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Annual Energy Outlook 2000

With Projections to 2020

December 1999

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For Further Information . . .

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AEO2000 will be available on the EIA web site at www.eia.doe.gov/oiaf/aeo/index.html by December 1999. Assumptions underlying the projections, tables of regional and other detailed results, model documentation reports for the National Energy Modeling System (NEMS), and the report *NEMS: An Overview* will also be available on the web site.

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Preface

The *Annual Energy Outlook 2000* (*AEO2000*) 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 *AEO2000* 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—appliance standards, gasoline and diesel fuel standards, natural gas industry expansion, competitive electricity pricing, renewable portfolio standards, and carbon emissions. It is followed by the analysis of energy market trends.

The analysis in *AEO2000* 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 *AEO2000* assumptions, with a summary table of the cases. Appendix H provides tables of energy and metric conversion factors. *AEO2000*, the detailed assumptions, and supplementary tables will be available on the EIA web site at www.eia.doe.gov/oiaf/aeo/index.html.

The *AEO2000* projections are based on Federal, State, and local laws and regulations in effect on July 1, 1999. 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 *AEO2000* projections were the most current available as of July 31, 1999, when most 1998 data but only partial 1999 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 *AEO2000* projections for 1999 and 2000 incorporate the short-term projections from EIA's September 1999 *Short-Term Energy Outlook*.

The *AEO2000* 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 *AEO2000* 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 *AEO2000* 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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Overview

Key Issues

Important energy issues addressed in the *Annual Energy Outlook 2000* (*AEO2000*) include, among others, the ongoing restructuring of U.S. electricity markets, near-term prospects for world oil markets, and the impacts of energy use on carbon emissions.

AEO2000 reflects the restructuring of U.S. electricity markets and the shift to increased competition by assuming changes in the financial structure of the industry. Ongoing efficiency and operating improvements are also assumed to continue. The projections assume a transition to full competitive pricing in States with specific deregulation plans—California, New York, New England, the Mid-Atlantic States, Illinois, Texas, Michigan, Ohio, Arizona, and New Mexico. Other States are assumed to continue cost-of-service electricity pricing. The provisions of the California legislation regarding stranded cost recovery and price caps are included. In other regions, stranded cost recovery is assumed to be phased out by 2008.

A national renewable portfolio standard has been proposed in the Comprehensive Electricity Competition Act, but it has not been enacted and is not included in the projections. State standards are included as enacted. Although *AEO99* included new proposed standards for control of nitrogen oxide (NO_x) by electricity generators, those standards have been challenged in court, are currently suspended, and are not included in *AEO2000*.

World oil prices fell sharply throughout most of 1997 and 1998, in part because of the economic recession in East Asia. Recently, economic recovery in that region and actions by the Organization of Petroleum Exporting Countries (OPEC) to restrain oil production have resulted in higher world oil prices, which are included in the oil market analysis and world oil price projections in *AEO2000*.

Although growth in carbon emissions in 1998 was slower than in previous years, emissions are projected to remain at levels similar to those projected in *AEO99*, as the demand for energy continues to grow.

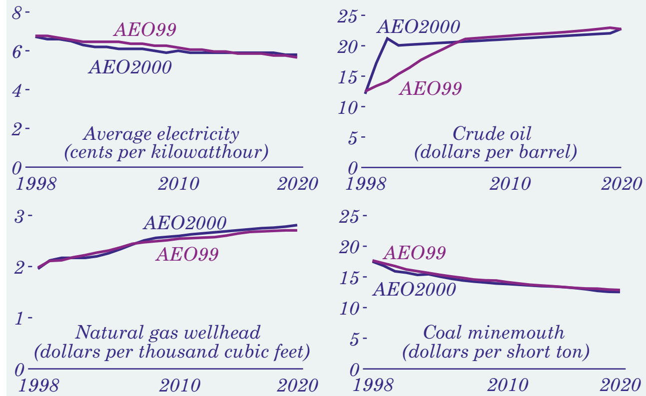
Prices

Average world crude oil prices in *AEO2000* increase from about $12.10 a barrel (all prices in 1998 dollars) to $22.04 a barrel in 2020 (Figure 1), nearly $1 a barrel lower than the price of $22.99 projected in *AEO99*. Price projections over the next several years are much higher than in *AEO99*, by about $7 a barrel in 2000. Higher near-term prices are projected as a result of the economic recovery in East Asia, which has occurred at a more rapid pace than projected in *AEO99*, and the March 1999 agreement by OPEC and four non-OPEC countries to cut oil production, which appears to be holding.

Lower world oil price projections for 2020 result from three factors. First, higher near-term prices stimulate drilling activity and increase production potential. Second, lower long-term economic growth is projected for the Pacific Rim. Finally, it appears likely that non-OPEC oil production will be higher than previously projected due to technology improvements, particularly for offshore production.

Worldwide demand for oil is expected to increase from 75.0 million barrels per day in 1998 to 112.4 million barrels per day in 2020, slightly lower than the *AEO99* projection of 114.7 million barrels per day. The potential for production increases in both OPEC and non-OPEC nations leads to relatively low growth of prices through 2020, although the demand for oil grows rapidly. OPEC oil production is expected to reach 55.5 million barrels per day in 2020, nearly double the 31.7 million barrels per day in 1998, assuming sufficient capital to expand production capacity. It is assumed that the United Nations resolution limiting Iraqi oil exports will remain in place until 2002. Once sanctions are lifted, Iraqi oil production is expected to reach 4.0 million barrels per day within 2 years and about 6.0 million barrels per day within a decade. Outside the Persian Gulf, production is expected to grow in the offshore regions of Nigeria and Algeria and in Venezuela.

Figure 1. Fuel price projections, 1998-2020: AEO99 and AEO2000 compared (1998 dollars)



Non-OPEC oil production is expected to increase from 44.3 million barrels per day in 1998 to 56.6 million barrels per day in 2020—1 million barrels per day higher than in *AEO99*. Production from the Caspian Basin is expected to reach 6 million barrels per day, resulting in a near doubling of production in the former Soviet Union by 2020, with continuing expansion of production from the North Sea and the offshore regions of West Africa. Both Brazil and Colombia are expected to produce 1 million barrels per day early in the next decade, and production in Mexico and Canada is also likely to increase.

The average U.S. wellhead price of natural gas is projected to increase from $1.96 per thousand cubic feet in 1998 to $2.81 per thousand cubic feet in 2020, at an average rate of 1.7 percent a year. Improvements in exploration and production technologies for natural gas moderate additional price increases. In 2020, the price is $0.10 per thousand cubic feet higher than projected in *AEO99*, even with slightly lower demand, because low prices tend to dampen reserve additions in the near term. Average delivered prices increase by 0.4 percent a year from 1998 to 2020. Although average transmission and distribution margins are about $0.10 per thousand cubic feet higher than in *AEO99*, the projected margins in the residential and commercial sectors are higher by about $0.30 to $0.50 because of an increase in projected capital costs and fewer cost reductions from efficiency improvements than previously assumed.

In *AEO2000*, the average minemouth price of coal in the United States is projected to decline from $17.51 a ton in 1998 to $12.54 a ton in 2020. The price declines through 2020 due to increasing productivity in the industry, a shift to lower cost western production, and competitive pressures on labor costs. Compared with *AEO99*, coal production is lower later in the projection period, and higher productivity, particularly in the Powder River Basin, is assumed. As a result, the average coal price is lower than the $12.89 a ton projected in *AEO99* for 2020.

Average electricity prices decline from 6.7 cents per kilowatthour in 1998 to 5.8 cents per kilowatthour in 2020, an average annual decline of 0.6 percent. Because competitive markets are assumed in more regions of the country than in *AEO99*, average prices are lower in *AEO2000* in the earlier years of the projections. In 2020, the price is slightly higher than the 5.7 cents per kilowatthour projected in *AEO99* because of the assumed higher cost of capital and a slower decline in the capital costs of natural gas generation in the later years. The restructuring of the electricity industry contributes to declining prices through lower operating and maintenance costs, lower administrative costs, and other cost reductions. Federal Energy Regulatory Commission actions on open access and other changes for competitive markets enacted by some State public utility commissions are included in the projections, as noted above. Because other State actions that have yet to be formulated are not included, the projections do not represent a fully restructured electricity market. Legislative actions related to the electricity industry are discussed on page 11, and competitive electricity markets are discussed on page 20.

Consumption

Total energy consumption is projected to increase from 94.9 to 120.9 quadrillion British thermal units (Btu) between 1998 and 2020, an average annual increase of 1.1 percent. Consumption in 2020 is 1 quadrillion Btu higher than projected in *AEO99*, primarily as a result of higher energy consumption for electricity generation and transportation.

Energy consumption in the residential and commercial sectors is projected to increase at average rates of 0.9 and 0.8 percent a year, respectively, led by growth in electricity use for a variety of equipment—telecommunications, computers, office equipment, and other appliances. In 2020, delivered residential energy demand is 12.8 quadrillion Btu, 0.3 quadrillion Btu lower than in *AEO99*, primarily because of a lower estimate for wood use in the Energy Information Administration's (EIA's) *Residential Energy Consumption Survey 1997*. Total demand is slightly higher, however, because more fuel is used to generate the electricity consumed in the sector. Higher projected energy intensity is offset by lower growth in the number of households. In the commercial sector, slightly lower energy intensity, particularly for lighting, leads to a slightly lower projection for delivered energy demand at 9.2 quadrillion Btu in 2020, 0.2 quadrillion Btu lower than in *AEO99*. As in the residential sector, primary energy demand in 2020 is slightly higher due to electricity losses.

Total demand in the industrial sector increases at an average rate of 0.9 percent a year, to 42.2 quadrillion Btu in 2020. Delivered energy demand is about 0.5 quadrillion Btu lower in 2020 than was projected in

AEO99 because of lower growth of coal use in industrial boilers and more recent data that indicate lower industrial consumption of natural gas.

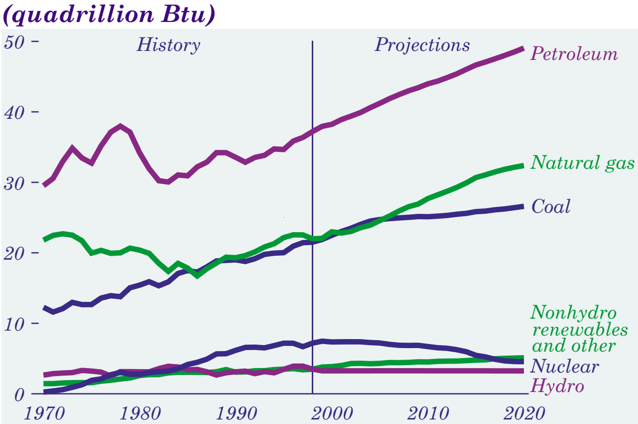
Transportation energy use grows at an average annual rate of 1.7 percent, to 37.5 quadrillion Btu in 2020, 0.7 quadrillion Btu higher than in *AEO99*. More travel is projected for light-duty vehicles, as recent data indicate that older drivers are driving more than previously assumed, slightly offset by lower assumed growth in driving by women. Compared with *AEO99*, lower gasoline prices and higher income reduce the expected average new car efficiency in 2020 from 32.1 to 31.6 miles per gallon.

AEO2000, like earlier *AEO*s, incorporates efficiency standards for new energy-using equipment in buildings and for motors, mandated through 1994 by the National Appliance Energy Conservation Act of 1987 and the Energy Policy Act of 1992. Several alternative cases examine the impacts of technology advances 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. Alternative efficiency standards are also analyzed for the buildings sectors.

Natural gas consumption increases in the forecast by an average of 1.8 percent a year (Figure 2). Increases are expected in all sectors, but the most rapid growth is for electricity generation, where natural gas use (excluding cogenerators) rises from 3.7 to 9.3 trillion cubic feet between 1998 and 2020. Total gas consumption in 2020 is lower than in *AEO99* by 0.8 trillion cubic feet, due to slightly lower projections for the commercial and industrial sectors.

Total coal consumption increases from 1,043 to 1,279 million tons a year between 1998 and 2020, an average annual increase of 0.9 percent, similar to the rate projected in *AEO99*. About 90 percent of the coal is used for electricity generation. Coal remains the primary fuel for generation, although its share of generation declines between 1998 and 2020.

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



Petroleum demand is projected to grow at an average rate of 1.3 percent a year through 2020, led by continued growth for transportation, which uses about 70 percent of the total. Increases in travel more than offset efficiency gains, and economic growth boosts petroleum use for freight and shipping through 2020. Total demand is higher than in *AEO99*, primarily due to higher light-duty vehicle travel.

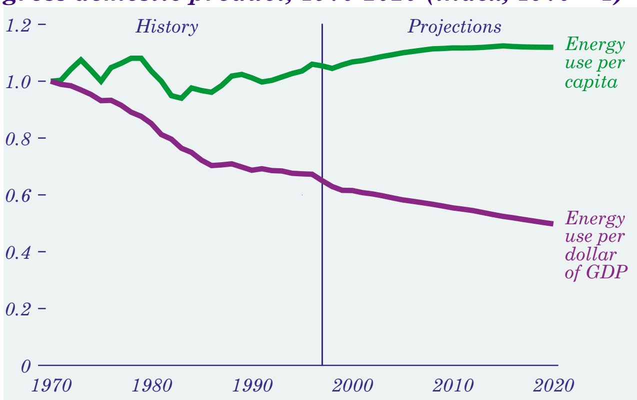
Renewable fuel consumption, including ethanol used for gasoline blending, increases at an average rate of 0.8 percent a year through 2020. About 60 percent of renewables are used for electricity generation and the rest for dispersed heating and cooling, industrial uses, and fuel blending. Renewable fuel use is 0.2 quadrillion Btu lower in 2020 than projected in *AEO99*, with slightly lower renewable electricity generation and residential wood demand.

Electricity consumption overall 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 the same as in *AEO99*, with slightly lower commercial and transportation demand but higher industrial demand. Energy consumption for electricity generation is higher than in *AEO99* due to slower penetration of more efficient technologies, fewer retirements of nuclear and coal-fired power plants, and more generation from natural gas turbines.

Energy Intensity

Energy intensity, measured as energy use per dollar of gross domestic product (GDP), has declined since 1970, particularly when energy prices have increased rapidly (Figure 3). Between 1970 and 1986, energy intensity declined at an average rate of 2.2 percent a year as the economy shifted to less energy-intensive industries and more efficient technologies. With smaller price increases and the growth of more energy-intensive industries, intensity declines moderated to an average of 1.0 percent a year between 1986 and 1998. Through 2020, energy intensity is projected to improve at an average rate of 1.1 percent a year as efficiency gains and structural shifts in the economy offset growth in demand for energy services.

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



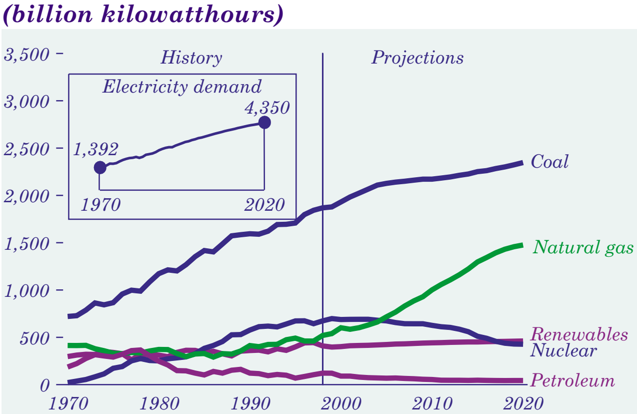
Energy use per person generally declined from 1970 through the mid-1980s, increasing when energy prices declined. Per capita energy use is expected to stabilize, as efficiency gains offset higher demand for energy services.

Electricity Generation

Nuclear electricity generation declines over the projection period (Figure 4) but is higher in 2020 than was projected in *AEO99*, due to fewer plant retirements. Of the 97 gigawatts of nuclear capacity available in 1998, 40 gigawatts are projected to be retired by 2020, and no new plants are constructed. Nuclear plant retirements are based on analysis of their operating costs and the costs of life extension, compared with the costs of new generating capacity. Retirements are lower than in *AEO99* due to higher capital costs for fossil fuel replacement capacity, resulting in higher nuclear capacity and generation.

Generation from both natural gas and coal is projected to increase through 2020 to meet growing demand for electricity and offset the decline in

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



nuclear power; however, the share of coal generation declines through 2020 because assumptions about electricity industry restructuring, such as higher cost of capital and shorter financial life of plants, favor the less capital-intensive and more efficient natural gas generation technologies. Compared with *AEO99*, coal generation is the same in 2020, and gas generation is lower because capital costs are projected to decline more slowly in the later years. The natural gas generation share increases from 14 percent to 31 percent between 1998 and 2020, a lower share than the 33 percent projected for 2020 in *AEO99*.

Renewable technologies penetrate slowly in the projections, because fossil fuel prices continue to be moderate. Also, electricity restructuring tends to favor the less capital-intensive natural gas technologies over coal and baseload renewables. Total renewable generation, including cogenerators, increases by 0.5 percent a year and is about 8 percent lower than in *AEO99*, primarily due to lower hydropower and biomass generation, offset in part by higher generation from wind and municipal solid waste. Hydropower is lower as a result of lower capacity factors and reduced capacity, and biomass generation is reduced because of its higher fuel costs. Hydropower declines through 2020 as regulatory actions limit capacity at existing sites and no large new sites are available for development. State renewable portfolio standards, where enacted, contribute to the growth of renewable generation.

Production and Imports

U.S. crude oil production declines at an average rate of 0.8 percent a year between 1998 and 2020 to a projected level of 5.3 million barrels per day. Advances in oil exploration and production technologies are insufficient to offset declining resources. Compared with *AEO99*, production is 0.3 million barrels a day higher in 2020, even though prices are slightly lower. A reevaluation of offshore resources contributes to rising oil production later in the projection period as oil prices increase. Increases in the production of natural gas plant liquids partially offset the decline in crude oil production through 2020 (Figure 5).

Falling production and rising demand increase petroleum imports through 2020 (Figure 6). The share of petroleum consumption met by net imports rises from 52 percent in 1998 (measured in barrels per day) to 64 percent in 2020. In 2020, the share is slightly lower than the 65-percent share in *AEO99*,

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

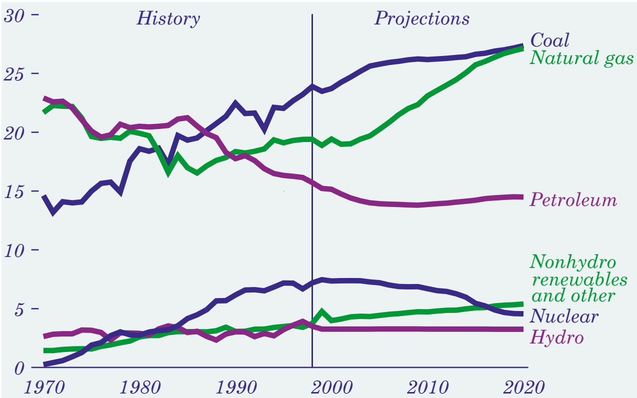
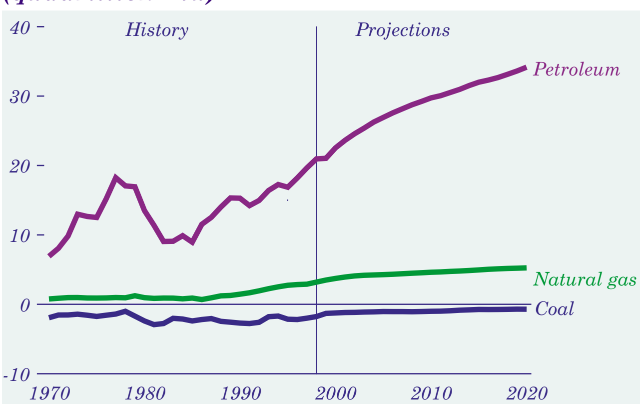


Figure 6. Net energy imports by fuel, 1970-2020 (quadrillion Btu)



although it is as much as 3 percentage points higher in 2005 as a result of lower domestic production.

In *AEO2000*, natural gas production is projected to increase from 18.9 trillion cubic feet in 1998 to 26.4 trillion cubic feet in 2020—an average rate of 1.5 percent a year—to meet growing demand for natural gas. Net imports of natural gas, primarily from Canada, also increase from 3.1 to 5.1 trillion cubic feet between 1998 and 2020. Pipeline capacity from Canada and capacity utilization rates increase to satisfy demand growth. Net imports of liquefied natural gas also increase, to 0.3 trillion cubic feet in 2020. Natural gas production is projected to be 1 trillion cubic feet lower in 2020 than projected in *AEO99*, due to lower demand and slightly higher imports.

Coal production increases from 1,128 million tons in 1998 to 1,316 million tons in 2020, an average of 0.7 percent a year, to meet rising domestic demand. In 2020, export demand is lower than in *AEO99* by 35 million tons. European imports are lower for environmental reasons, and exports from Australia are higher. As a result, U.S. coal production in 2020 is 42 million tons lower than projected in *AEO99*.

Renewable energy production grows from 6.7 to 8.0 quadrillion Btu between 1998 and 2020, with growth in electricity generation from geothermal and wind energy, biomass, and municipal solid waste generation, more use of biomass in the industrial sector, and more ethanol use. Slightly lower renewable generation, mostly hydropower, and lower residential wood demand reduce renewable energy production slightly from *AEO99*, although the *AEO2000* projections add commercial wood consumption based on EIA's *State Energy Data Report 1996*.

Carbon Emissions

Carbon emissions from energy use are projected to increase by an average of 1.3 percent a year through 2020, from 1,485 million metric tons in 1998 to 1,787 million metric tons in 2010 and 1,979 million in 2020 (Figure 7). Emissions in 2020 are higher by only 4 million metric tons than in *AEO99*. Although energy demand is higher in 2020 because of higher projected economic growth, travel, and fuel consumption for electricity generation, higher nuclear generation and more rapid efficiency improvements moderate the growth in emissions.

The Climate Change Action Plan (CCAP) was developed to stabilize greenhouse gas emissions in 2000 at 1990 levels. In 1990, energy-related carbon emissions were 1,345 million metric tons. *AEO2000* includes the impacts of CCAP provisions, including Climate Challenge and Climate Wise, which foster voluntary reductions in emissions by electric utilities and industry, but no new carbon reduction policies are incorporated. Carbon emissions and the Kyoto Protocol are discussed on pages 37 and 40.

