	8.58	7.52	8.98	10.12	7.32	8.97	10.10	7.20	8.97	10.06
Distillate Fuel[6]	8.53	7.44	8.58	9.68	7.26	8.56	9.71	7.15	8.53	9.56
Jet Fuel[7]	5.20	4.42	5.74	6.91	4.47	5.96	7.13	4.69	6.31	7.83
Motor Gasoline[8]	9.70	8.75	10.40	11.60	8.56	10.43	11.57	8.40	10.40	11.40
Residual Fuel	3.09	1.61	2.58	3.40	1.55	2.60	3.65	1.57	2.82	3.78
Liquid Petroleum Gas[9]	12.00	11.73	13.06	14.48	11.35	12.99	14.38	11.24	13.20	14.43
Natural Gas[10]	6.18	6.98	7.17	7.20	7.08	7.31	7.35	7.06	7.36	7.40
E85[11]	16.27	15.76	17.53	19.17	15.73	17.68	19.30	16.00	17.78	19.13
M85[12]	13.25	10.73	13.02	14.75	10.59	13.10	15.39	10.45	13.22	15.30
Electricity	16.30	14.70	14.55	14.39	13.83	13.67	13.57	13.14	13.04	12.98
Average End-Use Energy	8.72	7.81	8.62	9.25	7.64	8.53	9.16	7.54	8.52	9.10
Primary Energy	8.35	7.41	8.31	9.02	7.23	8.24	8.94	7.14	8.23	8.89
Electricity	20.26	17.87	18.00	17.96	17.07	17.10	17.06	16.42	16.50	16.46
Electric Generators[13]										
Fossil Fuel Average	1.55	1.55	1.57	1.58	1.59	1.61	1.62	1.61	1.61	1.60
Petroleum Products	2.94	2.29	3.89	5.09	2.23	4.05	5.53	2.36	4.33	5.62
Distillate Fuel	4.43	4.00	5.11	6.19	4.00	5.28	6.47	4.15	5.45	6.49
Residual Fuel	2.76	2.03	3.52	4.57	1.90	3.63	5.02	1.95	3.90	5.15
Natural Gas	2.70	3.00	3.08	3.09	3.11	3.17	3.18	3.16	3.24	3.24
Steam Coal	1.27	1.06	1.06	1.07	0.98	0.99	1.00	0.92	0.93	0.94

Table C3. Energy Prices by Sector and Source (Continued)
(1997 Dollars per Million Btu)

Sector and Source	1997	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
Average Price to All Users[14]										
Petroleum Products[2]	7.70	6.63	8.11	9.29	6.47	8.16	9.34	6.43	8.24	9.34
Distillate Fuel	7.51	6.69	7.88	8.99	6.55	7.91	9.10	6.49	7.94	8.99
Jet Fuel	5.20	4.42	5.74	6.91	4.47	5.96	7.13	4.69	6.31	7.83
Liquefied Petroleum Gas	9.01	6.70	7.88	9.34	6.50	8.03	9.37	6.61	8.46	9.58
Motor Gasoline[8]	9.70	8.75	10.40	11.60	8.56	10.43	11.57	8.40	10.41	11.40
Residual Fuel	2.95	1.76	2.76	3.57	1.67	2.76	3.80	1.69	2.96	3.90
Natural Gas	4.32	4.03	4.06	4.07	3.99	4.02	4.03	3.99	4.05	4.06
Coal	1.30	1.07	1.08	1.09	1.00	1.01	1.01	0.94	0.95	0.95
E85[11]	16.27	15.76	17.53	19.17	15.73	17.68	19.30	16.00	17.78	19.13
M85[12]	13.25	10.73	13.02	14.75	10.59	13.10	15.39	10.45	13.22	15.30
Electricity	20.26	17.87	18.00	17.96	17.07	17.10	17.06	16.42	16.50	16.46
Non-Renewable Energy Expenditures by Sector (Billion 1997 dollars)										
Residential	138.32	145.68	147.38	148.20	149.07	150.70	151.45	153.21	154.96	155.51
Commercial	99.87	104.42	105.54	105.69	105.88	106.71	106.94	105.78	106.97	107.10
Industrial	113.52	112.28	122.05	131.13	114.83	127.03	137.12	118.70	133.57	142.73
Transportation	207.85	242.99	285.93	316.27	251.38	301.75	332.45	261.27	317.40	347.65
Total Non-Renewable Expenditures	559.55	605.37	660.89	701.28	621.16	686.18	727.96	638.95	712.90	752.98
Transportation Renewable Expenditures	0.01	0.83	0.90	0.94	1.05	1.15	1.21	1.21	1.32	1.36
Total Expenditures	559.56	606.20	661.79	702.23	622.21	687.33	729.17	640.17	714.22	754.35

[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: 1997 figures may differ from published data due to internal rounding.
Sources: 1997 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 (97/03-98/04) (Washington, DC, 1997-98). 1997 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditures Report: 1995*, DOE/EIA-0376(95) (Washington, DC, August, 1998). 1997 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1991*. 1997 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(98/06) (Washington, DC, June 1998). Other 1997 natural gas delivered prices: EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B. Values for 1997 coal prices have been estimated from EIA, *State Energy Price and Expenditures Report: 1995*, DOE/EIA-0376(95) (Washington, DC, August, 1998) by use of consumption quantities aggregated from EIA, *State Energy Data Report 1995*, DOE/EIA-0214(95) (Washington, DC, December 1997) and the *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, November 1998). 1997 electricity prices for commercial, industrial, and transportation: EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B. **Projections:** EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Table C4. Residential Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1997	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	70.18	81.13	81.13	81.13	85.29	85.30	85.29	89.35	89.35	89.35
Multifamily	25.00	28.71	28.71	28.71	30.42	30.42	30.42	31.88	31.88	31.88
Mobile Homes	6.13	7.64	7.64	7.64	8.24	8.24	8.24	8.79	8.79	8.79
Total	**101.31**	**117.48**	**117.48**	**117.48**	**123.95**	**123.96**	**123.95**	**130.01**	**130.02**	**130.01**
Average House Square Footage	**1654**	**1703**	**1703**	**1703**	**1715**	**1715**	**1715**	**1727**	**1727**	**1727**
Energy Intensity (million Btu consumed per household)										
Delivered Energy Consumption	107.80	102.86	102.14	101.69	102.08	101.38	100.92	101.35	100.58	100.16
Electricity Related Losses	79.65	79.23	77.52	77.56	76.93	75.34	75.36	76.51	75.16	75.24
Total Energy Consumption	187.45	182.09	179.66	179.25	179.01	176.72	176.28	177.86	175.74	175.41
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.44	0.47	0.47	0.48	0.49	0.49	0.49	0.51	0.51	0.52
Space Cooling	0.46	0.55	0.55	0.55	0.58	0.58	0.58	0.60	0.60	0.60
Water Heating	0.35	0.37	0.37	0.37	0.38	0.38	0.39	0.40	0.40	0.40
Refrigeration	0.39	0.29	0.29	0.29	0.27	0.27	0.27	0.28	0.28	0.28
Cooking	0.13	0.15	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17
Clothes Dryers	0.19	0.22	0.22	0.22	0.24	0.24	0.24	0.25	0.25	0.25
Freezers	0.12	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Lighting	0.34	0.40	0.40	0.40	0.43	0.43	0.43	0.46	0.46	0.46
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]	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06
Color Televisions	0.21	0.29	0.29	0.30	0.31	0.31	0.31	0.33	0.33	0.33
Personal Computers	0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05
Furnace Fans	0.09	0.12	0.12	0.12	0.13	0.13	0.13	0.14	0.14	0.14
Other Uses[2]	0.83	1.52	1.52	1.52	1.74	1.74	1.74	1.95	1.95	1.94
Delivered Energy	**3.66**	**4.58**	**4.57**	**4.58**	**4.93**	**4.93**	**4.94**	**5.31**	**5.31**	**5.32**
Natural Gas										
Space Heating	3.58	3.79	3.80	3.82	3.94	3.96	3.98	4.04	4.07	4.09
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Water Heating	1.27	1.37	1.38	1.38	1.45	1.45	1.46	1.49	1.50	1.50
Cooking	0.16	0.17	0.17	0.18	0.18	0.18	0.18	0.19	0.19	0.19
Clothes Dryers	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Other Uses[3]	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12
Delivered Energy	**5.15**	**5.50**	**5.52**	**5.54**	**5.74**	**5.77**	**5.79**	**5.91**	**5.94**	**5.97**
Distillate										
Space Heating	0.84	0.69	0.64	0.61	0.65	0.60	0.56	0.62	0.57	0.53
Water Heating	0.10	0.09	0.09	0.09	0.09	0.09	0.08	0.09	0.09	0.08
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	**0.94**	**0.78**	**0.73**	**0.69**	**0.75**	**0.69**	**0.65**	**0.72**	**0.65**	**0.61**
Liquefied Petroleum Gas										
Space Heating	0.32	0.34	0.31	0.28	0.34	0.30	0.27	0.33	0.28	0.26
Water Heating	0.07	0.09	0.08	0.07	0.09	0.08	0.07	0.09	0.07	0.07
Cooking	0.03	0.04	0.03	0.03	0.04	0.03	0.03	0.04	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	**0.43**	**0.47**	**0.43**	**0.40**	**0.47**	**0.42**	**0.38**	**0.47**	**0.40**	**0.37**
Marketed Renewables (wood)[5]	0.60	0.62	0.62	0.62	0.64	0.64	0.64	0.65	0.65	0.65
Other Fuels[6]	0.15	0.13	0.12	0.12	0.12	0.12	0.11	0.12	0.12	0.11

Table C4. Residential Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1997	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
Delivered Energy Consumption by End-Use										
Space Heating	5.93	6.04	5.97	5.92	6.18	6.10	6.05	6.28	6.20	6.15
Space Cooling	0.46	0.55	0.55	0.55	0.58	0.58	0.58	0.61	0.61	0.61
Water Heating	1.79	1.92	1.91	1.91	2.01	2.00	1.99	2.08	2.06	2.06
Refrigeration	0.39	0.29	0.29	0.29	0.27	0.27	0.27	0.28	0.28	0.28
Cooking	0.33	0.36	0.36	0.36	0.38	0.38	0.38	0.40	0.40	0.40
Clothes Dryers	0.24	0.28	0.27	0.27	0.29	0.29	0.29	0.32	0.32	0.32
Freezers	0.12	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Lighting	0.34	0.40	0.40	0.40	0.43	0.43	0.43	0.46	0.46	0.46
Clothes Washers	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Dishwashers	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06
Color Televisions	0.21	0.29	0.29	0.30	0.31	0.31	0.31	0.33	0.33	0.33
Personal Computers	0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05
Furnace Fans	0.09	0.12	0.12	0.12	0.13	0.13	0.13	0.14	0.14	0.14
Other Uses[7]	0.93	1.64	1.63	1.64	1.86	1.86	1.86	2.08	2.08	2.08
Delivered Energy	10.92	12.08	12.00	11.95	12.65	12.57	12.51	13.18	13.08	13.02
Electricity Related Losses	8.07	9.31	9.11	9.11	9.54	9.34	9.34	9.95	9.77	9.78
Total Energy Consumption by End-Use										
Space Heating	6.90	7.00	6.91	6.87	7.12	7.03	6.99	7.23	7.14	7.10
Space Cooling	1.47	1.67	1.63	1.63	1.70	1.68	1.67	1.74	1.71	1.71
Water Heating	2.57	2.68	2.65	2.65	2.75	2.73	2.72	2.83	2.80	2.80
Refrigeration	1.26	0.87	0.85	0.85	0.80	0.79	0.79	0.79	0.78	0.78
Cooking	0.62	0.67	0.67	0.67	0.70	0.69	0.69	0.72	0.72	0.72
Clothes Dryers	0.65	0.72	0.71	0.71	0.75	0.74	0.74	0.79	0.78	0.78
Freezers	0.39	0.22	0.22	0.22	0.21	0.20	0.20	0.20	0.20	0.20
Lighting	1.09	1.22	1.20	1.20	1.27	1.25	1.25	1.32	1.30	1.30
Clothes Washers	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.11	0.11
Dishwashers	0.15	0.16	0.16	0.16	0.17	0.16	0.16	0.17	0.17	0.17
Color Televisions	0.69	0.89	0.88	0.88	0.90	0.89	0.89	0.95	0.94	0.94
Personal Computers	0.06	0.11	0.11	0.11	0.12	0.12	0.12	0.14	0.14	0.14
Furnace Fans	0.28	0.35	0.35	0.35	0.38	0.37	0.37	0.40	0.40	0.40
Other Uses[7]	2.77	4.72	4.65	4.65	5.22	5.15	5.15	5.72	5.65	5.65
Total	18.99	21.39	21.11	21.06	22.19	21.91	21.85	23.12	22.85	22.81
Non-Marketed Renewables										
Geothermal[8]	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.04
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	0.05	0.05	0.05

[1]Does not include electronic 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 1993.*
[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.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1997: Energy Information Administration (EIA) *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **Projections:** EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Table C5. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1997	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	58.8	68.0	68.0	68.0	70.7	70.7	70.7	71.9	71.9	71.9
New Additions	1.6	1.5	1.5	1.5	1.3	1.3	1.3	1.0	1.0	1.0
Total	60.3	69.5	69.5	69.5	72.0	72.0	72.0	72.9	72.9	72.9
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	126.5	127.0	126.2	125.7	128.2	127.5	127.0	129.3	128.5	128.0
Electricity Related Losses	125.9	124.8	122.0	122.0	122.1	119.5	119.5	121.4	119.1	119.2
Total Energy Consumption	252.4	251.8	248.1	247.7	250.3	247.0	246.5	250.6	247.5	247.2
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.13	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Space Cooling	0.34	0.36	0.35	0.35	0.36	0.36	0.36	0.36	0.36	0.36
Water Heating	0.07	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06
Ventilation	0.17	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.19	0.19
Cooking	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Lighting	1.22	1.28	1.28	1.28	1.32	1.32	1.32	1.32	1.32	1.32
Refrigeration	0.18	0.20	0.20	0.20	0.21	0.21	0.21	0.21	0.21	0.21
Office Equipment (PC)	0.12	0.20	0.20	0.20	0.22	0.22	0.22	0.24	0.24	0.24
Office Equipment (non-PC)	0.29	0.42	0.42	0.42	0.48	0.48	0.48	0.53	0.53	0.53
Other Uses[1]	0.91	1.41	1.41	1.41	1.57	1.57	1.58	1.69	1.69	1.69
Delivered Energy	3.44	4.26	4.26	4.26	4.54	4.54	4.55	4.72	4.72	4.72
Natural Gas[2]										
Space Heating	1.31	1.34	1.37	1.39	1.36	1.41	1.42	1.36	1.40	1.41
Space Cooling	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Water Heating	0.62	0.69	0.69	0.69	0.71	0.72	0.72	0.73	0.73	0.73
Cooking	0.23	0.28	0.28	0.28	0.29	0.29	0.29	0.30	0.30	0.30
Other Uses[3]	1.20	1.47	1.47	1.47	1.53	1.52	1.52	1.54	1.54	1.54
Delivered Energy	3.37	3.81	3.84	3.85	3.93	3.97	3.98	3.95	4.00	4.00
Distillate										
Space Heating	0.21	0.26	0.20	0.18	0.26	0.19	0.17	0.25	0.18	0.16
Water Heating	0.05	0.05	0.05	0.04	0.05	0.04	0.04	0.05	0.04	0.04
Other Uses[4]	0.23	0.11	0.09	0.08	0.11	0.10	0.08	0.11	0.09	0.08
Delivered Energy	0.49	0.42	0.34	0.30	0.42	0.33	0.29	0.41	0.32	0.28
Other Fuels[5]	0.32	0.33	0.32	0.32	0.33	0.33	0.33	0.33	0.33	0.33
Marketed Renewable Fuels										
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy Consumption by End-Use										
Space Heating	1.65	1.72	1.70	1.69	1.74	1.72	1.70	1.72	1.70	1.69
Space Cooling	0.35	0.38	0.38	0.38	0.39	0.39	0.39	0.39	0.39	0.39
Water Heating	0.74	0.81	0.80	0.80	0.83	0.82	0.82	0.84	0.83	0.83
Ventilation	0.17	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.19	0.19
Cooking	0.25	0.30	0.30	0.30	0.31	0.31	0.31	0.32	0.32	0.32
Lighting	1.22	1.28	1.28	1.28	1.32	1.32	1.32	1.32	1.32	1.32
Refrigeration	0.18	0.20	0.20	0.20	0.21	0.21	0.21	0.21	0.21	0.21
Office Equipment (PC)	0.12	0.20	0.20	0.20	0.22	0.22	0.22	0.24	0.24	0.24
Office Equipment (non-PC)	0.29	0.42	0.42	0.42	0.48	0.48	0.48	0.53	0.53	0.53
Other Uses[6]	2.67	3.32	3.30	3.29	3.55	3.53	3.51	3.68	3.65	3.64
Delivered Energy	7.63	8.82	8.77	8.74	9.23	9.18	9.14	9.42	9.37	9.33

Table C5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1997	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
Electricity Related Losses	7.59	8.67	8.48	8.48	8.79	8.60	8.60	8.85	8.68	8.69
Total Energy Consumption by End-Use										
Space Heating	1.94	1.98	1.95	1.93	1.98	1.95	1.93	1.94	1.91	1.90
Space Cooling	1.10	1.11	1.09	1.09	1.09	1.07	1.07	1.06	1.05	1.05
Water Heating	0.89	0.95	0.94	0.93	0.95	0.95	0.94	0.95	0.94	0.94
Ventilation	0.53	0.55	0.55	0.55	0.54	0.54	0.54	0.53	0.53	0.53
Cooking	0.30	0.34	0.34	0.34	0.35	0.35	0.35	0.35	0.35	0.35
Lighting	3.90	3.90	3.83	3.83	3.87	3.81	3.81	3.79	3.74	3.74
Refrigeration	0.58	0.61	0.60	0.60	0.61	0.60	0.60	0.61	0.60	0.60
Office Equipment (PC)	0.37	0.59	0.58	0.58	0.63	0.63	0.63	0.68	0.68	0.68
Office Equipment (non-PC)	0.93	1.28	1.26	1.26	1.40	1.38	1.38	1.51	1.49	1.49
Other Uses[6]	4.68	6.20	6.11	6.09	6.60	6.51	6.49	6.84	6.76	6.74
Total	15.22	17.50	17.24	17.21	18.02	17.78	17.75	18.27	18.05	18.02
Non-Marketed Renewable Fuels										
Solar[7]	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Total	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04

[1]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, and medical equipment.
[2]Excludes estimated consumption from independent power producers.
[3]Includes miscellaneous uses, such as district services, pumps, emergency electric generators, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, district services, and emergency electric generators.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes primary energy displaced by solar thermal space heating and water heating.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1997 Energy Information Administration, *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **Projections:** EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Table C6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1997	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										
Value of Gross Output (billion 1987 dollars)										
Manufacturing	3170	4223	4224	4223	4613	4613	4615	4988	4986	4988
Nonmanufacturing	812	1009	1013	1015	1074	1081	1084	1138	1145	1147
Total	3982	5231	5237	5238	5688	5693	5699	6126	6131	6135
Energy Prices (1997 dollars per million Btu)										
Electricity	13.56	11.85	11.89	11.83	11.13	11.09	11.04	10.66	10.68	10.63
Natural Gas	2.96	3.10	3.14	3.16	3.19	3.23	3.25	3.24	3.30	3.33
Steam Coal	1.47	1.24	1.26	1.27	1.18	1.20	1.21	1.13	1.14	1.15
Residual Oil	2.90	1.52	2.72	3.58	1.42	2.73	3.77	1.48	2.89	3.82
Distillate Oil	5.10	4.44	5.56	6.68	4.47	5.76	6.95	4.57	5.97	6.98
Liquefied Petroleum Gas	8.38	5.48	6.67	8.17	5.29	6.85	8.22	5.45	7.33	8.47
Motor Gasoline	9.69	8.77	10.42	11.60	8.59	10.47	11.59	8.46	10.46	11.42
Metallurgical Coal	1.77	1.55	1.57	1.57	1.49	1.50	1.51	1.43	1.45	1.45
Energy Consumption										
Consumption[1]										
Purchased Electricity	3.52	4.15	4.13	4.11	4.39	4.37	4.36	4.58	4.57	4.56
Natural Gas[2]	9.92	10.91	11.43	11.63	11.39	12.02	12.41	11.80	12.52	12.88
Steam Coal	1.56	1.64	1.67	1.68	1.66	1.73	1.76	1.70	1.80	1.83
Metallurgical Coal and Coke[3]	0.81	0.85	0.84	0.82	0.83	0.82	0.81	0.80	0.80	0.80
Residual Fuel	0.28	0.50	0.33	0.27	0.53	0.35	0.27	0.54	0.36	0.27
Distillate	1.13	1.39	1.35	1.32	1.47	1.42	1.39	1.54	1.48	1.45
Liquefied Petroleum Gas	2.14	2.51	2.45	2.41	2.67	2.58	2.54	2.79	2.69	2.65
Petrochemical Feedstocks	1.46	1.53	1.52	1.52	1.60	1.60	1.60	1.68	1.67	1.67
Other Petroleum[4]	4.33	5.45	5.16	4.92	5.56	5.23	4.89	5.70	5.29	4.97
Renewables[5]	1.88	2.29	2.31	2.34	2.42	2.45	2.49	2.52	2.56	2.60
Delivered Energy	27.01	31.22	31.18	31.02	32.54	32.57	32.51	33.66	33.73	33.69
Electricity Related Losses	7.78	8.45	8.22	8.18	8.48	8.27	8.24	8.58	8.40	8.39
Total	34.79	39.67	39.41	39.21	41.02	40.84	40.75	42.24	42.14	42.08
Consumption per Unit of Output[1] (thousand Btu per 1987 dollars)										
Purchased Electricity	0.88	0.79	0.79	0.79	0.77	0.77	0.76	0.75	0.75	0.74
Natural Gas[2]	2.49	2.09	2.18	2.22	2.00	2.11	2.18	1.93	2.04	2.10
Steam Coal	0.39	0.31	0.32	0.32	0.29	0.30	0.31	0.28	0.29	0.30
Metallurgical Coal and Coke[3]	0.20	0.16	0.16	0.16	0.15	0.14	0.14	0.13	0.13	0.13
Residual Fuel	0.07	0.10	0.06	0.05	0.09	0.06	0.05	0.09	0.06	0.04
Distillate	0.28	0.27	0.26	0.25	0.26	0.25	0.24	0.25	0.24	0.24
Liquefied Petroleum Gas	0.54	0.48	0.47	0.46	0.47	0.45	0.45	0.46	0.44	0.43
Petrochemical Feedstocks	0.37	0.29	0.29	0.29	0.28	0.28	0.28	0.27	0.27	0.27
Other Petroleum[4]	1.09	1.04	0.98	0.94	0.98	0.92	0.86	0.93	0.86	0.81
Renewables[5]	0.47	0.44	0.44	0.45	0.43	0.43	0.44	0.41	0.42	0.42
Delivered Energy	6.78	5.97	5.95	5.92	5.72	5.72	5.70	5.49	5.50	5.49
Electricity Related Losses	1.95	1.61	1.57	1.56	1.49	1.45	1.45	1.40	1.37	1.37
Total	8.74	7.58	7.52	7.49	7.21	7.17	7.15	6.90	6.87	6.86