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

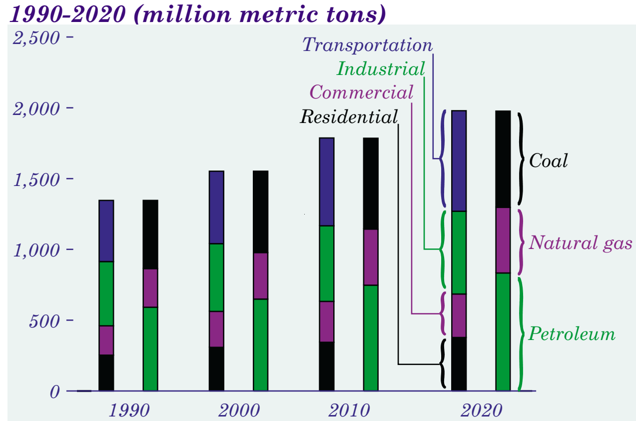


Table 1. Summary of results for five cases

Sensitivity Factors	1997	1998	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	16.23	15.73	14.49	14.14	15.44	13.18	16.12
Natural Gas	19.43	19.40	27.13	25.70	27.98	26.97	27.26
Coal	23.28	23.89	27.36	26.14	29.62	26.90	27.43
Nuclear Power	6.71	7.19	4.56	4.56	4.70	4.51	4.63
Renewable Energy	7.00	6.67	7.98	7.77	8.40	7.90	8.06
Other	0.66	0.57	0.66	0.66	0.68	0.59	0.73
Total Primary Production	**73.30**	**73.46**	**82.18**	**78.98**	**86.82**	**80.06**	**84.23**
Net Imports (quadrillion Btu)							
Petroleum (including SPR)	19.65	20.95	34.15	30.30	37.36	38.35	30.87
Natural Gas	2.90	3.20	5.25	4.59	5.62	5.15	5.18
Coal/Other (- indicates export)	-1.66	-1.46	-0.50	-0.55	-0.38	-0.50	-0.49
Total Net Imports	**20.89**	**22.69**	**38.91**	**34.35**	**42.60**	**43.00**	**35.56**
Discrepancy	-0.22	1.27	0.14	0.04	0.06	0.26	-0.09
Consumption (quadrillion Btu)							
Petroleum Products	36.43	37.21	49.05	44.99	53.27	51.73	47.71
Natural Gas	22.60	21.99	32.38	30.28	33.61	32.11	32.44
Coal	21.34	21.50	26.60	25.32	28.98	26.15	26.68
Nuclear Power	6.71	7.19	4.56	4.56	4.70	4.51	4.63
Renewable Energy	7.00	6.67	7.99	7.78	8.42	7.92	8.08
Other	0.33	0.32	0.36	0.34	0.38	0.37	0.34
Total Consumption	**94.41**	**94.88**	**120.95**	**113.28**	**129.36**	**122.79**	**119.88**
Prices (1998 dollars)							
World Oil Price (dollars per barrel)	18.71	12.10	22.04	20.99	23.11	14.90	28.04
Domestic Natural Gas at Wellhead (dollars per thousand cubic feet)	2.39	1.96	2.81	2.40	3.27	2.68	2.87
Domestic Coal at Minemouth (dollars per short ton)	18.32	17.51	12.54	12.40	12.58	12.38	12.53
Average Electricity Price (cents per kilowatthour)	6.9	6.7	5.8	5.5	6.1	5.8	5.9
Economic Indicators							
Real Gross Domestic Product (billion 1992 dollars)	7,270	7,552	12,179	10,870	13,413	12,205	12,151
(annual change, 1998-2020)	—	—	2.2%	1.7%	2.6%	2.2%	2.2%
GDP Implicit Price Deflator (index, 1992=1.00)	1.12	1.13	1.86	2.11	1.63	1.86	1.86
(annual change, 1998-2020)	—	—	2.3%	2.9%	1.7%	2.3%	2.3%
Real Disposable Personal Income (billion 1992 dollars)	5,183	5,348	9,008	8,281	9,679	9,037	8,974
(annual change, 1998-2020)	—	—	2.4%	2.0%	2.7%	2.4%	2.4%
Index of Manufacturing Gross Output (index, 1987=1.00)	1.365	1.411	2.160	1.972	2.483	2.166	2.158
(annual change, 1998-2020)	—	—	2.0%	1.5%	2.6%	2.0%	2.0%
Energy Intensity							
(thousand Btu per 1992 dollar of GDP)	12.99	12.57	9.94	10.43	9.65	10.07	9.87
(annual change, 1998-2020)	—	—	-1.1%	-0.8%	-1.2%	-1.0%	-1.1%
Carbon Emissions							
(million metric tons)	1,479	1,485	1,979	1,851	2,126	2,019	1,956
(annual change, 1998-2020)	—	—	1.3%	1.0%	1.6%	1.4%	1.3%

Notes: Specific assumptions underlying the alternative cases are defined in the Economic Activity and International Oil Markets sections beginning on page 48. Quantities are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, supplemental natural gas, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Some refinery inputs appear as petroleum product consumption. Other consumption includes net electricity imports, liquid hydrogen, and methanol.

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

Legislation and Regulations

Introduction

Because analyses by the Energy Information Administration (EIA) are required to be policy-neutral, the projections in this *Annual Energy Outlook 2000* (*AEO2000*) are based on Federal, State, and local laws and regulations in effect on July 1, 1999. The potential impacts of pending or proposed legislation, regulations, and standards and sections of existing legislation for which funds have not been appropriated are not reflected in the projections.

Federal legislation incorporated in the projections includes the 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; the Tax Payer Relief Act of 1997; and the Federal Highway Bill of 1998, which includes an extension of the ethanol tax credit. *AEO2000* assumes the continuation of the ethanol tax credit through 2020.

AEO2000 also assumes that State taxes on gasoline, diesel, jet fuel, M85, and E85 will increase with inflation and that Federal taxes on those fuels will continue at 1998 levels in nominal terms. Although the above tax and tax credit provisions include "sunset" clauses that limit their duration, they have been extended historically, and *AEO2000* assumes their continuation throughout the forecast.

AEO2000 also incorporates regulatory actions of the Federal Energy Regulatory Commission (FERC), including Orders 888 and 889, which provide open access to interstate transmission lines in electricity markets, and other FERC actions to foster more efficient natural gas markets. State plans for the restructuring of the electricity industry and State renewable portfolio standards are incorporated as enacted. As of July 1, 1999, 24 States had passed legislation or promulgated regulations to restructure their electricity markets. (See "Issues in Focus," pages 18 and 20, for discussions of renewable portfolio standards and competitive electricity prices.)

CAAA90 requires a phased reduction in vehicle emissions of regulated pollutants, to be met primarily through the use of reformulated gasoline. In addition, under CAAA90, there is a phased reduction in annual emissions of sulfur dioxide by electricity generators, which in general are capped at 8.95 million tons 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, but those standards have not been finalized and are not included in the forecast. Their status is discussed later in this section. The impacts of CAAA90 on electricity generators are discussed in "Market Trends" (see page 91).

The provisions of EPACT focus primarily on reducing energy demand. They require minimum building efficiency standards for Federal buildings and other new buildings that receive federally backed mortgages. Efficiency standards for electric motors, lights, and other equipment are required, and Federal, State, and utility vehicle fleets are required to phase in vehicles that do not rely on petroleum products. The projections include only those equipment standards for which final actions have been taken and which specify efficiency levels, including the refrigerator standard that goes into effect in July 2001. A discussion of the status of efficiency standards is included in "Issues in Focus" (see page 34).

Climate Change Action Plan

The *AEO2000* 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. *AEO2000* 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 37, for further discussion of carbon emissions and the Protocol).

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 *Voluntary Reporting of Greenhouse Gases 1997* [*2*]. The *AEO2000* reference case includes analysis of the impacts of both programs (see Appendix G).

Energy From Biomass Encouraged

In August 1999, President Clinton issued an Executive Order aimed at stimulating the use of biomass—including trees, crops, and agricultural waste—as a source of energy and other "biobased products" [*3*]. Biomass can be used not only to generate electricity and to fuel automobiles but also to produce an array of pharmaceuticals and other materials, including plastics, inks, and dyes. The Executive Order is designed to speed up technical advances and adoption of both bioenergy and biobased products. It is aimed at increasing the use of biofuels to offset fossil fuel consumption, which would reduce both reliance on foreign oil and carbon emissions in the United States. Increased use of biofuels, such as ethanol, would also expand markets for farm and forest waste products. Pursuant to the order, an interagency council has been established to foster research and development for bioenergy and biobased products.

Comprehensive Electricity Competition Act

On April 15, 1999, the Administration submitted its proposed Comprehensive Electricity Competition Act (CECA) to Congress. CECA is designed to facilitate the development of competitive generation markets throughout the United States. Its provisions are aimed at empowering and encouraging States to establish competitive markets for electricity generation, encouraging continued investments in energy efficiency and renewable generating resources, and ensuring that all consumers benefit from competition in the electricity generation sector. Bills have been submitted in both the House (H.R. 1828, Mr. Bliley, May 17, 1999) and the Senate (S. 1047, Mr. Murkowski, May 13, 1999) and referred to the appropriate committees. Because CECA has not been enacted, its provisions are not incorporated in the *AEO2000* reference case; however, the renewable portfolio standard of CECA—independent of the other CECA provisions—is analyzed in a sensitivity case (see "Issues in Focus," page 18).

CECA sets January 1, 2003, as the date when all consumers will have the ability to choose their electricity suppliers; however, a State can opt out of competition if it finds—through public proceedings—that consumers would be better off without a move to competition. To encourage States to choose competition, they are given the authority to impose reciprocity requirements on companies that are not within their jurisdictions. In other words, if a State chooses to open its markets to competition, it can prevent out-of-State companies from competing unless their home markets are also open to competition. The opt-out provision was included to allay concerns that companies operating in States with regulated markets might be able to sell power at below-market rates in neighboring States with competitive markets.

CECA includes provisions to clarify State and Federal authority over transmission services, and it would give States clear authority to establish retail electricity competition. There has been concern that the Federal Power Act is not clear about the authority of the FERC with respect to its formation of regional transmission groups or its imposition of fees to recover stranded costs. To prevent litigation on these issues, CECA would give the FERC authority to approve interstate transmission compacts, to impose charges to recover retail stranded costs if they are not collectible through other means, and to require the establishment of regional independent system operators. It also contains a provision clarifying that the Federal Power Act does not prohibit States from ordering retail competition or from collecting fees, such as those that may be needed to recover stranded costs, on retail electricity sales within the State.

CECA also contains provisions that would continue investments in energy efficiency and renewable generating sources in competitive electricity markets. It would create a Federal public benefits fund of approximately $3 billion a year that would be used to support low-income customers, implement energy conservation and efficiency programs, provide consumer information, and support emerging generating technologies. To facilitate the development of combined heat and power facilities, an 8-percent investment tax credit would be provided for combined heat and power facilities.

Renewable generating technologies would be supported through the creation of a Federal renewable portfolio standard (RPS). The RPS would require that, by 2010, 7.5 percent of total retail electricity sales be generated at facilities using nonhydroelectric renewable energy sources. Operators of qualifying renewable facilities would receive a credit for each kilowatthour of electricity they generate. The credits could be held for use by the plant operator or sold to others who need them to meet the 7.5-percent required renewable share.

The renewable credit system is intended to operate like the sulfur dioxide allowance trading system created in CAAA90. It should allow developers to build new renewable facilities where they are most economical, while selling credits wherever they are needed. Small renewable facilities (less than 20 kilowatts) located at customer sites would be supported through the establishment of net metering service, which would allow them to compete against the full retail price of electricity rather than the much lower wholesale price they would be offered if they sought to sell power to a local utility. Once these new programs for energy efficiency and renewable technologies are in place, the current requirement in Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), that utilities purchase power from qualifying small power and renewable facilities, would be removed under the proposed legislation.

CECA also would repeal the Public Utility Holding Company Act of 1935 (PUHCA), originally put in place to protect consumers from market abuses by large power companies that operated in many States with no single regulatory body overseeing their operations. To ensure that the formation of larger companies does not harm consumers, CECA would give the FERC responsibility to address the impacts of corporate mergers and acquisitions. Through amendments to the Federal Power Act, the FERC would have authority to “examine the books, accounts, memoranda, and other records of any company in a holding company system, or any affiliate thereof.” It would also be responsible for reviewing mergers or consolidations among electric utility holding companies and generation-only companies. If needed, the FERC could require changes, such as forcing independent system operation or divestiture of generation assets, to remedy potential market power problems.

Taken together, these and other provisions of CECA would standardize restructured electricity markets throughout the Nation. The amendments to the Federal Power Act clarifying State and Federal authority and responsibilities are intended to reduce the possibility that deregulation efforts will be repeatedly challenged in court. In addition, investments in energy efficiency and renewable energy technologies would clearly be stimulated by CECA, compared with a situation without such incentives. At this time, however, it is impossible to tell which provisions of CECA will be included in any legislation passed by Congress.

New Environmental Regulations on Hold

The *Annual Energy Outlook 1999* (*AEO99*) incorporated the Ozone Transport Rule issued by the EPA under the auspices of the Clean Air Act. The rule, also referred to as the “NO_x State Implementation Plan Call” (NO_x SIP Call), set NO_x emission caps for the summer season (May through September) in 22 Eastern and Midwestern States and the District of Columbia. The States were required to meet their assigned emission caps starting in 2003. The EPA was working to develop a regional cap and a program to ensure that the required emission reductions would be achieved at the lowest possible cost.

Two court decisions in 1999 have effectively put the SIP Call on hold. In one ruling, the U.S. Court of Appeals in the District of Columbia (D.C. Circuit) remanded the new national ambient air quality standard for ground-level ozone. Because NO_x emissions are a precursor to the formation of ground-level ozone, the new standards provided some of the technical support for the SIP Call. In a subsequent decision, the D.C. Circuit granted a motion to stay the requirement that States file their new implementation plans to comply with the SIP Call by September 1999.

In May 1999 the EPA announced plans to go forward with a revised SIP Call based on the national ambient air quality standards that are currently in place (based on Section 126 of the Clean Air Act). Under this plan, only 12 States and the District of Columbia would be issued summer season NO_x emission caps. In June 1999, however, the EPA announced an interim stay of the rules through November 30, 1999; and to date, the caps for the 12 States and the District of Columbia have not been finalized. Negotiations are ongoing among the States, EPA, and other interested parties, but no resolution is expected before December 1999. As a result, the NO_x SIP Call is not included in *AEO2000*.

Tier 2 Vehicle Emissions and Gasoline Sulfur Standards

The CAAA90 set "Tier 1" exhaust emission standards for carbon monoxide (CO), hydrocarbons, NO_x, and particulate matter (PM) for light-duty vehicles and trucks beginning with model year 1994. CAAA90 also required the EPA to study further "Tier 2" emission standards that would take effect in model year 2004. The EPA provided a Tier 2 study to Congress in July 1998. The study concluded that tighter vehicle standards are needed to achieve attainment of National Ambient Air Quality Standards (NAAQS) for ozone and PM between 2007 and 2010. In May 1999, the EPA published a Notice of Proposed Rulemaking (NPRM) on "Tier 2" Emission Standards for Vehicles and Gasoline Sulfur Standards for Refineries [*4*]. The NPRM includes standards that would significantly reduce the sulfur content of gasoline throughout the United States to ensure the effectiveness of emission control technologies that will be needed to meet the Tier 2 emissions targets. Recently, however, a U.S. Circuit Court ruling determined that the EPA was not authorized to set new standards without indicating their benefits.

The proposed standards would require manufacturers to begin producing vehicles in 2004 that are 77 percent cleaner than those being sold today. The standards would also be extended to light-duty trucks, minivans, and sport utility vehicles (SUVs), which currently produce 3 to 5 times more pollution than do cars. According to the NPRM, the proposed Tier 2 regulations would require light-duty vehicles (below 6,000 pounds) to meet a sales-weighted average of 0.07 grams of NO_x emissions per mile and approximately 0.01 to 0.02 grams of PM per mile by 2004 [*5*]. The previous Tier 1 emissions standards were set at 0.6 grams per mile for NO_x and 0.1 grams per mile for particulates [*6*]. The EPA has estimated that the costs of the Tier 2 standards to consumers would range from $100 per car to $200 per light truck [*7*].

In 1999, the National Research Council (NRC) released its fifth annual review of the Partnership for a New Generation of Vehicles (PNGV) [*8*]. In its review, the NRC commented, ". . . the most difficult technical challenge facing the CIDI (compression ignition direct injection-diesel) engine program will be meeting the standards for NO_x and particulate emissions. In addition, meeting an even more stringent research objective (0.01 grams/mile) for particulate matter instead of the 0.04 grams/mile PNGV target would require additional technological breakthroughs." The NRC noted that the Tier 2 regulations may affect the commercial viability of many advanced vehicles. Meeting the Tier 2 proposed standards may: require trading off emissions levels for fuel economy by redesigning engines; add significant cost to a technology as a result of the requirement for exhaust catalyst systems and their potential lack of effectiveness; stifle development of diesel technologies as a result of the potential health effects of particulates; and result in new specifications for diesel fuel or development of advanced low-emission fuels.

Because automotive emissions and fuel sulfur are linked, the NPRM also includes tighter standards on the sulfur content of gasoline. Sulfur reduces the effectiveness of the catalyst used in the emission control systems of advanced technology vehicles, increasing their emissions of hydrocarbons, CO, and NO_x. 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 NPRM sets the average annual sulfur content of gasoline at 30 parts per million (ppm), compared with the current standard of 1,000 ppm. The proposed standard is equivalent to the current standard for gasoline in California and is about one-tenth of the national average sulfur content. Because the standards will require refiners to invest in sulfur-removing processes, small refiners would be given an additional 4 years to comply. The rulemaking has not yet been finalized, however, and the Tier 2 standards and low-sulfur gasoline requirement are not included in the *AEO2000* reference case. The proposed changes in gasoline sulfur have been included in an alternative case, which is discussed in the "Issues in Focus" section of this report (see page 30).

Diesel Fuel Quality Standards

In May 1999 the EPA published an Advanced Notice of Proposed Rulemaking on Diesel Fuel Quality [*9*], along with the closely linked Tier 2 NPRM. The proposed Tier 2 emissions standards apply to all vehicles, regardless of what type of fuel is used. The EPA is looking at requiring improvements in the quality of diesel fuel that would enable diesel engine technologies to meet the new Tier 2 standards for NO_x and PM emissions, because some of the technologies under development seem to be very sensitive to sulfur.

The current standard for all on-highway diesel allows a maximum of 500 ppm. Although the Advanced NPRM does not specify a sulfur level, engine manufacturers have indicated that new technologies will require sulfur to be reduced to 30 ppm or lower. The new standards will initially apply to diesel used for light-duty vehicles (a small part of the market) but may be extended to heavy-duty use at a later time. The *AEO2000* reference case does not include the proposed change to the standard for sulfur in diesel fuel, which is only in the early stages of the rulemaking process.

California Ban of Methyl Tertiary Butyl Ether (MTBE)

In March 1999, California Governor Gray Davis issued an Executive Order announcing a ban on the use of MTBE in gasoline by the end of 2002. MTBE is blended with gasoline to raise its oxygen content (reducing emissions of carbon monoxide and air toxics) and enhance its octane rating. The use of MTBE climbed in the 1990s, when it was used to meet oxygen requirements for cleaner burning reformulated and oxygenated gasoline. Although these fuel programs have been hailed as a success in improving air quality, concerns have arisen about their impact on water quality. The California ban is aimed at protecting water resources from MTBE, which even at small concentrations results in an unpleasant taste and odor. Leaking underground pipes and storage tanks have resulted in the contamination of 56 drinking water sites in California [*10*] and between 5 and 10 percent of the water supplies in areas of the United States required to use reformulated or oxygenated gasoline [*11*].

California is governed by its own set of gasoline quality standards, but areas that do not meet Federal ozone standards—including Los Angeles, San Diego, and Sacramento—are bound by the 2 percent oxygen (by weight) Federal requirement. The California Energy Commission has requested that the EPA waive the oxygen requirement, claiming that an alternative gasoline formulation that does not include oxygen can give similar emissions reductions. The Commission is concerned about maintaining the oxygen requirement without MTBE, fearing that reliance on ethanol as a replacement for MTBE will lead to declining air quality and higher gasoline prices. To date, the EPA has not granted an oxygen waiver for California but is working with the State to resolve the issue. There have been several proposals by California Senators Barbara Boxer and Dianne Feinstein and Representative Brian Bilbray to waive the oxygen requirement in California.

AEO2000 reflects the California ban on MTBE but, in keeping with the assumption of current laws only, assumes that the existing oxygen requirement will stay in place. In the absence of an oxygen waiver, gasoline used in Los Angeles, San Diego, and Sacramento—which account for about two-thirds of the State's gasoline consumption—would require another oxygenate to replace MTBE. Ethanol is expected to be the predominant oxygenate used to replace MTBE. A study done for the California Energy Commission estimated additional ethanol requirements of about 75,000 barrels per day in the absence of an oxygen waiver [*12*]. In 1998, ethanol used for gasoline blending totaled 91,000 barrels per day nationally [*13*], and total production capacity was about 112,000 barrels per day [*14*]. Most of the additional ethanol will be drawn from the Midwest, where it is currently being used for octane blending. Some growth in ethanol production is also expected in California. The study put the cost of the MTBE ban without an oxygen waiver at between 6 and 7 cents per gallon of gasoline initially, declining to about 2 cents per gallon after about 6 years [*15*].

Concerns about MTBE in drinking water have spread beyond California and evolved into a national debate. The State of Maine, which had voluntarily joined the Federal reformulated gasoline (RFG) program, opted out in 1999 because of water quality concerns. Although the deadline for opting out of the RFG program has passed, the New Hampshire legislature recently passed a bill instructing the State to pursue an opt-out waiver from the EPA [*16*]. The Texas legislature proposed a gasoline formulation to be used in the eastern part of the State that would provide reduced emissions without requiring oxygenates [*17*].

In addition to State-level actions, there have been numerous legislative proposals in the U.S. Congress related to the MTBE issue. In July, a panel of experts convened by the EPA to study the issue recommended that the use of MTBE in gasoline be significantly reduced and that Congress pass legislation to remove the oxygen requirement in RFG. The panel's recommendations are not binding, however, and there is still considerable uncertainty about how the issue will play out. The "Issues in Focus" section of *AEO2000* includes further discuss of proposed MTBE legislation and explores the market effects of MTBE reduction (see page 32).

Executive Order 13123: Greening the Government Through Efficient Energy Management

On June 3, 1999, the President signed an Executive Order to promote improvement in the way the Federal Government manages its energy use. The goals stated in Executive Order 13123 [*18*] call for all Federal agencies to reduce energy consumption per square foot in their facilities (except for industrial and laboratory facilities) by 30 percent by 2005 and 35 percent by 2010 relative to 1985 levels, through the use of life-cycle cost-effective measures. The goal for Federal industrial and laboratory facilities is to reduce energy consumption per square foot, unit of production, or other applicable measure by 20 percent by 2005 and 25 percent by 2010 relative to 1990 levels. Each Federal agency also is given a goal to reduce greenhouse gas emissions attributed to facility energy use by 30 percent by 2010 relative to 1990 levels. Federal agencies are directed to reduce petroleum use within their facilities, reduce water consumption and associated energy use, strive to expand the use of renewable energy, and strive to reduce total energy use and associated greenhouse gas and other airborne emissions, measured at the source.

In order to meet the stated goals, life-cycle cost analysis is to be used for purchases of new equipment, the design of new buildings, and plans for energy and water efficiency projects. When the analysis determines them to be cost-effective, several strategies are to be used, including maximum use of Energy Star and other energy-efficient products, alternative financing (such as Energy Savings Performance contracts), sustainable building design, and renewable energy technologies. Federal agencies are to prepare annual reports to the President describing their progress toward meeting the goals of the order. The reports will be used to develop energy scorecards evaluating each agency's progress, which will be submitted to the President.

Executive Order 13123 supersedes and builds on a previous order mandating Federal agencies to reduce energy use by 30 percent by 2005 relative to 1985 levels. A number of tools are in place to assist agencies as a result of the earlier order and the National Energy Conservation Policy Act, as amended by the Energy Policy Act of 1992. Additional principles, standards, and guidance are currently being developed to assist agencies in all aspects of compliance with the new order.

The order calls for 2,000 solar energy systems to be installed at Federal facilities by the end of 2000 and 20,000 by 2010 in support of the Administration's Million Solar Roofs initiative. Toward that goal, in June 1999 DOE awarded more than $1.5 million for projects that will install 109 renewable energy systems at Federal facilities. An estimate of the current and planned installations of grid-connected solar photovoltaic energy systems at Federal facilities is included in *AEO2000*, resulting in cumulative energy savings that reach 8 trillion British thermal units (Btu) by 2020 [*19*]. In addition, Federal implementation of the strategies outlined in Executive Order 13123, such as adoption of Energy Star and other energy-efficient products and sustainable building design, were considered in developing projections of commercial sector energy use for *AEO2000*. Federal improvements in energy management as a result of Executive Order 13123 are projected to save 108 trillion Btu in commercial sector energy use and reduce carbon emissions attributable to the commercial sector by 1.8 million metric tons cumulatively over the forecast.

Low-Emission Vehicle Program

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

The LEVP was an emissions-based policy, setting sales mandates for three categories of low-emission vehicles according to their relative emissions of air pollutants: low-emission vehicles (LEVs), ultra-low-emission vehicles (ULEVs), and zero-emission vehicles (ZEVs). The only vehicles certified as ZEVs by the California Air Resources Board (CARB) were dedicated electric vehicles [*20*].

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.

On November 5, 1998, the CARB amended the original LEVP to include ZEV credits for advanced technology vehicles. According to the CARB, qualifying advanced technology vehicles must be capable of achieving "extremely low levels of emissions on the order of the power plant emissions that occur from charging battery-powered electric vehicles, and some that demonstrate other ZEV-like characteristics such as inherent durability and partial zero-emission range" [*21*]. There are three components in calculating the ZEV credit, which vary by vehicle technology: (1) a baseline ZEV allowance, (2) a zero-emission vehicle-miles traveled (VMT) allowance, and (3) a low fuel-cycle emission allowance. Using advanced technology vehicles in place of ZEVs in order to comply with the LEVP mandates requires assessment of each vehicle characteristic relative to the three criteria.

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

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

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

Loan Guarantee Program for Qualified Oil and Gas Companies

On August 17, 1999, a bill providing emergency authority to offer loan guarantees to qualified oil and gas companies (H.R. 1664) was signed into law (Public Law No. 106-51). Section 201, the Emergency Oil and Gas Guaranteed Loan Program Act, provides a total of $500 million in loan guarantees to qualified oil and gas companies and a maximum of $10 million to any single oil and gas company. In order to qualify, a company must (1) be an independent oil and gas company, or a small business as defined under Section 3 of the Small Business Act (or a company based in Alaska) that is an oilfield service company; and (2) have experienced layoffs, production losses, or financial losses since January 1, 1997. All loans guaranteed under Section 201 must be repaid by December 31, 2010. Although the Act will help small producers that have been experiencing financial difficulties, it is not expected to have a major impact on the overall oil and natural gas supply picture.

Issues in Focus

Electricity: Renewable Portfolio Standards

In an increasingly competitive U.S. electricity market, regulators and legislators at both the State and Federal levels are looking for ways to stimulate the development of generating capacity that uses renewable energy sources. One approach that has received considerable attention is the imposition of a renewable portfolio standard (RPS), which would promote the use of renewables by establishing a minimum annual share of electricity generation (or sales) that must come from specified types of renewable facilities. Owners or operators of qualifying renewable facilities would receive credits for each kilowatthour they generated, and the credits could be used in the current year, held for future use (banked) or sold to others to ensure that their mix of power (portfolio) contained a specified share of renewable generation.

The main differences among the various RPS proposals are the required renewable share, the timing of the program, the definition of qualifying facilities, and whether or not there is a limit (cap) on the allowable price for renewable credits. For example, the Administration's proposed Comprehensive Electricity Competition Act (CECA), submitted to Congress on April 15, 1999, includes a Federal RPS that would apply to all U.S. electricity suppliers. The key provisions of the CECA RPS are:

- The required renewable share of electricity sales would be set at 2.4 percent [*22*] for the years 2000 to 2004, increase to 7.5 percent by 2010, and then remain at 7.5 percent through 2015, after which it would expire (sunset).
- Qualifying renewables would include geothermal, biomass (including biomass used in coal-fired plants), solar thermal, solar photovoltaic, wind, and the portion of municipal solid waste (MSW) that consists of biomass products [*23*].
- The price for renewable credits would be capped at 1.5 cents per kilowatthour. If the market price for the credits rose above the cap, electricity retailers would be able to purchase credits from the U.S. Department of Energy (DOE) at the 1.5-cent price (with the resulting revenues deposited in a Public Benefits Fund). In that event, the qualifying renewable share actually achieved would fall below the required 7.5-percent share.

Other provisions of the CECA RPS include double credit for qualifying renewable generation on Indian lands or generation anywhere from biomass resources coming from Indian lands. In addition, qualifying renewable facilities taking advantage of other renewable incentive provisions of CECA could not receive credits under the RPS program.

To examine the potential impacts of the proposed RPS in CECA—independent of its other provisions—three sensitivity cases were prepared, analyzing the key features of the RPS:

- The *RPS with cap and sunset case* incorporates both the price cap for renewable generation credits (1.5 cents per kilowatthour) and the sunset provision (expiration after 2015).
- The *RPS with cap, no sunset case* includes the price cap but not the sunset provision, continuing the RPS throughout the projection period to 2020.
- The *RPS no cap, no sunset case* does not include either the price cap (the price of credits is allowed to rise to its full market value) or the sunset provision.

None of the sensitivity cases includes the Indian lands provisions of CECA. At this time, information on the quantity and quality of renewable resources available on Indian lands is insufficient for model analysis. A comparison of maps of available wind and biomass resources and maps of Indian lands shows some overlap, but more information would be needed for an assessment of the potential impact of the CECA provisions.

The RPS requirement does stimulate additional renewable generation and capacity in each of the three cases; however, the analysis suggests that the price cap and sunset provisions could prevent the 7.5-percent target share from being achieved. The combined effect of the 1.5-cent credit cap and the 2015 sunset is to reduce the average economic value of the proposed RPS credit. Under the proposal, receipt of the few early years' incentive—at a maximum of 1.5 cents per kilowatthour and only through 2015—would need to compensate for the higher costs of renewable energy facilities over their full productive life. In effect, then, the average additional cost of producing electricity from a renewable energy facility would have to be well below 1.5 cents per kilowatthour if significant additional amounts of new renewable capacity were to be built as a result of the CECA RPS.

In the *AEO2000* reference case, with no RPS, 6.6 gigawatts of new qualifying renewable generating capacity are installed by 2010, and an additional 3.6 gigawatts are added between 2010 and 2020. In total, qualifying renewables provide approximately 3.0 percent of U.S. electricity sales in both 2010 and 2020 in the reference case. In the RPS with cap and sunset case, generation from qualifying renewables reaches 3.9 percent of electricity sales in 2010, then declines to 3.4 percent in 2020. In 2010, just under 50 percent of the required RPS share is met through purchases of credits from the Federal Government.

Nearly 82 percent of the 36-billion-kilowatthour difference in qualifying renewable generation between the reference case and the RPS with cap and sunset case in 2010 comes from increased use of biomass for co-firing in existing coal plants (Figure 8), and only 800 megawatts of additional qualifying renewable capacity is added in this RPS case.

Removing the 2015 sunset provision encourages additional increases in renewable generation and capacity, especially in the later years of the projections. The qualifying renewable share in 2010 is 3.9 percent in the RPS with cap, no sunset case—the same as in the RPS case with cap and sunset—but it increases to 4.2 percent in 2020. In the first case, the incentive to use biomass in coal plants disappears when the RPS expires; but without the sunset provision, continued co-firing of biomass in coal plants along with higher geothermal generation increases the qualifying renewable share to 4.2 percent.

In the RPS no cap, no sunset case a large amount of qualifying renewable capacity is added to meet the 7.5-percent CECA RPS target. Relative to the reference case, more than 30 gigawatts of additional wind capacity, 9 gigawatts of additional biomass capacity, and more than 5 gigawatts of additional geothermal capacity are added by 2020 (Figure 9). Total U.S. wind capacity reaches nearly 36 gigawatts in 2020 in the third RPS case, approximately 18 times the amount that existed in 1998. Even in this case, however, solar technologies remain too costly for additional penetration into central station generation markets. Similarly, no additional MSW generating plants are projected, because of their high capital costs and environmental concerns. It is possible, however, that output from existing MSW-powered facilities could increase somewhat in response to the RPS credit price incentive.

The impact on electricity prices is relatively small in each of the three RPS cases (Figure 10). Although new renewable facilities are more expensive to build and operate than new gas-fired facilities, the RPS credit system would spread the incremental costs of new renewable facilities across all electricity sales. The largest change in electricity prices is projected for the RPS no cap, no sunset case in 2010, at 3.2 percent above reference case prices. Even in this case, however, electricity prices in 2020 are only 1.4 percent above the reference case prices. The changes in electricity prices do change the Nation's total annual electricity bill. In 2010, the projected increase in total expenditures for electricity purchases relative to the reference case projection ranges from $500 million in the RPS with cap and sunset case to $5.8 billion in the RPS no cap, no sunset case (in 1998

Figure 8. Renewable electricity generation in four cases, 2010 (billion kilowatthours)

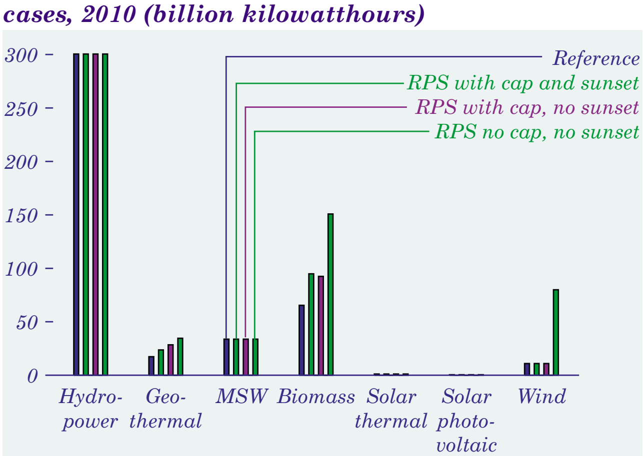


Figure 9. Renewable electricity generation in four cases, 2020 (billion kilowatthours)

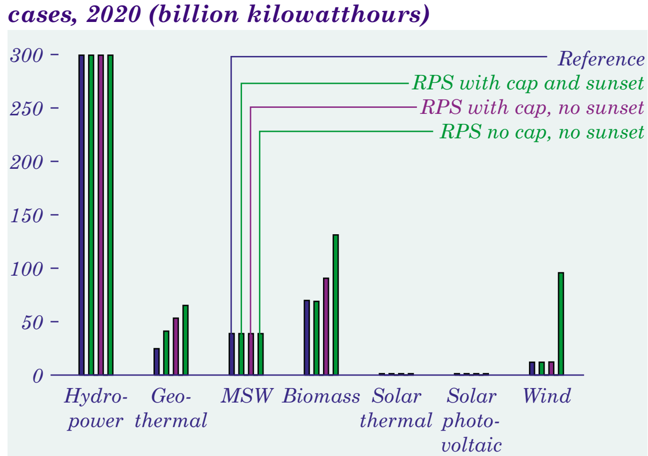
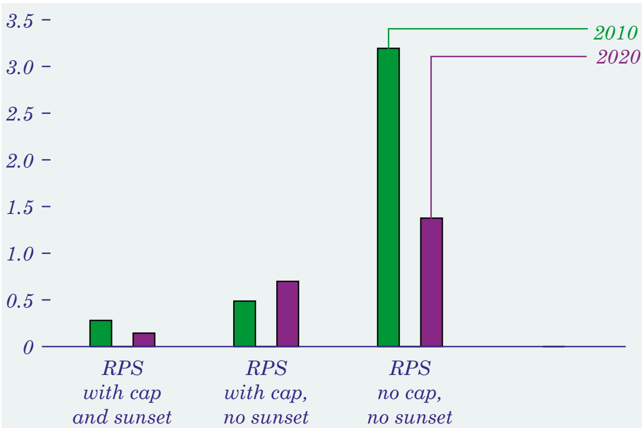


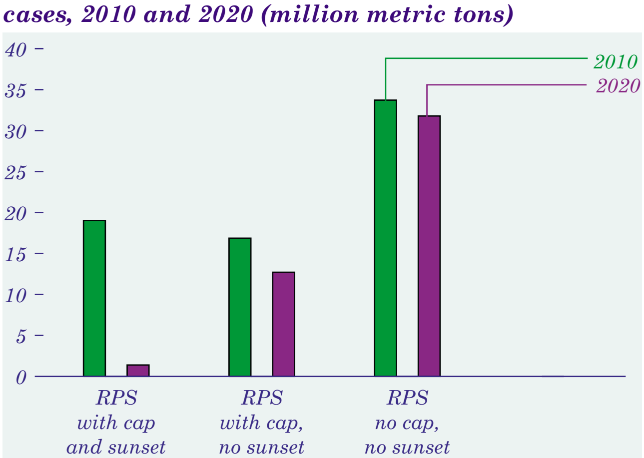
Figure 10. Difference from reference case electricity prices in three cases, 2010 and 2020 (percent)



dollars). In 2020 the differences range from $200 million to $2.1 billion.

As with electricity prices, the three RPS cases have relatively small impacts on U.S. carbon emissions (Figure 11). In the RPS with cap and sunset case, carbon emissions are estimated to be 19 million metric tons below the reference case level in 2010 and 1 million metric tons below the reference case level in 2020. The reduction is smaller in 2020, because the RPS expires in 2015. In the second RPS case (with the credit price cap but no sunset), carbon emissions are expected to be 13 million metric tons (0.6 percent) below the reference level in 2020. The impact is largest when both the price cap and sunset provisions are removed, because renewable generation is much higher. In this case, carbon emissions are 34 million metric tons (1.9 percent) and 32 million metric tons (1.6 percent) below reference case levels in 2010 and 2020, respectively.

Figure 11. Carbon emissions reductions in three cases, 2010 and 2020 (million metric tons)



The key result of this analysis is that, except in the RPS case with no price cap and no sunset provision, the share of electricity sales generated from qualifying renewables is likely to fall short of the 7.5-percent CECA target. In the first RPS case, the amount of generation from qualifying renewables increases by only a small amount above the reference case level. The economic value of the limited (capped at 1.5 cents per kilowatthour), temporary (through 2015) renewable energy credit is not large enough to overcome the cost advantage of fossil fuel technologies, especially new natural-gas-fired turbine and combined-cycle plants. The costs of new renewable plants are expected to continue to decline, but the cost and performance of fossil technologies also are projected to improve. As a result, the combination of the 1.5-cent renewable credit price cap and the need to recover any above-market costs of new qualifying renewable plants before the RPS expires in 2015 appears likely to limit the impact of the proposed CECA RPS on the development of new renewable electricity generating capacity.

Although it is not included in this analysis, if the 1.5 cent per kilowatthour production tax credit for generation from new wind and biomass facilities, which expired in June 1999, were extended, the amount of qualifying renewable generation stimulated by the RPS would be larger than projected in the RPS with cap and sunset case. Efforts to extend the credit through 2004 have been proposed, but they have not been approved. If the tax incentive were extended through 2020, the projected generation from wind units in 2010 would be 32 percent higher than projected in the RPS with cap and sunset case. In 2020, generation from biomass would be 10 percent higher, and generation from wind would be 46 percent higher. Continuation of the incentive would encourage the development of an estimated 1.41 gigawatts of additional biomass capacity and 1.81 gigawatts of additional wind capacity relative to the RPS with cap and sunset case, and carbon emissions in 2020 would be 2 million metric tons lower.

Electricity: Competitive Pricing

As States restructure their electricity markets, increasing numbers of consumers have the opportunity to choose their electricity suppliers. While this by itself represents a significant market adjustment, there may be an even more profound change in the way electricity is priced. In the past, electricity prices have had three components: generation, transmission, and distribution. The following analysis assumes that the generation component will be unbundled from transmission and distribution services, which will continue to be regulated.

Until recently, electricity prices in the United States were regulated on the basis of the average cost of producing and delivering electricity to consumers (cost of service). State regulators determined the average “embedded cost” of electricity generation by adding all costs—including fuel, recovery of investment costs, operations and maintenance costs, and a regulated profit—and dividing by the number of kilowatthours sold. Since about 1995, however, there has been a gradual movement by individual States toward competition in electricity generation services. Under competition, prices for generation are expected to approach the marginal, rather than the average, cost of production.

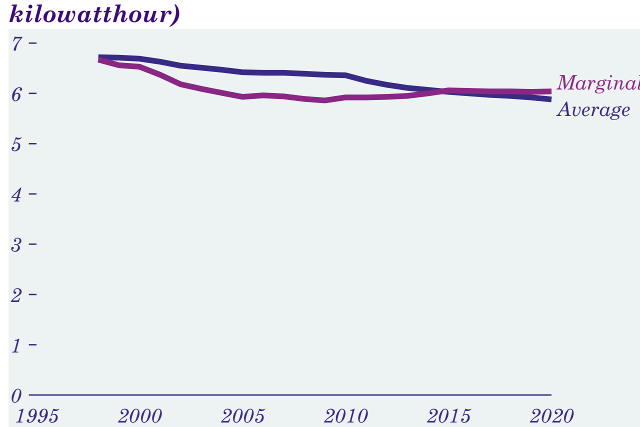
The movement to prices based on marginal costs has several implications. First, electricity prices are likely to vary from hour to hour as consumer demand changes. In most of the country, consumer demand for electricity during a typical summer day is lowest in the early morning hours, when people are asleep and businesses are closed. Through the day, demand rises as temperatures rise and homes and businesses use more air conditioning. As a result, in the early morning hours, only generators with the lowest operating costs are running. Over the course of the day, more expensive generators are brought into service. Because the costs of generating power are based on the last unit brought on line during any given time period (the “marginal unit”), market prices typically rise as demand increases. In a truly competitive market, demand and supply are kept in balance during periods of extremely high demand through an increase in the price corresponding to the cost of electricity supplied by the marginal generating unit.

This analysis discusses the impacts of a movement to electricity prices based on marginal costs and their sensitivity to demand variations and the operating costs of the marginal generator. Because the marginal generator typically consumes natural gas, three sensitivity cases are discussed: low gas price, mid gas price, and high gas price. The cases incorporate the common assumption of competitive electricity prices but differ in the assumed wellhead price of natural gas. In each of the three cases it is assumed that competition will be phased in over a 10-year period, reflecting the transition to a competitive market and recovery of stranded costs. Full competition, with generation prices based entirely on marginal costs, is assumed to begin in 2008.

Initially, at the national level, marginal operating costs would be lower than average embedded costs (Figure 12). Because some plants have costs, including recovery of construction costs, that make them uneconomical in today’s market for power, competitive electricity prices (based purely on marginal operating costs) fall below the average-cost-based (regulated) prices until near the end of the projection period. The gap is fairly narrow, because it is assumed that the transition to competitive prices based on marginal costs will occur slowly over a 10-year period, and that improvements in operating costs that have already occurred in recent years will continue with or without a movement to full retail competition. It is unclear whether full retail competition will spur additional improvements beyond those that are already occurring. After 2015, rising gas prices cause marginal prices to slightly exceed average-cost-based prices. If retail competition leads to additional operating cost improvements, marginal costs might remain below average costs after 2015.

The difference between the two price lines in Figure 12 represents a rough measure of stranded costs. In a few regions of the country, where average costs already are extremely low, stranded costs may be negligible or actually negative. In most regions, marginal-cost-based prices in 2010 are expected to be up to 16 percent lower than average-cost-based prices. Only in the Northwest, where average-cost-based prices are very low as a result of the large share of low-cost hydroelectricity, would marginal-cost-based

Figure 12. Marginal- and average-cost-based prices for electricity in the competitive pricing case with reference gas prices, 1998-2020 (1998 cents per kilowatthour)



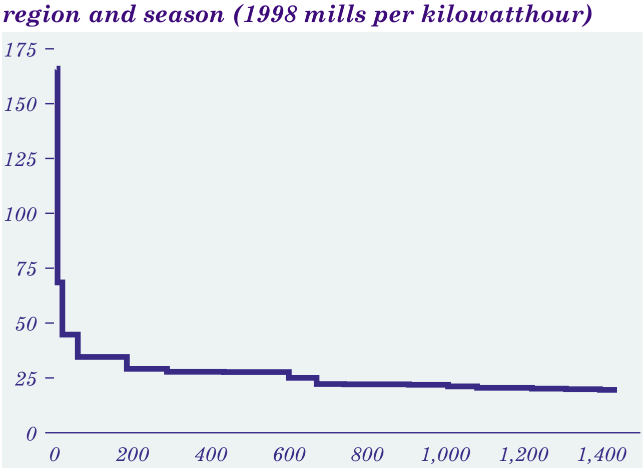
prices be higher, by about 10 percent. It is also possible that, in a competitive pricing environment, some costs could rise—such as the costs of sales, marketing, and system operations. The recovery of such costs in competitive prices might reduce the amount of stranded costs. Over time, the difference between costs and prices narrows, as stranded costs are recovered or written off.

Over the course of a year, competitive prices vary with demand. In the fall and spring, when consumer needs for electricity are relatively low, prices are also low. Conversely, in the summer, or when a large number of plants are out of service, prices rise as the most expensive generators—normally idle—are brought on line to meet demand. In the sample region and season shown in Figure 13, the generation component of competitive prices in 2020 ranges from a high of 17 cents per kilowatthour to a low of just over 2 cents per kilowatthour in the mid gas price case. Because the periods of high prices are expected to be limited to only a few hours during the season, they have a relatively small impact on the average annual price.

In all the marginal cost cases, it is assumed that consumers will see and respond to the effect of time-of-use prices. This response has the effect of reducing the total capacity needed over the course of the projection in comparison with the reference case, primarily through a reduction in the need for combustion turbines used to meet peaking loads.

Figure 14 shows the technology type of the marginal unit for the years 2000, 2010, and 2020 by region in the mid price case. In most regions, the marginal generating unit throughout most of the year uses

Figure 13. Generation price by hour for a sample region and season (1998 mills per kilowatthour)



natural gas. As a result, natural gas prices will have a far greater effect on electricity prices under marginal cost pricing than under average cost pricing.

The high and low gas price cases—which incorporate alternative assumptions about improvements in natural gas recovery and distribution technology, leading to different gas price paths—are used here for illustrative purposes, to demonstrate how competitive electricity prices might respond. As in the mid price case, it is assumed in the low and high price cases that competition will be phased in over a 10-year period, with full competition and prices based entirely on marginal costs by 2008. The mid price case assumes moderate improvement in natural gas availability, the low gas price case assumes rapid improvement, and the high gas case assumes little improvement.

Table 2 shows projected wellhead natural gas prices in the three cases. Higher or lower gas prices affect both the average embedded cost and the marginal cost of electricity generation; however, the effects differ in magnitude (Figure 15 and Tables 3 and 4). With 20 percent lower gas prices in 2020 in the low price case, average-cost-based prices are only 3 percent lower than in the mid price case, but marginal-cost-based prices are 8 percent lower. Similarly, with 32 percent higher gas prices in 2020 in the high price case, average-cost-based prices are

Figure 14. Projected percentage of time marginal electricity prices are set by different capacity types, 2000, 2010, and 2020 (percent of total year)

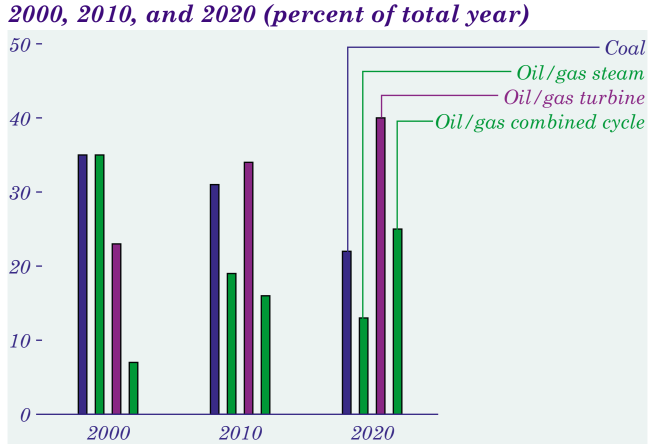


Table 2. Natural gas wellhead prices in three cases, 2000-2020 (1998 dollars per thousand cubic feet)

	2000	2010	2015	2020
Low gas price	2.16	2.34	2.24	2.26
Mid gas price	2.17	2.59	2.70	2.82
High gas price	2.17	2.88	3.20	3.71

Figure 15. Marginal- and average-cost-based prices for electricity in three competitive pricing cases, 1998-2020 (1998 cents per kilowatthour)

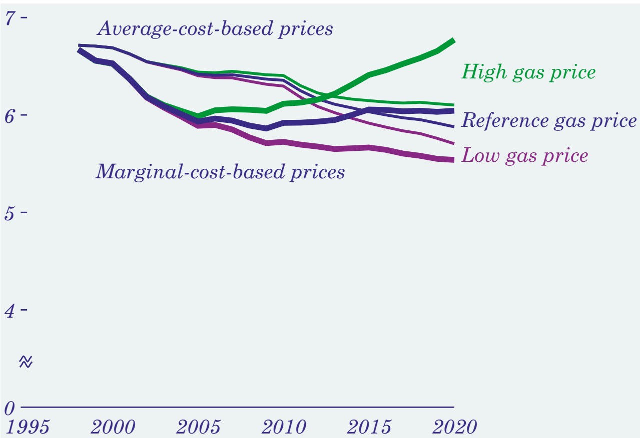


Table 3. Regulated (average-cost-based) electricity prices in three cases, 2000-2020 (1998 cents per kilowatthour)

	2000	2010	2015	2020
Low gas price	6.7	6.3	5.9	5.7
Mid gas price	6.7	6.4	6.0	5.9
High gas price	6.7	6.4	6.2	6.1

Table 4. Competitive (marginal-cost-based) electricity prices in three cases, 2000-2020 (1998 cents per kilowatthour)

	2000	2010	2015	2020
Low gas price	6.5	5.7	5.7	5.5
Mid gas price	6.5	5.9	6.1	6.0
High gas price	6.5	6.1	6.4	6.8

3 percent higher than in the mid price case, but marginal-cost-based prices are 13 percent higher. In the high gas price case, marginal-cost-based prices actually exceed average-cost-based prices by 11 percent in 2020. The difference is explained by the fact that prices based on marginal costs are much more sensitive to changes in the operating cost of the marginal unit than are prices based on average costs.