[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.
Sources: 1997 prices for gasoline and distillate are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380 (97/03-98/04) (Washington, DC, 1997-98). 1997 coal prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(98/08) (Washington, DC, August 1998). 1997 electricity prices: EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B Other 1997 prices derived from EIA, *State Energy Data Report 1995*, DOE/EIA-0214(95) (Washington, DC, December 1997). Other 1997 values: EIA, *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **Projections:** EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Table C7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	1997	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 lbs. (VMT)	2301	2904	2887	2845	3117	3097	3049	3324	3303	3260
Commercial Light Trucks (VMT)[1]	69	91	90	90	98	97	97	105	104	104
Freight Trucks >10,000 lbs. (VMT)	177	243	243	243	258	258	258	270	270	270
Air (seat miles available)	1049	1827	1814	1797	2143	2127	2102	2480	2462	2413
Rail (ton miles traveled)	1229	1524	1519	1519	1617	1620	1622	1708	1719	1724
Marine (ton miles traveled)	757	864	879	887	906	928	939	941	964	972
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)	24.0	24.8	25.4	25.9	25.4	26.1	26.6	25.6	26.5	26.9
New Car (miles per gallon)[2]	27.9	30.7	31.6	32.3	31.0	32.1	32.6	30.9	32.1	32.6
New Light Truck (miles per gallon)[2]	20.2	20.3	20.7	21.0	20.9	21.5	21.7	21.4	22.0	22.3
Light-Duty Fleet (miles per gallon)[3]	20.5	20.1	20.3	20.6	20.5	20.9	21.2	20.9	21.4	21.8
New Commercial Light Truck (MPG)[1]	19.9	19.4	19.8	20.1	19.9	20.5	20.8	20.4	21.0	21.3
Stock Commercial Light Truck (MPG)[1]	14.6	14.8	15.0	15.1	15.0	15.2	15.4	15.3	15.6	15.7
Aircraft Efficiency (seat miles per gallon)	51.0	55.7	55.7	55.8	57.4	57.6	58.0	59.1	59.6	59.9
Freight Truck Efficiency (miles per gallon)	5.6	6.1	6.1	6.1	6.2	6.2	6.2	6.2	6.3	6.3
Rail Efficiency (ton miles per thousand Btu)	2.7	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.1
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.4	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.7
Energy Use by Mode (quadrillion Btu)										
Light-Duty Vehicles	13.94	18.44	18.10	17.63	19.34	18.85	18.30	20.20	19.60	19.04
Commercial Light Trucks[1]	0.59	0.76	0.76	0.75	0.81	0.80	0.79	0.86	0.84	0.82
Freight Trucks[4]	4.24	5.32	5.30	5.28	5.54	5.51	5.48	5.73	5.68	5.65
Air	3.35	5.20	5.17	5.11	5.83	5.77	5.68	6.47	6.38	6.23
Rail[5]	0.53	0.61	0.61	0.61	0.64	0.64	0.64	0.66	0.66	0.66
Marine[6]	1.28	1.64	1.64	1.65	1.80	1.81	1.82	1.98	1.98	1.99
Pipeline Fuel	0.73	0.88	0.90	0.90	0.94	0.97	0.97	0.99	1.01	1.01
Other[7]	0.24	0.30	0.30	0.30	0.31	0.31	0.31	0.32	0.32	0.32
Total	24.91	33.15	32.77	32.23	35.21	34.65	33.98	37.17	36.44	35.70

[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 passenger rail.
[6]Includes military residual fuel use and recreation boats.
[7]Includes lubricants and aviation gasoline.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Lbs. = Pounds.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1997: U.S. Department of Transportation, Bureau of Transportation Statistics, *Air Carrier Traffic Statistics Monthly, December 1997/1996,* (Washington, DC, 1997); Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998); EIA, *Fuel Oil and Kerosene Sales 1997,* DOE/EIA-0535(97) (Washington, DC, August 1998); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Table C8. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1997	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	1796	2055	2046	2055	2137	2151	2155	2235	2298	2321
Petroleum	82	98	28	20	113	26	18	112	24	19
Natural Gas	299	857	919	910	1157	1213	1209	1343	1349	1314
Nuclear Power	629	551	554	554	411	419	419	351	359	367
Pumped Storage	-3	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[2]	389	388	388	390	399	401	403	418	420	425
Total	3192	3947	3934	3927	4216	4208	4203	4457	4450	4445
Non-Utility Generation for Own Use	10	9	9	9	9	9	9	9	9	9
Cogenerators[3]										
Coal	60	56	55	55	56	55	54	55	54	54
Petroleum	10	8	7	7	8	7	7	8	7	7
Natural Gas	210	210	221	229	213	230	239	215	233	238
Other Gaseous Fuels[4]	4	5	5	5	5	5	5	5	5	5
Renewable Sources[2]	41	56	57	58	59	60	62	61	63	64
Other[5]	4	4	4	4	4	4	4	4	4	4
Total	328	340	350	358	345	362	371	348	367	373
Sales to Utilities	183	179	180	182	180	182	183	181	183	183
Generation for Own Use	146	161	169	177	165	180	188	168	184	190
Net Imports[6]	32	30	30	33	27	27	30	27	27	30
Electricity Sales by Sector										
Residential	1072	1341	1341	1342	1445	1446	1447	1557	1557	1558
Commercial	1008	1250	1247	1248	1332	1332	1333	1384	1383	1384
Industrial	1033	1218	1211	1205	1286	1280	1278	1343	1339	1336
Transportation	17	45	44	44	56	55	54	66	65	64
Total	3130	3854	3843	3840	4118	4113	4112	4350	4345	4343
End-Use Prices (1997 cents per kilowatthour)[7]										
Residential	8.5	7.6	7.7	7.7	7.3	7.3	7.3	7.0	7.1	7.0
Commercial	7.6	6.5	6.6	6.5	6.2	6.2	6.2	6.0	6.0	6.0
Industrial	4.6	4.0	4.1	4.0	3.8	3.8	3.8	3.6	3.6	3.6
Transportation	5.6	5.0	5.0	4.9	4.7	4.7	4.6	4.5	4.4	4.4
All Sectors Average	6.9	6.1	6.1	6.1	5.8	5.8	5.8	5.6	5.6	5.6
Emissions (million short tons)										
Sulfur Dioxide	12.7	8.95	9.06	9.27	8.95	8.95	8.95	8.95	8.95	8.95
Nitrogen Oxide	5.8	4.19	4.06	4.04	4.35	4.21	4.20	4.41	4.29	4.25

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[2]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[3]Cogenerators produce electricity and other useful thermal energy. Includes sales to utilities and generation for own use.
[4]Other gaseous fuels include refinery and still gas.
[5]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[6]In 1997 approximately two-thirds of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions.
[7]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1997 commercial and transportation sales derived from: Total transportation plus commercial sales come from Energy Information Administration (EIA), *State Energy Data Report 1995*, DOE/EIA-0214(95) (Washington, DC, December 1997), but individual sectors do not match because sales taken from commercial and placed in transportation, according to Oak Ridge National Laboratories, *Transportation Energy Data Book 17* (August 1997) which indicates the transportation value should be higher. 1997 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: EIA, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). 1997 residential electricity prices derived from EIA, *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **1997 electricity prices for commercial, industrial, and transportation; emissions; and projections:** EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Table C9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	1997	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
Electric Generators[2]										
Capability										
Coal Steam	304.7	306.9	308.9	309.4	312.0	316.2	317.2	323.2	333.0	336.7
Other Fossil Steam[3]	138.7	110.8	80.2	79.7	109.6	79.5	78.4	108.5	75.7	76.6
Combined Cycle	16.4	100.4	126.0	132.4	147.5	175.9	180.2	183.7	211.5	211.3
Combustion Turbine/Diesel	78.2	155.8	151.0	144.9	180.1	174.9	170.7	194.0	186.7	182.2
Nuclear Power	99.0	73.4	74.2	74.2	55.3	56.4	56.4	47.8	48.9	50.0
Pumped Storage	19.6	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
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]	87.9	92.1	92.1	92.3	93.6	93.9	94.2	96.3	96.7	97.4
Total	744.5	861.0	853.9	854.5	919.7	918.4	918.6	975.0	974.0	975.7
Cumulative Planned Additions[5]										
Coal Steam	0.1	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Other Fossil Steam[3]	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combined Cycle	0.7	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Combustion Turbine/Diesel	1.5	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6
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	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
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]	0.1	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Total	2.5	30.1	30.1	30.1	30.2	30.2	30.2	30.2	30.2	30.2
Cumulative Unplanned Additions[5]										
Coal Steam	0.0	3.9	5.6	6.4	9.6	13.5	14.9	21.4	31.0	34.9
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	105.0	111.4	126.5	155.0	159.2	162.7	190.5	190.3
Combustion Turbine/Diesel	20.2	87.6	81.1	73.3	115.1	108.2	100.2	130.0	120.2	112.9
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]	0.8	2.2	2.3	2.5	4.0	4.3	4.6	6.9	7.3	8.0
Total	21.0	173.2	194.0	193.6	255.3	281.0	278.9	321.0	348.9	346.1
Cumulative Total Additions	23.5	203.4	224.2	223.8	285.4	311.1	309.1	351.2	379.0	376.3
Cumulative Retirements[6]	14.8	80.7	105.7	105.9	104.2	128.3	126.5	114.6	140.6	136.7

Table C9. Electricity Generating Capability (Continued)
(Thousand Megawatts)

Net Summer Capability[1]	1997	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[7]										
Capability										
Coal	9.4	9.9	9.9	9.9	10.0	9.9	9.9	10.0	10.0	10.0
Petroleum	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Natural Gas	33.4	34.9	36.2	37.2	35.3	37.3	38.5	35.6	37.7	38.5
Other Gaseous Fuels	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Renewable Sources[4]	6.9	8.2	8.2	8.3	8.5	8.5	8.6	8.7	8.8	8.9
Other	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	51.8	55.6	56.8	57.8	56.3	58.3	59.6	56.8	59.1	59.9
Cumulative Additions[5]	20.2	23.9	25.1	26.2	24.6	26.7	28.0	25.2	27.4	28.3

[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]Cumulative additions after December 31, 1996.
[6]Cumulative total retirements from 1990.
[7]Nameplate capacity is reported for nonutilities on Form EIA-867, "Annual Nonutility Power Producer Report." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.
Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO99. Net summer capacity is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recent data available as of July 1, 1998. Therefore, capacity estimates may differ from other Energy Information Administration sources.
Sources: 1997 net summer capability at electric utilities and planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report." Net summer capability for nonutilities and cogeneration in 1997 and planned additions estimated based on EIA, Form EIA-867, "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Table C10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1997	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 Sales	190.3	148.6	148.6	148.6	148.6	148.6	148.6	148.6	148.6	148.6
Gross Domestic Economy Sales	87.6	77.5	67.2	68.9	88.0	78.4	77.5	97.2	83.9	84.9
Gross Domestic Trade	277.9	226.1	215.8	217.5	236.6	227.0	226.1	245.8	232.5	233.5
Gross Domestic Firm Power Sales (million 1997 dollars)	8942.1	6983.5	6983.5	6983.5	6983.5	6983.5	6983.5	6983.5	6983.5	6983.5
Gross Domestic Economy Sales (million 1997 dollars)	2186.7	1975.8	1730.9	1693.4	2137.8	1843.5	1779.9	2155.5	1839.1	1847.7
Gross Domestic Sales (million 1997 dollars)	11128.9	8959.3	8714.5	8677.0	9121.3	8827.0	8763.4	9139.0	8822.6	8831.3
International Electricity Trade										
Firm Power Imports From Canada and Mexico[1]	23.9	19.3	19.3	21.7	19.3	19.3	21.7	19.3	19.3	21.7
Economy Imports From Canada and Mexico[1]	18.0	32.9	32.8	32.9	29.9	29.9	29.9	29.7	29.6	29.8
Gross Imports From Canada and Mexico[1]	42.0	52.2	52.2	54.6	49.3	49.2	51.6	49.0	49.0	51.5
Firm Power Exports To Canada and Mexico	4.7	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1
Economy Exports To Canada and Mexico	5.3	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	10.0	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8

[1]Historically electric imports were primarily from renewable resources, principally hydroelectric.

Note: Totals may not equal sum of components due to independent rounding. 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: 1997 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1997 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 1997 Firm/economy share: National Energy Board, *Annual Report 1993.* 1997 Planned interregional and international firm power sales: DOE Form IE-411, "Coordinated Bulk Power Supply Program Report," April 1995. **Projections:** EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B .

Oil Price Case Comparisons

Table C11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1997	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]	6.45	4.96	5.59	6.06	4.52	5.34	5.89	4.12	4.96	5.48
Alaska	1.30	0.73	0.78	0.87	0.57	0.61	0.71	0.45	0.49	0.59
Lower 48 States	5.15	4.23	4.81	5.19	3.95	4.72	5.18	3.67	4.47	4.89
Net Imports	8.12	11.76	10.97	10.05	12.58	11.46	10.84	13.13	11.97	11.50
Gross Imports	8.23	11.77	11.02	10.11	12.59	11.50	10.90	13.14	11.99	11.54
Exports	0.11	0.02	0.04	0.07	0.01	0.03	0.06	0.01	0.02	0.04
Other Crude Supply[2]	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	14.57	16.72	16.56	16.11	17.10	16.80	16.74	17.25	16.94	16.97
Natural Gas Plant Liquids	1.82	2.11	2.15	2.16	2.28	2.34	2.37	2.41	2.45	2.46
Other Inputs[3]	0.28	0.25	0.31	0.34	0.27	0.35	0.39	0.29	0.36	0.45
Refinery Processing Gain[4]	0.85	0.77	0.90	0.91	0.77	0.89	0.93	0.76	0.89	0.92
Net Product Imports[5]	1.04	3.70	2.73	2.57	4.39	3.30	2.55	5.22	4.00	3.13
Gross Refined Product Imports[6]	1.52	4.38	3.12	2.80	5.03	3.59	2.96	5.63	4.26	3.59
Unfinished Oil Imports	0.35	0.23	0.54	0.62	0.34	0.61	0.47	0.58	0.68	0.41
Ether Imports	0.06	0.06	0.02	0.02	0.03	0.02	0.01	0.00	0.00	0.02
Exports	0.90	0.98	0.96	0.88	1.01	0.93	0.88	0.98	0.94	0.90
Total Primary Supply[7]	18.55	23.55	22.65	22.09	24.81	23.67	22.98	25.93	24.64	23.93
Refined Petroleum Product Supplied										
Motor Gasoline[8]	7.99	10.20	10.01	9.77	10.61	10.34	10.06	11.01	10.69	10.40
Jet Fuel[9]	1.60	2.48	2.46	2.44	2.78	2.75	2.70	3.08	3.03	2.96
Distillate Fuel[10]	3.43	4.11	3.99	3.93	4.31	4.15	4.08	4.47	4.28	4.21
Residual Fuel	0.83	1.08	0.72	0.66	1.19	0.78	0.71	1.24	0.83	0.78
Other[11]	4.77	5.72	5.51	5.33	5.95	5.68	5.46	6.15	5.82	5.62
Total	18.62	23.60	22.69	22.13	24.84	23.71	23.01	25.95	24.66	23.96
Refined Petroleum Products Supplied										
Residential and Commercial	1.18	1.09	0.99	0.93	1.08	0.96	0.89	1.05	0.92	0.86
Industrial[12]	4.92	5.97	5.70	5.51	6.23	5.90	5.66	6.45	6.07	5.84
Transportation	12.14	16.10	15.88	15.60	17.04	16.73	16.38	17.95	17.56	17.18
Electric Generators[13]	0.38	0.44	0.12	0.09	0.50	0.11	0.08	0.49	0.11	0.08
Total	18.62	23.60	22.69	22.13	24.84	23.71	23.01	25.95	24.66	23.96
Discrepancy[14]	-0.07	-0.05	-0.04	-0.04	-0.03	-0.03	-0.03	-0.02	-0.02	-0.03
World Oil Price (1997 dollars per barrel)[15]	18.55	14.57	21.30	27.33	14.57	21.91	29.14	14.57	22.73	29.35
Import Share of Product Supplied	0.49	0.65	0.60	0.57	0.68	0.62	0.58	0.71	0.65	0.61
Net Expenditures for Imported Crude Oil and Products (billion 1997 dollars)	60.87	83.18	107.95	127.02	90.99	119.49	143.24	99.72	135.20	158.06
Domestic Refinery Distillation Capacity	16.0	17.7	17.5	17.0	18.1	17.7	17.7	18.2	17.9	18.0
Capacity Utilization Rate (percent)	95.0	95.0	95.1	95.1	95.2	95.1	95.1	95.2	95.2	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.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1997 expenditures for imported crude oil and petroleum products based on internal calculations. 1997 product supplied data from table C2. Other 1997 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1997*, DOE/EIA-0340(97/1) (Washington, DC, June 1998). Projections: EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Table C12. Petroleum Product Prices

(1997 Cents per Gallon Unless Otherwise Noted)

Sector and Fuel	1997	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 (1997 dollars per barrel)	18.55	14.57	21.30	27.33	14.57	21.91	29.14	14.57	22.73	29.35
Delivered Sector Product Prices										
Residential										
Distillate Fuel	97.1	91.5	107.4	122.1	91.0	108.4	124.7	90.1	108.1	123.2
Liquefied Petroleum Gas	100.2	94.2	105.4	118.1	92.6	106.9	119.2	93.8	110.9	121.7
Commercial										
Distillate Fuel	68.4	60.2	76.2	91.2	59.9	77.8	94.2	60.2	78.9	93.5
Residual Fuel	51.6	32.5	46.8	60.0	30.9	47.6	63.7	31.7	50.7	65.4
Residual Fuel (1997 dollars per barrel)	21.67	13.65	19.66	25.22	12.97	20.00	26.76	13.32	21.30	27.46
Industrial[1]										
Distillate Fuel	70.7	61.5	77.2	92.7	62.0	79.9	96.4	63.4	82.7	96.9
Liquefied Petroleum Gas	72.4	47.3	57.6	70.5	45.7	59.1	70.9	47.1	63.2	73.1
Residual Fuel	43.4	22.8	40.7	53.6	21.3	40.8	56.4	22.1	43.2	57.2
Residual Fuel (1997 dollars per barrel)	18.21	9.57	17.10	22.50	8.93	17.14	23.68	9.28	18.15	24.02
Transportation										
Diesel Fuel (distillate)[2]	118.4	103.2	119.0	134.2	100.6	118.7	134.7	99.1	118.3	132.6
Jet Fuel[3]	70.2	59.7	77.6	93.3	60.4	80.4	96.3	63.3	85.1	105.7
Motor Gasoline[4]	121.4	108.2	128.8	143.6	105.9	129.2	143.3	103.9	128.8	141.1
Liquefied Petroleum Gas	103.6	101.3	112.7	125.0	98.0	112.1	124.1	97.0	113.9	124.5
Residual Fuel	46.2	24.2	38.6	50.9	23.3	38.8	54.7	23.5	42.2	56.6
Residual Fuel (1997 dollars per barrel)	19.40	10.14	16.20	21.40	9.77	16.32	22.97	9.86	17.74	23.75
E85	145.8	140.9	156.7	171.4	140.6	158.1	172.6	143.0	158.9	171.1
M85	97.3	78.5	95.3	108.0	77.5	95.9	112.7	76.5	96.8	112.0
Electric Generators[5]										
Distillate Fuel	61.4	55.5	70.9	85.9	55.5	73.2	89.8	57.5	75.6	90.0
Residual Fuel	41.3	30.3	52.7	68.5	28.4	54.4	75.2	29.3	58.4	77.1
Residual Fuel (1997 dollars per barrel)	17.36	12.74	22.14	28.76	11.93	22.84	31.59	12.29	24.51	32.40
Refined Petroleum Product Prices[6]										
Distillate Fuel	104.2	92.7	109.2	124.7	90.9	109.8	126.2	90.1	110.1	124.7
Jet Fuel[3]	70.2	59.7	77.6	93.3	60.4	80.4	96.3	63.3	85.1	105.7
Liquefied Petroleum Gas	77.7	57.9	68.0	80.6	56.1	69.3	80.8	57.1	73.0	82.7
Motor Gasoline[4]	121.4	108.2	128.8	143.6	105.9	129.2	143.3	103.9	128.8	141.1
Residual Fuel	44.1	26.4	41.3	53.5	24.9	41.3	56.9	25.3	44.3	58.4
Residual Fuel (1997 dollars per barrel)	18.53	11.07	17.33	22.47	10.47	17.35	23.91	10.64	18.59	24.55
Average	101.2	87.5	106.3	121.1	85.2	106.7	121.5	84.5	107.5	121.3

[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.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption. Includes small power producers and exempt wholesale generators.