Natural Gas: Industry Expansion

Pipeline Capacity

Considerable expansion of the interstate pipelines that transport natural gas will be needed between now and 2020 to satisfy the demand for natural gas that is projected in the *AEO2000* reference case. Although the overall increase in pipeline capacity would be significant, the industry demonstrated the ability to handle expansions of the same order of magnitude in the early 1990s. The increase in demand for natural gas in the reference case would require pipeline capacity increases of approximately 2 percent a year from 1999 through 2001 for capacity crossing the 12 regions represented in the projections. By comparison, from 1991 through 1993, capacity grew by an average of more than 4 percent a year (Figure 16). The total increase from 1991 through 1993 was 3.2 trillion cubic feet, compared with the 2.7 trillion cubic feet of new capacity needed from 1999 through 2001.

Much of the expansion expected through 2001 is already underway, and several major projects are likely to be completed in 1999 or 2000. The current projects are providing access to new sources of both supply and demand, as well as increasing capacity along transportation corridors where utilization is high during peak periods and bottlenecks either are already occurring or could occur in the near future.

After 2001, the projected annual growth of pipeline capacity slows to less than 1 percent a year. One reason is that most of the projected increase in demand for natural gas is for electricity generation, much of which can be met by increasing and levelizing the load on existing capacity without additional expansion of the pipeline infrastructure (Figure 17). Thus, although actual capacity expansion slows after 2001, flows on the interstate pipeline system increase significantly (Figure 18). Total interregional gas flow across the 12 domestic regions and Canada is projected to grow from 25.7 trillion cubic feet a year in 2001 to 35.2 trillion in 2020, an increase of 36.8 percent, compared with a capacity increase of 14.5 percent.

In 1998, 18.7 percent of total U.S. natural gas consumption was for space heating in the residential and commercial sectors, and 17.2 percent was for electricity generation. As a result, both demand and pipeline capacity utilization peaked during the

Figure 16. Additions of interstate natural gas pipeline capacity, 1991-2020 (billion cubic feet)

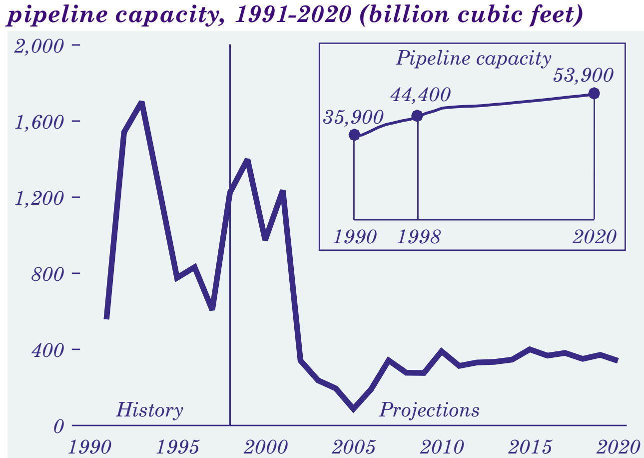
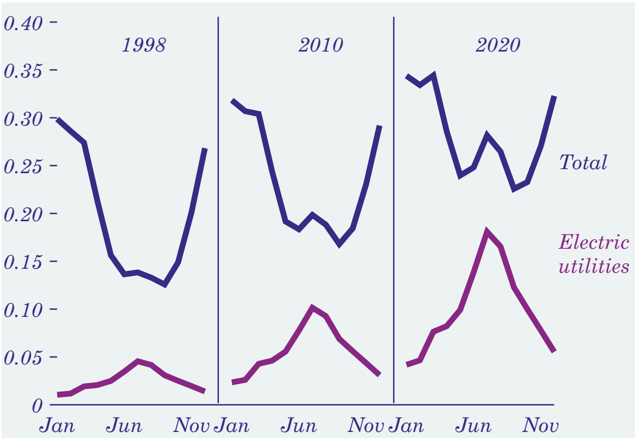


Figure 17. Total natural gas use and use for electricity generation by month in the Mid-Atlantic Census division, 1998-2020 (quadrillion Btu)



winter heating season, whereas significant amounts of capacity were idle during the summer months. In the *AEO2000* forecast, more than half the total projected increase in natural gas consumption is for electricity generation. In 2020, gas use for space heating makes up only 16.2 percent of the total and use for electricity generation grows to 29.4 percent, significantly increasing the utilization rate of existing capacity during the summer. Some new capacity will be needed to provide service to residential, commercial, and industrial users (as well as to new gas-fired generating plants in areas not currently or adequately served), but much of the increased load will be handled by excess space on pipelines during traditionally off-peak periods.

One of the forces behind capacity expansion has been, and will continue to be, the desire to provide access to new and expanding production areas. Significant increases in annual production are projected for the Rocky Mountain and Gulf Coast onshore production regions between 1998 and 2020—2.31 and 1.71 trillion cubic feet, respectively (Figure 19). For the Rocky Mountain region, an area that has long experienced bottlenecks in pipeline capacity that have prevented full use of its production capacity, the additional production represents a 79.7-percent increase from 1998 levels.

Several pipeline projects recently completed will provide producers in the Rocky Mountain region with new access to customers in the Midwest. KN

Figure 18. Natural gas pipeline flows between Census divisions, 1990-2020 (trillion cubic feet)

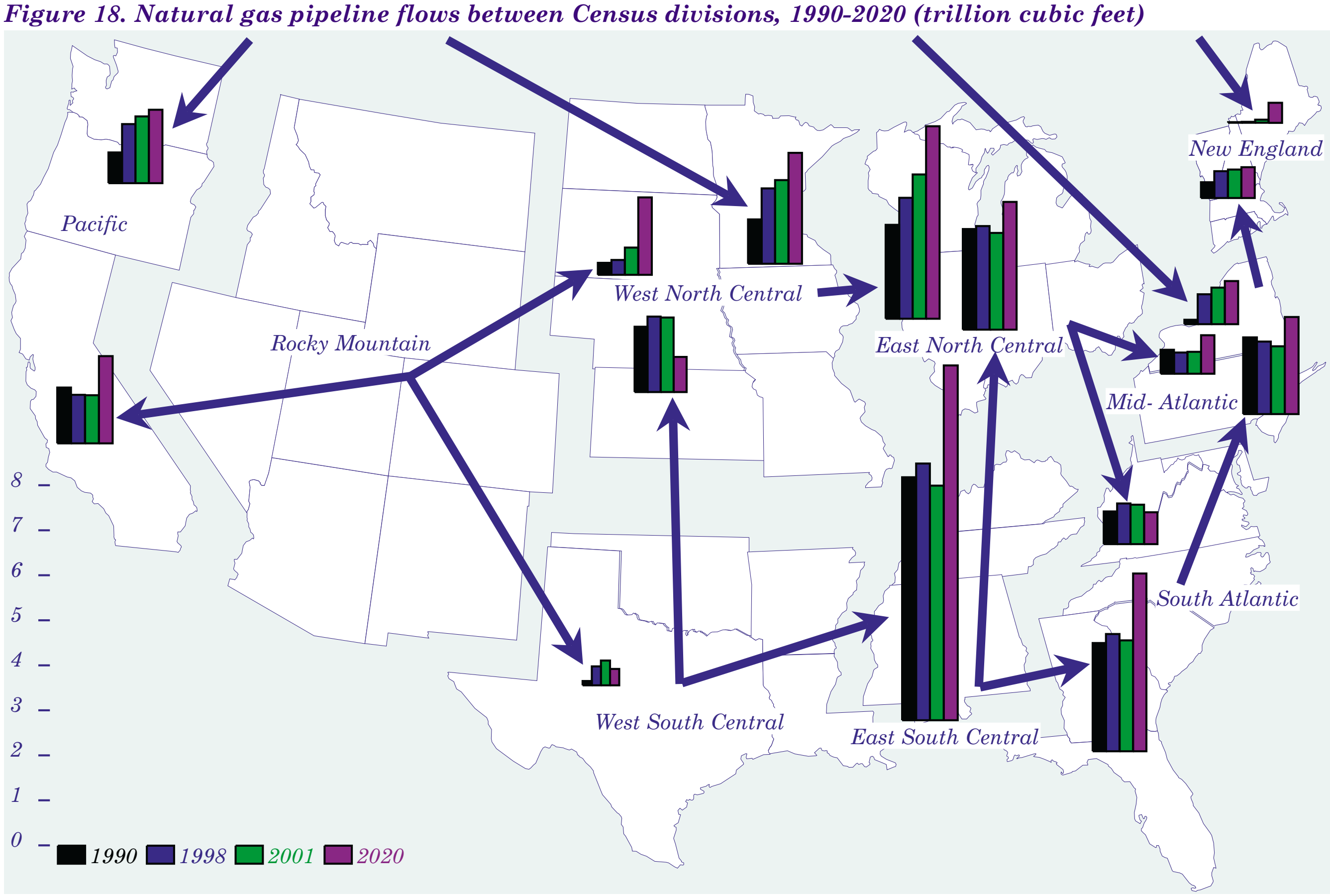
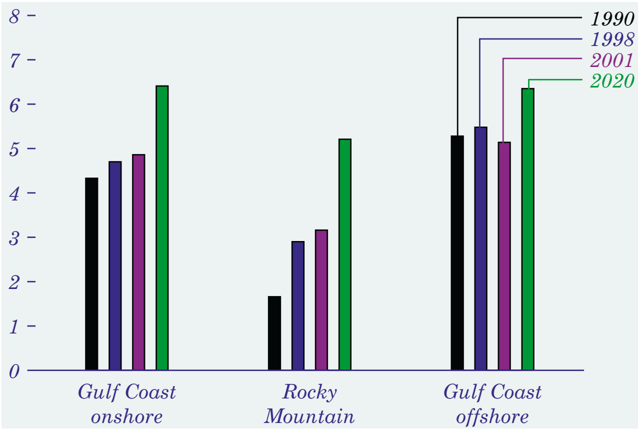


Figure 19. Natural gas production in three regions, 1990-2020 (trillion cubic feet)



Interstate's new Pony Express project and the Trailblazer system expansion provide access from the Wyoming and Montana production regions, and the Transwestern Pipeline and El Paso Natural Gas expansions have increased the capacity to move supplies out of New Mexico's San Juan Basin. Along with increases in capacity, significant increases in flows from the region to markets on the east and west coasts are expected between 1998 and 2020.

Canada is another rapidly expanding source of natural gas supply for U.S. consumers. The greatest increase in pipeline capacity from 1990 to the present has been a near doubling of import capacity between western Canada and the United States. As a result, markets in the United States have been able to tap into western Canadian supplies, mainly from Alberta and British Columbia. The most significant recent pipeline project is the Northern Border expansion through Montana into the Midwest. In addition, several major projects are expected to be completed within the next few years. The Alliance pipeline system, scheduled to be completed in 2000, will move supplies from western Canada to markets in the Midwest and Mid-Atlantic regions, and the Maritime & Northeast system, also scheduled for completion in 2000, will transport Sable Island supplies to markets in New England. Additional expansions have been proposed, including the NOVA system expansion that would link with the TRANSCANADA expansion to move additional supplies to U.S. markets.

The expansion of gas pipeline capacity between the United States and Canada is projected to continue throughout the forecast period at an average rate close to 1.8 percent a year. As production in western Canada continues to increase, gas flows into the West North Central region are expected to increase by 47.2 percent and flows into the Pacific region by 24.3 percent between 1998 and 2020. Eastern Canada will become a new source of U.S. supply as resources from Sable Island off the eastern coast of Nova Scotia are developed. Imports into New England, largely from Sable Island, are expected to reach 448 billion cubic feet a year by 2020.

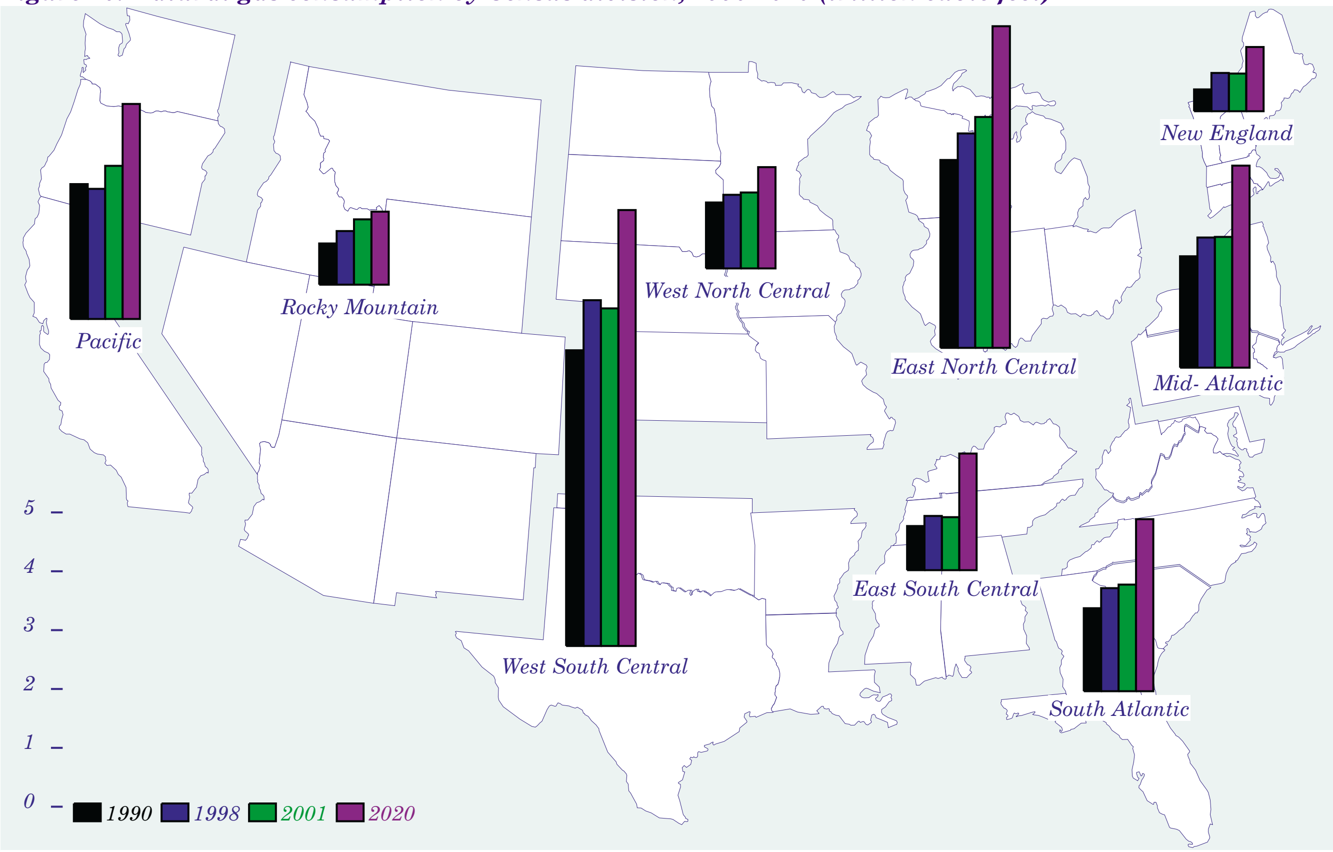
The third area of expanding production is the Gulf Coast offshore region. There has been considerable pipeline expansion in the area, but much of it is for gathering systems and short-haul pipelines to move supplies onshore, rather than major interstate pipeline expansions. Expansion out of the East South Central and West South Central regions was strong from 1990 through 1998 but has slowed recently along with a slowdown in production. Offshore Gulf Coast production continues to grow steadily in the projections, picking up after 2001 as a result of further deepwater exploration and development.

Between 1998 and 2001, the reference case shows little expansion of interstate pipeline capacity from the Gulf Coast region. Increases are expected between 2001 and 2020, as Gulf Coast producers expand production and seek access to eastern markets. Although potential shortages of skilled manpower and offshore drilling rigs lend some uncertainty to the prospect for increased offshore production in the short term, investments continue to be made in exploration and production, and it is anticipated that the rising levels of both demand and prices for natural gas throughout the forecast will provide the necessary economic incentives.

Also important as a motivation for pipeline capacity expansion are shifting and growing demand areas (Figure 20). New England saw the strongest percentage increase in demand (75.7 percent) from 1990 to 1998, and continued increases are projected through 2020, at an average of 2.4 percent a year. In the absence of the pipeline infrastructure to bring gas into the area, oil long dominated New England markets. In 1998, New England was the only region in which oil use was higher than natural gas use in the residential sector. With natural gas infrastructure expansion in the 1990s, however, the picture is now changing.

Capacity entering New England increased by more than 50 percent from 1990 through 1998, facilitating

Figure 20. Natural gas consumption by Census division, 1990-2020 (trillion cubic feet)



strong growth in overall natural gas consumption. Still, New England lags behind the rest of the Nation in natural gas use and thus presents an opportunity for the natural gas industry. More natural gas use in all sectors is projected, and gas-fired electricity generation is expected to grow more than fivefold. Increases in pipeline capacity to serve the area, especially to provide access to Canadian supplies, are expected to continue, nearly doubling current gas flows into New England by 2020.

The largest absolute increases in capacity between 1998 and 2020 are expected for the corridors serving the West North Central, South Atlantic, and Pacific regions, where demand for natural gas is projected to grow by 1.5, 2.4, and 2.3 percent a year, respectively, between 1998 and 2020. In the South Atlantic region, rapid population growth is expected to increase the demand for natural gas in all sectors, and especially for electricity generation. Gas-fired electricity generation is projected to more than double in the South Atlantic region between 1998 and 2020. Gulf Coast supplies destined for the Northeast will also flow through the South Atlantic, increasing even more the need for added capacity. Similarly, Canadian and Mountain Region supplies will flow through the West North Central Region en route to the Northeast.

Although the growth in demand for natural gas has slowed in the Pacific region in recent years, partly as a result of increases in hydroelectric generation, it has recently begun to accelerate. Consistent growth is projected for the Pacific region in the reference case through 2020. Two proposed projects, Questar's Four Corners project and the Kern River expansion, would move an estimated 430 million cubic feet per day into California.

All this expansion requires considerable investment. In 1997 and 1998, it is estimated that more than $2 billion was invested in pipeline expansion. The projected costs for new capacity on completed and proposed natural gas pipeline projects from 1996 through 2000 average 15 cents per cubic foot per day for projects consisting predominantly of compression, 26 cents for pipeline system expansions of 250 miles and over, and 94 cents for new projects 250 miles and over.

Although all are not likely to be built, more than 100 pipeline projects have already been proposed for 1998 through 2001. For the 70 projects for which preliminary estimates are available, the estimated costs total more than $12.3 billion. The largest is the Alliance project, which has been estimated to cost as much as $1.81 per added cubic foot per day of capacity, for a total project cost of more than $2.9 billion [*24*]. Because the costs of expansion vary widely depending on many factors, including the type of expansion (compression, looping, or new pipe), the size of the expansion, and the area of the country, averages based on recent project costs are used in estimating the costs associated with projected expansions.

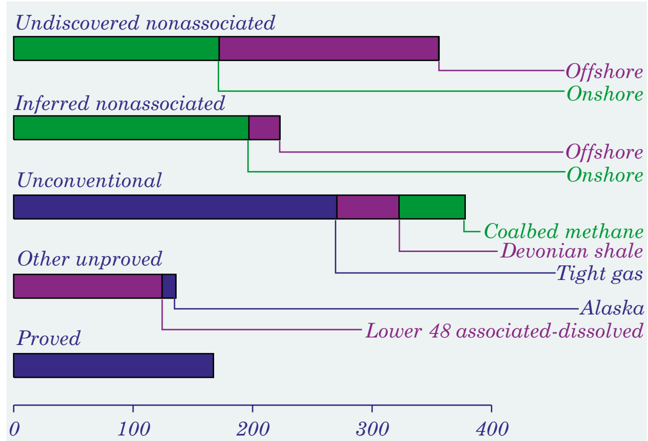
The pipeline capacity expansion currently underway and proposed reflects the industry's anticipation of an expanding market. The rising levels of consumption and prices for natural gas projected in *AEO2000* will provide the economic incentives for the infrastructure expansion and the investment that will be required to support the projected increases in natural gas production and demand. As a result, it is expected that the natural gas industry will be in a position to meet the challenge of providing the production and infrastructure expansion anticipated in the *AEO2000* projections.

Supply Availability

In the *AEO2000* reference case forecast, natural gas consumption increases by 1.8 percent a year between 1998 and 2020, and the projected demand in 2020, at 31.5 trillion cubic feet, exceeds the 1998 level by almost 50 percent. The challenge for the natural gas supply industry is whether adequate supplies will be available at the projected prices to meet the expected demand, which exceeds 30 trillion cubic feet by 2016. The historical record and current conditions suggest that the challenge can be met.

Uncertainty with regard to estimates of the Nation's natural gas resources has always been an issue in projecting production, and it is widely acknowledged that assessing actual resource levels is a difficult task. The *AEO2000* resource estimates (Figure 21) are based on assessments by the U.S. Geological Survey (USGS), Minerals Management Service (MMS), and National Petroleum Council (NPC). Some uncertainty is associated with each of the estimates. Because historical data are more limited for offshore fields, the uncertainty is higher for offshore than for onshore resources.

Figure 21. Technically recoverable U.S. natural gas resources as of January 1, 1998 (trillion cubic feet)



The uncertainty surrounding recoverable gas resource estimates is reflected in the differing views on the subject. For example, an April 1998 study by the Gas Research Institute (GRI), contending that the industry has "significantly underestimated" the growth potential of existing fields in the Midcontinent, onshore Gulf Coast, East Texas, and San Juan Basin areas, proposes higher reserve estimates for those areas. The USGS, MMS, and NPC estimates, however, are based on well documented and extensively reviewed methodologies and fall within the range of current expert opinion.

A key factor in making newer sources of production economical is the rate at which technology improvements will allow production from previously marginal sources without much higher prices. A few examples of significant technological advances in recent history include: (1) polycrystalline-diamond-compact drill bits, which are durable and versatile and are credited with significantly reducing the time required to drill a well; (2) measurement while drilling technology, which permits drilling and geologic information to be sent to the surface in real time; and (3) horizontal drilling, which exposes more reservoir rock to the wellbore.

The *AEO2000* reference case assumes that improvements in technology will continue at historical rates [*25*]. To assess the potential effects of faster and slower rates of improvement, rapid and slow technology cases are also examined (see "Market Trends," pages 78 and 79). Whereas the reference case projects total U.S. natural gas production in 2020 at 26.4 trillion cubic feet, the rapid technology case projects 28.1 trillion cubic feet of production in 2020, with the increase coming primarily from offshore and unconventional sources.

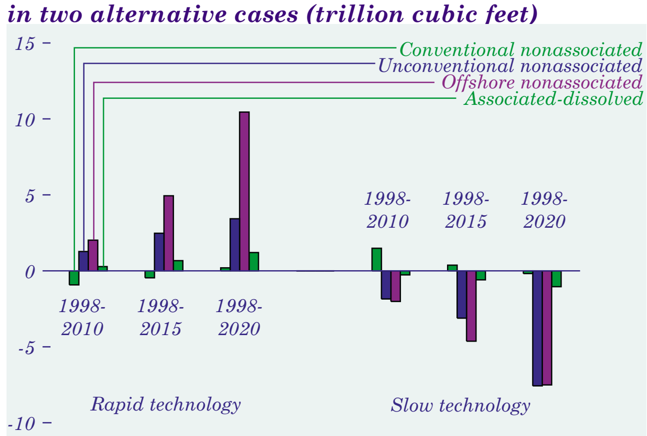
The offshore is an area that the industry hopes will provide considerable supplies in the future. Offshore gas production has increased somewhat in recent years, and larger increases are expected. Recent technological advances have made recovery from wells in progressively deeper waters possible (the record water depth has increased from 1,760 feet in 1989 for the Jolliet platform to 5,376 feet for the Mensa project, which began production in July 1997).

Offshore gas production in the Gulf of Mexico is expected to grow from 5.5 trillion cubic feet in 1998 to a peak of 6.7 trillion cubic feet in 2015 in the reference case. In the rapid technology case, however, offshore Gulf of Mexico production peaks at 7.7 trillion cubic feet in 2017, and cumulative offshore production between 1998 and 2020 is 148.3 trillion cubic feet, compared with 137.1 trillion cubic feet in the reference case. The rapid technology assumption has a similar but less dramatic, effect on unconventional gas recovery (UGR). Cumulative UGR production between 1998 and 2020 is 132.9 trillion cubic feet in the rapid technology case, compared with 129.5 trillion cubic feet in the reference case.

Technological progress makes it possible to produce more gas at lower cost from all sources. The projections of total annual production in 2010, 2015, and 2020 are lower in the slow technology case and higher in the rapid technology case than in the reference case. However, the effects of rapid technology improvement—lower costs and higher productivity—are greater for offshore and UGR production than for onshore conventional production, especially in the early part of the forecast (Figure 22). The reverse is true in the slow technology case.