Sources: 1997 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 (97/03-98/04) (Washington, DC, 1997-98). 1997 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1995*, DOE/EIA-0376(95) (Washington, DC, August, 1998). **Projections:** EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Table C13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1997	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										
Dry Gas Production[1]	18.94	23.25	23.77	23.88	25.45	26.11	26.45	26.89	27.35	27.47
Supplemental Natural Gas[2]	0.12	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	2.84	4.16	4.35	4.38	4.65	4.78	4.80	4.90	5.02	5.03
Canada	2.84	3.96	4.15	4.18	4.47	4.61	4.63	4.78	4.91	4.91
Mexico	-0.02	-0.09	-0.09	-0.09	-0.12	-0.12	-0.12	-0.17	-0.17	-0.17
Liquefied Natural Gas	0.02	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
Total Supply	21.89	27.47	28.18	28.32	30.15	30.95	31.32	31.85	32.44	32.56
Consumption by Sector										
Residential	5.00	5.35	5.36	5.38	5.58	5.61	5.63	5.74	5.77	5.80
Commercial	3.28	3.70	3.73	3.74	3.82	3.86	3.86	3.84	3.88	3.89
Industrial[3]	8.40	8.99	9.46	9.65	9.30	9.87	10.23	9.57	10.24	10.58
Electric Generators[4]	3.33	6.54	6.69	6.60	8.31	8.42	8.40	9.36	9.16	8.92
Lease and Plant Fuel[5]	1.25	1.62	1.65	1.65	1.77	1.81	1.83	1.90	1.93	1.94
Pipeline Fuel	0.71	0.86	0.87	0.88	0.92	0.94	0.95	0.96	0.98	0.99
Transportation[6]	0.01	0.25	0.25	0.25	0.30	0.30	0.30	0.34	0.33	0.33
Total	21.98	27.31	28.02	28.16	30.00	30.81	31.20	31.71	32.30	32.45
Discrepancy[7]	-0.10	0.16	0.16	0.16	0.15	0.14	0.12	0.15	0.14	0.11

[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, 1997 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1997 may differ from published data due to internal conversion factors.
Sources: 1997 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(98/06) (Washington, DC, June 1998). 1997 imports and dry gas production derived from: EIA, *Natural Gas Annual 1996*, DOE/EIA-0131(96) (Washington, DC, September 1997). 1997 transportation sector consumption: EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B. Other 1997 consumption: EIA, *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B. **Projections:** EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Table C14. Natural Gas Prices, Margins, and Revenue
(1997 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1997	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]	2.23	2.48	2.52	2.52	2.58	2.62	2.64	2.62	2.68	2.70
Average Import Price	2.15	2.34	2.48	2.54	2.43	2.55	2.61	2.53	2.68	2.73
Average[2]	2.22	2.45	2.51	2.52	2.55	2.60	2.63	2.61	2.68	2.71
Delivered Prices										
Residential	7.00	6.13	6.17	6.18	5.91	5.95	5.97	5.86	5.91	5.93
Commercial	5.79	5.27	5.32	5.34	5.17	5.22	5.25	5.17	5.24	5.26
Industrial[3]	3.04	3.19	3.23	3.25	3.28	3.32	3.35	3.34	3.40	3.42
Electric Generators[4]	2.76	3.07	3.15	3.16	3.18	3.24	3.25	3.23	3.31	3.31
Transportation[5]	6.36	7.19	7.37	7.41	7.28	7.52	7.56	7.27	7.57	7.61
Average[6]	4.44	4.15	4.18	4.19	4.10	4.13	4.15	4.10	4.16	4.18
Transmission and Distribution Margins[7]										
Residential	4.78	3.67	3.66	3.66	3.36	3.35	3.34	3.25	3.23	3.22
Commercial	3.57	2.82	2.81	2.82	2.62	2.62	2.62	2.56	2.56	2.56
Industrial[3]	0.82	0.74	0.72	0.72	0.73	0.72	0.71	0.73	0.72	0.72
Electric Generators[4]	0.54	0.62	0.64	0.63	0.63	0.63	0.62	0.63	0.63	0.60
Transportation[5]	4.15	4.73	4.86	4.88	4.73	4.92	4.93	4.66	4.89	4.90
Average[6]	2.22	1.69	1.67	1.67	1.55	1.53	1.51	1.49	1.48	1.47
Transmission and Distribution Revenue (billion 1997 dollars)										
Residential	23.92	19.65	19.64	19.68	18.74	18.76	18.80	18.65	18.65	18.69
Commercial	11.70	10.43	10.50	10.54	10.01	10.10	10.12	9.84	9.93	9.94
Industrial[3]	6.92	6.64	6.82	6.98	6.82	7.06	7.30	6.97	7.33	7.58
Electric Generators[4]	1.80	4.03	4.28	4.17	5.25	5.31	5.17	5.86	5.76	5.39
Transportation[5]	0.06	1.20	1.22	1.22	1.43	1.48	1.48	1.56	1.64	1.64
Total	44.39	41.95	42.47	42.59	42.24	42.72	42.87	42.88	43.31	43.23

[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.
Sources: 1997 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1991.* 1997 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly,* DOE/EIA-0130(98/06) (Washington, DC, June 1998). **Other 1997 values, and projections:** EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Table C15. Oil and Gas Supply

Production and Supply	1997	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] (1997 dollars per barrel)	16.25	14.20	20.80	26.73	13.81	21.05	28.09	13.68	21.73	28.12
Production (million barrels per day)[2]										
U.S. Total	6.45	4.96	5.59	6.06	4.52	5.34	5.89	4.12	4.96	5.48
Lower 48 Onshore	3.75	2.65	3.07	3.35	2.58	3.21	3.57	2.56	3.28	3.64
Conventional	3.17	2.33	2.54	2.60	2.26	2.56	2.57	2.25	2.57	2.55
Enhanced Oil Recovery	0.58	0.33	0.53	0.76	0.32	0.66	1.00	0.32	0.71	1.09
Lower 48 Offshore	1.40	1.57	1.74	1.84	1.37	1.51	1.61	1.11	1.19	1.25
Alaska	1.30	0.73	0.78	0.87	0.57	0.61	0.71	0.45	0.49	0.59
Lower 48 End of Year Reserves (billion barrels)[2]	18.28	12.02	13.80	15.14	11.17	13.70	15.64	10.70	13.70	15.92
Natural Gas										
Lower 48 Average Wellhead Price[1] (1997 dollars per thousand cubic feet)	2.23	2.48	2.52	2.52	2.58	2.62	2.64	2.62	2.68	2.70
Production (trillion cubic feet)[3]										
U.S. Total	18.94	23.25	23.77	23.88	25.45	26.11	26.45	26.89	27.35	27.47
Lower 48 Onshore	12.88	15.87	16.36	16.45	17.97	18.47	18.83	19.86	20.24	20.44
Associated-Dissolved[4]	1.77	1.15	1.19	1.21	1.11	1.19	1.22	1.11	1.21	1.23
Non-Associated	11.11	14.72	15.18	15.23	16.86	17.28	17.61	18.75	19.04	19.21
Conventional	7.43	10.05	10.27	10.15	11.11	11.30	11.60	12.14	12.32	12.45
Unconventional	3.68	4.68	4.90	5.08	5.74	5.97	6.01	6.61	6.72	6.75
Lower 48 Offshore	5.62	6.69	6.73	6.75	6.77	6.94	6.92	6.29	6.38	6.30
Associated-Dissolved[4]	0.80	0.90	0.93	0.95	0.85	0.89	0.91	0.79	0.81	0.83
Non-Associated	4.82	5.80	5.80	5.80	5.92	6.05	6.01	5.51	5.57	5.48
Alaska	0.44	0.68	0.68	0.68	0.71	0.71	0.71	0.73	0.73	0.73
Lower 48 End of Year Reserves (trillion cubic feet)	158.13	168.41	174.29	179.50	172.06	175.73	178.13	169.54	172.03	173.44
Supplemental Gas Supplies (trillion cubic feet)[5]	0.12	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Total Lower 48 Wells (thousands)	27.02	26.70	31.54	35.46	28.76	33.66	39.13	30.30	35.62	41.36

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Market 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.
Ft. = feet.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1997 may differ from published data due to internal conversion factors.
Sources: 1997 lower 48 onshore, lower 48 offshore, Alaska crude oil production: Energy Information Administration (EIA), EIA, *Petroleum Supply Annual 1997*, DOE/EIA-0340(97/1) (Washington, DC. June 1998). 1997 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(98/06) (Washington, DC, June 1998). Other 1997 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Table C16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1997	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	477	484	482	493	473	479	472	457	466	469
Interior	171	125	127	133	151	146	157	161	164	165
West	451	634	627	615	661	670	671	716	728	734
East of the Mississippi	589	564	563	576	580	580	585	574	586	590
West of the Mississippi	511	677	672	665	705	714	715	760	772	778
Total	1099	1242	1236	1241	1286	1294	1299	1335	1358	1368
Net Imports										
Imports	7	8	8	8	8	8	8	8	8	8
Exports	84	90	90	90	91	91	91	93	93	93
Total	-76	-82	-82	-82	-84	-84	-84	-86	-86	-86
Total Supply[2]	1023	1160	1154	1159	1202	1211	1216	1249	1272	1283
Consumption by Sector										
Residential and Commercial	6	7	7	7	7	7	7	7	7	7
Industrial[3]	70	75	77	77	76	79	81	78	82	84
Coke Plants	29	24	24	23	22	22	21	20	20	19
Electric Generators[4]	924	1054	1050	1052	1099	1103	1105	1145	1166	1173
Total	1030	1160	1156	1158	1204	1211	1214	1249	1275	1282
Discrepancy and Stock Change[5]	-7	-0	-3	0	-2	0	2	-0	-3	0
Average Minemouth Price										
(1997 dollars per short ton)	18.14	14.06	14.00	14.15	13.29	13.21	13.22	12.66	12.74	12.76
(1997 dollars per million Btu)	0.85	0.67	0.67	0.67	0.64	0.63	0.64	0.61	0.62	0.62
Delivered Prices (1997 dollars per short ton)[6]										
Industrial	32.41	27.10	27.40	27.75	25.83	26.15	26.43	24.60	24.96	25.23
Coke Plants	47.36	41.59	41.98	42.17	39.86	40.16	40.53	38.26	38.74	38.88
Electric Generators										
(1997 dollars per short ton)	26.16	21.65	21.66	21.84	19.93	20.03	20.16	18.60	18.77	18.88
(1997 dollars per million Btu)	1.27	1.06	1.06	1.07	0.98	0.99	1.00	0.92	0.93	0.94
Average	27.20	22.42	22.46	22.65	20.67	20.80	20.93	19.29	19.49	19.60
Exports[7]	40.55	34.87	35.15	35.37	33.11	33.38	33.66	31.50	31.90	32.05

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 7.9 million tons in 1994, 8.5 million tons in 1995, 8.9 million tons in 1996, 9.4 million tons in 1997, and are projected to reach 10.0 million tons in 1998 and 10.6 million tons in 1999.
[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.
Sources: 1997 data derived from: Energy Information Administration (EIA), *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, November 1998). Projections: EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Table C17. Renewable Energy Generating Capability and Generation
(Thousand Megawatts, Unless Otherwise Noted)

Capacity and Generation	1997	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	77.60	78.51	78.51	78.51	78.51	78.51	78.51	78.51	78.51	78.51
Geothermal[2]	3.00	3.16	3.16	3.19	3.25	3.25	3.25	3.53	3.52	3.46
Municipal Solid Waste[3]	3.41	4.01	4.01	4.01	4.17	4.17	4.17	4.27	4.27	4.27
Wood and Other Biomass[4]	1.66	2.27	2.33	2.49	3.31	3.61	3.87	5.19	5.61	6.36
Solar Thermal	0.35	0.44	0.44	0.44	0.48	0.48	0.48	0.52	0.52	0.52
Solar Photovoltaic	0.01	0.30	0.30	0.30	0.46	0.46	0.46	0.64	0.64	0.64
Wind	1.88	3.39	3.39	3.39	3.41	3.41	3.42	3.63	3.61	3.63
Total	87.92	92.07	92.14	92.33	93.60	93.89	94.17	96.28	96.68	97.39
Generation (billion kilowatthours)										
Conventional Hydropower	350.62	323.42	323.42	323.42	323.50	323.50	323.50	323.57	323.58	323.58
Geothermal[2]	15.67	17.88	17.86	18.11	19.71	19.69	19.72	23.01	22.99	22.51
Municipal Solid Waste[3]	14.30	26.49	26.49	26.49	27.65	27.65	27.65	28.34	28.34	28.34
Wood and Other Biomass[4]	4.21	11.48	11.97	13.08	18.82	20.90	22.75	31.95	34.89	40.18
Solar Thermal	0.90	1.19	1.19	1.19	1.31	1.31	1.31	1.44	1.44	1.44
Solar Photovoltaic	0.00	0.71	0.71	0.71	1.12	1.12	1.12	1.56	1.56	1.56
Wind	3.41	7.69	7.69	7.69	7.76	7.76	7.78	8.50	8.44	8.50
Total	389.11	388.86	389.33	390.70	399.87	401.92	403.84	418.36	421.24	426.11
Cogenerators[5]										
Net Summer Capability										
Conventional Hydropower[6]	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
Municipal Solid Waste	0.46	0.48	0.48	0.48	0.49	0.49	0.49	0.49	0.49	0.49
Biomass	5.45	6.79	6.77	6.85	7.04	7.13	7.22	7.23	7.39	7.49
Total	6.85	8.20	8.19	8.27	8.46	8.55	8.64	8.65	8.81	8.91
Generation (billion kilowatthours)										
Conventional Hydropower[6]	6.16	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.90
Municipal Solid Waste	1.80	2.32	2.32	2.32	2.34	2.34	2.34	2.34	2.34	2.34
Biomass	32.69	48.65	49.59	50.65	51.62	53.17	54.36	53.78	55.82	57.03
Total	40.65	55.88	56.81	57.87	58.86	60.41	61.60	61.02	63.06	64.27

[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]Represents own-use industrial hydroelectric power.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO99. Net summer capability is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recently available as of July 1, 1998. Additional retirements are also determined on the basis of the size and age of the units. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: 1997 electric utility capability: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report." 1997 nonutility and cogenerator capability: EIA, Form EIA-867, "Annual Nonutility Power Producer Report." 1997 generation: EIA, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Table C18. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1997	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	0.60	0.62	0.62	0.62	0.64	0.64	0.64	0.65	0.65	0.65
Wood	0.60	0.62	0.62	0.62	0.64	0.64	0.64	0.65	0.65	0.65
Commercial[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[4]	1.88	2.29	2.31	2.34	2.42	2.45	2.49	2.52	2.56	2.60
Conventional Hydroelectric	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	1.84	2.25	2.27	2.30	2.38	2.41	2.45	2.48	2.52	2.57
Transportation	0.10	0.12	0.20	0.24	0.15	0.25	0.33	0.17	0.28	0.40
Ethanol used in E85[5]	0.00	0.04	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.06
Ethanol used in Gasoline Blending	0.10	0.08	0.16	0.20	0.10	0.20	0.28	0.11	0.22	0.34
Electric Generators[6]	4.35	4.47	4.48	4.50	4.63	4.64	4.66	4.87	4.90	4.93
Conventional Hydroelectric	3.60	3.32	3.32	3.32	3.33	3.33	3.33	3.33	3.33	3.33
Geothermal	0.43	0.52	0.52	0.53	0.59	0.59	0.59	0.69	0.69	0.67
Municipal Solid Waste	0.23	0.42	0.42	0.42	0.44	0.44	0.44	0.45	0.45	0.45
Biomass	0.04	0.10	0.11	0.12	0.17	0.19	0.20	0.28	0.31	0.36
Solar Thermal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar Photovoltaic	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02
Wind	0.04	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09
Total Marketed Renewable Energy	6.92	7.51	7.61	7.70	7.83	7.99	8.12	8.21	8.38	8.58
Non-Marketed Renewable Energy[7]										
Selected Consumption										
Residential	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.05
Solar Hot Water Heating	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Geothermal Heat Pumps	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.04
Commercial	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Solar Thermal	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04

[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]Value is less than 0.005 quadrillion Btu per year and rounds to zero.
[4]Includes all electricity production by industrial and other cogenerators for the grid and for own use.
[5]Excludes motor gasoline component of E85.
[6]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.
[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.
Notes: Totals may not equal sum of components due to independent rounding.
Sources: 1997 ethanol: EIA, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). 1997 electric generators: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report," and EIA, Form EIA-867, "Annual Nonutility Power Producer Report." Other 1997: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Oil Price Case Comparisons

Table C19. Carbon Emissions by Sector and Source
(Million Metric Tons per Year)

Sector and Source	1997	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
Residential										
Petroleum	27.8	24.8	23.0	21.6	24.2	22.0	20.4	23.4	21.0	19.4
Natural Gas	74.1	79.3	79.5	79.8	82.7	83.1	83.4	85.1	85.6	85.9
Coal	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Electricity	182.3	233.9	228.6	228.7	252.9	247.9	247.7	270.5	267.2	267.1
Total	285.6	339.3	332.5	331.4	361.1	354.3	352.8	380.3	375.0	373.7
Commercial										
Petroleum	14.4	12.7	11.1	10.3	12.8	11.0	10.0	12.6	10.6	9.8
Natural Gas	48.6	54.9	55.3	55.5	56.5	57.1	57.3	56.9	57.6	57.7
Coal	2.1	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.6	2.6
Electricity	171.5	217.9	212.8	212.7	233.1	228.3	228.1	240.6	237.3	237.3
Total	236.6	288.0	281.7	280.9	305.1	299.0	298.0	312.7	308.1	307.3
Industrial[1]										
Petroleum	105.8	128.3	117.4	110.5	132.4	120.0	111.2	135.7	121.4	113.0
Natural Gas[2]	142.2	154.5	161.9	164.9	161.4	170.4	175.6	167.1	177.4	182.3
Coal	58.5	63.0	63.5	63.5	63.3	64.6	65.4	63.4	65.9	66.7
Electricity	175.6	212.3	206.5	205.4	225.1	219.5	218.6	233.4	229.8	229.1
Total	482.1	558.2	549.4	544.2	582.1	574.5	570.8	599.6	594.5	591.1
Transportation										
Petroleum[3]	461.9	609.9	600.8	589.7	645.8	632.9	618.5	681.0	664.7	648.2
Natural Gas[4]	10.5	16.4	16.7	16.7	18.1	18.4	18.5	19.2	19.5	19.6
Other[5]	0.0	1.4	1.4	1.3	1.8	1.7	1.5	2.0	1.9	1.7
Electricity	2.9	7.8	7.6	7.5	9.7	9.4	9.3	11.5	11.2	11.0
Total[3]	475.3	635.5	626.3	615.1	675.4	662.3	647.7	713.7	697.3	680.5
Total Carbon Emissions by Delivered Fuel										
Petroleum[3]	609.9	775.7	752.4	732.1	815.3	785.9	760.1	852.7	817.7	790.4
Natural Gas	275.4	305.1	313.4	316.8	318.7	328.9	334.8	328.3	340.0	345.5
Coal	62.0	66.8	67.4	67.3	67.1	68.4	69.2	67.3	69.8	70.6
Other[5]	0.0	1.4	1.4	1.3	1.8	1.7	1.5	2.0	1.9	1.7
Electricity	532.4	671.9	655.4	654.3	720.8	705.1	703.7	755.9	745.5	744.5
Total[3]	1479.6	1820.9	1789.9	1771.7	1923.6	1890.1	1869.3	2006.3	1974.9	1952.6
Electric Generatorsl[6]										
Petroleum	17.6	21.1	5.8	4.1	24.0	5.3	3.7	23.4	4.9	3.7
Natural Gas	43.8	96.2	98.5	97.2	122.3	124.0	123.6	137.8	134.8	131.3
Coal	471.0	554.5	551.1	553.0	574.6	575.9	576.4	594.7	605.8	609.4
Total	532.4	671.9	655.4	654.3	720.8	705.1	703.7	755.9	745.5	744.5
Total Carbon Emissions by Primary Fuel[7]										
Petroleum[3]	627.5	796.8	758.1	736.1	839.2	791.1	763.8	876.1	822.6	794.1
Natural Gas	319.1	401.3	411.9	414.0	440.9	452.9	458.3	466.1	474.8	476.8
Coal	533.0	621.4	618.5	620.3	641.7	644.4	645.7	662.0	675.6	680.0
Other[5]	0.0	1.4	1.4	1.3	1.8	1.7	1.5	2.0	1.9	1.7
Total[3]	1479.6	1820.9	1789.9	1771.7	1923.6	1890.1	1869.3	2006.3	1974.9	1952.6
Carbon Emissions (tons per person)	5.5	6.1	6.0	5.9	6.2	6.1	6.0	6.2	6.1	6.0

Years 2010–2020 are Projections.