The development of needed infrastructure in strategic areas is positioning the industry well to exploit its best opportunities for expanded production. Numerous pipeline expansion projects have recently been completed that greatly improve access to areas of growing production, such as the Midcontinent and the offshore, including seven projects completed in 1997 and 1998 that move offshore production to onshore Louisiana. They include the Destin Pipeline (1 billion cubic feet per day) and the Nautilus and Discovery projects (600 million cubic feet per day each). Also in 1997 and 1998, five gathering systems

Figure 22. Change from reference case projections of cumulative U.S. natural gas production in two alternative cases (trillion cubic feet)



were completed, linking offshore production platforms in the Gulf to the onshore.

The resource estimates used for *AEO2000* do not include areas in which drilling is restricted. Drilling moratoria have placed offshore areas in the eastern Gulf of Mexico, North Carolina, and California off limits, and drilling is limited in some areas of the West because of concern about emissions. There are also substantial resources in the Arctic National Wildlife Refuge (ANWR), where exploratory drilling is prohibited; however, the current inability to market natural gas from northern Alaska has rendered the ANWR accessibility issue moot.

Should it become economical to tap Alaskan gas resources, there is significant supply available outside the ANWR. Alaska's North Slope contains some 38 trillion cubic feet of technically recoverable natural gas in developed and known fields, and the 1995 USGS mean estimate for undiscovered Alaskan North Slope fields is 64 trillion cubic feet. Currently most of the North Slope gas production is being reinjected to enhance oil production. Of the 3.2 trillion cubic feet produced in 1998, 92 percent was reinjected. This resource is not being marketed at present, because the economics have not been favorable for the development of an infrastructure to transport the gas to market. Options for North Slope gas that are being considered include conversion to liquefied natural gas (LNG), the use of gas-to-liquids technology, and the development of pipelines to the lower 48 States.

Other areas of uncertainty include the availability of offshore rigs and skilled personnel. Employment in the oil and gas industries has fallen in recent years, as oil production has declined and productivity has increased. According to the Bureau of Labor Statistics, employment in the oil and gas extraction industries declined from an average of 400,000 employees in 1988 to an average of 340,000 in 1998, a reduction of 15 percent. Over the same period, total oil and gas production (excluding natural gas liquids) dropped by just 7 percent, from 34.9 quadrillion Btu to 32.6 quadrillion Btu, as rising productivity accelerated the decline in employment relative to the decline in production.

Although falling prices in 1998 led to layoffs in the extraction industry, preliminary Bureau of Labor Statistics estimates for September 1999 indicate that employment is now beginning to rise. Some potential employees may be reluctant to enter the workforce because of its cyclical history and the potential for future layoffs. Higher wages should provide sufficient incentive to attract workers, however, and there is ample time to develop a skilled workforce before the market reaches the projected demand level of 30 trillion cubic feet in 2015, given the economic incentives provided by rising prices.

Rig utilization was extremely high in 1997, averaging 86.9 percent overall. Offshore, virtually every available rig remained in use throughout the year. With declining prices in 1998, overall rig utilization dropped to 76.5 percent [*26*], alleviating the problem of rig availability, but the lower prices also slowed investment in the construction of new rigs. High capital requirements, as well as uncertainty about the actual demand for new rigs, currently are limiting investment in rig construction. Estimates of more than $100 million to upgrade an existing rig [*27*] and more than $300 million to construct a new deepwater semisubmersible rig [*28*] have been reported.

Price increases are a powerful incentive, however, for increased drilling and purchases of new equipment. Because the construction lead time for rigs is only 2 to 3 years, rig availability is unlikely to be a long-term issue between now and 2020, given the historical response to rising prices. The number of available drilling rigs increased by almost 14 percent annually between 1974 and 1982—from 1,767 to 5,644—as natural gas prices more than quadrupled in real terms. The rigs needed over the forecast period are assumed to be constructed, with the total rig count projected to increase from 1,705 in 1998 to 1,994 by 2020 [*29*].

A final key element in the supply outlook is the availability of imports, both pipeline imports from Canada and Mexico and LNG imports from foreign suppliers, such as Algeria, Australia, Trinidad and Tobago, and Qatar. The majority of the growth in imports in the *AEO2000* forecast comes from Canada, which has a resource base sufficient to increase both domestic consumption and exports significantly. The Canadian Gas Potential Committee estimated in 1997 that remaining discovered and undiscovered plays in the Western Canada Sedimentary Basin contained 184 trillion cubic feet of marketable gas.

Pipeline capacity has limited imports from Canada in the past, but new capacity has been and will continue to be built, as described above, making increased imports a likely contributor to increased supplies. In addition, drilling in new areas has the potential to increase Canada's exports still further. By the end of 1999, natural gas is expected to start flowing into the United States from the eastern Canadian Scotian Shelf, an area that has only begun to be tapped. In addition, interest in developing the MacKenzie Delta/Beaufort Sea region of the Northwest Territories has recently begun to increase. The Canadian National Energy Board estimates the undiscovered marketable potential for natural gas in the region at 55 trillion cubic feet. With most Canadian oil- and gas-producing regions less mature than those in the United States, the potential for additional low-cost production is strong, and imports from Canada remain competitive with U.S. domestic supplies in the forecast.

Mexico also has considerable natural gas resources that could be developed, and there is unused pipeline capacity from Mexico into the United States, although Mexico is expected to remain a net importer of U.S. natural gas. LNG imports, which have been constrained by their costs in the past, are becoming more economical and are projected to increase from 0.1 trillion cubic feet to 0.4 trillion cubic feet a year between 1998 and 2020. LNG offloading capacity has been expanded at the port facility in Everett, Massachusetts [*30*], and Southern LNG has applied to the Federal Energy Regulatory Commission to reactivate its mothballed facility on Elba Island, Georgia, to provide open-access service [*31*]. Thus, increased imports of LNG and natural gas imports from both Canada and Mexico could contribute to needed supply, over and above sufficient domestic production.

Overall, the natural gas industry is thought to be in a position to meet the supply requirements for a market of 30 trillion cubic feet, with adequate supplies available from numerous sources at the prices projected in the *AEO2000* reference case. As long as the industry remains confident that the demand will be there, the economic incentive of higher prices will assure that the necessary investments in infrastructure, rigs, drilling, and manpower will be made.

Petroleum: Gasoline and Diesel Fuel

Fuel Quality Changes

During the 1990s gasoline and diesel fuel were "reformulated" many times to meet requirements included in the Clean Air Act Amendments of 1990 (CAAA90) and other, State-initiated requirements (Table 5). Although the changes went unnoticed by most motorists, they required many adjustments at refineries and in fuel distribution systems. Refineries changed existing processes and invested in new ones, and storage and distribution systems were modified to handle additional products.

Table 5. Major fuel quality changes, past and future

Current	
1975	*Gasoline lead phaseout begins*
1989-1990	*Phase I summer gasoline volatility*
1992	*Oxygenated gasoline, wintertime*
	Phase II summer gasoline volatility
	California gasoline Phase I
1993	*Diesel sulfur reduction (500 ppm sulfur)*
	California diesel (500 ppm sulfur)
1995	*Phase I reformulated gasoline: simple model*
1996	*California cleaner gasoline Phase II*
1998	*Phase I reformulated gasoline: complex model*
2000	*Phase II reformulated gasoline*
2002	*California ban on MTBE*
Proposed	
2000-2003	*Removal of oxygen requirement on reformulated gasoline*
	Reduction of MTBE blended in gasoline
2002	*California cleaner gasoline Phase III, proposed*
2004-2007	*Reduced-sulfur gasoline, proposed 30 ppm*
Post-2007	*Ultra-low-sulfur diesel*

Note: Proposed regulations are not reflected in the AEO2000 reference case.

"Phase II" reformulated gasoline, which will be required in 2000, is the last fuel quality change specified by the CAAA90, but further changes are on the horizon. Two widely publicized fuel quality issues—sulfur removal and the reduction of the widely used gasoline additive methyl tertiary butyl ether (MTBE)—point to new challenges for the refining industry. The U.S. Environmental Protection Agency (EPA) is in the process of finalizing regulations that would severely restrict the sulfur content of gasoline and is proposing similar restrictions for diesel fuel. The State of California is already phasing MTBE out of gasoline, and there have been numerous proposals to restrict its use at the national level. Because it is current law, the California ban on MTBE is reflected in *AEO2000*. The proposed national MTBE and sulfur restrictions are not. To examine the potential impacts of the latter changes, two alternative cases, reflecting restrictions on fuel sulfur content and on MTBE blending, were prepared for this analysis.

Gasoline and Diesel Fuel Sulfur Reduction

In late 1999, the EPA is expected to finalize a rulemaking that would tighten restrictions on the amount of sulfur allowed in gasoline. Because gasoline sulfur and automotive emissions are linked, the rule 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 13). 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 nitrogen oxides (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. In a Notice of Proposed Rulemaking (NPRM) published in May 1999, the EPA proposed lowering the average annual sulfur content of gasoline to 30 parts per million (ppm), which is about one-tenth the current national average.

Because the proposed Tier 2 emissions standards will apply to all vehicles, regardless of what type of fuel is used, the EPA is also planning to reduce the sulfur content of diesel fuel. Reduced-sulfur diesel fuel would enable diesel engine technologies, which are very sensitive to sulfur, to meet the new Tier 2 standards for NO_x and particulate matter (PM) emissions. Sulfur in all on-road diesel is currently restricted to 500 ppm, but engine manufacturers have indicated that new technologies will require sulfur contents of no more than 30 ppm [*32*]. The new standards may apply initially to diesel used for light-duty vehicles, which is only a small part of the market, and be extended to heavy-duty vehicle fuels at a later time.

Refinery Issues. Gasoline desulfurization is most often done in conjunction with a fluid catalytic cracking (FCC) unit that breaks down heavier crude oil components, which are often high in sulfur, into lighter gasoline streams. Sulfur reduction can be accomplished either by "hydrotreating" the feed going into the FCC unit or by desulfurizing the gasoline produced from the unit. Hydrotreating is a process that removes objectionable elements from the products or feedstocks by reacting them with hydrogen. Hydrotreating the inputs to the FCC unit improves the quality of the gasoline produced and reduces SO_x emissions from the FCC unit. It also improves the refineries' material balance and produces environmentally better diesel fuel [*33*]. However, this type of desulfurization is very capital intensive and requires treatment of a larger volume of feedstock and additional hydrogen-making capacity. Desulfurizing the gasoline output from the FCC unit is less capital intensive, allows smaller volumes to be treated, and consumes less hydrogen.

Recently developed technologies, such as CDTECH's CD HYDRO/HDS and Mobil's OCTGAIN processes, are variations on conventional hydrotreating applied to FCC gasoline that require less hydrogen. These technologies are not commercially proven, but they are expected to result in lower desulfurization costs than conventional hydrotreaters because they have lower operating and capital costs and produce gasoline with a higher octane than conventional hydrotreating. EPA originally pegged the cost of meeting a 40-ppm sulfur limit at 5.4 cents a gallon but now estimates that desulfurizing with newer technologies will cost only about 1.7 cents a gallon [*34*]. The American Petroleum Institute (API) has also cut its desulfurization cost estimate in half, from 5 cents a gallon to 2.5 cents a gallon, in view of the new technologies.

Because the new desulfurization technologies are not commercially proven, there is some concern that estimates of their operating costs and octane losses might be overly optimistic. Using less optimistic operating cost estimates for the new technologies, the API estimated that desulfurization costs could be as high as 3.3 cents a gallon [*35*]. A study done for DOE estimated the cost of the new technologies at an average of 2.9 cents a gallon [*36*]. The above cost estimates are single-year estimates in 1998 dollars and reflect full implementation of the sulfur regulations in 2004. The gasoline sulfur reduction sensitivity case provides cost estimates for years leading up to and after the change in regulations, with full implementation in 2007.

Regardless of the technology used, achieving the 30-ppm sulfur limit will be more difficult if recent proposals to waive the Federal oxygen requirement for reformulated gasoline are enacted (see discussion of MTBE below). Sulfur-free additives, such as MTBE, used to boost the oxygen content of reformulated gasoline, serve to dilute the sulfur content of the other gasoline components.

Gasoline Sulfur Reduction Sensitivity Case. The regulation for Tier 2 emissions standards and related sulfur reductions for gasoline has not been finalized and is therefore not included in the *AEO2000* reference case. The gasoline sulfur reduction case assumes a gasoline sulfur limit of 30 ppm, which is fully implemented by 2007. Reformulated gasoline is assumed to meet the 30-ppm limit by 2004. Conventional gasoline is initially allowed to meet a less stringent specification of 80 ppm but meets the 30-ppm limit by 2007. The more gradual sulfur reduction for conventional gasoline reflects a time extension for small and challenged refiners that is expected to be included in the final rule.

In order to reduce gasoline sulfur to the 30-ppm level, refiners will need to invest in conventional hydrotreating processes or in newly developed desulfurization processes that are potentially less costly but commercially unproven. Last year, the *Annual Energy Outlook 1999* (*AEO99*), included a national low-sulfur gasoline scenario that did not include new desulfurization technologies. In the *AEO99* automakers' national low-sulfur gasoline case, the cost of desulfurization using conventional processes was initially set at 8.3 cents a gallon in 2004, falling to 6.8 cents a gallon in 2010. Unlike the low-sulfur case in *AEO99*, this year's gasoline sulfur reduction case incorporates new desulfurization technologies.

The *AEO2000* sulfur reduction sensitivity case results in a national average gasoline price that is 2.3 cents a gallon higher that the reference case price in 2004, increasing to 3.9 cents a gallon higher when all gasoline is in compliance. The difference declines slightly, to 3.5 cents a gallon, by 2010. The alternative case results in additional capacity using hydroprocessing and new desulfurization technologies. Unlike cost estimates by EPA, API, and DOE mentioned above, which estimate the average cost of desulfurization, these estimates represent the desulfurization cost of the marginal barrel. In 2007, when all gasoline is assumed to meet the 30-ppm sulfur limit, cumulative refinery investment is $5.65 billion higher than in the reference case. Refineries invest even after 2007, in order to meet the sulfur limit in a growing gasoline market. By 2010 cumulative investment is $7.74 billion higher than in the reference case.

Restricted Use of the Gasoline Additive MTBE

MTBE became a widely used gasoline additive in the 1990s as a result of CAAA90 requirements to provide cleaner burning gasoline in some areas of the country. The use of MTBE to meet a requirement for 2.0 percent oxygen (by weight) in cleaner burning reformulated gasoline (RFG) has recently been called into question, because traces of MTBE have been found in 5 to 10 percent of the drinking water supplies in areas using RFG [*37*].

MTBE moves more quickly into water than do other gasoline components and has made its way from leaking pipes and underground storage tanks to water sources. MTBE has not been classified as a carcinogen, but it has been shown to cause cancer in animals. For the most part, MTBE found in water supplies has been well below levels of health concern, but it has become a big water quality issue because only trace amounts cause water to smell and taste bad. In 1999, water quality concerns resulted in the announcement by the Governor of California of a State-wide phaseout of MTBE, as well as numerous legislative proposals at both the State and Federal levels aimed at reducing or eliminating the use of MTBE in gasoline.

In response to rising concerns about the detection of MTBE in water supplies, the EPA convened a "Blue Ribbon Panel" (BRP) of experts early in 1999 to assess the extent of the problem and make recommendations. In a report submitted to the EPA in July [*38*], the BRP recommended a four-part plan that would protect water quality while maintaining the air quality benefits of RFG:

- A set of actions should be implemented to protect water supplies by enhancing programs for underground storage tanks, safe drinking water, and private well protection.
- The use of MTBE should be "substantially" reduced, and Congress should clarify the Federal and State authority to regulate the use of MTBE and other gasoline additives.
- To assure a cost-effective phasedown of MTBE, Congress should remove the current CAAA90 requirement that RFG contain 2 percent oxygen by weight.
- The EPA should identify a mechanism to ensure that current air quality benefits from RFG are not reduced.

The recommendations of the BRP are not binding, and it is unclear whether they will be implemented by Congress.

The *AEO2000* reference case reflects the California ban on MTBE but does not assume any changes in Federal legislation. The possible implications of a national reduction in MTBE blending were examined in a sensitivity case that reflects the recommendations of the BRP.

Refinery Issues. MTBE is an important blending component for RFG, used primarily as an oxygenate, a volume extender, and an octane enhancer. The EPA mandates a minimum oxygen content of 2.0 percent (by weight) in Federal RFG, primarily to reduce toxic exhaust emissions. To meet this requirement, MTBE is blended into RFG at approximately 11 percent by volume, with the added benefit of some important dilution effects. When MTBE is added to a gasoline blendstock, it replaces undesirable compounds such as benzene, aromatics, and sulfur. MTBE is also an effective octane enhancer. Its high octane helps offset the octane losses resulting from Federal restrictions on aromatics, benzene, and other gasoline components. If the use of MTBE in gasoline is reduced or banned, refiners will have to find other measures to maintain the octane level of gasoline while meeting the requirements for RFG. If the oxygen requirement is waived as suggested by the BRP, replacement of oxygen will not be a concern, but refiners will still need to make up for the MTBE volume and octane loss.

Legislation that would ban MTBE at either the national or State level without waiving the CAAA90 requirement for oxygen in RFG [*39*] would force the refining industry to find an alternative source of oxygen. Other EPA-approved oxygenates, including ethyl tertiary butyl ether (ETBE) and tertiary amyl methyl ether (TAME), would be suitable replacements; however, those ethers are similar to MTBE in some respects and could raise some of the same groundwater contamination concerns. Ethanol, which is currently used chiefly as an octane enhancer and volume extender in traditional gasoline, would be the leading candidate to replace MTBE. Ethanol is thought to be less toxic than ethers, has a high octane value, and enjoys a fair amount of political support at both the State and Federal levels.

The use of ethanol has some drawbacks, however, which must be considered. Compared with MTBE, ethanol contains more oxygen and is more volatile, resulting in higher emissions of smog-forming volatile organic compounds (VOCs). Because ethanol has a higher oxygen content than MTBE, only about half the volume is required to produce the same gasoline oxygen level. A gasoline volume loss results, because the other half of the displaced MTBE volume must come from other petroleum-based gasoline components. In addition, the relatively high volatility of ethanol limits its use in gasoline, because gasoline volatility, as measured by Reid vapor pressure (Rvp), is restricted depending on season and location. Ethanol's volatility also limits the use of other gasoline components, such as pentane, which are highly volatile and must be removed from gasoline to counterbalance the addition of ethanol. Finally, the "dilution effect" of ethanol is not as significant as that of MTBE, because the use of smaller volumes of ethanol is not as effective in diluting the undesirable qualities of the crude-base blending components [*40*].

The use of ethanol as a replacement for MTBE also poses some logistical problems. Gasoline blended with ethanol, unlike MTBE and other ethers, cannot be shipped in multi-fuel pipelines, because the moisture that is always present in pipelines and storage tanks causes the ethanol to separate from the gasoline. The petroleum-based gasoline components would have to be shipped separately and then blended with ethanol at a terminal as the product is loaded into trucks. Changes in the current infrastructure would have to be made to accommodate this type of terminal blending.

Ethanol supply is another issue, as current ethanol production capacity is not adequate to replace MTBE nationwide. The increase in demand should, however, cause ethanol prices to rise enough to make new ethanol facilities economically viable. Sufficient capacity could be in place depending on the timing of the MTBE ban. At present, ethanol supplies come primarily from the Midwest, where most of it is produced from corn feedstocks. Shipments to the West Coast and elsewhere via rail have been estimated to cost an additional 14.6 to 18.7 cents a gallon for transportation [*41*]. Ethanol use in the RFG program would displace its current usage in the Midwest as an extender and octane enhancer for traditional gasoline.

The BRP recommended that Congress eliminate the minimum oxygen requirement for RFG in order to dampen the effect of restrictions on MTBE use. If the oxygen requirement were removed, refiners would not have to replace the oxygen content provided by the MTBE. In addition, refiners would have more flexibility to meet RFG emissions reductions by blending alternatives such as alkylates, depending on an individual refinery's configuration and market conditions. The BRP suggested that the toxic standard on RFG be effectively tightened to maintain the current emissions level without an oxygenate requirement.

Producing RFG without ethanol or MTBE would require additional petroleum-based gasoline to make up for lost volume. In 1998, about 245,000 barrels of MTBE a day was blended into gasoline at U.S. refineries. If MTBE use were reduced from the current level of about 9 percent of RFG and oxygenated gasoline to 3 percent, about 165,000 barrels a day of relatively clean high-octane material might have to be replaced. The additional volumes are likely to consist of a combination of domestic production and imports.

The additional petroleum-based volumes would have to have more stringent specifications because of the loss of the dilution effect of oxygenates. As a result, alkylate would likely become a key blending component. Alkylate is an ideal blending component for RFG because it lacks benzene, other aromatics, olefins, and sulfur and has good octane and Rvp characteristics. The availability of large volumes of alkylate would require adjustments to refinery operations and capital expenditures to expand alkylation capacity. Petrochemical plants that are currently producing MTBE for sale to refineries could also convert their plants to produce alkylate.

Sulfur removal is another likely response to MTBE reduction, because the MTBE (and ethanol to a lesser extent) serve to dilute the sulfur content of the other gasoline components. Without MTBE the gasoline pool would have a higher sulfur content and might not meet NO_x emissions targets. Methods for desulfurizing gasoline are discussed above. If the currently proposed Tier 2 gasoline sulfur regulations are finalized, refiners will be forced to invest in sulfur removal to meet those standards.

BRP/MTBE Reduction Sensitivity Case. Based on the BRP recommendations, an alternative case was developed in which the oxygen requirement in gasoline was dropped and a cap was placed on the amount of MTBE in gasoline. In addition, the use of all ethers in gasoline was limited in the sensitivity case. The BRP noted that other ethers, such as ETBE and TAME, have similar but not identical characteristics and recommended "accelerated study of the health effects and groundwater characteristics of these compounds before they are allowed to be placed in widespread use." Because of such scrutiny, refiners and blenders are unlikely to increase the use of other ethers significantly.

Although the BRP did not specify a target level of MTBE, but only stated that its use should be reduced substantially, the level of MTBE and other ethers in gasoline was assumed in the sensitivity case to be limited to 3 percent by volume, which is consistent with MTBE in gasoline before the start of the RFG program. The elimination of the oxygen specification in RFG requires that other specifications be adjusted to maintain air quality. In order to maintain current air toxics emissions levels, as recommended by the BRP, the MTBE reduction case assumed tighter limits on benzene and sulfur in RFG than the reference case.

The projections for gasoline consumption and crude oil prices in the MTBE reduction sensitivity case are the same as in the reference case. The only changes relative to the reference case are gasoline specifications and the cap on ether use. The alternative case results in projected average gasoline prices that are between 1.3 and 1.4 cents a gallon higher than in the reference case between 2003 and 2005. RFG prices increase slightly more, starting at 2.8 cents a gallon in 2003 and dropping to 1.8 cents a gallon by 2005. The alternative case results in an additional 20,000 to 27,000 barrels a day of ethanol blending between 2003 and 2005 to offset some of the lost volume and octane associated with MTBE reduction. The alternative case also results in additional imports of gasoline and blending components, varying from 123,000 to 141,000 barrels a day between 2003 and 2005.

The pattern of refinery investment is different in the alternative case, with greater investment before 2003 and less thereafter. In 2003, cumulative investment is $2.43 billion more than in the reference case. The difference in cumulative investment narrows to $1.71 billion by 2005.

Energy Use: Appliance Efficiency Standards

Current Status

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

From 1988 to 1995, DOE established and revised efficiency standards almost on an annual basis, as shown in Table 6. In 1995, however, Congress issued a standards moratorium for fiscal year 1996, which prohibited DOE from establishing any new standards. The moratorium caused a delay of several years, with no standards becoming effective from 1996 through July 2000. After a reevaluation of the standards program, DOE established a new process that allows for greater input from stakeholders by creating the Advisory Committee on Appliance Energy Efficiency Standards, which comprises technical experts representing the concerns of industry, environmentalists, and the general public.

With input from stakeholders early in the promulgation process, it was believed that the rulemaking process would become more predictable, more timely, and less controversial. The refrigerator standard issued for July 2001, for example, was promulgated through a series of compromises in December 1996, allowing a later enforcement date but at a higher efficiency level. Achieving similar consensus among

Table 6. Effective dates of appliance efficiency standards, 1988-2001

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

disparate concerns such as the gas and electric industries and environmentalists may prove difficult, however, when multi-fuel products, such as water heaters, are considered for review. The debate over end-use efficiency versus total system efficiency is a lively one, with electric and gas concerns generally disagreeing as to how efficiency and environmental benefits should be measured. In fact, the inability to create a single national home energy rating system (HERS) has shown that achieving consensus among these groups is difficult, signaling a continued debate as to how efficiency should be evaluated across fuel types.

Currently, DOE is in the process of evaluating new efficiency standards for several products. The schedule calls for final rules to be established for water heaters in June 2000, clothes washers in December 2000, and central air conditioners and heat pumps in April 2001. After the final rules are published in the *Federal Register*, a lead time of 3 to 5 years is required for the standards to take effect. Because the *AEO2000* reference case includes only standards that have been finalized, with the effective dates and efficiency levels specified in the *Federal Register*, no new efficiency standards are included in the projections.

An agreement between manufacturers and energy efficiency advocates was reached in October 1999 on fluorescent lighting standards for commercial and industrial applications. Still subject to a final rulemaking by DOE, the new efficiency standards for electronic ballasts are not included in the reference case. Less efficient magnetic ballasts are projected to make up 6 percent of new and replacement fluorescent lighting sales in the commercial sector in the reference case at the time the standards are expected to go into effect on April 1, 2005. The next products DOE intends to evaluate for standards include distribution transformers, commercial furnaces and boilers, commercial heat pumps and air conditioners, and commercial water heaters.

Appliance Standards Sensitivity Cases

To examine the potential impacts of future appliance efficiency standards on energy consumption in the residential and commercial sectors, two cases were analyzed in which it was assumed that DOE would effectively promulgate standards for most appliances on a regular basis. For these cases, near-term efficiency levels and effective dates were based on a report by the American Council for an Energy-Efficient Economy (ACEEE), *Approaching the Kyoto Targets: Five Key Strategies for the United States*

[*42*]. Because the schedule for implementation of some of the standards in the near term has changed since the ACEEE report was published, the effective dates assumed for some products differ from those in the report. In addition, it was assumed that DOE would revise the standards every 8 years, increasing the efficiency level by 10 percent and 20 percent in the two cases, if technologically feasible. It was further assumed that major shifts in technology—including heat-pump water heaters and horizontal-axis washing machines—would not be subject to the standards. Table 7 shows the products and dates for the standards assumed in the two sensitivity cases.

Figure 23 shows the cumulative primary energy saved from the standards listed in Table 7 through 2020, the end of the forecast horizon. Because the sensitivity cases do not include changes in the fuel mix for electricity generation, the conversion from delivered electricity to primary energy is the same as that in the reference case. Overall, more than 11 quadrillion Btu of energy is saved cumulatively through 2020 in the 10-percent standards case, nearly one-half of the projected energy consumption in the residential sector in 2020. In the 20-percent standards case, more than 12 quadrillion Btu of energy is saved cumulatively through 2020. However, because the near-term standards account for the majority of the savings and many technologies reach their technological limits before achieving the 20-percent efficiency increase, the incremental savings seen when the 20-percent standards case is compared with the 10-percent case are less than those seen when the 10-percent case is compared with the reference case.

Electricity-related energy savings, including reductions in conversion losses, account for nearly 78 percent of the cumulative savings by 2020 in the 20-percent standards case. The decrease in the amount of electricity generated throughout the forecast reduces carbon emissions by more than 17 million metric tons in 2020 (3.5 percent) and by nearly 163 million metric tons cumulatively through 2020. The residential sector accounts for 60 percent of the cumulative energy savings, with the majority of the savings attributable to the standards for water heaters and air conditioners. For the commercial sector, fluorescent lighting standards contribute the most to the reduction in energy use in both cases.

Figure 23. Cumulative energy savings from appliance standards by fuel in two cases, 2003-2020 (quadrillion Btu)

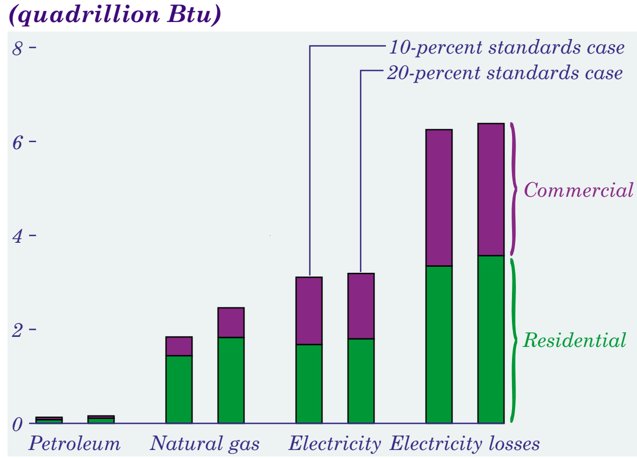


Table 7. Projected effective dates of appliance efficiency standards, 2003-2020

Product	*2003*	*2005*	*2006*	*2008*	*2009*	*2011*	*2013*	*2016*	*2017*	*2019*
Clothes dryers					X					
Clothes washers			X							
Dishwashers					X				X	
Refrigerators and freezers					X					
Kitchen ranges and ovens					X					
Room air conditioners					X				X	
Fluorescent lamp ballasts	X									
Water heaters	X					X				X
Central air conditioners and heat pumps		X					X			
Fluorescent lamps						X				
Commercial furnaces and boilers				X				X		
Commercial air conditioners and heat pumps				X				X		
Commercial water heaters				X				X		

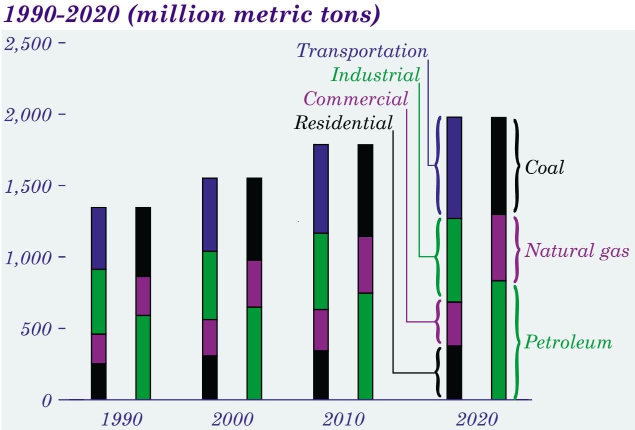
Carbon Emissions in *AEO2000*

Reference Case

In the *AEO2000* reference case, carbon emissions from energy consumption are expected to reach 1,552 million metric tons in 2000, 15 percent above the 1990 level of 1,345 million metric tons. The projected emissions continue to rise to 1,787 million metric tons in 2010 and 1,979 million metric tons in 2020, 33 percent and 47 percent above the 1990 levels, respectively (Figure 24). Total emissions increase at an average annual rate of 1.3 percent between 1998 and 2020, and per capita emissions also increase at an average rate of 0.5 percent a year.

Carbon emissions rise throughout the projection period, because continued economic growth and moderate increases in energy prices are expected to lead to increasing energy consumption. The 1.3-percent growth rate for emissions is faster than for total energy consumption, which increases at an average annual rate of 1.1 percent, for two primary reasons. First, approximately 41 percent of nuclear generating capacity (which is carbon free) is retired by 2020, and no new nuclear plants are constructed. Second, continued moderate prices for both natural gas and coal lead to slow growth in renewable energy use.

Figure 24. U.S. carbon emissions by sector and fuel, 1990-2020 (million metric tons)



In 2020, electricity generation accounts for 38 percent of all carbon emissions, up from 37 percent in 1998. 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 7 percent is fueled with coal and 90 percent with natural gas.

The growth of energy consumption and carbon emissions in the transportation sector is faster than in the other end-use sectors because of increased travel and the slow improvement in fuel efficiency in the reference case. Between 1998 and 2020, transportation energy demand and carbon emissions both grow at an average annual rate of 1.7 percent, and in 2020 the transportation sector accounts for 36 percent of all carbon emissions. The average efficiency of the light-duty vehicle fleet—cars, light trucks, vans, and sport utility vehicles—remains essentially unchanged between 1998 and 2020. Over the same period, vehicle-miles traveled by light-duty vehicles increase by 1.7 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 4.0 percent and 1.5 percent a year, also contributes to the increase in emissions from the transportation sector.

Emissions from the residential and commercial sectors grow by 1.3 percent and 1.2 percent a year, respectively, 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, small growth in coal use for boiler fuel, 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 833 million metric tons of the total of 1,979 million metric tons in 2020, are from petroleum products, and about 82 percent of the petroleum emissions are from transportation uses.

Coal is the second leading source of carbon emissions at about 34 percent, or 680 million metric tons, in 2020. Coal has the highest carbon content of all the fossil fuels and remains the predominant fuel source for electricity generation. By 2020, the share of coal-fired generation, excluding cogeneration, declines slightly from its 1998 level of 55 percent but still accounts for 52 percent of all generation. About 90 percent of carbon emissions from coal 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 1.8 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 464 million metric tons in 2020, about 23 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 *AEO2000*, 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 1998 to 2020, compared with a growth rate of 2.2 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 120.9 quadrillion Btu in the reference case. As a result of the higher consumption, carbon emissions are 2,126 million metric tons, or 7 percent, higher than the reference case level of 1,979 million metric tons in 2020.

In the low economic growth case, assumptions of lower growth in population, the labor force, and labor productivity result in an average annual growth rate of 1.7 percent through 2020. With lower economic growth, energy consumption in 2020 is reduced from 120.9 quadrillion Btu to 113.3 quadrillion Btu, and carbon emissions are 1,851 million metric tons, or 6 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 high 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 1998 through 2020, compared with 1.1 percent in the reference case and 0.8 percent in the low economic growth case.

Technology Improvement

The *AEO2000* 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 1.1 percent between 1998 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 2.2 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 1998, energy intensity declined at an average annual rate of 1.0 percent.

Regulatory programs have contributed to some of the past improvements in energy efficiency, including the Corporate Average Fuel Economy standards for light-duty vehicles and standards for motors and energy-using equipment in buildings in the Energy Policy Act of 1992 and the National Appliance Energy Conservation Act of 1987. In keeping with the general practice of incorporating only current policy and regulations, the reference case for *AEO2000* 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. *AEO2000* 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 and new renewable generating technologies were assumed to improve from reference case values [*43*].

The low technology case assumes that all future equipment choices are from the equipment and vehicles available in 2000, with new building shell and industrial plant efficiencies frozen at 2000 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 for all four end-use demand sectors and the electricity generation sector combined, aggregate energy intensity declines at an average of 1.4 percent a year from 1998 to 2020, compared with 1.1 percent a year in the reference case (Figure 25). In the 2000 technology case, the average decline is only 0.9 percent a year through 2020. Total energy consumption increases to 112.6 quadrillion Btu in 2020 in the high technology case, compared with 120.9 quadrillion Btu in the reference case (Figure 26), but increases to 126.3 quadrillion Btu in the 2000 technology case.

The lower energy consumption in the high technology case lowers carbon emissions from 1,979 million metric tons in the reference case in 2020 to 1,820 million metric tons (Figure 27). In the 2000 technology case, emissions increase to 2,080 million metric tons

Figure 25. U.S. energy intensity in three cases, 1998-2020 (thousand Btu per dollar GDP)

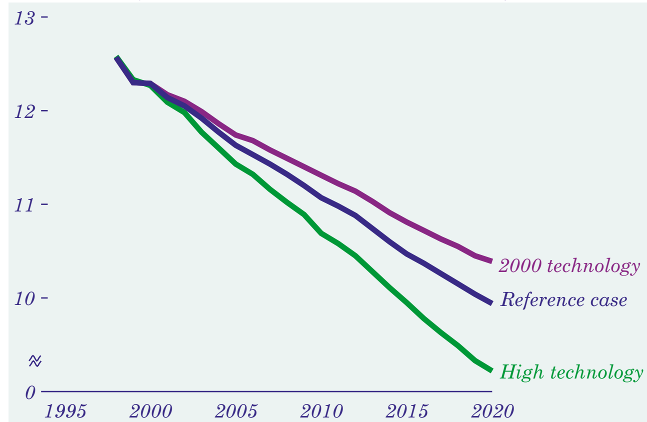


Figure 26. U.S. energy consumption in three cases, 1998-2020 (quadrillion Btu)

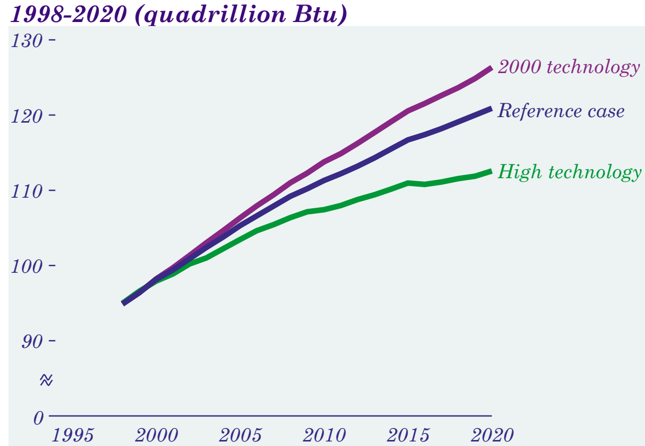
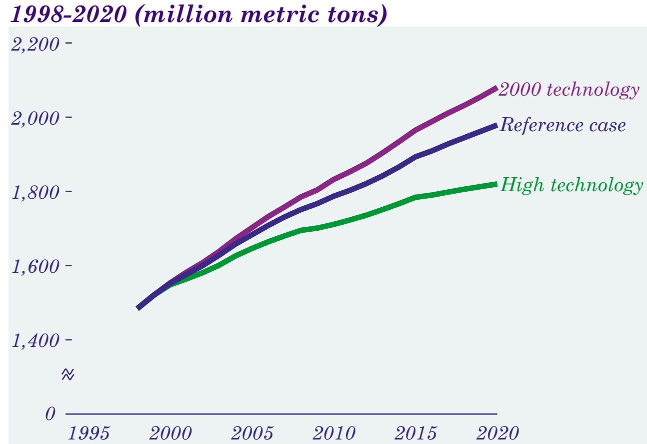


Figure 27. U.S. carbon emissions in three cases, 1998-2020 (million metric tons)



in 2020. About 38 percent, or 60 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 72 million metric tons of the reduction, or 45 percent, results from shifts to more efficient or alternative-fuel 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.

The Kyoto Protocol

From December 1 through 11, 1997, representatives from more than 160 countries met in Kyoto, Japan, at the third session of the Conference of the Parties to the 1992 Framework Convention on Climate Change. Although the Framework Convention called for the developed countries to undertake actions to reduce greenhouse gas emissions to 1990 levels by 2000, the goal of the Conference was the negotiation of binding limits for greenhouse gas emissions for the developed nations. In the resulting Kyoto Protocol to the Framework Convention, targets for greenhouse gas emissions were established for the developed nations—the Annex I countries [*44*]—relative to their emissions levels in 1990. The targets are to be achieved, on average, from 2008 through 2012, the first commitment period in the Protocol.

The overall emissions reduction target for the Annex I countries is 5.2 percent below 1990 levels. Relative to 1990, the individual targets range from an 8-percent reduction for the European Union (EU) to a 10-percent increase for Iceland. Australia and Norway are also allowed increases of 8 percent and 1 percent above 1990 levels, 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 between 5 percent and 8 percent below 1990 levels. The reduction target for Canada and Japan is 6 percent and for the United States 7 percent below 1990 levels. Non-Annex I countries have no targets under the Protocol, although the Protocol reaffirms the commitments of the Framework Convention by all parties to formulate and implement climate change mitigation and adaptation programs.

The Protocol was opened for signature on March 16, 1998, for a 1-year period. It will enter into force 90 days after 55 Parties, including Annex I countries accounting for at least 55 percent of the 1990 carbon dioxide emissions from Annex I nations, have deposited their instruments of ratification, acceptance, approval, or accession. By March 15, 1999, 84 countries had signed the Protocol, including all but two of the Annex I countries, Hungary and Iceland. The Annex I signatories accounted for more than 99 percent of Annex I carbon emissions in 1990, not including the emissions from Belarus and Turkey. As of October 12, 1999, 16 countries had ratified or acceded to the Protocol—Antigua and Barbuda, Bahamas, Cyprus, El Salvador, Fiji, Georgia, Guatemala, Jamaica, the Maldives, Micronesia, Niue, Panama, Paraguay, Trinidad and Tobago, Tuvalu, and Uzbekistan.

Although the Protocol does not prescribe specific steps to be taken, a number of potential actions are enumerated. They include energy efficiency improvements, enhancement of carbon-absorbing sinks, 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. Sources of emissions include energy combustion, fugitive emissions from fuels, industrial processes, solvents, agriculture, and waste management and disposal.

Energy use is naturally a focus of greenhouse gas reductions. In 1990, total greenhouse gas emissions in the United States were 1,641 million metric tons carbon equivalent, of which carbon emissions from the combustion of energy comprised 1,345 million metric tons, or 82 percent. By 1998, total greenhouse gas emissions had risen to 1,803 million metric tons carbon equivalent, with 1,485 million metric tons (82 percent) from energy combustion [*45*]. Because energy-related carbon emissions constitute such a large percentage of total greenhouse gas emissions, any action or policy to reduce emissions will affect U.S. energy markets.

The Kyoto Protocol includes a number of flexibility measures for compliance—often referred to as *what*, *where*, and *when* flexibility. *What* flexibility refers to the source of the emissions. Although carbon dioxide is the major greenhouse gas in terms of the level of emissions, the Protocol includes methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride [*46*], in addition to carbon dioxide. The aggregate target is established using the carbon dioxide equivalent of each of the greenhouse gases, based on the global warming potential of each gas. Carbon-absorbing sinks—forests, other vegetation, and soils—are also included in *what* flexibility. Net changes in emissions by direct anthropogenic land-use changes and forestry activities will be used in meeting the commitment, limited to afforestation, reforestation, and deforestation since 1990. Specific guidelines and rules for the accounting of land-use and forestry activities must be resolved by the Conference of the Parties.

Where flexibility includes a variety of international activities, which would allow a country to meet its emissions target by taking action with or within other countries. Emissions trading among the Annex I countries is permitted. Groups of Annex I countries, such as the EU, may also jointly meet the total commitment of all the member nations either by allocating a share of the total reduction to each member or by trading emissions rights. Joint implementation projects are also allowed among the Annex I countries, allowing a nation to take emissions credits for projects that reduce emissions or enhance emissions-absorbing sinks in other Annex I countries. It is specifically indicated in the Protocol that trading and joint implementation are supplemental to domestic actions.

The Protocol also establishes a Clean Development Mechanism (CDM), a program under which Annex I countries can earn credits for projects that reduce emissions in non-Annex I countries. Such projects must lead to measurable, long-term benefits. Reductions from projects occurring from 2000 up to the beginning of the first commitment period can be used to assist in compliance in the commitment period. An executive board will be established to supervise the CDM, and an unspecified share of the proceeds from certified project activities will be used to cover administrative expenses and to assist developing country Parties that are particularly vulnerable to adverse effects of climate change to meet the costs of adaptation.

Under *when* flexibility, the targets can be achieved on average over the first commitment period of 2008 to 2012 rather than in each individual year. Averaging emissions over the 5-year period smooths out short-term fluctuations that might result from economic cycles or weather conditions. No targets are established for periods after 2012, although the Conference of the Parties will initiate consideration of future commitments at least 7 years before the end of the first commitment period. Banking—carrying over emissions reductions that go beyond the target from one commitment period to some subsequent commitment period—is allowed. The Protocol indicates that each Annex I country must have made demonstrable progress in achieving its commitments by 2005.

At the fourth session of the Conference of the Parties in Buenos Aires, in November 1998, a plan of action was adopted to finalize a number of the implementation issues at the sixth Conference of the Parties, which is likely to be held late in 2000 or early in 2001. Also at issue is the possibility of limiting the amount of credits received through international actions that may be used to meet a country's target.

EIA's Analysis of the Kyoto Protocol

In 1998, at the request of the U.S. House of Representatives Committee on Science, EIA analyzed the likely impacts of the Kyoto Protocol on U.S. energy prices, energy use, and the economy in the 2008 to 2012 period, using the same methodologies and assumptions that were used for the *Annual Energy Outlook 1998* (*AEO98*) [*47*], the latest *AEO* at the time. The analysis was published in *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* [*48*], with an accompanying briefing report, *What Does the Kyoto Protocol Mean to U.S. Energy Markets and the U.S. Economy?* [*49*].

In 1999, the Committee on Science requested that EIA analyze the impacts of an earlier phased-in start date for U.S. carbon emissions reductions based on the original analysis of the Kyoto Protocol, with only those changes in assumptions caused by the early start date. Earlier carbon reductions could lead to the purchase of more efficient or less carbon-intensive equipment at an earlier date, making it easier and less expensive to meet greenhouse gas emissions targets. The resulting analysis, *Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol* [*50*], was published in July 1999.

Because of the uncertainties surrounding the final implementation of the Kyoto Protocol, EIA's analysis of the Protocol included a range of six cases with different levels of reductions for domestic energy-related carbon emissions. EIA assumed that the United States would reach its goal of a 7-percent reduction in net greenhouse gas emissions in each of the carbon reduction cases, but each case implicitly assumed different levels of forestry and agricultural sinks, reductions from other greenhouse gases, international trading, and other international activities, which may offset the domestic reductions required from carbon. Each of the cases with higher carbon targets (smaller reductions) assumed more contribution from sinks, other gases, and international activities to offset carbon reductions.

- **Reference Case.** Carbon emissions from energy increase to 33 percent above 1990 levels in 2010, reaching 1,791 million metric tons compared to 1,345 million metric tons in 1990. Between 2008 and 2012, carbon emissions from energy average 1,792 million metric tons.
- **24 Percent Above 1990 Levels (1990+24%).** Carbon emissions from energy increase to an annual average of 1,670 million metric tons between 2008 and 2012, 24 percent above the 1990 levels, reducing carbon emissions from energy by an average of 122 million metric tons below the reference case during that period. International activities and net offsets from carbon-absorbing sinks and other gases account for the remaining reductions of 420 million metric tons, nearly 80 percent of the total net greenhouse gas reduction.
- **14 Percent Above 1990 Levels (1990+14%).** Carbon emissions from energy average 1,539 million metric tons annually between 2008 and 2012, which is approximately the level estimated for 1998 in *AEO98*, and is 14 percent above 1990 levels. This requires the average annual carbon emissions from energy to be reduced by 253 million metric tons between 2008 and 2012. International activities and net offsets from carbon-absorbing sinks and other gases account for the remaining reductions of 289 million metric tons.
- **9 Percent Above 1990 Levels (1990+9%).** Carbon emissions from energy increase to an annual average of 1,467 million metric tons between 2008 and 2012, 9 percent above 1990 levels, an average reduction in energy-related carbon emissions of 325 million metric tons from the reference case projection. International activities and net offsets from carbon-absorbing sinks and other gases account for the remaining reductions of 217 million metric tons.
- **Stabilization at 1990 Levels (1990).** Carbon emissions from energy are stabilized at the 1990 level, averaging 1,345 million metric tons during the commitment period of 2008 through 2012, a reduction of 447 million metric tons in energy-related carbon emissions from the reference case. International activities and net offsets from carbon-absorbing sinks and other gases account for the remaining reductions of 95 million metric tons.
- **3 Percent Below 1990 Levels (1990-3%).** Carbon emissions from energy are reduced to an annual average of 1,307 million metric tons between 2008 and 2012, a reduction of 485 million metric tons in energy-related carbon emissions from the reference case. International activities and net offsets from carbon-absorbing sinks and other gases account for the remaining reductions of 57 million metric tons.
- **7 Percent Below 1990 Levels (1990-7%).** Carbon emissions from energy are reduced to an annual average of 1,250 million metric tons in the period 2008 to 2012, a reduction of 542 million metric tons in energy-related carbon emissions relative to the reference case. This case essentially assumes that the 7-percent target in the Kyoto Protocol for reducing emissions below 1990 levels must be met by energy-related carbon emissions with no net offsets 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. The target is assumed to be constant from 2013 through 2020, the end of the forecast horizon, because the Protocol does not specify any targets beyond the first commitment period, although consideration of commitments for subsequent periods will be initiated at least 7 years before the end of the first commitment period, i.e., prior to 2005.

In the 1998 study, the target was 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 3 years prior to 2008. In the 1999 analysis of an earlier start date for emissions reductions, the Committee requested that EIA analyze the impact of a start date of 2000, instead of 2005, reaching the same emissions target during the commitment period 2008 through 2012, using the 1990+24%, 1990+9%, and 1990-7% cases from the earlier study.