[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 emissions. In the years from 1989 through 1996, international bunker fuels account for 22 to 24 million metric ton of carbon 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.
[7]Emissions from electric power generator are distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Carbon coefficients from Energy Information Administration, (EIA) *Emissions of Greenhouse Gases in the United States 1997,* DOE/EIA-0573(97) (Washington, DC, October 1998). 1997 consumption estimates based on: EIA, *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **Projections:** EIA, AEO99 National Energy Modeling System run LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Table C20. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1997	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 (1997 dollars per barrel)[1]	18.55	14.57	21.30	27.33	14.57	21.91	29.14	14.57	22.73	29.35
Production[2]										
OECD										
U.S. (50 states)	9.34	8.12	8.99	9.50	7.87	8.94	9.63	7.60	8.70	9.34
Canada	2.59	3.25	3.31	3.36	3.27	3.35	3.41	3.29	3.38	3.43
Mexico	3.44	3.85	3.97	4.06	3.81	3.95	4.05	3.71	3.87	3.97
OECD Europe[3]	7.02	7.36	7.47	7.56	6.62	6.75	6.83	6.13	6.26	6.34
Other OECD	0.83	0.87	0.91	0.94	0.82	0.87	0.91	0.75	0.80	0.84
Total OECD	23.21	23.45	24.66	25.42	22.39	23.86	24.83	21.48	23.00	23.92
Developing Countries										
Other South & Central America	3.40	4.62	4.77	4.88	4.72	4.90	5.03	4.77	4.97	5.11
Pacific Rim	2.17	3.06	3.16	3.23	3.11	3.23	3.32	3.12	3.25	3.34
OPEC	29.85	48.30	40.35	35.12	59.07	48.70	42.00	71.38	58.81	51.39
Other Developing Countries	4.58	6.13	6.33	6.47	6.57	6.82	6.99	7.02	7.32	7.52
Total Developing Countries	39.99	62.11	54.60	49.69	73.48	63.65	57.34	86.30	74.36	67.35
Eurasia										
Former Soviet Union	7.13	11.66	12.03	12.31	12.16	12.62	12.95	12.65	13.18	13.53
Eastern Europe	0.25	0.41	0.42	0.43	0.42	0.44	0.45	0.40	0.42	0.43
China	3.20	3.45	3.56	3.65	3.47	3.60	3.69	3.32	3.46	3.56
Total Eurasia	10.58	15.52	16.02	16.38	16.05	16.65	17.09	16.37	17.06	17.51
Total Production	73.78	101.08	95.28	91.49	111.92	104.17	99.26	124.14	114.41	108.79
Consumption										
OECD										
U.S. (50 states)	18.62	23.60	22.69	22.13	24.84	23.71	23.03	25.95	24.67	23.94
U.S. Territories	0.20	0.44	0.38	0.35	0.49	0.42	0.38	0.55	0.47	0.42
Canada	1.86	2.47	2.19	2.01	2.68	2.32	2.11	2.90	2.48	2.24
Mexico	1.91	3.04	2.78	2.61	3.38	3.02	2.79	3.71	3.26	3.00
Japan	5.71	8.43	7.21	6.42	9.31	7.58	6.55	10.24	8.02	6.80
Australia and New Zealand	0.95	1.27	1.21	1.17	1.32	1.25	1.20	1.38	1.30	1.25
OECD Europe[3]	14.43	16.40	15.50	14.92	16.62	15.59	14.91	16.83	15.69	15.02
Total OECD	43.68	55.65	51.97	49.60	58.62	53.89	50.96	61.56	55.88	52.67
Developing Countries										
Other South and Central America	3.77	6.86	6.64	6.49	8.01	7.71	7.52	9.33	8.97	8.74
Pacific Rim	4.77	7.66	7.38	7.18	9.14	8.74	8.48	10.89	10.38	10.07
OPEC	5.56	7.06	7.06	7.06	7.91	7.91	7.91	8.86	8.86	8.86
Other Developing Countries	5.50	8.97	8.20	7.67	10.32	9.14	8.38	11.87	10.24	9.26
Total Developing Countries	19.60	30.55	29.28	28.41	35.37	33.51	32.29	40.96	38.45	36.93

Table C20. International Petroleum Supply and Disposition Summary (Continued)

(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1997	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
Eurasia										
Former Soviet Union	4.43	6.23	5.96	5.78	7.06	6.71	6.48	7.90	7.47	7.22
Eastern Europe	1.37	1.96	1.90	1.87	2.31	2.24	2.19	2.74	2.65	2.59
China	3.88	6.99	6.47	6.14	8.86	8.12	7.64	11.29	10.26	9.67
Total Eurasia	**9.68**	**15.17**	**14.33**	**13.78**	**18.23**	**17.07**	**16.31**	**21.92**	**20.38**	**19.48**
Total Consumption	**72.96**	**101.38**	**95.58**	**91.79**	**112.22**	**104.47**	**99.56**	**124.44**	**114.71**	**109.09**
Non-OPEC Production	43.94	52.77	54.93	56.37	52.84	55.46	57.26	52.76	55.60	57.40
Net Eurasia Exports	0.91	0.35	1.69	2.60	-2.18	-0.41	0.78	-5.56	-3.32	-1.97
OPEC Market Share	0.40	0.48	0.42	0.38	0.53	0.47	0.42	0.58	0.51	0.47

[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, Slovak Republic, the Former Soviet Union, and the Former Yugoslavia.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1997 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1998.* Online http://www.eia.doe.gov/emeu/steo/pub/upd/sep98/contents.html (October 15, 1998). **Projections:** EIA, AEO99 National Energy Modeling System runs LWOP99.D100298B, AEO99B.D100198A, and HWOP99.D100298B.

Crude Oil Equivalency Summary

Table D1. Total Energy Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Production								
Crude Oil and Lease Condensate	6.47	6.45	6.29	5.82	5.59	5.34	4.96	-1.1%
Natural Gas Plant Liquids	1.23	1.22	1.20	1.32	1.44	1.57	1.64	1.3%
Dry Natural Gas	9.10	9.20	9.34	10.47	11.54	12.68	13.25	1.6%
Coal	10.72	11.02	11.61	11.90	12.24	12.73	13.25	0.8%
Nuclear Power	3.39	3.17	3.32	3.18	2.79	2.11	1.80	-2.4%
Renewable Energy[1]	3.21	3.22	3.21	3.36	3.51	3.67	3.84	0.8%
Other[2]	0.61	0.31	0.25	0.27	0.27	0.29	0.31	-0.1%
Total	34.72	34.59	35.22	36.32	37.39	38.39	39.05	0.5%
Imports								
Crude Oil[3]	7.51	8.23	9.02	9.92	11.02	11.50	11.99	1.7%
Petroleum Products[4]	1.88	1.84	2.48	3.05	3.47	4.02	4.68	4.2%
Natural Gas	1.41	1.44	1.67	1.88	2.21	2.43	2.57	2.5%
Other Imports[5]	0.27	0.25	0.35	0.33	0.33	0.34	0.35	1.5%
Total	11.07	11.76	13.52	15.17	17.04	18.29	19.60	2.2%
Exports								
Petroleum[6]	0.96	0.99	0.96	0.97	1.00	0.95	0.94	-0.2%
Natural Gas	0.07	0.08	0.09	0.10	0.11	0.13	0.15	3.1%
Coal	1.12	1.01	1.01	1.04	1.07	1.09	1.11	0.4%
Total	2.15	2.10	2.06	2.11	2.18	2.17	2.21	0.3%
Discrepancy[7]	0.47	0.16	0.01	-0.01	0.01	-0.05	-0.09	N/A
Consumption								
Petroleum Products[8]	16.97	17.24	18.35	19.49	20.89	21.82	22.65	1.2%
Natural Gas	10.64	10.67	10.91	12.23	13.60	14.95	15.62	1.7%
Coal	9.71	9.96	10.68	10.93	11.27	11.72	12.24	0.9%
Nuclear Power	3.39	3.17	3.32	3.18	2.79	2.11	1.80	-2.4%
Renewable Energy[1]	3.21	3.22	3.21	3.36	3.52	3.68	3.85	0.8%
Other[9]	0.18	0.16	0.22	0.18	0.18	0.18	0.18	0.7%
Total	44.11	44.42	46.69	49.37	52.26	54.46	56.35	1.0%
Net Imports - Petroleum	8.43	9.07	10.54	11.99	13.49	14.56	15.73	2.4%
Prices (1997 dollars per unit)								
World Oil Price (dollars per barrel)[10]	21.01	18.55	13.97	19.25	21.30	21.91	22.73	0.9%
Gas Wellhead Price (dollars per Mcf)[11]	2.28	2.23	2.10	2.35	2.52	2.62	2.68	0.8%
Coal Minemouth Price (dollars per ton)	18.85	18.14	16.59	14.93	14.00	13.21	12.74	-1.5%
Average Electric Price (cents per kilowatthour)	6.9	6.9	6.6	6.4	6.1	5.8	5.6	-0.9%

[1]Includes grid connected electricity from hydroelectric; wood and wood waste; 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 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 withdraws.
[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.
Mcf = Thousand cubic feet.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1996 and 1997 may differ from published data due to internal conversion factors.
Sources: 1996 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1996*, DOE/EIA-0131(96) (Washington, DC, September 1997). 1996 coal minemouth prices: EIA, *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997). Other 1996 values: EIA, *Annual Energy Review 1997*, DOE/EIA-0384(96) (Washington, DC, July 1998). 1997 natural gas values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(98/06) (Washington, DC, June 1998). 1997 coal minemouth price: *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, November 1998). Coal production and exports derived from: EIA, *Monthly Energy Review*, DOE/EIA-0035(98/08) (Washington, DC, August 1998). Other 1997 values: EIA, *Annual Energy Review 1997*, DOE/EIA-0384(96) (Washington, DC, July 1998). **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table D2. Total Energy Supply and Disposition Summary
(Mtoes per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case 1996	1997	2000	2005	2010	2015	2020	Annual Growth 1997-2020 (percent)
Production								
Crude Oil and Lease Condensate	345.05	344.10	335.59	310.22	298.19	284.64	264.76	-1.1%
Natural Gas Plant Liquids	65.51	64.88	64.12	70.61	77.00	83.69	87.55	1.3%
Dry Natural Gas	486.83	490.54	499.46	558.70	615.79	676.44	708.61	1.6%
Coal	573.30	587.94	620.94	635.03	652.98	679.21	708.68	0.8%
Nuclear Power	181.56	169.16	177.46	169.60	149.04	112.71	96.48	-2.4%
Renewable Energy[1]	171.66	171.94	171.82	179.19	187.52	195.91	205.39	0.8%
Other[2]	32.36	16.69	13.30	14.29	14.27	15.62	16.40	-0.1%
Total	**1856.27**	**1845.24**	**1882.69**	**1937.63**	**1994.80**	**2048.22**	**2087.87**	**0.5%**
Imports								
Crude Oil[3]	410.98	450.04	493.39	542.50	602.64	628.95	656.00	1.7%
Petroleum Products[4]	100.23	97.90	132.30	162.50	185.23	214.25	249.89	4.2%
Natural Gas	75.64	77.07	89.56	100.13	118.12	129.87	137.54	2.6%
Other Imports[5]	14.26	13.49	18.60	17.63	17.81	18.08	18.81	1.5%
Total	**601.11**	**638.51**	**733.86**	**822.76**	**923.79**	**991.15**	**1062.25**	**2.2%**
Exports								
Petroleum[6]	51.42	52.68	51.34	51.62	53.15	50.80	50.36	-0.2%
Natural Gas	3.91	4.04	4.73	5.35	5.99	6.71	8.13	3.1%
Coal	59.72	55.11	53.90	55.72	57.23	58.14	59.40	0.3%
Total	**115.05**	**111.84**	**109.96**	**112.69**	**116.37**	**115.66**	**117.89**	**0.2%**
Discrepancy[7]	**17.22**	**-1.98**	**-6.40**	**-9.76**	**-9.31**	**-12.39**	**-11.12**	**N/A**
Consumption								
Petroleum Products[8]	908.07	919.56	981.49	1039.50	1114.47	1164.27	1211.60	1.2%
Natural Gas	569.21	569.37	583.78	652.35	725.43	797.32	835.81	1.7%
Coal	519.24	531.54	573.96	587.29	606.33	631.25	661.64	1.0%
Nuclear Power	181.56	169.16	177.46	169.60	149.04	112.71	96.48	-2.4%
Renewable Energy[1]	171.67	171.95	171.87	179.34	187.78	196.24	205.77	0.8%
Other[9]	9.80	8.35	11.63	9.87	9.86	9.55	9.82	0.7%
Total	**2359.55**	**2369.93**	**2500.18**	**2637.94**	**2792.91**	**2911.34**	**3021.12**	**1.1%**
Net Imports - Petroleum	**459.79**	**495.26**	**574.36**	**653.38**	**734.72**	**792.40**	**855.53**	**2.4%**
Prices (1997 dollars per unit)								
World Oil Price (dollars per barrel)[10]	21.01	18.55	13.97	19.25	21.30	21.91	22.73	0.9%
Gas Wellhead Price (dollars per Mcf)[11]	2.28	2.23	2.10	2.35	2.52	2.62	2.68	0.8%
Coal Minemouth Price (dollars per ton)	18.85	18.14	16.59	14.93	14.00	13.21	12.74	-1.5%
Average Electric Price (cents per kilowatt hour)	6.9	6.9	6.6	6.4	6.1	5.8	5.6	-0.9%

[1]Includes grid connected electricity from hydroelectric; wood and wood waste; 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 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 withdraws.
[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.
MTOE = Million tons of oil equivalent.
Mcf = Thousand cubic feet.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1996 and 1997 may differ from published data due to internal conversion factors.
Sources: 1996 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1996*, DOE/EIA-0131(96) (Washington, DC, September 1997). 1996 coal minemouth prices: EIA, *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997). Other 1996 values: EIA, *Annual Energy Review 1997*, DOE/EIA-0384(96) (Washington, DC, July 1998). 1997 natural gas values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(98/06) (Washington, DC, June 1998). 1997 coal minemouth price: *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, November 1998). Coal production and exports derived from: EIA, *Monthly Energy Review*, DOE/EIA-0035(98/08) (Washington, DC, August 1998). Other 1997 values: EIA, *Annual Energy Review 1997*, DOE/EIA-0384(96) (Washington, DC, July 1998). **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

Household Expenditures

Table E1. 1997 Average Household Expenditures for Energy by Household Characteristic (1997 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2273.34**	**1205.77**	**782.81**	**347.93**	**75.03**	**1067.57**
Households by Income Quintile						
1st	1438.48	932.56	581.55	298.72	52.28	505.92
2nd	1882.65	1067.53	672.70	331.89	62.95	815.11
3rd	2401.35	1196.55	806.05	311.15	79.35	1204.80
4th	2562.22	1302.42	865.52	352.12	84.79	1259.80
5th	3113.69	1533.25	995.88	440.39	96.97	1580.44
Households by Census Division						
New England	2587.41	1530.44	790.66	339.90	399.87	1056.98
Middle Atlantic	2354.54	1524.45	752.52	533.77	238.16	830.09
South Atlantic	2320.25	1182.07	611.87	540.80	29.41	1138.18
East North Central	2220.65	1116.31	683.88	375.56	56.87	1104.34
East South Central	2147.57	1169.28	955.17	174.86	39.25	978.29
West North Central	2572.36	1287.53	1055.07	225.42	7.04	1284.84
West South Central	2412.75	1295.21	983.73	311.48	0.00	1117.55
Mountain	2149.82	893.19	603.74	282.29	7.16	1256.63
Pacific	2036.54	921.66	649.05	255.49	17.12	1114.88

Source: Energy Information Administration, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table E2. 2000 Average Household Expenditures for Energy by Household Characteristics (1997 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2099.97**	**1146.98**	**754.19**	**332.40**	**60.39**	**952.98**
Households by Income Quintile						
1st	1338.43	884.80	560.81	281.84	42.16	453.62
2nd	1741.45	1016.91	650.16	316.48	50.26	724.55
3rd	2212.64	1138.17	778.34	296.35	63.48	1074.46
4th	2365.95	1239.88	833.91	337.67	68.29	1126.07
5th	2871.54	1459.42	955.93	424.79	78.70	1412.13
Households by Census Division						
New England	2362.86	1384.26	738.01	310.76	335.49	978.60
Middle Atlantic	2208.32	1447.51	719.18	527.45	200.88	760.82
South Atlantic	2131.47	1126.25	594.07	509.86	22.33	1005.22
East North Central	2074.68	1069.56	649.66	376.23	43.67	1005.12
East South Central	1971.58	1114.02	924.12	158.87	31.03	857.56
West North Central	2422.31	1263.02	1043.51	214.14	5.37	1159.30
West South Central	2242.56	1218.99	947.73	271.26	0.00	1023.57
Mountain	1884.30	878.59	586.01	287.67	4.91	1005.71
Pacific	1898.02	893.86	609.13	271.21	13.51	1004.15

Source: Energy Information Administration, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table E3. 2005 Average Household Expenditures for Energy by Household Characteristic
(1997 Dollars)

Household Characteristics	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
	Fuels					
Average U.S. Household	2230.70	1116.59	749.75	307.08	59.76	1114.12
Households by Income Quintile						
1st	1391.15	858.27	558.24	258.29	41.74	532.88
2nd	1837.35	991.37	650.21	291.86	49.31	845.98
3rd	2365.92	1110.66	774.03	274.33	62.30	1255.26
4th	2525.59	1208.27	828.49	311.94	67.84	1317.32
5th	3071.36	1420.17	946.87	394.75	78.55	1651.19
Households by Census Division						
New England	2498.17	1350.05	694.32	301.98	353.75	1148.12
Middle Atlantic	2279.26	1386.05	701.54	476.33	208.18	893.21
South Atlantic	2231.31	1062.44	572.29	468.62	21.53	1168.87
East North Central	2219.82	1032.27	638.09	352.71	41.47	1187.55
East South Central	2105.87	1113.86	930.65	154.56	28.65	992.01
West North Central	2550.52	1223.91	1015.12	203.94	4.85	1326.61
West South Central	2393.21	1201.46	957.47	243.99	0.00	1191.75
Mountain	2117.67	933.08	637.49	291.32	4.27	1184.60
Pacific	2060.07	868.40	601.39	254.68	12.32	1191.67

Source: Energy Information Administration, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table E4. 2010 Average Household Expenditures for Energy by Household Characteristic
(1997 Dollars)

Household Characteristics	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
	Fuels					
Average U.S. Household	2269.85	1083.82	739.06	289.91	54.85	1186.03
Households by Income Quintile						
1st	1400.13	831.32	550.27	242.76	38.30	568.81
2nd	1861.50	962.47	642.78	274.85	44.84	899.03
3rd	2414.22	1078.38	761.70	259.95	56.72	1335.85
4th	2578.45	1174.14	817.14	294.51	62.49	1404.31
5th	3141.51	1380.75	933.88	374.04	72.82	1760.76
Households by Census Division						
New England	2532.34	1311.59	670.41	297.72	343.45	1220.75
Middle Atlantic	2299.16	1350.35	713.79	436.76	199.80	948.81
South Atlantic	2254.86	1013.26	554.58	439.71	18.98	1241.59
East North Central	2262.77	995.36	623.77	335.90	35.68	1267.41
East South Central	2158.29	1103.98	922.38	156.82	24.78	1054.31
West North Central	2549.78	1161.30	954.60	202.66	4.04	1388.48
West South Central	2424.20	1149.32	918.11	231.20	0.00	1274.88
Mountain	2205.36	937.62	644.42	289.72	3.49	1267.74
Pacific	2124.19	850.89	603.27	237.17	10.44	1273.30

Source: Energy Information Administration, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table E5. 2015 Average Household Expenditures for Energy by Household Characteristic (1997 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2211.98**	**1048.78**	**722.28**	**276.98**	**49.52**	**1163.20**
Households by Income Quintile						
1st	1363.49	803.79	538.00	231.21	34.58	559.70
2nd	1810.96	930.42	628.11	261.91	40.40	880.54
3rd	2353.43	1043.32	743.34	248.84	51.13	1310.11
4th	2516.91	1138.12	799.68	281.83	56.61	1378.79
5th	3067.39	1338.23	913.98	358.37	65.88	1729.16
Households by Census Division						
New England	2485.41	1293.98	683.34	292.80	317.84	1191.43
Middle Atlantic	2245.00	1324.18	722.30	415.46	186.42	920.82
South Atlantic	2176.85	966.86	527.97	421.46	17.43	1210.00
East North Central	2195.43	954.14	598.21	323.04	32.89	1241.30
East South Central	2121.27	1085.30	907.95	155.61	21.74	1035.96
West North Central	2462.36	1120.94	919.52	197.85	3.57	1341.42
West South Central	2347.08	1088.50	863.67	224.83	0.00	1258.58
Mountain	2157.78	891.14	616.48	271.67	2.99	1266.64
Pacific	2084.71	831.75	598.42	223.91	9.42	1252.95

Source: Energy Information Administration, AEO99 National Energy Modeling System run AEO99B.D100198A.

Table E6. 2020 Average Household Expenditures for Energy by Household Characteristic (1997 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2165.25**	**1023.72**	**710.02**	**269.29**	**44.40**	**1141.52**
Households by Income Quintile						
1st	1335.61	783.62	528.59	223.98	31.05	551.99
2nd	1771.80	908.09	617.82	254.05	36.22	863.71
3rd	2303.69	1017.77	729.99	241.98	45.80	1285.92
4th	2465.89	1112.48	787.27	274.33	50.89	1353.41
5th	3003.98	1307.63	898.87	349.74	59.02	1696.36
Households by Census Division						
New England	2424.79	1267.37	683.61	293.12	290.64	1157.42
Middle Atlantic	2196.25	1307.05	731.10	404.30	171.65	889.20
South Atlantic	2110.41	935.21	511.52	407.77	15.92	1175.20
East North Central	2140.68	927.13	584.70	312.13	30.30	1213.55
East South Central	2083.78	1061.07	887.77	154.15	19.15	1022.71
West North Central	2376.25	1080.25	884.25	192.84	3.15	1296.01
West South Central	2309.48	1062.98	843.21	219.77	0.00	1246.50
Mountain	2147.77	872.99	603.88	266.55	2.56	1274.78
Pacific	2051.54	819.64	590.36	220.67	8.62	1231.90

Source: Energy Information Administration, AEO99 National Energy Modeling System run AEO99B.D100198A.

Results from Side Cases

Table F1. Key Results for Residential Sector Technology Cases

Energy Consumption	1997	2005 1999 Tech.	2005 Reference Case	2005 High Technology	2005 Best Available Tech.	2010 1999 Tech.	2010 Reference Case	2010 High Technology	2010 Best Available Tech.
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.94	0.81	0.79	0.74	0.70	0.79	0.73	0.67	0.61
Kerosene	0.09	0.07	0.07	0.07	0.06	0.07	0.07	0.07	0.06
Liquefied Petroleum Gas	0.43	0.45	0.44	0.41	0.38	0.46	0.43	0.40	0.36
Petroleum Subtotal	1.47	1.33	1.29	1.23	1.14	1.32	1.23	1.14	1.03
Natural Gas	5.15	5.44	5.31	5.02	4.80	5.76	5.52	5.08	4.74
Coal	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy	0.60	0.62	0.61	0.60	0.59	0.64	0.62	0.60	0.60
Electricity	3.66	4.37	4.31	4.15	3.85	4.73	4.57	4.23	3.70
Delivered Energy	**10.92**	**11.82**	**11.57**	**11.05**	**10.44**	**12.50**	**12.00**	**11.11**	**10.13**
Electricity Related Losses	8.07	9.03	8.89	8.57	7.95	9.42	9.11	8.43	7.37
Total	**18.99**	**20.84**	**20.47**	**19.62**	**18.39**	**21.92**	**21.11**	**19.54**	**17.50**
Delivered Energy Consumption per Household (million Btu per Year)	**107.80**	**106.48**	**104.28**	**99.57**	**94.07**	**106.39**	**102.14**	**94.56**	**86.20**

Table F2. Key Results for Commercial Sector Technology Cases

Energy Consumption	1997	2005 1999 Tech.	2005 Reference Case	2005 High Technology	2005 Best Available Tech.	2010 1999 Tech.	2010 Reference Case	2010 High Technology	2010 Best Available Tech.
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.49	0.36	0.36	0.36	0.34	0.34	0.34	0.34	0.32
Residual Fuel	0.11	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Kerosene	0.03	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03
Liquid Petroleum Gas	0.08	0.08	0.08	0.08	0.08	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	0.73	0.58	0.58	0.58	0.56	0.57	0.57	0.57	0.55
Natural Gas	3.37	3.69	3.68	3.67	3.58	3.86	3.84	3.80	3.69
Coal	0.08	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10
Renewable Energy	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	3.44	4.00	3.97	3.92	3.69	4.32	4.26	4.17	3.82
Delivered Energy	**7.63**	**8.36**	**8.32**	**8.27**	**7.93**	**8.85**	**8.77**	**8.64**	**8.16**
Electricity Related Losses	7.59	8.26	8.19	8.10	7.62	8.60	8.48	8.31	7.61
Total	**15.22**	**16.62**	**16.51**	**16.37**	**15.55**	**17.45**	**17.24**	**16.95**	**15.77**
Delivered Energy Consumption per Square Foot (thousand Btu per year)	**126.49**	**126.18**	**125.55**	**124.70**	**119.63**	**127.39**	**126.18**	**124.40**	**117.47**

Table F1. Key Results for Residential Sector Technology Cases (Continued)

2015				2020				Annual Growth 1997-2020			
1999 Tech.	Reference Case	High Technology	Best Available Tech.	1999 Tech.	Reference Case	High Technology	Best Available Tech.	1999 Tech.	Reference Case	High Technology	Best Available Tech.
0.77	0.69	0.62	0.54	0.75	0.65	0.57	0.49	-1.0%	-1.6%	-2.1%	-2.8%
0.07	0.07	0.06	0.06	0.07	0.07	0.06	0.05	-1.1%	-1.4%	-1.6%	-2.3%
0.45	0.42	0.39	0.35	0.45	0.40	0.38	0.34	0.2%	-0.3%	-0.6%	-1.0%
1.29	1.18	1.07	0.95	1.27	1.12	1.01	0.88	-0.6%	-1.2%	-1.6%	-2.2%
6.16	5.77	5.20	4.68	6.52	5.94	5.28	4.45	1.0%	0.6%	0.1%	-0.6%
0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	-0.5%	-0.5%	-0.5%	-0.5%
0.66	0.64	0.61	0.61	0.68	0.65	0.62	0.62	0.6%	0.4%	0.2%	0.2%
5.18	4.93	4.47	3.78	5.64	5.31	4.73	3.89	1.9%	1.6%	1.1%	0.3%
13.34	**12.57**	**11.40**	**10.07**	**14.17**	**13.08**	**11.69**	**9.89**	**1.1%**	**0.8%**	**0.3%**	**-0.4%**
9.80	9.34	8.46	7.15	10.37	9.77	8.70	7.15	1.1%	0.8%	0.3%	-0.5%
23.14	**21.91**	**19.86**	**17.22**	**24.54**	**22.85**	**20.39**	**17.04**	**1.1%**	**0.8%**	**0.3%**	**-0.5%**
107.64	**101.38**	**91.99**	**81.20**	**108.96**	**100.58**	**89.94**	**76.09**	**0.0%**	**-0.3%**	**-0.8%**	**-1.5%**

Tech. = Technology.
Btu = British thermal units.
Note: 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, AEO99 National Energy Modeling System, runs RSFRZN.D100598A, AEO99B.D100198A, RSHTEK.D100598A, and RSBTEK.D100598A.

Table F2. Key Results for Commercial Sector Technology Cases (Continued)

2015				2020				Annual Growth 1997-2020			
1999 Tech.	Reference Case	High Technology	Best Available Tech.	1999 Tech.	Reference Case	High Technology	Best Available Tech.	1999 Tech.	Reference Case	High Technology	Best Available Tech.
0.33	0.33	0.33	0.31	0.32	0.32	0.31	0.30	-1.9%	-1.9%	-2.0%	-2.2%
0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	-0.8%	-0.8%	-0.8%	-0.8%
0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.2%	-0.2%	-0.2%	-0.2%
0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.7%	0.7%	0.7%	0.7%
0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.3%	-0.3%	-0.3%	-0.3%
0.57	0.56	0.56	0.54	0.55	0.55	0.54	0.53	-1.2%	-1.3%	-1.3%	-1.4%
4.00	3.97	3.91	3.79	4.04	4.00	3.93	3.80	0.8%	0.7%	0.7%	0.5%
0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.9%	0.9%	0.9%	0.9%
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.0%	1.0%	1.0%	1.0%
4.64	4.54	4.41	3.99	4.85	4.72	4.55	4.10	1.5%	1.4%	1.2%	0.8%
9.31	**9.18**	**8.99**	**8.43**	**9.55**	**9.37**	**9.13**	**8.53**	**1.0%**	**0.9%**	**0.8%**	**0.5%**
8.78	8.60	8.36	7.55	8.92	8.68	8.38	7.54	0.7%	0.6%	0.4%	-0.0%
18.09	**17.78**	**17.35**	**15.98**	**18.47**	**18.05**	**17.51**	**16.06**	**0.8%**	**0.7%**	**0.6%**	**0.2%**
129.28	**127.49**	**124.89**	**117.03**	**130.94**	**128.47**	**125.30**	**116.95**	**0.2%**	**0.1%**	**-0.0%**	**-0.3%**

Tech. = Technology.
Btu = British thermal units.
Note: 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, AEO99 National Energy Modeling System, runs COMFZN.D100598A, AEO99B.D100198A, COMADV.D100598A, and COMBEST.D100598A.

Table F3. Key Results for Industrial Technology Cases

Consumption	1997	2010			2015			2020		
		1999 Technology	Reference Case	High Technology	1999 Technology	Reference Case	High Technology	1999 Technology	Reference Case	High Technology
Energy Consumption (quadrillion Btu)										
Distillate Fuel	1.13	1.35	1.35	1.29	1.43	1.42	1.31	1.49	1.48	1.32
Liquefied Petroleum Gas	2.14	2.46	2.45	2.33	2.59	2.58	2.41	2.70	2.69	2.48
Petrochemical Feedstocks	1.46	1.53	1.52	1.45	1.60	1.60	1.51	1.68	1.67	1.57
Residual Fuel	0.28	0.34	0.33	0.31	0.36	0.35	0.32	0.37	0.36	0.31
Motor Gasoline	0.21	0.26	0.26	0.25	0.28	0.28	0.26	0.30	0.29	0.27
Other Petroleum	4.11	4.98	4.89	4.71	5.05	4.95	4.64	5.10	4.99	4.56
Petroleum Subtotal	9.33	10.92	10.81	10.35	11.31	11.18	10.45	11.63	11.49	10.51
Natural Gas	9.93	11.75	11.43	11.17	12.38	12.02	11.58	12.88	12.52	11.97
Metallurgical Coal	0.79	0.67	0.63	0.64	0.62	0.58	0.58	0.58	0.53	0.52
Steam Coal	1.56	1.73	1.67	1.57	1.79	1.73	1.54	1.85	1.80	1.54
Net Coal Coke Imports	0.02	0.23	0.20	0.07	0.28	0.24	0.05	0.31	0.27	0.08
Coal Subtotal	2.36	2.63	2.51	2.29	2.69	2.55	2.17	2.73	2.60	2.14
Renewable Energy	1.88	2.29	2.31	2.35	2.42	2.45	2.52	2.52	2.56	2.66
Electricity	3.52	4.22	4.13	3.90	4.48	4.37	3.98	4.68	4.57	4.05
Delivered Energy	27.01	31.81	31.18	30.05	33.27	32.57	30.70	34.44	33.73	31.32
Electricity Related Losses	7.78	8.41	8.22	7.76	8.48	8.27	7.53	8.62	8.40	7.44
Total	34.79	40.22	39.41	37.81	41.75	40.84	38.22	43.06	42.14	38.77
Delivered Energy Use per Dollar of Output (thousand Btu per 1987 dollar)	6.78	6.07	5.95	5.74	5.84	5.72	5.39	5.62	5.50	5.11

Btu = British thermal units.
Note: 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, AEO99 Forecasting System runs INDLTECH.D100698A, AEO99B.D100198A, and INDHTECH.D100698A.

Table F4. Key Results for Transportation Technology Cases

Consumption and Indicators	1997	2010			2015			2020		
		1999 Technology	Reference Case	High Technology	1999 Technology	Reference Case	High Technology	1999 Technology	Reference Case	High Technology
Energy Consumption (quadrillion Btu)										
Distillate Fuel	4.64	6.27	6.00	5.63	6.74	6.31	5.65	7.15	6.58	5.60
Jet Fuel	3.31	5.18	5.10	5.10	5.87	5.69	5.56	6.60	6.27	5.90
Motor Gasoline	15.08	19.39	18.70	18.05	20.49	19.31	18.20	21.58	19.94	18.37
Residual Fuel	0.75	1.02	1.02	1.01	1.16	1.16	1.14	1.31	1.30	1.28
Liquid Petroleum Gas	0.04	0.18	0.18	0.20	0.22	0.20	0.23	0.24	0.22	0.25
Other Petroleum	0.29	0.34	0.34	0.34	0.35	0.35	0.35	0.36	0.36	0.36
Petroleum Subtotal	24.10	32.38	31.33	30.33	34.84	33.03	31.14	37.24	34.68	31.76
Pipeline Fuel Natural Gas	0.73	0.90	0.90	0.90	0.97	0.97	0.97	1.01	1.01	1.01
Compressed Natural Gas	0.01	0.25	0.26	0.29	0.30	0.31	0.34	0.33	0.34	0.37
Renewables (E85)	0.00	0.06	0.05	0.05	0.07	0.07	0.06	0.09	0.07	0.07
Methanol	0.00	0.08	0.08	0.07	0.11	0.10	0.09	0.13	0.11	0.10
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	0.18	0.15	0.15	0.24	0.19	0.20	0.29	0.22	0.22
Delivered Energy	24.91	33.85	32.77	31.79	36.53	34.65	32.79	39.09	36.44	33.54
Electricity Related Losses	0.13	0.36	0.30	0.30	0.46	0.36	0.37	0.53	0.41	0.41
Total	25.04	34.21	33.07	32.09	36.98	35.00	33.16	39.62	36.85	33.95
New Light-Duty Vehicle (miles per gallon)	24.0	23.2	25.4	27.5	23.3	26.1	29.0	23.3	26.5	30.2
Light-Duty Vehicles < 8500 pounds (VMT)	2301	2882	2887	2890	3089	3097	3104	3292	3303	3312

Tech = Technology.
Btu = British thermal units.
Vmt = Vehicle miles traveled.
Note: Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured.
Source: Energy Information Administration, AEO99 Forecasting System runs FZTECH.D100898A, AEO99B.D100198A, and HITECH.D100898A.

Table F5. Key Results for Integrated End-Use Technology Cases

Consumption and Emissions	1997	2010 1999 Tech.	2010 Reference Case	2010 High Tech.	2015 1999 Tech.	2015 Reference Case	2015 High Tech.	2020 1999 Tech.	2020 Reference Case	2020 High Tech.
Consumption by Sector (quadrillion Btu)										
Residential	18.99	22.18	21.11	19.61	23.64	21.91	20.03	25.14	22.85	20.53
Commercial	15.22	17.68	17.24	17.09	18.55	17.78	17.61	19.06	18.05	17.75
Industrial	34.79	40.54	39.41	38.25	42.21	40.84	38.90	43.71	42.14	39.43
Transportation	25.04	34.12	33.07	32.07	36.80	35.00	33.26	38.70	36.85	34.16
Total	94.04	114.52	110.83	107.02	121.19	115.53	109.80	126.61	119.89	111.86
Energy Intensity (thousand Btu per 1992 dollar of GDP)	12.94	11.58	11.21	10.82	11.22	10.70	10.17	10.84	10.27	9.59
Carbon Emissions by Sector (million metric tons)										
Residential	285.6	350.7	332.5	308.1	385.1	354.3	326.9	416.8	375.0	342.7
Commercial	236.6	289.9	281.7	278.6	314.4	299.0	299.3	329.4	308.1	309.2
Industrial	482.1	570.1	549.4	527.4	600.9	574.5	541.5	626.1	594.5	549.6
Transportation	475.3	646.0	626.3	607.1	696.2	662.3	628.5	732.8	697.3	646.4
Total	1479.6	1856.7	1789.9	1721.1	1996.5	1890.1	1796.3	2105.2	1974.9	1848.0
Carbon Emissions by End-Use Fuel (million metric tons)										
Petroleum	609.9	774.0	752.4	726.1	820.2	785.9	741.7	854.2	817.7	754.2
Natural Gas	275.4	321.7	313.4	305.5	340.7	328.9	317.7	355.5	340.0	326.4
Coal	62.0	70.6	67.4	62.6	72.1	68.4	60.6	73.0	69.8	58.7
Other	0.0	1.5	1.4	1.2	2.0	1.7	1.5	2.6	1.9	1.7
Electricity	532.4	688.8	655.4	625.6	761.4	705.1	674.9	820.0	745.5	707.1
Total	1479.6	1856.7	1789.9	1721.1	1996.5	1890.1	1796.3	2105.2	1974.9	1848.0
Carbon Emissions by Electric Generators (million metric tons)										
Petroleum	17.6	8.8	5.8	4.8	7.0	5.3	4.3	5.9	4.9	3.7
Natural Gas	43.8	95.5	98.5	81.6	109.0	124.0	99.6	117.8	134.8	106.7
Coal	471.0	584.5	551.1	539.3	645.5	575.9	571.0	696.3	605.8	596.6
Total	532.4	688.8	655.4	625.6	761.4	705.1	674.9	820.0	745.5	707.1
Carbon Emissions by Primary Fuel (million metric tons)										
Petroleum	627.5	782.7	758.1	730.9	827.3	791.1	746.0	860.1	822.6	757.9
Natural Gas	319.1	417.3	411.9	387.1	449.7	452.9	417.2	473.2	474.8	433.1
Coal	533.0	655.1	618.5	601.9	717.5	644.4	631.6	769.3	675.6	655.3
Other	0.0	1.5	1.4	1.2	2.0	1.7	1.5	2.6	1.9	1.7
Total	1479.6	1856.7	1789.9	1721.1	1996.5	1890.1	1796.3	2105.2	1974.9	1848.0

Btu = British thermal units.
GDP = Gross domestic product.
Tech. = Technology
Note: Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, AEO99 National Energy Modeling System runs LDELTEK.D100898A, AEO99B.D100198A, and HDELTEK.D100898A.

Table F6. Key Results for Nuclear Retirement Cases
(Thousand Megawatts)

Net Summer Capability	1997	Projections 2010 Low Nuclear	2010 Reference Case	2010 High Nuclear	2015 Low Nuclear	2015 Reference Case	2015 High Nuclear	2020 Low Nuclear	2020 Reference Case	2020 High Nuclear
Electric Generators										
Capability (thousand megawatts)										
Coal Steam	304.7	308.6	308.9	308.2	317.2	316.2	314.2	338.8	333.0	326.1
Other Fossil Steam	138.7	79.7	80.2	82.2	75.6	79.5	80.2	74.2	75.7	78.7
Combined Cycle	16.4	130.3	126.0	122.0	181.3	175.9	162.4	217.0	211.5	196.5
Combustion Turbine/Diesel	78.2	151.9	151.0	145.6	182.7	174.9	167.4	193.3	186.7	179.6
Nuclear Power	99.0	72.1	74.2	85.5	45.0	56.4	79.4	31.8	48.9	78.2
Pumped Storage	19.6	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	87.9	92.1	92.1	92.1	93.9	93.9	93.5	97.0	96.7	95.8
Total	744.5	856.3	853.9	857.1	917.3	918.4	918.6	973.6	974.0	976.3
Cumulative Planned Additions										
Total	2.5	30.1	30.1	30.1	30.2	30.2	30.2	30.2	30.2	30.2
Cumulative Unplanned Additions										
Coal Steam	0.0	5.4	5.6	5.0	14.6	13.5	11.7	36.8	31.0	24.1
Other Fossil Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	109.3	105.0	101.1	160.3	155.0	141.4	196.0	190.5	175.5
Combustion Turbine/Diesel	20.2	84.6	81.1	78.1	116.6	108.2	100.9	128.4	120.2	113.7
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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.8	2.3	2.3	2.3	4.4	4.3	3.9	7.6	7.3	6.4
Total	21.0	201.6	194.0	186.4	295.9	281.0	257.8	368.8	348.9	319.7
Cumulative Total Additions	23.5	231.7	224.2	216.6	326.0	311.1	288.0	399.0	379.0	349.8
Cumulative Retirement	14.8	110.9	105.7	95.5	144.3	128.3	104.9	160.9	140.6	109.0
Generation by Fuel Type (billion kilowatthours)										
Coal	1796	2050	2046	2023	2168	2151	2109	2349	2298	2213
Petroleum	82	27	28	26	26	26	24	26	24	22
Natural Gas	299	925	919	879	1269	1213	1100	1415	1349	1237
Nuclear Power	629	544	554	619	343	419	578	239	359	564
Pumped Power	-3	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources	389	389	388	388	401	401	398	422	420	414
Total	3192	3934	3934	3934	4207	4208	4208	4450	4450	4450
Carbon Emissions by Electric Generators (million metric tons)										
Petroleum	17.6	5.7	5.8	5.5	5.3	5.3	4.9	5.3	4.9	4.5
Natural Gas	43.8	98.6	98.5	94.2	129.6	124.0	113.1	141.2	134.8	124.0
Coal	471.0	552.2	551.1	544.5	580.4	575.9	564.9	616.0	605.8	585.9
Total	532.4	656.4	655.4	644.2	715.3	705.1	682.8	762.5	745.5	714.4
Natural Gas Prices to Electric Generators (1997 dollars per tcf)	2.76	3.16	3.15	3.13	3.31	3.24	3.13	3.39	3.31	3.16
Coal Prices to Electric Generators (1997 dollars per short ton)	26.05	21.67	21.66	21.62	20.04	20.03	19.93	18.75	18.77	18.72

tcf = Thousand cubic feet.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO98. Net summer capacity is used to be consistent with electric utility capacity estimates. Electric utility capacity is the most recent data available as of July 1, 1998. Therefore, capacity estimates may differ from other Energy Information Administration sources. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured.

Source: Energy Information Administration, AEO99 National Energy Modeling System runs LNUC99.D101698A, AEO99B.D100198A, and HNUC99.D101698A.

Table F7. Key Results for Electricity Demand Cases

Key Indicators	1997	2000		2010		2020		Annual Growth 1997-2020	
		Reference Case	High Demand	Reference Case	High Demand	Reference Case	High Demand	Reference Case	High Demand
Electricity Sales (billion kilowatthours)	3,130	3,333	3,355	3,843	4,116	4,345	4,935	1.4%	2.0%
Net Imports (billion kilowatthours)	32	43	43	30	32	27	27	-0.7%	-0.7%
Electricity Prices (1997 cents per kilowatthour)	6.9	6.6	6.6	6.1	6.5	5.6	6.2	-0.9%	-0.5%
Generation by Fuel (billion kilowatthours)									
Coal	1,855	1,989	1,999	2,101	2,160	2,353	2,716	1.0%	1.7%
Natural Gas	509	548	558	1,140	1,364	1,582	1,807	5.1%	5.7%
Renewables	430	423	423	445	448	483	505	0.5%	0.7%
Other	725	777	781	597	603	398	415	-2.6%	-2.4%
Total	3,520	3,737	3,761	4,283	4,574	4,816	5,443	1.4%	1.9%
Generating Capacity (gigawatts)									
Coal	304.7	305.4	305.4	308.9	310.6	333.0	378.7	0.4%	0.9%
Combined-Cycle/Combustion Turbine	94.6	126.0	126.0	277.0	317.6	398.2	462.7	6.4%	7.1%
Renewables	87.9	89.7	89.7	92.1	92.5	96.7	100.0	0.4%	0.6%
Nuclear Power	99.0	94.8	94.8	74.2	74.2	48.9	50.8	-3.0%	-2.9%
Cogenerators	51.8	54.6	54.7	56.8	56.8	59.1	59.1	0.6%	0.6%
Other	158.2	159.9	159.9	101.7	99.2	97.2	83.6	-2.1%	-2.7%
Total	796.3	830.5	830.6	910.7	950.9	1,033.0	1,134.9	1.1%	1.6%
Energy Production									
Coal (million short tons)	1,099	1,168	1,174	1,236	1,265	1,358	1,497	0.9%	1.3%
Natural Gas (trillion cubic feet)	22	22.69	22.80	28.18	29.93	32.44	34.17	1.7%	2.0%
Carbon Emissions (million metric tons)	1,480	1,585	1,590	1,790	1,833	1,975	2,073	1.3%	1.5%
Prices to Electric Generators (1997 dollars per million Btu)									
Coal	1.27	1.19	1.20	1.06	1.07	0.93	0.93	-1.3%	-1.3%
Natural Gas	2.70	2.62	2.63	3.08	3.29	3.24	3.55	0..8%	1.2%

Btu = British thermal units.

Notes: Other includes non-coal fossil steam, pumped storage, methane, propane and blast furnace gas. Coal Energy Production is production plus net imports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured.

Source: Energy Information Administration, AEO99 Forecasting System runs HDEMEL99.D100798A and AEO99B.D100198A.