Both analyses assumed that a carbon price would be applied to each of the energy fuels at its point of consumption, relative to its carbon content. The carbon price would not be applied directly to electricity but would be applied to the fossil fuels used for electricity generation and reflected in the delivered price of electricity. The carbon price represents the marginal cost of reducing domestic carbon emissions, reflecting the price the United States would be willing to pay to purchase carbon permits from other countries or to induce carbon reductions in other countries. It does not represent the international market-clearing price of carbon permits or the price at which other countries would be willing to offer permits. The analyses also assumed that a carbon permit trading system would function as a Federal Government auction, and that the revenues collected by the Government would be recycled to the economy through either a lump sum rebate in personal income taxes or a reduction in social security tax rates.

The most significant results of both studies are:

- Higher energy prices, as a result of the carbon price, and their impact on the U.S. economy will encourage fuel switching and reductions in energy consumption. Consumers will reduce energy consumption by reducing demand for energy services and purchasing more efficient equipment.

- With a start date of 2005 for carbon emissions reductions, 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. Imposing carbon prices before 2005 reduces energy consumption and carbon emissions in that period by encouraging earlier efficient improvements, accelerated retirements of less efficient equipment, and the acceleration of technology improvements. The early start date reduces the carbon price in 2010 for each of the carbon reduction cases (Figure 28), and average carbon prices over the first commitment period, 2008 through 2012, are also lowered (Figure 29). However, because carbon prices are incurred earlier, average carbon prices over the entire projection period, 2000 through 2020, increase with the early start date.

- With a 2005 start date for carbon reductions, the average price of electricity increases by between 20 and 86 percent across the various cases. The price increases by between 19 and 76 percent with a start date of 2000. In all cases, the electricity generation sector accounts for most of the carbon reductions, as a result of lower electricity demand, improved generating efficiency, and, primarily, fuel switching.

- Because coal is the most carbon-intensive of the fossil fuels, the price of coal will increase more than the prices of other fossil fuels as a result of the carbon price, and coal use, particularly for electricity generation, will be sharply reduced (by between 18 and 78 percent in 2010). 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.

Figure 28. Projected carbon prices in six cases, 2010 (1996 dollars per metric ton)

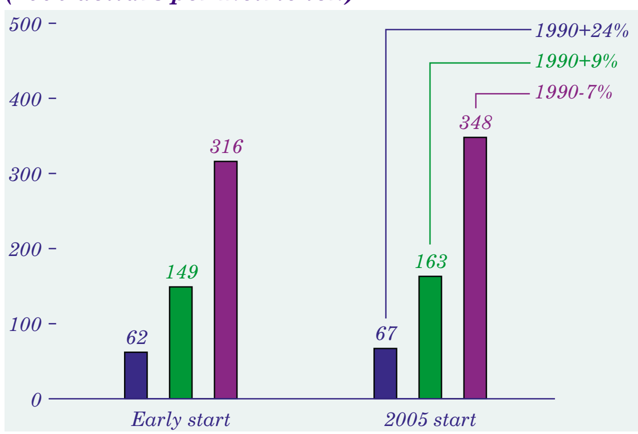
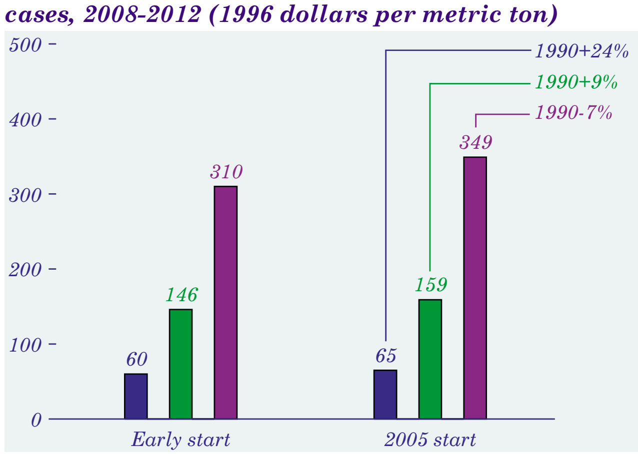


Figure 29. Average projected carbon prices in six cases, 2008-2012 (1996 dollars per metric ton)



- 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. Renewable technologies, particularly biomass and wind, become economical with high fossil fuel prices. It also becomes economical to extend the operating lives of existing nuclear plants rather than retire them.
- With a start date for carbon reductions of 2005, the average price of motor gasoline will increase by between 11 percent and 53 percent across the various cases. With a start date of 2000, the price increases range between 10 percent and 46 percent. With the higher prices of motor gasoline and other transportation fuels, travel will be lower and vehicle efficiency will be higher in all cases compared with the reference case.
- As a result of the carbon prices and higher energy prices, the growth in U.S. gross domestic product (GDP) will be lower than in the reference case during the transition period; however, the economy will continue to grow. As carbon prices decline and the economy adjusts, GDP will rebound by 2020 to about the level in the reference case. With an earlier start date, the economy experiences a loss in GDP beginning in 2000; however, the early start date smooths the transition of the economy to the longer run target. Potential GDP losses [*51*] begin in 2000 in the early start case at a slower rate than with the 2005 start date (Figure 30). Once in the compliance period, potential GDP takes on the same path in both cases. The loss in actual GDP in the early start cases between 2000 and 2005 is between one-half and nearly three-quarters of the loss in the cases with the 2005 start date between 2005 and 2010. By 2010, in the 1990+24% case with the early start date, the GDP loss is about half the loss seen with the 2005 start date. For the 1990+9% and 1990-7% cases, the GDP losses with the early start date are about one-third of the losses with the 2005 start date (Figure 31).
- The loss in GDP, plus the funds used to purchase permits internationally, represents the total cost to the economy. With the 2005 start date, the total cost in the compliance period, 2008 to 2012, ranges from an annual average of $77 billion

Figure 30. Projected dollar losses in potential gross domestic product in the 1990+9% and 1990+9% early start cases, 1998-2020 (billion 1992 dollars)

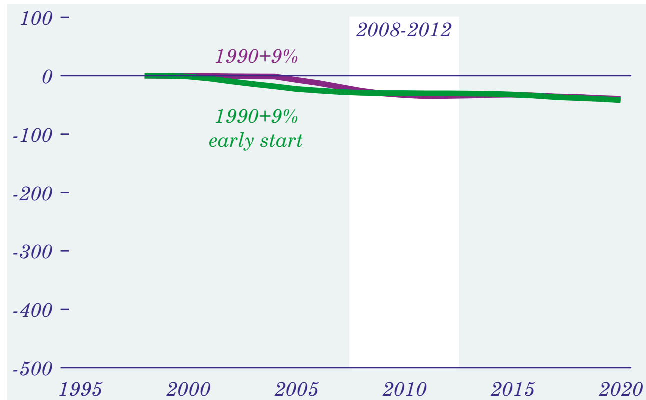
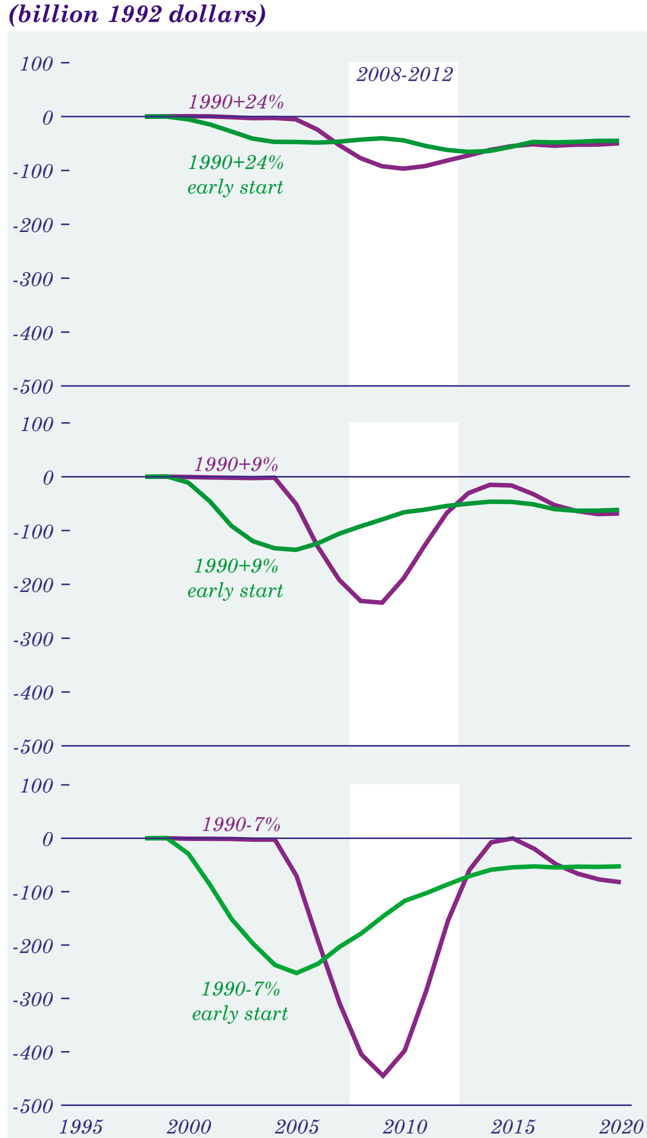


Figure 31. Projected dollar losses in actual gross domestic product in the 1990+24%, 1990+9%, and 1990-7% early start and 2005 start cases, 1998-2020 (billion 1992 dollars)



(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.

Proposed Ceilings on Kyoto Mechanisms

As noted above, the Kyoto Protocol includes several flexibility mechanisms; however, in Articles 6 and 17, the Protocol specifically indicates that joint implementation and Annex I trading of emissions credits "shall be supplemental to domestic actions." Supplementarity has been a topic of some debate. Those proposing limits on the flexibility mechanisms suggest that limits would lead to a more equitable method for countries to share the burden of emissions reductions; however, those opposing limits argue that the most economically efficient method for reductions is through unlimited access to the flexibility mechanisms.

On May 17, 1999, the Council of Ministers of the European Union adopted a Community Strategy on Climate Change. The Council affirmed the Buenos Aires Plan of Action as a "satisfactory result of COP4 [the fourth Conference of the Parties]," while believing "that urgent preparatory work is needed in order to implement the Buenos Aires Plan of Action by COP6 [the sixth Conference of the Parties, likely to be held late in 2000 or early in 2001].

Among other conclusions and recommendations, the Council reaffirmed "that the provisions in Articles 6, 12 and 17 of the Protocol [*52*] require that domestic action should provide the main means of meeting the commitments under Article 3 of the Protocol [*53*] and that a concrete ceiling on the use of the Kyoto mechanisms should be defined." Furthermore, the Council adopted the following proposal for limitations on trade in the commitment period:

- For purchasers, the net acquisitions for all three Kyoto mechanisms together must not exceed the higher of the two following alternatives:

  5 percent of [(base year emissions multiplied by 5) + (assigned amount over the commitment period)] / 2, or

  50 percent of the difference between the actual annual emissions in any year between 1994 and 2002 multiplied by 5 and its assigned amount over the commitment period.

- For sellers, net transfers for all three Kyoto mechanisms together must not exceed 5 percent of [(base year emissions multiplied by 5) + (assigned amount over the commitment period)] / 2.

Under the Council proposal, the limits on both acquisitions and transfers can be increased to the extent that a party achieves reductions larger than the ceiling in the commitment period through verifiable domestic actions undertaken after 1993.

The proposed limit on sellers of carbon permits is aimed at Annex I countries such as those comprising the former Soviet Union, which are likely to have lower emissions in the commitment period than in 1990 due to the economic decline of those countries in the 1990s. Compared with an unlimited trading system, restrictions on the sales of carbon permits are likely to increase the average price for the permits in an international market.

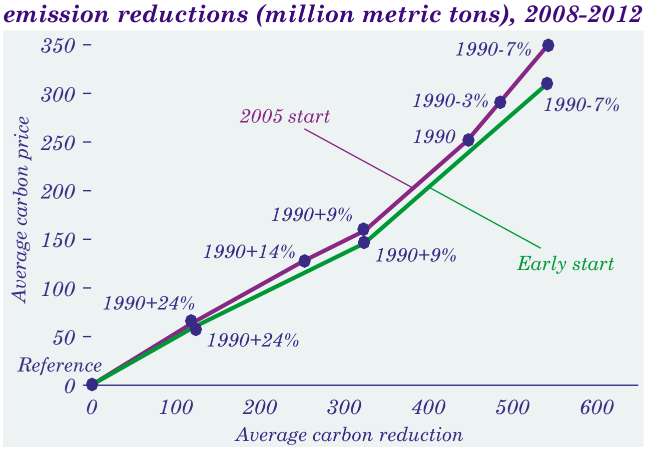
The Council proposal applies to all greenhouse gases included in the Kyoto Protocol; however, in order to consider the potential impact on the United States of the purchase limits in this proposal, only U.S. carbon emissions from energy are considered. Under the first provision: U.S. carbon emissions are 1,345 million metric tons in the base year of 1990, and its assigned amount is 7 percent below that level over 5 years, or 6,254 million metric tons. Therefore, under the first provision—5 percent of [$1,345 \times 5 + 6,254$] / 2—purchases would be limited to 324 million metric tons over the 5-year commitment period. Under the second provision, U.S. carbon emissions in the reference case of the Kyoto Protocol analysis are projected to grow to 1,600 million metric tons in 2002. Therefore, purchases would be limited to 50 percent of $1,600 \times 5 - 6,254$, or 873 million metric tons. Because the second provision results in a higher value, it establishes the U.S. limit on the use of the flexibility measures at an average annual of 175 million metric tons.

In the reference case, U.S. carbon emissions are expected to total 8,929 million metric tons in the commitment period, 2008 through 2012. Its assigned amount of carbon emissions is 6,254 million metric tons, of which 873 million metric tons can be met through the flexibility mechanisms under the Council proposal. Therefore, of average annual reductions of 535 million metric tons in the commitment period, an average of 175 million metric tons, or 33 percent, can be purchased.

Using the results of the six carbon reduction cases in the analysis of the Kyoto Protocol and the three cases in the early start analysis, the average carbon prices in the commitment period can be displayed as a function of the average carbon reductions required in that period (Figure 32). This curve represents the marginal cost of reducing energy-related carbon emissions in the United States.

Assuming that about 4 percent of the total required reduction in emissions can be met by cost-effective measures to reduce other greenhouse gases and enhance sinks, plus the ability to purchase 175 million metric tons of emissions credits abroad, a reduction in energy-related carbon emissions of 310 million metric tons is required. Using the curve for a 2005 start date, this reduction would require an average carbon price of about $150 per metric ton (1996 dollars)—about $10 per metric ton lower than the average price of $159 per metric ton in the 1990+9% case and about $85 per metric ton higher than the $65 per metric ton price in the 1990+24% case, which is the case most analogous to a full trading case in which the various flexibility measures are unlimited. With the earlier start date, the average carbon price resulting from the Council proposal would be reduced from about $150 per metric ton to about $140 per metric ton.

Figure 32. Average projected carbon prices (1996 dollars per metric ton) and annual carbon emission reductions (million metric tons), 2008-2012



The purchase of 175 million metric tons of permits, as derived from the Council proposal, is slightly higher than the level of 160 million metric tons in the 1990+9% case with the 2005 start date. As a result, the ultimate impact on the economy is moderated somewhat relative to that case. The loss in potential GDP is $31 billion (1992 dollars), compared with $32 billion in the 1990+9% case. The loss in actual GDP declines from $169 billion to $164 billion. The value of the permits purchased is $24 billion, slightly higher than the $23 billion cost in the 1990+9% case. Therefore, the total cost to the economy—the loss in actual GDP plus the purchases of international permits—totals $188 billion, compared with $192 billion in the 1990+9% case.

Market Trends

The projections in *AEO2000* 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.

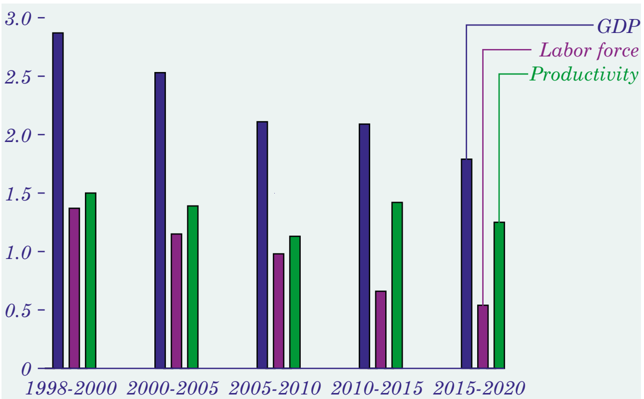
Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics 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 *AEO2000* projections are addressed through alternative cases.

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

Strong Economic Growth Is Expected To Continue

Figure 33. Average annual real growth rates of economic factors, 1998-2020 (percent)

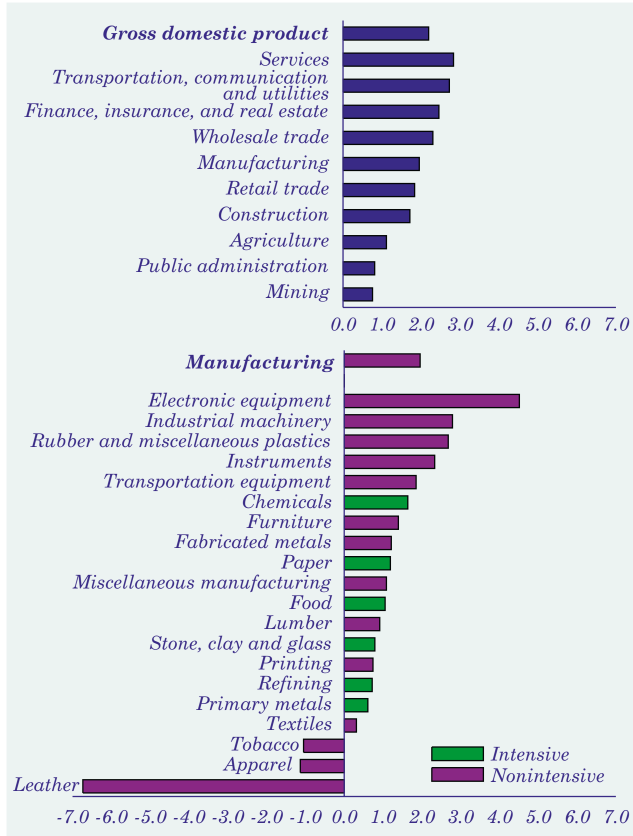


The output of the Nation's economy, measured by gross domestic product (GDP), is projected to increase by 2.2 percent a year between 1998 and 2020 (with GDP based on 1992 chain-weighted dollars) (Figure 33), slightly higher than the 2.0-percent growth projected in *AEO99* for the same period. The projected growth rate for the labor force is similar to last year's forecast through 2020; however, in the *AEO2000* projection, productivity growth (GDP growth minus labor force growth) is 1.3 percent a year, up from 1.2 percent a year in *AEO99*.

The projected rate of growth in GDP slows in the latter half of the forecast period as the expansion of the labor force slows, but sustained levels of labor productivity growth moderate the effects of lower labor force growth. Total population growth 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— 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. Thus, from 2010 to 2015, labor force growth slows to 0.7 percent, and from 2015 to 2020 it falls to 0.5 percent a year. Labor force productivity growth, however, remains above 1 percent a year throughout each of the 5-year periods.

Electronic, Industrial Equipment Lead Manufacturing Growth

Figure 34. Sectoral composition of GDP growth, 1998-2020 (percent per year)

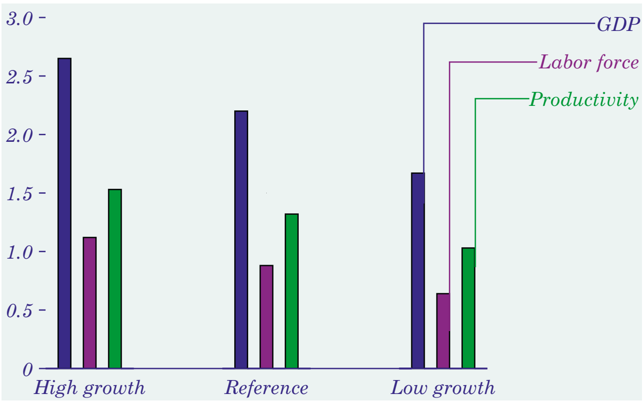


The projected growth rate for manufacturing production is 2.0 percent a year, slightly lower than the 2.2-percent annual growth projected for the aggregate economy. Energy-intensive manufacturing sectors are projected to grow more slowly than non-energy-intensive manufacturing sectors (1.1 percent and 2.4 percent annual growth, respectively) [*54*], 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 services sector than for the manufacturing sector, as in last year's forecast.

High and Low Growth Cases Reflect Uncertainty of Economic Growth

Figure 35. Average annual real growth rates of economic factors in three cases, 1998-2020 (percent)



To reflect the uncertainty in forecasts of economic growth, *AEO2000* 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 Standard & Poor's DRI (DRI) [*55*]. The DRI forecast used in generating the *AEO2000* reference case is the August 1999 trend growth scenario, adjusted to incorporate the world oil price assumptions used in the *AEO2000* reference case. The *AEO2000* high and low economic growth cases are based on the spread between the optimistic and pessimistic growth projections prepared by DRI in February 1999.

The high economic growth case incorporates higher 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 1.4 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 1.7 percent a year from 1998 through 2020, and growth in GDP per capita slows to 1.1 percent a year.

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

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

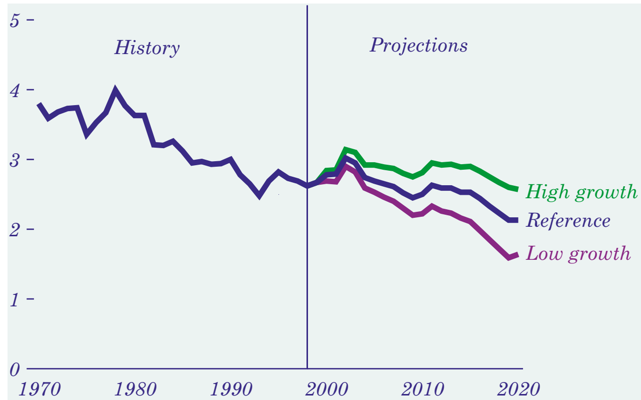
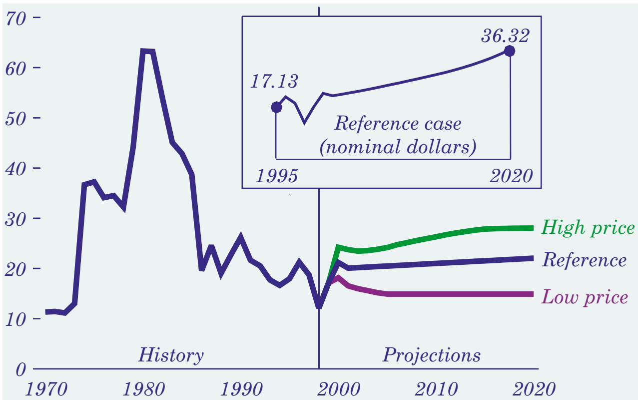


Figure 36 shows the trend in the moving 20-year annual growth rate for GDP, including projections for the three *AEO2000* cases. The value for each year is calculated as the annual growth rate over the preceding 20 years. The 20-year average shows major long-term trends in GDP growth by smoothing more 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 2.9-percent annual rate. In the high growth case, growth in investment increases to 3.6 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 1.9 percent. With the labor force also growing more slowly, aggregate economic growth slows considerably.

Projections Vary in Cases With Different Oil Price Assumptions

Figure 37. World oil prices in three cases, 1970-2020 (1998 dollars per barrel)



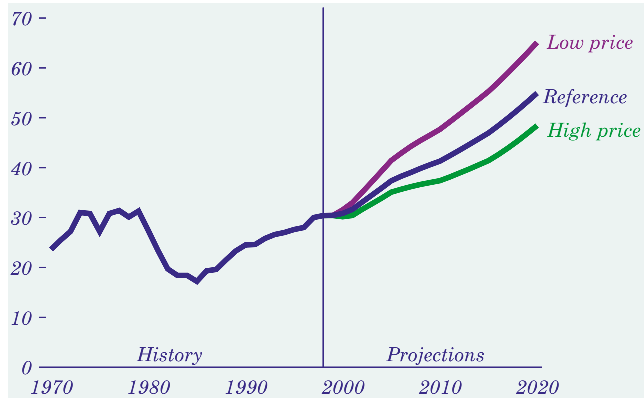
Just as the historical record shows substantial variability in world oil prices, there is considerable uncertainty about future prices. Three *AEO2000* cases with different price paths allow an assessment of alternative views on the course of future oil prices (Figure 37). For the reference case, prices rise by about 2.8 percent a year, reaching $22.04 in 2020 (all prices in 1998 dollars unless otherwise noted). In nominal dollars, the reference case price exceeds $36 in 2020. The low price case has prices declining, after the current price rise, to $14.90 by 2005 and remaining at about that level out to 2020. The high price case has a price rise of about 5.0 percent a year out to 2015 and then remains at about $28 out to 2020. The leveling off in the high price case is due to the market penetration of alternative energy supplies that could become economically viable at that price.