Table F8. Key Results for Electricity Generation Sector Technology Cases
(Thousand Megawatts)

Net Summer Capability	1997	2000			2010			2020		
		Low Fossil	Reference Case	High Fossil	Low Fossil	Reference Case	High Fossil	Low Fossil	Reference Case	High Fossil
Electric Generators										
Capability										
Pulverized Coal	304.2	304.9	304.9	304.9	315.3	305.3	302.7	353.3	307.3	301.6
Coal Gasification Combined-Cycle	0.5	0.5	0.5	0.5	0.5	3.5	10.3	0.5	25.8	88.8
Conventional Natural Gas Combined-Cycle	16.4	22.7	22.0	18.8	82.5	27.0	22.4	154.9	27.0	22.4
Advanced Natural Gas Combined-Cycle	0.0	4.4	5.1	9.2	19.0	99.1	109.8	19.7	184.5	159.8
Conventional Combustion Turbine	78.2	97.6	96.8	96.8	136.7	116.9	103.1	176.6	123.4	103.2
Advanced Combustion Turbine	0.0	1.3	2.1	4.2	3.7	34.1	43.6	3.7	63.3	78.8
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	99.0	94.8	94.8	94.8	81.3	74.2	74.2	58.2	48.9	41.9
Oil and Gas Steam	138.7	138.4	138.4	138.4	100.0	80.2	74.8	80.6	75.7	68.2
Renewable Sources	107.5	111.3	111.3	111.3	114.9	113.7	113.6	124.2	118.2	114.9
Total	**744.5**	**775.9**	**775.9**	**779.0**	**854.0**	**853.9**	**854.5**	**971.6**	**974.0**	**979.6**
Cumulative Planned Additions										
Pulverized Coal	0.1	0.9	0.9	0.9	1.4	1.4	1.4	1.4	1.4	1.4
Coal Gasification Combined-Cycle	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Conventional Natural Gas Combined-Cycle	0.7	2.0	2.0	2.0	5.3	5.3	5.3	5.3	5.3	5.3
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Conventional Cmbustion Turbine	1.5	6.7	6.7	6.7	18.6	18.6	18.6	18.6	18.6	18.6
Advanced Combustion Turbine	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
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	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Renewable Sources	0.1	3.6	3.6	3.6	4.7	4.7	4.7	4.7	4.7	4.7
Total	**2.5**	**13.3**	**13.3**	**13.3**	**30.1**	**30.1**	**30.1**	**30.2**	**30.2**	**30.2**
Cumulative Unplanned Additions										
Pulerized Coal	0.0	0.0	0.0	0.0	12.6	2.6	0.8	51.7	5.7	0.9
Coal Gasification Comined-Cycle	0.0	0.0	0.0	0.0	0.0	3.0	9.8	0.0	25.3	88.2
Conventional Natural Gas Combined-Cycle	0.0	5.0	4.3	1.2	61.5	6.0	1.4	133.9	6.0	1.4
Advanced Natural Gas Combined-Cycle	0.0	4.4	5.1	9.2	19.0	99.1	109.8	19.7	184.5	159.8
Conventional Combustion Turbine	20.2	34.4	33.6	33.6	64.9	47.0	36.0	110.7	56.8	37.3
Advanced Combustion Turbine	0.0	1.3	2.1	4.2	3.7	34.1	43.6	3.7	63.3	78.8
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.8	0.9	0.9	0.9	3.5	2.3	2.2	13.3	7.3	4.0
Total	**21.0**	**46.0**	**46.0**	**49.1**	**165.1**	**194.0**	**203.6**	**332.9**	**348.9**	**370.4**
Cumulative Total Additions	**23.5**	**59.2**	**59.3**	**62.3**	**195.3**	**224.2**	**233.7**	**363.1**	**379.0**	**400.6**
Cumulative Retirements	**14.8**	**19.4**	**19.4**	**19.4**	**76.8**	**105.7**	**115.8**	**127.0**	**140.6**	**157.6**
Cogenerators										
Capability										
Coal	9.4	9.8	9.8	9.8	9.9	9.9	9.9	10.0	10.0	10.0
Petroleum	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5
Natural Gas	33.4	34.9	34.8	34.9	36.2	36.2	36.2	37.7	37.7	37.7
Other Gaseous Fuels	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Renewables	6.9	7.5	7.5	7.5	8.2	8.2	8.2	8.8	8.8	8.8
Other	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**51.8**	**54.7**	**54.6**	**54.7**	**56.7**	**56.8**	**56.7**	**59.1**	**59.1**	**59.0**
Cumulative Additions	**20.2**	**23.1**	**23.0**	**23.1**	**25.1**	**25.1**	**25.1**	**27.4**	**27.4**	**27.4**

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO98. Net summer capacity is used to be consistent with electric utility capacity estimates. Electric utility capacity is the most recent data available as of August 31, 1997. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Source: Energy Information Administration, AEO99 National Energy Modeling System runs LTECEL.D100398A, AEO99A.D100198A, and HTECEL.D100798A.

Table F9. Key Results for Competitive Pricing Case

Key Indicators and Consumption	Competitive Pricing						
	1996	1997	2000	2005	2010	2015	2020
Electricity Sales by Sector (billion kilowatthours)							
Residential	1082	1072	1178	1279	1356	1448	1556
Commercial	981	1008	1083	1173	1261	1333	1379
Industrial	1030	1033	1059	1132	1215	1274	1329
Transportation	17	17	18	31	44	55	65
Total	**3111**	**3130**	**3338**	**3614**	**3876**	**4109**	**4329**
End-Use Prices (1997 cents per kwh)							
Residential	8.5	8.5	7.8	7.4	7.4	7.4	7.2
Commercial	7.7	7.6	7.1	6.6	6.3	6.2	6.1
Industrial	4.6	4.6	4.5	4.3	4.0	4.0	4.0
Transportation	5.5	5.6	5.3	5.0	4.9	4.8	4.7
All Sectors Average	**6.9**	**6.9**	**6.5**	**6.1**	**6.0**	**5.9**	**5.8**
Generation by Fuel Type (billion kilowatthours)							
Coal	1745	1796	1931	1982	2063	2162	2319
Petroleum	72	82	101	35	25	27	22
Natural Gas	278	299	342	676	940	1197	1319
Nuclear Power	675	629	659	630	554	419	359
Pumped Storage	-2	-3	-1	-1	-1	-1	-1
Renewable Sources	379	389	375	381	389	401	416
Total	**3147**	**3192**	**3408**	**3703**	**3970**	**4204**	**4433**
Capability (Thousand Megawatts)							
Coal Steam	304.7	304.7	305.4	305.2	308.9	316.6	336.0
Other Fossil Steam	137.8	138.7	138.4	102.5	86.1	78.5	61.4
Combined Cycle	15.4	16.4	27.3	90.3	133.6	171.6	200.6
Combustion Turbine/Diesel	70.1	78.1	98.9	144.9	154.3	163.8	172.5
Nuclear Power	100.7	99.0	94.8	87.4	74.2	56.4	48.9
Pumped Storage	19.6	19.6	21.5	21.5	21.5	21.5	21.5
Fuel Cells	0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	87.7	87.9	89.7	91.1	92.3	93.9	96.0
Total	**736**	**744.4**	**776.1**	**842.8**	**871.0**	**902.3**	**937.0**
Cumulative Planned Additions							
Total	**1.7**	**2.5**	**13.3**	**29.8**	**30.1**	**30.2**	**30.2**
Cumulative Unplanned Additions							
Coal Steam	0	0.0	0.0	1.5	5.8	14.1	34.0
Other Fossil Steam	0	0.0	0.0	0.0	0.0	0.0	0.0
Combied Cycle	0	0.0	9.6	69.3	112.6	150.6	179.7
Combustion Turbine/Diesel	13.3	20.1	35.7	72.2	81.8	91.8	100.5
Nuclear Power	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
Fuel Cells	0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.8	0.8	0.9	1.4	2.4	4.3	6.7
Total	**14.1**	**21.0**	**46.2**	**144.3**	**202.7**	**260.8**	**320.8**
Cumulative Total Additions	15.8	23.4	59.4	174.2	232.8	290.9	351.0
Cumulative Retirements	12.7	14.8	19.4	68.3	98.4	124.2	149.5
Total Carbon Emissions by Electric Generators (million metric tons per year)	**513.2**	**532.4**	**589.5**	**616.9**	**661.0**	**708.3**	**747.6**
Natural Gas Prices to Electric Generators (1997 dollars per thousand cubic foot)	**2.76**	**2.76**	**2.68**	**3.03**	**3.17**	**3.22**	**3.27**
Coal Prices to Electric Generators (1997 dollars per short ton)	**26.96**	**26.16**	**24.48**	**23.24**	**21.70**	**20.19**	**19.00**

Note: Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, AEO99 National Energy Modeling System run COMPETE.D100398A.

Table F10. Key Results for Renewable Portfolio Standard Cases

Key Indicators	1997	2000		2010		2020	
		Reference	5.5% RPS	Reference	5.5% RPS	Reference	5.5% RPS
Electricity Sales							
(billion kilowatthours)	3,130	3,333	3,333	3,843	3,827	4,345	4,336
Electricity Prices							
(1997 cents per kilowatthour)	6.9	6.58	6.58	6.14	6.25	5.63	5.64
Generation by Fuel (billion kilowatthours)							
Coal	1,855	1,989	1,990	2,101	2,069	2,353	2,258
Natural Gas	509	548	547	1,140	1,035	1,582	1,527
Oil	92	110	110	35	33	31	30
Conventional Hydropower	357	327	327	328	328	328	328
Geothermal	16	15	15	18	29	23	34
Municipal Solid Waste	16	26	26	29	29	31	31
Wood and Other Biomass	37	49	49	62	129	91	179
Solar Thermal	1	1	1	1	1	1	1
Solar Photovoltaic	0	0	0	1	1	2	2
Wind	3	6	6	8	51	8	52
Other	634	668	667	562	561	367	366
Total	3,520	3,738	3,737	4,284	4,267	4,817	4,807
Generating Capacity (gigawatts)							
Coal	314	315	315	319	317	343	332
Natural Gas and Oil	268	301	301	395	381	513	509
Conventional Hydropower	79	79	79	79	79	79	79
Geothermal	3	4	3	4	5	4	5
Municipal Solid Waste	4	4	4	4	4	5	5
Wood and Other Biomass	7	8	8	9	19	13	26
Solar Thermal	0	0	0	0	0	1	1
Solar Photovoltaic	0	0	0	0	0	1	1
Wind	2	3	3	3	19	4	19
Other	119	117	117	97	97	71	71
Total	796	831	831	911	921	1033	1,047
Energy Production							
Coal (million short tons)	1,099	1,168	1,168	1,236	1,224	1,358	1,322
Natural Gas (trillion cubic feet)	18.9	19.3	19.3	23.8	23.0	27.4	27.1
Carbon Emissions (million metric tons)	532	589	589	655	635	745	720
Prices to Generators (1997 dollars per million btu)							
Coal	1.27	1.19	1.19	1.06	1.07	0.93	0.94
Natural Gas	2.70	2.62	2.63	3.08	2.97	3.24	3.12

Source: Energy Information Administration, AEO99 National Energy Modeling System runs AEO99B.D100198A and RPS99.D100698B.

Table F11. Key Results for High Renewable Energy Case

Capacity and Generation	1997	2010		2020	
		Reference	High Renewables	Reference	High Renewables
Capacity (Gigawatts)					
Net Summer Capability					
Electric Generators					
Conventional Hydropower	77.60	78.51	78.51	78.51	78.51
Geothermal	3.00	3.16	3.77	3.52	4.93
Municipal Solid Waste	3.41	4.01	4.01	4.27	4.27
Wood and Other Biomass	1.66	2.33	5.14	5.61	14.51
Solar Thermal	0.35	0.44	0.45	0.52	0.53
Solar Photovoltaic	0.01	0.30	0.31	0.64	0.65
Wind	1.88	3.39	10.42	3.61	22.03
Total	**87.92**	**92.14**	**102.59**	**96.68**	**125.43**
Cogenerators					
Conventional Hydropower	0.93	0.93	0.93	0.93	0.93
Municipal Solid Waste	0.46	0.48	0.48	0.49	0.49
Wood and Other Biomass	5.45	6.77	6.78	7.39	7.39
Total	**6.85**	**8.19**	**8.19**	**8.81**	**8.81**
Generation (billion kilowatthours)					
Electric Generators					
Coal	1,796	2,046	2,001	2,298	2,089
Petroleum	82	28	31	24	25
Natural Gas	299	919	900	1,349	1,409
Total Fossil[1]	**2,177**	**2,992**	**2,932**	**3,672**	**3,523**
Conventional Hydropower	350.62	323.42	323.44	323.58	323.59
Geothermal	15.67	17.86	22.47	22.99	33.69
Municipal Solid Waste	14.30	26.49	26.50	28.34	28.35
Wood and Other Biomass	4.21	11.97	31.59	34.89	97.22
Solar Thermal	0.90	1.19	1.21	1.44	1.49
Solar Photovoltaic	0.00	0.71	0.72	1.56	1.59
Wind	3.41	7.69	34.16	8.44	78.74
Total Renewable	**389.11**	**389.33**	**440.09**	**421.24**	**564.68**
Cogenerators					
Coal	60	55	55	54	54
Petroleum	10	7	7	7	7
Natural Gas	210	221	221	233	232
Total Fossil[1]	**280**	**283**	**283**	**294**	**294**
Conventional Hydropower	6.16	4.90	4.90	4.90	4.90
Municipal Solid Waste	1.80	2.32	2.32	2.34	2.34
Wood and Other Biomass	32.69	49.59	49.59	55.82	55.78
Total Renewables	**40.65**	**56.82**	**56.82**	**63.06**	**63.02**

[1]Total of items presented.
Source: Energy Information Administration, AEO99 Forecasting System runs AEO99B.D100198A and HIRENEW.D100398B.

Table F12. Key Results for Oil and Gas Technological Progress Cases
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1997	Projections								
		2005			2010			2020		
		Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress	Slow Technology Progress	Reference	Rapid Technology Progress
Total Energy Supply and Disposition										
Production										
Crude Oil and Lease Condensate	13.65	11.99	12.31	12.60	11.24	11.83	12.40	9.65	10.51	11.09
Natural Gas Plant Liquids	2.57	2.75	2.80	2.83	2.97	3.06	3.12	3.24	3.47	3.69
Dry Natural Gas	19.46	21.75	22.17	22.38	23.69	24.44	24.93	26.11	28.12	29.96
Coal	23.29	25.31	25.20	25.14	26.30	25.91	25.75	29.38	28.12	27.14
Nuclear Power	6.71	6.73	6.73	6.73	5.91	5.91	5.91	3.98	3.83	3.75
Renewable Energy	6.82	7.11	7.11	7.11	7.45	7.44	7.44	8.25	8.15	8.09
Other	0.66	0.56	0.57	0.57	0.58	0.57	0.57	0.65	0.65	0.65
Total	**73.18**	**76.21**	**76.89**	**77.36**	**78.15**	**79.16**	**80.11**	**81.26**	**82.85**	**84.38**
Imports										
Crude Oil[1]	17.85	21.84	21.53	21.19	24.49	23.91	23.35	26.90	26.03	25.46
Petroleum Products	3.88	6.58	6.45	6.42	7.47	7.35	7.24	10.18	9.92	9.64
Natural Gas	3.05	4.04	3.97	3.96	4.76	4.69	4.71	5.67	5.46	5.19
Other Imports	0.52	0.70	0.70	0.70	0.71	0.71	0.71	0.75	0.75	0.75
Total	**25.32**	**33.16**	**32.65**	**32.28**	**37.43**	**36.66**	**36.01**	**43.50**	**42.15**	**41.03**
Exports										
Petroleum	2.09	2.03	2.05	2.06	2.09	2.11	2.14	1.95	2.00	2.02
Natural Gas	0.16	0.21	0.21	0.21	0.24	0.24	0.24	0.32	0.32	0.32
Coal	2.14	2.21	2.21	2.21	2.27	2.27	2.27	2.36	2.36	2.36
Total	**4.39**	**4.45**	**4.47**	**4.48**	**4.60**	**4.62**	**4.65**	**4.63**	**4.68**	**4.70**
Discrepancy	**-0.06**	**-0.36**	**-0.39**	**-0.35**	**-0.45**	**-0.37**	**-0.42**	**-0.50**	**-0.44**	**-0.47**
Consumption										
Petroleum Products	36.49	41.31	41.25	41.23	44.28	44.22	44.16	48.12	48.08	48.02
Natural Gas	22.59	25.54	25.89	26.07	28.11	28.79	29.30	31.38	33.17	34.73
Coal	21.09	23.46	23.31	23.27	24.38	24.06	23.84	27.50	26.26	25.23
Nuclear Power	6.71	6.73	6.73	6.73	5.91	5.91	5.91	3.98	3.83	3.75
Renewable Energy	6.82	7.12	7.12	7.11	7.46	7.45	7.45	8.26	8.17	8.11
Other	0.33	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39
Total	**94.04**	**104.55**	**104.68**	**104.81**	**110.53**	**110.83**	**111.05**	**119.63**	**119.89**	**120.23**
Net Imports - Petroleum	**19.65**	**26.38**	**25.93**	**25.56**	**29.87**	**29.16**	**28.45**	**35.12**	**33.95**	**33.08**
Prices (1997 dollars per unit)										
World Oil Price (dollars per barrel)	18.55	19.25	19.25	19.25	21.30	21.30	21.30	22.73	22.73	22.73
Gas Wellhead Price (dollars per Mcf)	2.23	2.53	2.35	2.25	2.85	2.52	2.29	2.99	2.68	2.23
Coal Minemouth Price (dollars per ton)	18.04	14.97	14.93	14.94	14.06	14.00	13.85	12.66	12.74	12.67
Avg. Electricity Price (cents per Kwh)	6.9	6.4	6.4	6.3	6.2	6.1	6.1	5.7	5.6	5.5
Natural Gas Supply and Disposition										
Production (trillion cubic feet)										
Dry Gas Production	18.93	21.16	21.57	21.77	23.05	23.77	24.25	25.40	27.35	29.15
Supplemental Natural Gas	0.11	0.11	0.11	0.11	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports (trillion cubic feet)	**2.83**	**3.75**	**3.68**	**3.66**	**4.42**	**4.35**	**4.37**	**5.24**	**5.02**	**4.76**
Total Supply (trillion cubic feet)	**21.88**	**25.02**	**25.36**	**25.55**	**27.53**	**28.18**	**28.68**	**30.69**	**32.44**	**33.97**
Consumption by Sector (trillion cubic feet)										
Residential	5.00	5.12	5.16	5.19	5.28	5.36	5.43	5.66	5.77	5.92
Commercial	3.27	3.55	3.58	3.60	3.68	3.73	3.77	3.82	3.88	3.96
Industrial	8.40	8.96	9.04	9.09	9.32	9.46	9.59	10.09	10.24	10.45
Electric Generators	3.32	4.77	4.92	4.99	6.38	6.69	6.91	7.91	9.16	10.11
Lease and Plant Fuel	1.24	1.49	1.50	1.51	1.61	1.65	1.67	1.83	1.93	2.00
Pipeline Fuel	0.71	0.80	0.82	0.82	0.85	0.87	0.90	0.91	0.98	1.06
Transportation	0.01	0.18	0.18	0.18	0.25	0.25	0.25	0.33	0.33	0.34
Total	**21.98**	**24.86**	**25.19**	**25.37**	**27.36**	**28.02**	**28.52**	**30.55**	**32.30**	**33.83**
Discrepancy (trillion cubic feet)	**-0.09**	**0.16**	**0.17**	**0.18**	**0.17**	**0.16**	**0.16**	**0.14**	**0.14**	**0.14**

Table F12. Key Results for Oil and Gas Technological Progress Cases (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1997	Projections								
		2005			2010			2020		
		Slow Tech. Progress	Reference	Rapid Tech. Progress	Slow Tech. Progress	Reference	Rapid Tech. Progress	Slow Tech. Progress	Reference	Rapid Tech. Progress
Crude Oil Supply										
Lower 48 Average Wellhead Price (1997 dollars per barrel)	16.25	18.87	18.80	18.74	20.99	20.80	20.66	21.79	21.73	21.48
Production (million barrels per day)										
U.S. Total	6.45	5.66	5.82	5.95	5.31	5.59	5.86	4.56	4.96	5.24
Lower 48 Onshore	3.75	3.07	3.11	3.13	3.00	3.07	3.13	3.08	3.28	3.40
Conventional	3.17	2.64	2.66	2.68	2.49	2.54	2.58	2.47	2.57	2.62
Enhanced Oil Recovery	0.58	0.43	0.45	0.45	0.50	0.53	0.55	0.62	0.71	0.78
Lower 48 Offshore	1.40	1.69	1.73	1.78	1.65	1.74	1.83	1.11	1.19	1.18
Alaska	1.29	0.91	0.97	1.04	0.67	0.78	0.90	0.37	0.49	0.66
Lower 48 End of Year Reserves (billion barrels)	18.27	14.25	14.44	14.67	13.44	13.80	14.21	12.92	13.70	14.14
Natural Gas Supply										
Lower 48 Average Wellhead Price (1997 dollars per Mcf)	2.23	2.53	2.35	2.25	2.85	2.52	2.29	2.99	2.68	2.23
Production (trillion cubic feet)										
U.S. Total	18.93	21.16	21.57	21.77	23.05	23.77	24.25	25.40	27.35	29.15
Lower 48 Onshore	12.88	14.06	14.31	14.24	15.89	16.36	16.78	18.05	20.24	22.57
Associated-Dissolved	1.77	1.32	1.32	1.33	1.18	1.19	1.20	1.17	1.21	1.24
Non-Associated	11.11	12.74	12.99	12.92	14.71	15.18	15.58	16.88	19.04	21.34
Conventional	7.42	9.17	9.01	8.76	10.29	10.27	9.87	12.12	12.32	11.81
Unconventional	3.68	3.57	3.97	4.16	4.42	4.90	5.71	4.76	6.72	9.52
Lower 48 Offshore	5.61	6.44	6.61	6.88	6.48	6.73	6.79	6.61	6.38	5.84
Associated-Dissolved	0.79	0.91	0.92	0.92	0.91	0.93	0.95	0.79	0.81	0.80
Non-Associated	4.81	5.53	5.69	5.96	5.57	5.80	5.84	5.82	5.57	5.03
Alaska	0.43	0.65	0.65	0.65	0.68	0.68	0.68	0.73	0.73	0.73
U.S. End of Year Reserves (trillion cubic feet)	158.12	157.63	166.77	174.19	165.15	174.29	189.68	149.29	172.03	210.84
Supplemental Gas Supplies (trillion cubic feet)	0.12	0.11	0.11	0.11	0.05	0.05	0.05	0.05	0.05	0.05
Total Lower 48 Wells Completed (thousands)	27.02	26.00	27.00	26.86	32.02	31.54	31.25	31.11	35.62	38.21

Tech = Technology.
Kwh = Kilowatthour.
Btu = British thermal unit.
Mcf = Thousand cubic feet.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1997 may differ from published data due to internal conversion factors.
Sources: Energy Information Administration, AEO99 National Energy Modeling System runs LTECOG.D100298A, AEO99B.D100198A, and HTECOG.D100298A.

Table F13. Key Results for Reduced Sulfur Gasoline Cases

Demand, Prices, and Imports	1997	2004 Reference	2004 API/NPRA Regional Reduced Sulfur	2004 Automakers' National Low Sulfur	2010 Reference	2010 API/NPRA Regional Reduced Sulfur	2010 Automakers' National Low Sulfur
Assumed Gasoline Content by Area (parts per million)							
California Reformulated Gasoline[1]	40	40	40	40.	40	40	40
Federal Reformulated Gasoline Areas[2]	340	150	150	40	150	40	40
23 Eastern States and East Texas[3]	340	340	150	40	340	40	40
All Other Areas	340	340	300	40	340	300	40
Percentage of Total Gasoline Demand by Sulfur Content							
340 ppm average[4]	89%	66%			66%		
less than 300 ppm			24%			24%	
less than 150 ppm		23%	65%		23%		
less than 40 ppm	11%	11%	11%	100%	11%	76%	100%
National Average Gasoline Price (1997 dollars per gallon)	1.214	1.201	1.214	1.284	1.288	1.337	1.356
Consumer Expenditures for Gasoline (billions 1997 dollars)	148.7	169.8	171.6	181.5	197.6	205.2	208.1
Net Gasoline and Blending Components Imports (mbcd)	359	806	744	717	1193	1122	784
Net Crude Oil Imports (mbcd)	8,118	9,677	10,033	10,474	10,959	11,125	11,193
Import Share of Product Supplied (percentage)	0.49	0.57	0.57	0.58	0.60	0.61	0.61

[1]California requires a 40 parts per million (ppm) flat limit, or 30 ppm annual average with an 80 ppm cap.
[2]Required areas: Baltimore, Chicago, Houston, Los Angeles, Milwaukee, New York City, Philadelphia, San Diego, Sacramento, and Washington, DC, and the entire states of Connecticut, Delaware, New Jersey, Massachusetts, and Rhode Island. Plus opt-in areas in Arizona, Kentucky, Maine, Missouri, Maryland, New Hampshire, New York, Texas, and Virginia.
[3]Includes Alabama, Florida, Georgia, Illinois, Indiana, Kentucky, Louisiana, Maine, Maryland, Michigan, Mississippi, Missouri, New Hampshire, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Vermont, Virginia, West Virginia, and Wisconsin.
[4]The current average sulfur content is 340 parts per million (ppm) though 1000 ppm is the maximum allowed.
mbcd = thousand barrels per day.
DC = District of Columbia.
API/NPRA = American Petroleum Institute and National Petrochemical and Refiners Association.
Note: Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured.
Source: Energy Information Administration, AEO99 National Energy Modeling System runs AEO99B.D100198A, TRLAPI.D101698A, and TRLAAMA.D101698A.

Table F14. Key Results for Coal Mining Cost Cases

Prices, Productivity, and Wages	1997	2000			2010			2020		
		Low Cost	Reference Case	High Cost	Low Cost	Reference Case	High Cost	Low Cost	Reference Case	High Cost
Minemouth Price (1997 dollars per short ton)	18.14	16.31	16.59	16.82	12.56	14.00	15.00	10.42	12.74	14.94
Delivered Price to Electric Generators (1997 dollars per million Btu)	1.27	1.18	1.19	1.21	0.99	1.06	1.14	0.82	0.93	1.07
Labor Productivity (short tons per miner per hour)	6.04	6.99	6.85	6.73	10.66	8.96	7.99	14.14	10.18	7.99
Labor Productivity (average annual growth from 1997)	N/A	5.0	4.3	3.7	4.5	3.1	2.2	3.8	2.3	1.2
Average Coal Miner Wage (1997 dollars per hour)	19.01	18.73	19.01	19.30	17.81	19.01	20.28	16.94	19.01	21.32
Average Coal Miner Wage (average annual growth from 1997)	N/A	-0.5	0.0	0.5	-0.5	0.0	0.5	-0.5	0.0	0.5

N/A = Not Applicable.

Note: Side cases were run without the fully integrated modeling system, so not all potential feedbacks are captured.

Source: Energy Information Administration, AEO99 National Energy Modeling System runs LLCST99.D100598B, AEO99.D100198A, and HLCST99.D100598B.

Appendix G

Major Assumptions for the Forecasts

The National Energy Modeling System

The projections in the *Annual Energy Outlook 1999* (*AEO99*) are generated with 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 the energy supply and demand, accounting for the economic competition between 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 9 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. This modularity allows 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 impact and cost of legislation and environmental regulations that affect that sector and reports key emissions. NEMS represents current legislation and environmental regulations as of July 1, 1998, such as the Clean Air Act Amendments of 1990 (CAAA90), the Ozone Transport Rule (OTR), and the costs of compliance with other regulations.

In general, the *AEO99* projections were prepared by using the most current data available as of July 31, 1998. At that time, most 1997 data were available, but only partial 1998 data were available. Carbon emissions were calculated by using carbon coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 1997*, published in October 1998 [*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 *AEO99* 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 *AEO99* includes cogeneration in the industrial 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 *AEO99* projections for 1998 and 1999 incorporate short-term projections from the September update of EIA's *Short-Term Energy Outlook* (*STEO*), Third Quarter 1998 [*2*], published in July 1998. For short-term energy projections, readers are referred to the monthly updates of the *STEO*.

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 DRI/McGraw-Hill U.S. 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 5 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.

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 8 energy-intensive industries, 7 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 alternatively-fueled 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 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 and OTR compliance options are explicitly represented in the capacity expansion and dispatch decisions. Both new generating technologies and renewable technologies compete directly in these decisions.

Renewable Fuels Module

The Renewable Fuels Module includes submodules that provide explicit representation of the supply of biomass (including wood and energy crops), municipal solid waste (including landfill gas), wind energy, solar thermal electric and photovoltaic energy, and geothermal energy. It contains natural resource supply estimates and provides cost and performance criteria to the Electricity Market Module. The Electricity Market Module represents market penetration of renewable technologies used for centralized electricity generation, and the end-use demand modules incorporate market penetration of selected off-grid electric and nonmarketed non-electric renewables.

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 tight gas formations, shale, and coalbeds. 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 new automotive fuels, such as oxygenated and reformulated gasoline, and includes oxygenate production and blending for reformulated gasoline. Costs include capacity expansion for refinery processing units. 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 4 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 1999*

Table G1 provides a summary of the cases used to derive the *AEO99* 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 on world oil markets and domestic macroeconomic activity are primary drivers to the forecasts presented in *AEO99*. These assumptions 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 will be available via the EIA Home Page on the Internet and on the EIA CD-ROM, along with regional results and other details of the projections.

Buildings sector assumptions

The buildings sector includes both residential and commercial structures. Both the National Appliance Energy Conservation Act of 1987 (NAECA), the Energy Policy Act of 1992 (EPACT), and the Climate Change Action Plan (CCAP) contain provisions which impact future buildings sector energy use. The provisions with the most significant effect are minimum equipment efficiency standards. These standards 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.

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.

Table G1. Summary of the *AEO99* 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 1.5 percent, compared to the reference case growth of 2.1 percent.	Fully integrated	p. 45	
High Economic Growth	Gross domestic product grows at an average annual rate of 2.6 percent, compared to the reference case growth of 2.1 percent.	Fully integrated	p. 45	
Low World Oil Price	World oil prices are $14.57 per barrel in 2020, compared to $22.73 per barrel in the reference case.	Partially integrated	p. 46	
High World Oil Price	World oil prices are $29.35 per barrel in 2020, compared to $22.73 per barrel in the reference case.	Partially integrated	p. 46	
Residential: 1999 Technology	Future equipment purchases based on equipment available in 1999. Building shell efficiencies fixed at 1999 levels.	Standalone	p. 57	p. 220
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone	p. 57	p. 220
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available. Existing building shell efficiencies increase by 30 percent from 1993 values by 2020.	Standalone	p. 57	p. 220
Commercial: 1999 Technology	Future equipment purchases based on equipment available in 1999. Building shell efficiencies fixed at 1999 levels.	Standalone	p. 58	p. 221
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone	p. 58	p. 221
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available. Building shell efficiencies increase by 50 percent from reference values by 2020.	Standalone	p. 58	p. 221
Industrial: 1999 Technology	Efficiency of plant and equipment fixed at 1999 levels.	Standalone	p. 59	p. 222
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone	p. 59	p. 222
Transportation: 1999 Technology	Efficiencies for new equipment in all modes of travel are fixed at 1999 levels.	Standalone	p. 59	p. 223
Transportation: High Technology	Reduced costs and improved efficiencies are assumed for advanced technologies.	Standalone	p. 59	p. 223
Consumption: 1999 Technology	Combination of the residential, commercial, industrial, and transportation 1999 technology cases and electricity low fossil technology case.	Fully integrated	p. 40	
Consumption: High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases and electricity high fossil technology case.	Fully integrated	p. 40	

Table G1. Summary of the *AEO99* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix G
Electricity: Low Nuclear	Higher capital investments are assumed after 30 to 40 years of operation.	Partially integrated	p. 65	p. 225
Electricity: High Nuclear	No capital investments are required for license renewal.	Partially integrated	p. 65	p. 225
Electricity: High Demand	Electricity demand increases at an annual rate of 2.0 percent, compared to 1.4 percent in the reference case.	Partially integrated	p. 65	p. 225
Electricity: Low Fossil Technology	New generating technologies are assumed not to improve over time from 1997.	Fully integrated	p. 66	p. 225
Electricity: High Fossil Technology	Costs and efficiencies for advanced fossil-fired generating technologies are assumed to improve from reference case values.	Fully integrated	p. 66	p. 225
Electricity: Competitive Pricing	Competitive pricing is phased in over 10 years in all regions of the country.	Fully integrated	p. 28	p. 226
Electricity: 5.5-Percent Renewable Portfolio Standard	Nonhydroelectric renewable generation increases to 5.5 percent of total generation for the period 2010-2015.	Fully integrated	p. 23	p. 226
Renewables: High Renewables	Lower costs and higher efficiencies are assumed for new renewable generating technologies	Fully integrated	p. 68	p. 227
Oil and Gas: Slow Technology	Cost, finding rate, and success rate parameters adjusted for slower improvement.	Fully integrated	p. 74	p. 228
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate parameters adjusted for more rapid improvement.	Fully integrated	p. 74	p. 228
Oil and Gas: Automakers' National Low-Sulfur Gasoline	Starting in 2004, sulfur levels of all gasoline in the United States meet a 40 ppm annual average standard.	Standalone	p. 29	p. 230
Oil and Gas: API/NPRA Regional Reduced-Sulfur Gasoline	Starting in 2004, gasoline in Federal reformulated gasoline areas, in 23 States, and in East Texas meets a 150 ppm annual average standard. California gasoline continues to meet the current 40 ppm standard, and gasoline in all other areas of the country meets a 300 ppm standard. In 2010, the areas that were using 150 ppm gasoline are assumed to switch to 40 ppm gasoline.	Standalone	p. 29	p. 230
Coal: Low Mining Cost	Productivity increases at an annual rate of 3.8 percent, compared to the reference case growth of 2.3 percent. Real wages decrease by 0.5 percent annually, compared to constant real wages in the reference case.	Partially integrated	p. 80	p. 230
Coal: High Mining Cost	Productivity increases at an annual rate of 1.2 percent, compared to the reference case growth of 2.3 percent. Real wages increase by 0.5 percent annually, compared to constant real wages in the reference case.	Partially integrated	p. 80	p. 230

Improvements to existing building shells are based on both energy prices and assumed annual efficiency increases. New building shell efficiencies relative to existing construction vary by main heating fuel and assumed annual increases. The effects of shell improvements are modeled differentially for heating and cooling. For space heating, existing and new shells improve by 15 percent and 26 percent, respectively, by 2020 relative to the 1993 stock average. For space cooling, the corresponding increases are 13 percent and 25 percent for existing and new buildings. Building codes relevant to CCAP are represented by an increase in the shell integrity of new construction over time.

Other CCAP programs which could have a major impact on residential energy consumption are the Environmental Protection Agency's (EPA) Green Programs. These programs, which are cooperative efforts between the EPA and home builders and energy appliance manufacturers, encourage the development and production of highly energy-efficient housing and equipment. At fully funded levels, residential CCAP programs are estimated by program sponsors to reduce carbon emissions by approximately 28 million metric tons by the year 2010. For the reference case, carbon reductions are estimated to be 11.5 million metric tons, primarily because of differences in the estimated penetration of energy-saving technologies.

In addition to the *AEO99* 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 *1999 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 1999. Building shell efficiencies are assumed to be fixed at 1999 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 30 percent over 1993 levels by 2020.

- The *high technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [4].

Commercial assumptions. Minimum equipment efficiency standards for the commercial sector are mandated in the EPACT legislation [5]. 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 a 80.0 lumens per watt efficiency standard for 8-foot F96T12 lamps (May 1994).

Improvements to existing building shells are based on assumed annual efficiency increases. New building shell efficiencies relative to 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.

The CCAP programs recognized in the *AEO99* reference case include 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 via discount parameters for controlling cost-based equipment retrofit decisions for various market segments. To model programs such as Green Lights, which target particular end uses, the *AEO99* version of the commercial module includes end-use-specific segmentation of discount rates. At fully funded levels, commercial CCAP programs are estimated by program sponsors to reduce carbon emissions by approximately 25 million metric tons by the year 2010. For the reference case, carbon reductions are estimated to be 13.0 million metric tons in 2010, primarily because of differences in the estimated penetration of energy-saving technologies.

The definition of the commercial sector for *AEO99* is based on data from the 1995 Commercial Buildings Energy Consumption Survey (CBECS) [*6*]. Parking garages and commercial buildings on multibuilding manufacturing sites were included in earlier CBECS, but eliminated from the target building population for the 1995 CBECS. In addition, the data provided by any CBECS 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 value errors are 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 [*7*].

Due to the change in the target population and the variability caused by the nonsampling and sampling errors, the estimates of commercial floorspace for the 1995 CBECS are lower than estimates found in previous CBECS. For example, the 1995 CBECS reports 13 percent less commercial floorspace in the United States than the 1992 CBECS reported. The most notable effect on *AEO99* projections is seen in commercial energy intensity. Commercial energy use per square foot reported in *AEO99* is significantly higher than in previous *AEO*s, 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 *AEO99* 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 *AEO99* 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 *1999 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 1999. Building shell efficiencies are assumed to be fixed at 1999 levels.
- The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than the reference case [*8*]. 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.

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* [*9*]. Compared to the building sector, there are relatively few regulations which 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 [*10*]. These standards have been incorporated into the Industrial Demand Module through the analysis of efficiencies for new industrial processes. These standards are expected to lead to significant improvements in efficiency since it has been estimated that electric motors account for about 60 percent of industrial process electricity use.

Climate Change Action Plan. Several programs included in the CCAP target the industrial sector. Note that the potential impacts of the Climate Wise Program are also included in the CCAP impacts. The intent of these programs is to reduce greenhouse gas emissions by lowering industrial energy consumption. For their annual update, the program offices estimated that full implementation of these programs would reduce industrial electricity consumption by 20 billion kilowatthours and nonelectric consumption by 193 trillion Btu by 2000. However, since the energy savings associated with the voluntary programs in the CCAP are, to a large extent, already contained in the *AEO99* baseline, total CCAP energy savings were reduced. Consequently, CCAP is assumed to reduce electricity consumption by 9 billion kilowatthours and non-electric energy consumption by 48 trillion Btu. The non-electric energy is assumed to be 85 percent natural gas, based on the fuel shares for nonboiler, nonfeedstock industrial energy use.

For 2010, the program offices estimated electricity savings of 79 billion kilowatthours and fossil fuel savings of 359 trillion Btu. For the reason cited above, these estimates for *AEO99* were revised to 41 billion kilowatthours for electricity and 90 trillion Btu for fossil fuels. In this situation, carbon emissions would be reduced by about 7 million metric tons (1 percent) in 2010.

High technology and 1999 technology cases. The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*11*]. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changing composition of industrial output. Since the composition of industrial output remains the same as in the reference case, aggregate intensity falls by only 1.4 percent annually, even though the intensity decline for some individual industries doubles. In the reference case, aggregate intensity falls by 1.0 percent annually between 1997 and 2020.

The *1999 technology case* holds the energy efficiency of plant and equipment constant at the 1999 level over the forecast.

Both cases were run with only the Industrial Demand Module rather than as a fully integrated NEMS run. Consequently, no potential feedback effects from energy market interactions were captured.

Transportation sector assumptions

The transportation sector accounts for the 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 projections appearing in this report 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 automobile fleet operators—Federal, State, and local governments, and fuel providers (e.g., gas and electric utilities)—purchase a minimum fraction of alternative-fuel vehicles [*12*]. 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 realize 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 2000. 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. It is assumed that the municipal and private business fleet mandates begin in 2002 at 20 percent and scale up to 70 percent by 2005.

In addition to these requirements, the State of California has delayed the Low Emission Vehicle Program, which now requires that 10 percent of all new vehicles sold by 2003 meet the "zero emissions requirements." At present, only electric-dedicated vehicles meet these requirements. Originally, Massachusetts and New York adopted this program. The projections currently assume that California, Massachusetts, and New York have formally delayed the Low Emission Vehicle Program to 2003, based on the recent court decision to overturn the original 1998 starting date.

The projections assume that these regulations represent minimum requirements for alternative-fuel vehicle sales; consumers are allowed to purchase more of these vehicles, should vehicle cost, fuel efficiency, range, and performance characteristics make them desirable.

Projections for both personal travel [*13*] and freight travel [*14*] are based on the assumption that modal shares, for example, personal automobile travel versus mass transit, remain stable over the forecast and track recent historical patterns. Important factors affecting the forecast of vehicle-miles traveled 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 100 percent by 2010; and the aging of the population, which will slow the growth in vehicle-miles traveled. These projections incorporate recent data which indicate that retirees are driving far more than retirees of a decade ago.

Climate Change Action Plan. There are four CCAP programs that 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 combined assumed effect of the Federal subsidy, system efficiency, and telecommuting policies in the *AEO99* reference case is a 1.6-percent reduction in vehicle-miles traveled (270 trillion Btu) by 2010, with a net carbon reduction of 6.5 million metric tons. The fuel economy tire labeling program improved new fuel efficiency by 4 percent among vehicles that switched to low rolling resistance tires, and resulted in a reduction in fuel consumption of 1 trillion Btu by 2010 and a carbon reduction of 19,000 metric tons.

1999 technology case. The *1999 technology case* assumes that new fuel efficiency levels are held constant at 1999 levels through the forecast horizon for all modes of travel.

High technology case. The *high technology case* assumes the cost and performance criteria from the efficiency case in the U.S. Department of Energy (DOE) interlaboratory study, *Scenarios of U.S. Carbon Reductions* for air, freight, marine, and rail travel. 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 [*15*]. The case includes new technologies including 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 light-duty vehicles. In the freight sector, the case assumes technologies including advanced drag reduction, reduced weight, and engines such as the advanced turbocompound diesel engines and the lean burn diesel LE-55 engine all with shorter market penetration periods and lower cost-effectiveness criteria—from a range of $8 to $10.50 to a range of $5 to $7 per million Btu of the fuel type. The case also assumes increasing load factors and an increase in efficiency of 18 percent above the 1997 level for aircraft.

Both cases were run with only the Transportation Demand Module rather than as a fully integrated NEMS run. Consequently, no potential macroeconomic feedback on travel demand 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 26 fossil, renewable, and nuclear generating technologies included in these projections. Technologies represented include those currently available as well as those that are assumed 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 where 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 via the EIA Home Page on the Internet and on the EIA CD-ROM.

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 by 2010. Utilities are assumed to comply with the limits on sulfur emissions by retrofitting units with flue gas desulfurization (FGD) equipment, transferring or purchasing sulfur emission allowances, operating high-sulfur coal units at a lower capacity utilization rate, or switching to low-sulfur fuels. The costs for FGD equipment average approximately $192 per kilowatt, in 1997 dollars, although the costs vary widely across the regions. It is also assumed that the market for trading emission allowances is allowed to operate without regulation and that the States do not further regulate the selection of coal to be used. Utilities are also assumed to comply with the NO_x emission caps established by the OTR.

The reference case assumes a transition to competitive pricing in California, New York, the New England States, the Mid-Atlantic States, and the Mid-America Interconnected Network (Illinois, plus parts of Missouri and Wisconsin). Although other States are allowing consumers to choose their electricity suppliers, the regional configuration assumed in the reference case prevents the representation of competitive markets in the regions where most States have not moved to competitive pricing. Nevertheless, the reference case assumes that, in California, electricity prices will remain constant at nominal 1997 levels between 1999 and 2001 for commercial and industrial customers, whereas residential customers will see a 10-percent reduction from 1997 prices in 1999; that there will be a transition from regulated to competitive prices between 2002 and 2007; and that the market will be fully competitive by 2008. Similarly, in the other regions for which competitive pricing is assumed, the transition period is assumed to be from 1999 through 2007, with fully competitive pricing of electricity beginning in 2008. 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 competitive prices in these regions will be the marginal cost of generation.

Competitive cost of capital. To capture the increased risks that new power plant operators are expected to face in a competitive market, the cost of capital for the generation sector is assumed to be 100 basis points higher than that for the transmission and distribution sector. In addition, 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 have reported plans to spend more than $2.2 billion per year by 2000.

Representation of utility Climate Challenge participation agreements. As a result of the Climate Challenge Program, many utilities have announced efforts to voluntarily reduce their greenhouse gas emissions between now and 2000. These efforts cover a wide variety of programs, including increasing demand-side management (DSM) investments, repowering (fuel-switching) fossil plants, restarting nuclear plants that have been out-of-service, planting trees, and purchasing emission offsets from international sources.

To the degree possible, each one 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 like tree planting and emission offset purchasing are not addressable in NEMS. With regard to the other programs, they 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, life extend a plant, cancel a previously planned plant, build a new plant, or switch fuel at a plant. These data are inputs to NEMS. Thus, programs that would affect these areas are reflected in 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, and *AEO99* does not assume any new units becoming operational in the forecast period.

It is assumed that nuclear power plants will operate until some major capital expenditure is required to repair the effects of aging. The decision to either incur the costs of repairing the unit or retire the unit is based on the relative economics of the alternatives. In the reference case, it is first assumed that a retrofit costing $150 per kilowatt will be required after 30 years of operation to operate the plant for another 10 years. Plants that have already incurred a major expenditure (such as a steam generator replacement) are assumed not to need additional retrofits and to run for 40 years. For other units, the capital investment is assumed to be recovered over 10 years, and an annual payment is calculated. If the combined operating costs and capital payment costs are cheaper than building new capacity, then the plant is run through its license period. If it is not economical, the plant is retired at 30 years.

It is also assumed that nuclear licenses will be renewed if it is economical to continue running the plant. A more extensive capital investment ($250 per kilowatt) is assumed to be required to operate a nuclear unit for 20 years past its current license expiration date. If this investment, recovered over 20 years, is less expensive than building new capacity, the unit is assumed to continue operating. Otherwise, it will be retired when it reaches the expiration date on its license. For both of these investment decisions, adjustments are made for new units to capture the improvements in their designs compared with older units.

Two side cases were developed with different assumptions regarding the capital investments, which changes the retirement decisions. In the *low nuclear case*, the adjustments for the new plants were removed, making these units face higher capital investments. The *high nuclear case* assumes that fewer units need major repairs during the first 40 years of operation, and that no capital expenditures required for license renewal.

The average nuclear capacity factor in 1997 was 71 percent, a drop from 1996 due to several units being down for extended outages. The capacity factor is expected to increase throughout the forecast, to as high as 85 percent in 2020. Capacity factor assumptions are developed at the unit level, and improvements or decrements are forecast based on the age of the reactor.

Fossil-steam 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 the plants receive is not sufficient to cover their forward costs (mainly fuel and operations and maintenance costs) the plant will be retired.

International learning. For *AEO99*, capital costs for all new electricity generating technologies—fossil, nuclear, and renewable—decrease in response to foreign as well as domestic experience, to the extent the new plants reflect technologies and firms also competing inside the United States. International learning effects include 1,553 megawatts advanced coal, 2,330 megawatts advanced combined cycle, 360 megawatts advanced combustion turbine, 110 megawatts geothermal, 1,250 megawatts wind, 115 megawatts grid-connected photovoltaics, and 57 megawatts biomass integrated combined cycle capacity in operation, under construction, or under contract for construction outside the United States.

High electricity demand case. The *high electricity demand case*, which is a standalone case, assumes that the demand for electricity grows by 2.0 percent annually between 1997 and 2020, compared with 1.4 percent in the reference case. No attempt was made to determine the changes necessary in the end-use sectors needed to result in the stronger demand growth. The high electricity demand case is a partially integrated run, i.e., the Macroeconomic Activity, Petroleum Marketing, International Energy, and end-use demand modules use the reference case values and are not effected by the higher electricity demand growth. Conversely, the Oil and Gas, Natural Gas Transmission and Distribution, Coal Market, and Renewable Fuels Modules are allowed to interact with the Electricity Market Module in the high electricity demand case.

High and low fossil technology cases. The high and low fossil technology cases are standalone, partially integrated cases. These cases use cost estimates for fossil-fuel-based technologies provided by the DOE Office of Fossil Energy. In the *high fossil case*, capital costs for coal gasification combined-cycle units and molten carbonate fuel cells are assumed to be lower than the reference case, and the costs for advanced combustion turbine and advanced combined-cycle units are higher than those in the reference case. In the *low fossil case*, capital costs and heat rates for advanced generating technologies remain fixed over the forecast period.

In both the high and low fossil technology cases, generating technologies other than those for which capital costs were provided by DOE's Office of Fossil Energy are assumed to use the same technological optimism and learning factors as the reference case. Details about annual capital costs, operating and maintenance costs, plant efficiencies, and technological optimism and learning factors are described in the detailed assumptions which will be available via the Internet (ftp://ftp.eia.doe.gov/pub/forecasting/aeo99/aeo99asu.pdf) and on the EIA CD-ROM.

Competitive pricing case. The *competitive pricing case* assumes that all regions of the country move toward competitive pricing, as discussed in the "Issues in Focus" section of this report. Competitive pricing for most regions is phased in over 10 years (1999-2008) by computing a weighted average of the traditional average-cost-based price and a linearly increasing fraction of the prices based on marginal costs. Prices in two regions, CNV and MAIN, in which the sole or the preponderance of the States have legislatively enacted restructuring plans, are adjusted to reflect the price caps embodied in the State plans. Reserve margins are set endogenously so that the full costs of new capacity will be recovered. In the competitive pricing case, customers using certain end-use services, including commercial heating, cooling, and hot water heating and industrial shift work, are able to respond to spot, or "time-of-use," prices through changes in their demand for electricity. This is represented as a transfer of demand from peak, high-usage periods to off-peak, lower-usage periods. All other assumptions, including improvements in operations and maintenance efficiency are identical to those in the reference case.

Renewable portfolio standard case. A case was run in which a minimum level of nonhydroelectric renewable generation was required. The minimum percentage of renewable generation (defined as generation from wind, biomass, geothermal, solar thermal, photovoltaic, and landfill gases divided by total sales multiplied by 100) increased from 2 percent to 5.5 percent over the period 2000 to 2010, stays at 5.5 percent through 2015, and then is sunset.

Renewable fuels assumptions

Energy Policy Act of 1992. Under EPACT, the Renewable Fuels Module (RFM) provides a renewable electricity production credit of 1.5 cents per kilowatthour for electricity produced by wind, applied to plants becoming operational between January 1, 1994, and December 31, 1999, and continuing for 10 years [*16*]. EPACT and the RFM also include a 10 percent investment tax credit for solar and geothermal technologies that generate electric power [*17*].

Supplemental Additions. AEO99 includes 2,897 megawatts of assumed new generating capacity using renewable resources, including 2,290 megawatts of planned new capacity not reported among EIA data collections and 607 megawatts assumed by EIA to be built for reasons not incorporated in the NEMS, such as for investment, testing, for distributed applications, or in response to State mandates. Total supplementals include 288 megawatts biomass, 168 megawatts geothermal, 134 megawatts landfill gas, 627 megawatts solar photovoltaic, 162 megawatts solar thermal, and 1,518 megawatts wind.

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 nearly 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 economically amenable only in drier regions, west of the Mississippi River; photovoltaics, however, can be considered 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, alternative land uses, and environmental objections. The geographic distribution of available wind resources is based on work by the Pacific Northwest Laboratory [*18*], enumerating winds among average annual wind-speed 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). Municipal solid waste resources are limited by the amount of the waste that is managed by other methods, such as recycling or landfills, and by the impact of waste minimization as a strategy for addressing the waste problem.

For *AEO99*, EIA incorporates in NEMS recognition of higher costs (proxies for supply elasticities) for uses of biomass and wind resources as generating capacity consumes more of the available resources. Costs increase in response to (1) increasing costs as natural resource quality declines, such as from wind turbulence, more difficult land access, or declining land quality, (2) increasing costs of local and regional transmission network improvements, and (3) market conditions increasing costs of alternative land uses, including for crops, recreation, or environmental or cultural preferences. Although the effects generally apply only with very large capacity increases not experienced in *AEO99*, some wind costs in California are increased this year in response to these factors.

High renewables case. For the *high renewables case,* EIA incorporates approximations of the DOE Office of Energy Efficiency and Renewable Energy's August 1997, draft technology characterizations of lower capital and operating costs and higher efficiencies (capacity factors) for new renewable energy generating technologies than used in the reference case [*19*]. EIA also assumes that the yields for energy crops grown on pasture and crop land are nearly 20 percent higher than in the reference case. In addition, for the high renewables case, EIA assumes that additional capacity effects of State RPS programs included in the reference case will extend beyond 2010, by 2020 adding 97 megawatts of additional supplemental capacity. The additions include 39 megawatts wind, 20 megawatts biomass, 17 megawatts solar photovoltaics, 12 megawatts solar thermal, 8 megawatts municipal solid waste (landfill gas), and 2 megawatts geothermal generating capacity. All other technologies and other NEMS modeling characteristics remain unchanged.

Non-electric renewable energy. The forecast for wood consumption in the residential sector is based on the Residential Energy Consumption Survey [*20*] (RECS) and data from the *Characteristics of New Housing: 1993,* published by the Bureau of the Census [*21*]. The RECS data provide a benchmark for Btu of wood use in 1993. The Census data are used to develop the forecasts of new housing units utilizing wood. 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 consumption is also based on the latest RECS and Census data; 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. Solar thermal consumption for water heating is also represented by displaced primary energy relative to an electric water heater.

Exogenous projections of active and passive solar technologies and geothermal heat pumps in the commercial sector are based on projections from the National Renewable Energy Laboratory [*22*]. Industrial use of renewable energy is primarily the use of wood and wood byproducts in the paper and lumber industries as well as a small amount of hydropower for electricity generation.

Oil and gas supply assumptions

Domestic oil and gas technically recoverable resources. The assumed resource levels 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 [*23*].

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 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 from roughly 0.3 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. Exploratory success rates are assumed to improve by 0.5 percent per year, and finding rates are expected to improve by 1.0 to 6.0 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 plus or minus 50 percent. A number of key exploration and production technologies were assumed to penetrate at alternate rates with varying degrees of effectiveness in the *rapid and slow technology cases.*

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 (LNG) and natural gas trade between the United States and Canada and Mexico. Specific detail by region and fuel category is presented in the supplementary tables to the *Annual Energy Outlook 1999*, which will be available in December 1998 on EIA's FTP site (ftp://ftp.eia.doe.gov/pub/forecasting/AEO99/AEO99tables).

Climate Change Action Plan (CCAP). The CCAP includes a program promoting the capture of methane from coal mining activities to reduce carbon emissions. The methane would be marketed as part of the domestic natural gas supply. This program began in 1995. The *AEO99* assumption is that it reaches a 2010 production level of 29 billion cubic feet and a level of 35 billion cubic feet by 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 2005 and only after the U.S.-Canada border price reaches $3.89, in 1997 dollars per thousand cubic feet. The liquefied natural gas facilities at Everett, Massachusetts, and Lake Charles, Louisiana (the only ones currently in operation) have an operating capacity of 311 billion cubic feet. The facilities at Cove Point, Maryland, and Elba Island, Georgia, are assumed to reopen when economically justified, but not before 1999. Should these facilities reopen, total liquefied natural gas operating capacity would increase to 794 billion cubic feet.

Natural gas transmission and distribution assumptions. It is assumed that industry restructuring is fully in place in the transmission segment of the industry and making considerable inroads in the distribution segment.

Transportation rates for pipeline services are calculated with the assumption that the costs of new pipeline capacity will be rolled into the existing rate base. While cost of service forms the basis for pricing these services, an adjustment is made to the resulting tariff based on the utilization of the pipeline to reflect a more market-based approach.

In determining interstate pipeline tariffs, capital expenditures for refurbishment over and above that 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.) Reductions in operations and maintenance costs and total administrative and general costs as a result of efficiency improvements are accounted for on the basis of historical trends.

Distribution markups to core customers (not including electricity generators) change over the forecast in response to changes in consumption levels, cost of capital, and assumed industry efficiency improvements. It is assumed that, independent of changes in costs related to the cost of capital and consumption levels, distributor costs for firm service customers will decline by 1 percent per year through 2015.

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 1994 nominal dollars per thousand cubic feet.

CCAP initiatives to increase the natural gas share of total energy use through Federal regulatory reform (Action 23) are reflected in the methodology for the pricing of pipeline services. Provisions of the CCAP to expand the Natural Gas Star program (Action 32) are assumed to recover 35 billion cubic feet of natural gas per year by the year 2000 that otherwise might be lost to fugitive emissions. This is phased in by recovering 21 and 28 billion cubic feet per year in 1998 and 1999, respectively. The full 35 billion cubic feet is recovered from 2000 through the end of the forecast period.

Petroleum market assumptions

The petroleum refining and marketing industry is assumed to incur large 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 [*24*] are allocated among the prices of liquefied petroleum gases, gasoline, distillate, and jet fuel, assuming they are recovered in the prices of light products. The lighter products, such as gasoline and distillate, are assumed to bear a greater amount of these costs because demand for these products is less price-responsive than for the heavier products.

Petroleum product prices also include additional costs resulting from requirements for new fuels, including oxygenated and reformulated gasolines and low-sulfur diesel. These additional costs are determined in the representation of refinery operations by incorporating specifications and demands for these fuels. Demands for traditional, reformulated, and oxygenated gasolines are disaggregated from composite gasoline consumption based on their 1997 market shares in each Census Division. The expected oxygenated gasoline market shares assume continued wintertime participation of carbon monoxide nonattainment areas and statewide 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 in 13 States and the District of Columbia that voluntarily opted into the program [*25*]. An additional 63 million barrels per day of demand is assumed to reflect the June 1999 addition of St. Louis, Missouri, to the RFG program. Reformulated gasoline projections also reflect a statewide requirement in California. Phoenix, Arizona, which by State law may use either Federal RFG or California RFG, is assumed to use Federal RFG. RFG is assumed to account for about 33 percent of annual gasoline sales throughout the *AEO99* forecast, which reflects the 1997 market share with adjustments for the opt-in of St. Louis in June 1999.

Reformulated gasoline reflects the "Complex Model" definition as required by the EPA and the tighter Phase 2 requirements beginning in 2000. *AEO99* projections also reflect California's statewide requirement for severely reformulated gasoline first required in 1996. Throughout the forecast, traditional gasoline is blended according to 1990 baseline specifications, to reflect CAAA90 "antidumping" requirements aimed at preventing traditional gasoline from becoming more polluting.

AEO99 assumes that State taxes on gasoline, diesel, jet fuel, M85, and E85 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 1997 nominal levels (a decline in real terms).

AEO99 reflects the extension of the tax credit for blending corn-based ethanol with gasoline included in the Federal Highway Bill of 1998. The bill extends the tax credit through 2007 but reduces the current credit of 54 cents per gallon by 1 cent per gallon in 2001, 2003, and 2005. *AEO99* assumes that the tax credit will be extended beyond 2007 through 2020 at the nominal level of 51 cents per gallon (a decline in real terms).

AEO99 assumes that refining capacity expansion may occur on the east and west coasts, as well as the Gulf Coast.

Automakers' national low-sulfur gasoline. The alternative case reflects the American Automobile Manufacturers Association/Association of International Automobile Manufacturers (automakers) petition to the EPA to reduce the average allowable sulfur content of gasoline in the United States to 40 ppm, which is equivalent to the current standard in the State of California. The reduced sulfur standard is assumed to be enforced in 2004 as it is associated with requirements for technology for lower emissions "Tier 2" vehicles, which are required for model year 2004. Sensitivities to gasoline supply and prices are explored.

API/NPRA regional reduced-sulfur gasoline. The alternative case reflects a proposal by the American Petroleum Institute/National Petrochemical and Refiners Association for a reduced-sulfur gasoline program beginning in 2004. The proposal is a regional plan in which all gasoline in Federal reformulated gasoline areas and in 23 States and East Texas must meet an annual average of 150 ppm. Gasoline in California would continue to meet statewide gasoline requirements, which include a 40 ppm annual average sulfur limit, while gasoline in all other parts of the country would have an annual average of 300 ppm. The "second step" of the proposal includes further reduction of sulfur in 2010 for gasoline in areas that require year-round NO_x control gasoline. The actual sulfur level and participants would be determined by an EPA study in 2006. The alternative case assumes 40 ppm gasoline requirements beginning in 2010 for the areas with the 150 ppm limit in 2004. Sensitivities to gasoline supply and prices are explored.

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 deep. On a national basis, labor productivity is assumed to improve on average at a rate of 2.3 percent per year, declining from an annual rate of 6.2 percent in 1997 to approximately 1.3 percent over the 2010 to 2020 period.

In two alternative mining cost cases that were run to examine the impacts of different labor productivity and labor 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 *AEO99* reference case productivity path by 1 standard deviation, although productivity growth rates were adjusted gradually (with full variation from the reference case phased in by 2000). The resulting national average productivities attained in 2020 (in short tons per hour) were 14.14 in the *low mining cost case* and 7.99 in the *high mining cost case*, compared with 10.18 in the reference case.

In the reference case, labor wage rates for coal mine production workers are assumed to remain constant in real terms over the forecast period. In the alternative low and high mining cost cases, wages 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, since minemouth prices vary with the levels of production required to meet demand.

Notes

[1] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1997*, DOE/EIA-0573(97) (Washington, DC, October 1998).

[2] Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202(98/3Q) (Washington, DC, July 1998), and web site www.eia.doe.gov/emeu/steo/pub/upd/sep98/index.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] 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).

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

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

[7] A detailed discussion of the Nonsampling and Sampling Errors for CBECS is provided in Appendix B of the 1995 CBECS Building Characteristics and Energy Consumption and Expenditures reports at www.eia.doe.gov/ emeu/cbecs/.

[8] 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).

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

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

[11] These assumptions are based in part on Arthur D. Little, "Aggressive Technology Strategy for the NEMS Model" (September 1998).

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

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

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

[15] 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 99* (December 1997); 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).

[16] National Energy Policy Act of 1992, P.L. 102-486, Title XIX, Section 1914.

[17] National Energy Policy Act of 1992, P.L. 102-486, Title XIX, Section 1916.

[18] 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 Schwartz, M.N.; Elliott, O.L.; and Gower, G.L.; *Gridded State Maps of Wind Electric Potential. Proceedings, Wind Power 1992*, October 19-23, 1992, Seattle.

[19] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, draft, *Renewable Energy Technology Characterizations*, Vol. 1, (Washington, DC, February 1997), as updated in internal revisions, Summer 1997.

[20] Energy Information Administration, *Household Energy Consumption and Expenditures 1993*, DOE/EIA-0321(93) (Washington, DC, 1995).

[21] U.S. Bureau of the Census, U.S. Department of Commerce, *Current Construction Reports, Series C25 Characteristics of New Housing: 1993* (Washington, DC, 1994).

[22] National Renewable Energy Laboratory, "Baseline Projections of Renewables Use in the Buildings Sector," prepared for the U.S. Department of Energy under Contract DE-AC02-83CH10093 (December 1992).

[23] Goutier, Donald L., et al., U.S. Department of the Interior, U.S. Geological Survey, *1995 National Assessment of the United States Oil and Gas Resources* (Washington, DC, 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); Cooke, Larry W., U.S. Department of the Interior, Minerals Management Service, *Estimates of Undiscovered, Economically Recoverable Oil and Gas Resources for the Outer Continental Shelf, Revised as of January 1990*, OCS Report MMS 91-0051 (July 1991).

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

[25] 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: Arizona, Connecticut, Delaware, Kentucky, Maine, Massachusetts, Maryland, New Hampshire, New Jersey, New York, Rhode Island, Texas, Virginia, and the District of Columbia. Excludes areas that "opted-out" prior to June 1997.

Conversion Factors

Table H1. Heat Rates

Fuel	Units	Approximate Heat Content
Coal[1]		
Production	million Btu per short ton	21.287
Consumption	million Btu per short ton	20.856
Coke Plants	million Btu per short ton	26.800
Industrial	million Btu per short ton	22.105
Residential and Commercial	million Btu per short ton	23.011
Electric Utilities	million Btu per short ton	20.525
Imports	million Btu per short ton	25.000
Exports	million Btu per short ton	26.174
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	-5.362
Motor Gasoline[2]	million Btu per barrel	5.206
Jet Fuel (Kerosene)	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	5.800
Imports[2]	million Btu per barrel	-5.493
Exports[2]	million Btu per barrel	-5.769
Natural Gas Plant Liquids		
Production[2]	million Btu per barrel	-3.885
Natural Gas		
Production, Dry	Btu per cubic foot	1,028
Consumption	Btu per cubic foot	1,028
Non-electric Utilities	Btu per cubic foot	1,029
Electric Utilities	Btu per cubic foot	1,022
Imports	Btu per cubic foot	1,022
Exports	Btu per cubic foot	1,022
Electricity Consumption	Btu per kilowatthour	3,412

[1]Conversion factors vary from year to year. 1996 values are reported.
[2]Conversion factors vary from year to year. 2000 values are reported.
Source: Energy Information Administration, AEO99 National Energy Modeling System run AEO99B.D100198A.

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				
Miles	X	1.609 344	=	kilometers (km)
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 1997*, DOE/EIA-0384(97)(Washington DC, July 1998), Table B1 and EIA, *International Energy Outlook 1998*, DOE/EIA-0484 (98) (Washington, DC, April 1998).

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 1997*, DOE/EIA-0384(97)(Washington, DC, July 1998), Table B2, and EIA, Statistics and Methods Group.

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The Energy Information Administration
National Energy Modeling System/Annual Energy Outlook Conference

Crystal Gateway Marriott, Arlington, VA *March 22, 1999*

Morning Program

8:15 a.m. **Opening Remarks -** ***Jay E. Hakes,*** *Administrator*, Energy Information Administration

8:30 a.m. - 9:00 **Overview of the** ***Annual Energy Outlook 1999*** **-** ***Mary J. Hutzler,*** *Director*, Office of Integrated Analysis and Forecasting, Energy Information Administration

9:00 a.m. - 9:45 **Keynote Address: Carbon Mitigation Topic -** *Speaker to be announced*

10:00 a.m. - 12:00 **Meeting U.S. Carbon Targets**

Afternoon Program

1:15 p.m. - 3:00 **Concurrent Sessions A**

1. **Impact of Asian Economic Crises on Oil Markets and the Economy**
2. **Electricity Restructuring: A State Update**
3. **Emerging Transportation Technologies**

3:15 p.m. - 5:00 **Concurrent Sessions B**

1. **Electricity Transmission Issues in a Competitive Environment**
2. **Natural Gas Pipeline and Production Availability**
3. **Renewables in a Carbon-Constrained World**

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 1, 1999.

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 Registration

Conference registration is free, but space is limited. Please register by March 10, 1999.

To register, 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: ______________________________
____
Phone: ______________________________
Fax: ______________________________

Please indicate which sessions you will be attending:

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