All three price cases are similar to the price projections in *AEO99* beyond 2005, reflecting considerable optimism about the potential for worldwide petroleum supply, even in the face of the substantial expected increase in demand. Production from countries outside OPEC is expected to show a steady increase, exceeding 45 million barrels per day by the turn of the century and increasing gradually thereafter to more than 56 million barrels per day by 2020.

Total worldwide demand for oil is expected to reach 112 million barrels per day by 2020. Developing countries in Asia show the largest growth in demand, averaging 3.1 percent a year.

Uncertain Prospects for Persian Gulf Production Shape Oil Price Cases

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



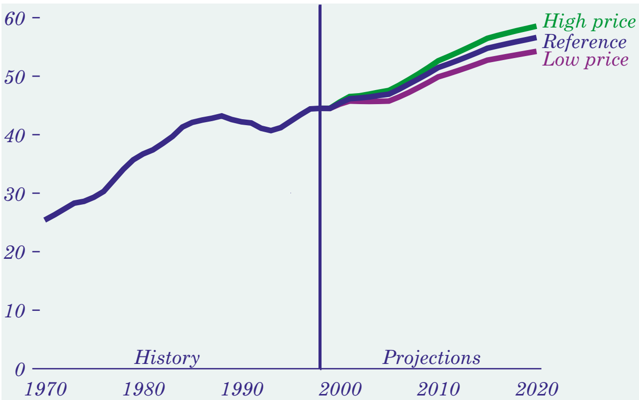
The three price cases are based on alternative assumptions about oil production levels in OPEC nations: higher production in the low price case and lower production in the high price case. With its vast store of readily accessible oil reserves, OPEC—primarily the Persian Gulf nations—is expected to be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

By 2000, OPEC supply in the reference case is over 32 million barrels per day, consistent with announced plans for OPEC capacity expansion [*56*]. By 2020, OPEC production is more than 55 million barrels per day (almost twice its 1998 production) in the reference case, almost 49 million in the high case, and nearly 66 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 120.3 million barrels per day in the low price case to 107.8 million barrels per day in the high price case.

The variation in oil production forecasts reflects uncertainty about the prospects for future production from the Persian Gulf region. The expansion of productive capacity will require major capital investments, which could depend on the availability and acceptability of foreign investments. Iraq is assumed to continue selling oil only at sanction-allowed volumes until 2002. 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.

Production Increases Are Expected for Non-OPEC Oil Producers

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

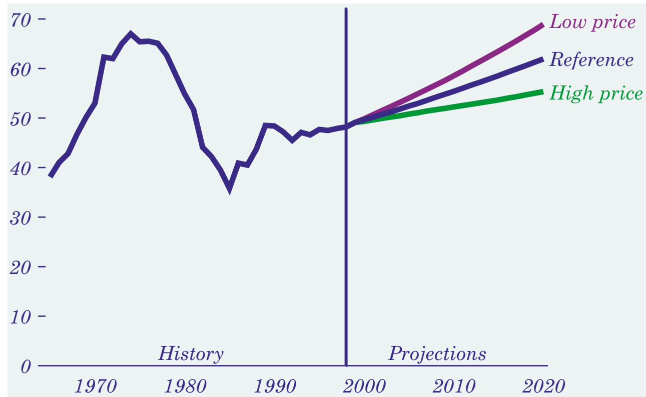


The growth and diversity in non-OPEC oil supply have shown surprising resilience even in the low price environment of this decade. Although OPEC producers will certainly benefit from the projected growth in oil demand, significant competition is expected from non-OPEC suppliers. Countries in the Organization 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 *AEO2000* reference case, non-OPEC supply is projected to reach almost 57 million barrels per day by 2020 (Figure 39). In the low oil price case, non-OPEC supply grows to more than 54 million barrels per day by 2020, whereas in the high oil price case it reaches more than 58 million barrels per day by the end of the forecast period.

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

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

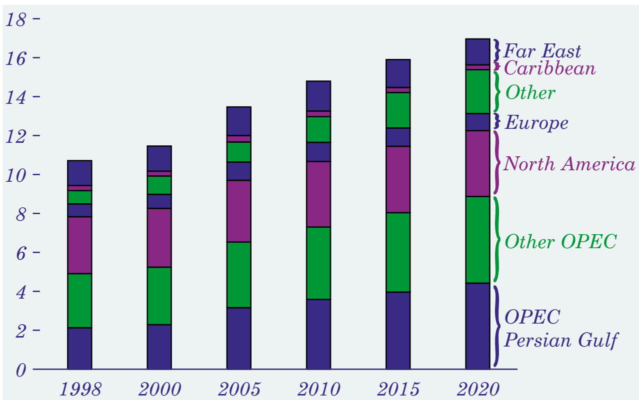


Considering the world market in oil exports, the historical peak for Persian Gulf exports (as a percent of world oil exports) occurred in 1974, when they made up more than two-thirds of the oil traded in world markets (Figure 40). The most recent historical low for Persian Gulf oil exports came in 1985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

In the reference case, the Persian Gulf share of worldwide petroleum exports exceeds 50 percent shortly after the turn of the century and increases gradually to almost 62 percent by 2020. In the low oil price case, the Persian Gulf share of total exports reaches almost 69 percent by 2020. All Persian Gulf producers are expected to increase oil production capacity significantly over the forecast period, and both Saudi Arabia and Iraq are expected to more than double their current production capacity.

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

Figure 41. U.S. gross petroleum imports by source, 1998-2020 (million barrels per day)



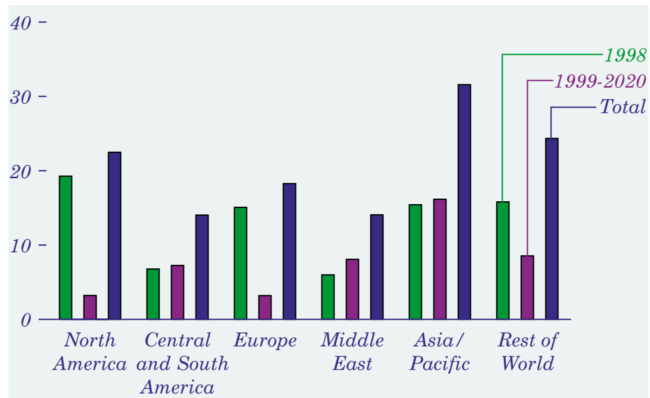
In the reference case, total U.S. gross oil imports increase from 10.7 million barrels per day in 1998 to almost 17 million in 2020 (Figure 41). Crude oil accounts for most of the increase in imports through 2000, whereas imports of petroleum products make up a larger share of the increase after 2000. Product imports increase more rapidly, as U.S. production stabilizes and U.S. refineries lack the capacity to process larger quantities of imported crude oil.

Not until 2014 does OPEC account for more than 50 percent of total projected U.S. petroleum imports. The OPEC share increases gradually to more than 52 percent in 2020. The Persian Gulf share of U.S. imports from OPEC increases from about 43 percent in 1998 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 declining production of Alaskan crude oil.

Imports of light products are expected to more than triple by 2020, to more than 3.9 million barrels per day. Most of the projected increase is from refiners in the Caribbean Basin and the Middle East, where refining capacity is expected to expand significantly. Vigorous growth in demand for lighter petroleum products in developing countries means that U.S. refiners are likely to import smaller volumes of light, low-sulfur crude oils.

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

Figure 42. Worldwide refining capacity by region, 1998 and 2020 (million barrels per day)



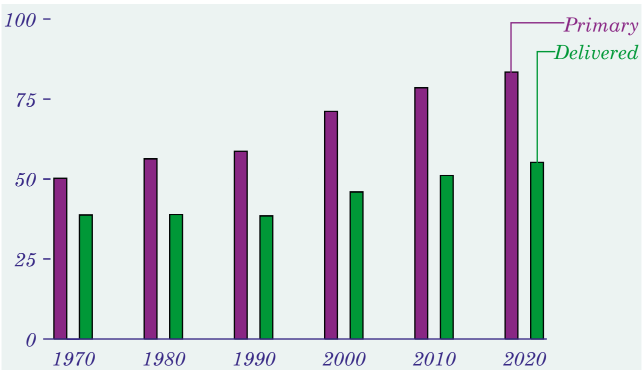
Worldwide crude oil distillation capacity was 78.3 million barrels per day at the beginning of 1998. To meet the growth in international oil demand in the reference case, worldwide refining capacity is expected to increase by almost 60 percent—to nearly 125 million barrels per day—by 2020. Substantial growth in distillation capacity is expected in the Middle East, Central and South America, and the Asia/Pacific region (Figure 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.

Annual Growth in Energy Use Is Projected To Continue

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



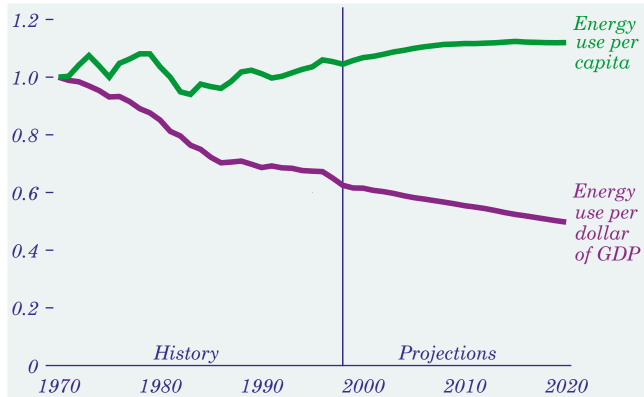
Net energy delivered to consumers represents only a part of total primary energy consumption. Primary consumption includes energy losses associated with the generation, transmission, and distribution of electricity, which are allocated to the end-use sectors (residential, commercial, and industrial) in proportion to each sector's share of electricity use [*57*].

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 in the forecast, as more efficient generating technologies offset increased demand for electricity. Projected primary energy consumption and delivered energy consumption grow by 0.9 percent and 1.0 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.

Average Energy Use per Person Shows Little Change in the Forecast

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

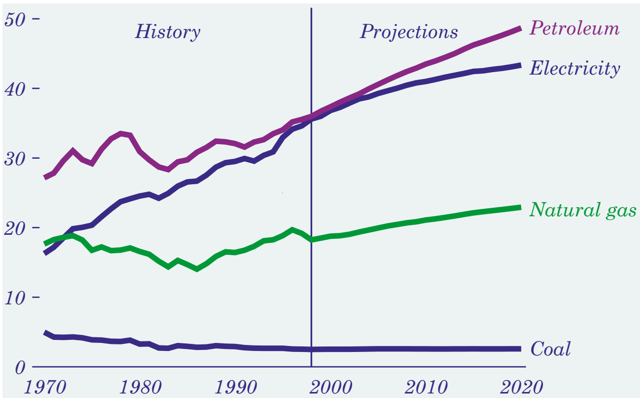


Energy intensity, both as measured by primary energy consumption per dollar of GDP and as measured on a per capita basis, declined between 1970 and the mid-1980s (Figure 44). Although the overall GDP-based energy intensity of the economy is projected to continue declining between 1998 and 2020, the decline is not expected to be as rapid as it was in the earlier period. GDP is estimated to increase by 61 percent between 1998 and 2020, compared with a 27-percent increase in primary energy use. Relatively stable energy prices are expected to slow the decline in energy intensity, as is increased use of electricity-based energy services. When electricity claims a greater share of energy use, consumption of primary energy per dollar of GDP declines at a slower rate, because electricity use contributes both end-use consumption and energy losses to total energy consumption.

In the *AEO2000* forecast, the demand for energy services increases markedly over 1998 levels. The average home in 2020 is expected to be 2 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 21 percent and 97 percent higher, respectively, than in 1998. Nevertheless, despite the growth in demand for energy services, primary energy intensity on a per capita basis remains 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 total energy use per capita.

Petroleum Products Lead Growth in Energy Consumption

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



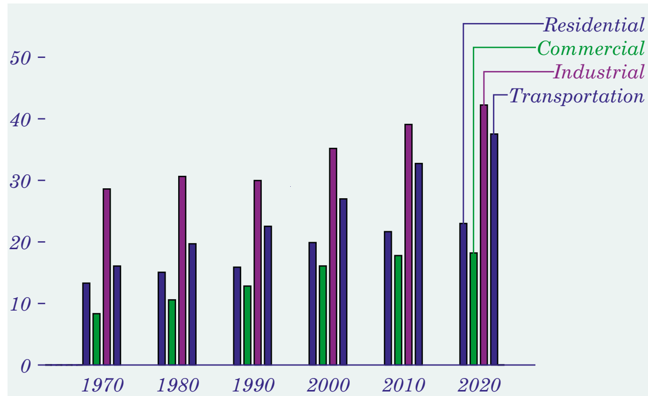
Consumption of petroleum products, mainly for transportation, claims the greatest share of primary energy use in the *AEO2000* forecast (Figure 45). Growth in energy demand in the transportation sector, which averaged 2.0 percent a year during the 1970s, was slowed in the 1980s by rising fuel prices and by new Federal vehicle efficiency standards, which led to an unprecedented 2.1-percent annual increase in average vehicle fuel economy. In the *AEO2000* 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. Excluding consumption for electricity generation, 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 18.9 percent of all end-use energy requirements in 2020.

End-use demand for renewable energy from sources such as wood, wood wastes, and ethanol increases by 1.1 percent a year in the forecast. The use of geothermal and solar energy in buildings increases by about 3.8 percent a year but does not exceed 1 percent of energy consumption for space and water heating.

U.S. Primary Energy Use Exceeds 120 Quadrillion Btu a Year by 2020

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



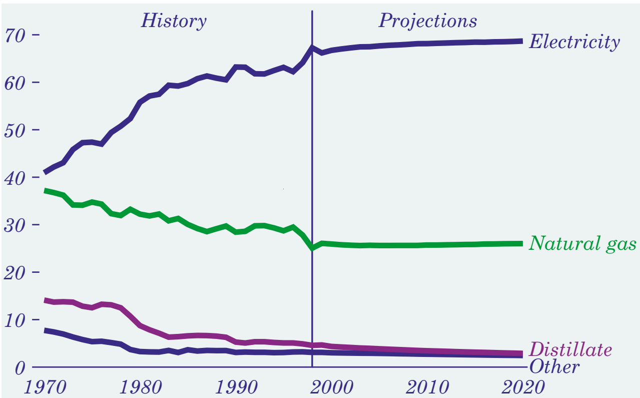
Primary energy use in the reference case is projected to exceed 120 quadrillion Btu by 2020, 27 percent higher than the 1998 level. In the early 1980s, as energy prices rose, sectoral energy consumption grew relatively little (Figure 46). Between 1985 and 1998, however, stable energy prices contributed 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 *AEO2000* 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 the demand for travel services is reduced slightly. In contrast, variations in economic growth assumptions lead to larger changes in the projections of overall energy demand in each of the end-use sectors [*58*]. For 2020, the projection of total annual energy use in the high economic growth case is 14 percent higher than in the low economic growth case.

Residential Energy Use Grows by More Than One-Fifth From 1998 to 2020

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



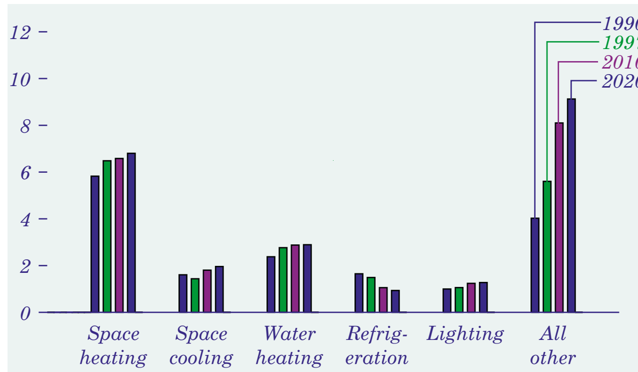
Residential energy consumption is projected to increase by more than 22 percent overall between 1998 and 2020. Most (74 percent) of the growth in total energy use is related to increased use of electricity. Sustained growth in housing in the South, where almost all new homes use central air conditioning, 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 increases slightly, natural gas use in the residential sector is projected to grow by 1.1 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. Petroleum use is projected to fall, with the number of homes using petroleum-based fuels for space heating applications expected to decrease over time.

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

Efficiency Standards Should Moderate Residential Energy Use

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



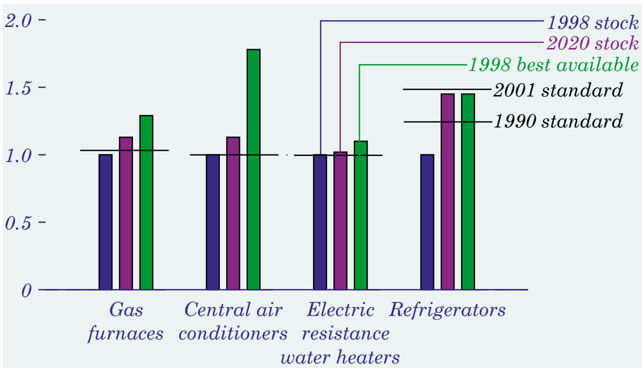
Energy use for space heating, the most energy-intensive end use in the residential sector, grew by 1.5 percent a year from 1990 to 1997 (Figure 48). Future growth should be slowed by higher equipment efficiency and tighter building codes. Building shell efficiency gains are projected to cut space heating demand in new homes by nearly 8 percent per household in 2020 relative to the demand in 1998.

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 1.4 percent a year from 1990 to 1997 and is expected 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 nearly 5 percent a year from 1990 to 1997 (Figure 48) and now accounts for 30 percent of residential primary energy use. It is projected to account for 40 percent in 2020, as small electric appliances continue to penetrate the market. The promotion of voluntary standards, both within and outside the appliance industry, is expected to forestall even larger increases. Even so, the "all other" category is expected to exceed other components of residential demand by 2020.

Available Technologies Can Slow Future Residential Energy Demand

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

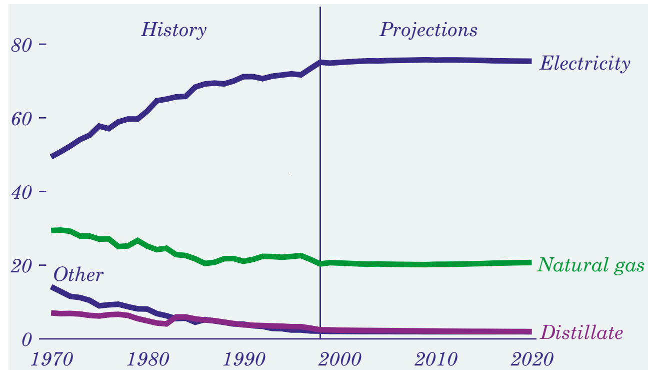


The *AEO2000* reference case projects an increase in the stock efficiency of residential appliances, as stock turnover and technology advances in most end-use services combine to reduce residential energy intensity over time. For most appliances covered by the National Appliance Energy Conservation Act 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 water heaters are expected to be announced by June 2000, and several other product announcements are expected by spring 2001.

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

Energy Fuel Shares for Commercial Users Are Expected To Remain Stable

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

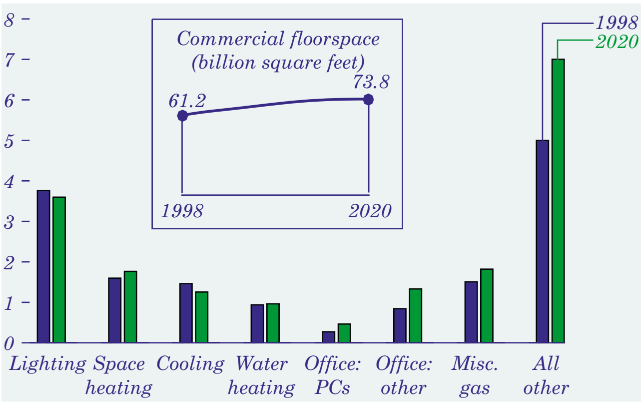


Projected energy use trends in the commercial sector show stable shares for all fuels, with growth in overall consumption slowing from its pace over the past two decades (Figure 50). Slow growth (0.8 percent a year) is expected in the commercial sector, for two reasons. Commercial floorspace is projected to grow by only 0.9 percent a year between 1998 and 2020, compared with an average of 1.5 percent a year over the past two decades. Lower growth in floorspace reflects the slowing labor force growth expected later in the forecast. 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 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 20 percent of commercial energy consumption in 1998 and maintains that share throughout the forecast. Distillate fuel oil makes up only 2 percent of commercial demand in 1998, down from 6 percent in the years before deregulation of the natural gas industry. The fuel share projected for distillate remains at 2 percent in 2020, as natural gas continues to compete for space and water heating uses. With stable prices projected for conventional fuels, no appreciable growth in the share of renewable energy in the commercial sector is anticipated.

Commercial Lighting Is the Sector's Most Important Energy Application

Figure 51. Commercial primary energy consumption by end use, 1998 and 2020 (quadrillion Btu)

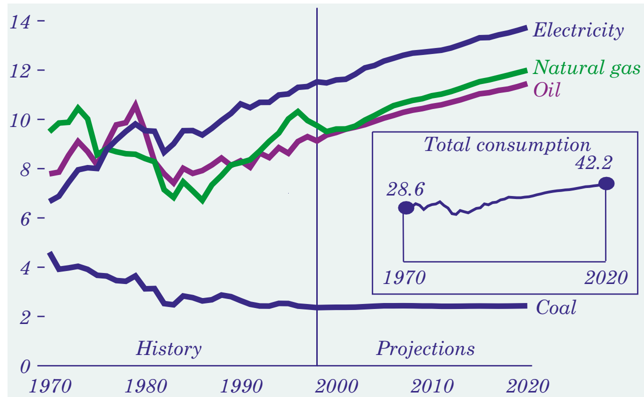


Through 2020, lighting remains the most important individual end use in the commercial sector [*59*]. Energy use for lighting declines slightly in the forecast as more energy-efficient lighting equipment and more efficient generating technologies are adopted. Efficiency also improves for space heating, 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 2.4 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 0.9 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 of the projection period, as emerging technologies achieve greater market penetration.

Industrial Energy Use Could Grow by More Than 20 Percent by 2020

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

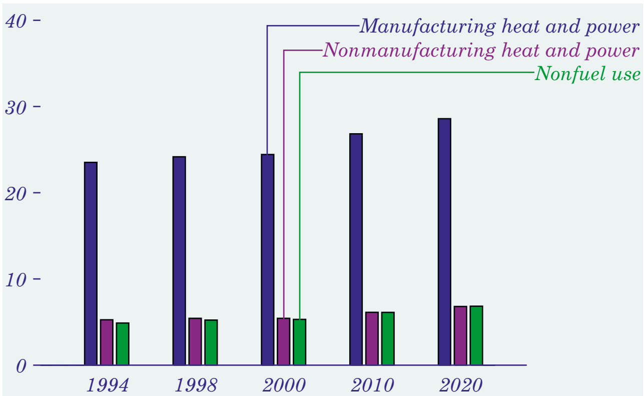


From 1970 to 1986, with demand for coking coal reduced by declines in steel production and natural gas use falling as a result of end-use restrictions and curtailments, electricity's share of industrial energy use increased from 23 percent to 35 percent. The natural gas share fell from 33 percent to 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 *AEO2000* projections of plentiful supplies and relatively stable prices allow natural gas to maintain its current share of industrial energy consumption while electricity's share of delivered energy increases slightly.

Primary energy use in the industrial sector—which includes the agriculture, mining, and construction industries in addition to traditional manufacturing—increases by 0.9 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 31.7 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 23.0 percent over its 1998 level by 2020. Industrial petroleum use grows by 25.4 percent over the same period. Coal use increases slowly, by 0.1 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.

Industrial Energy Use Grows Steadily in the Projections

Figure 53. Industrial primary energy consumption by industry category, 1994-2020 (quadrillion Btu)



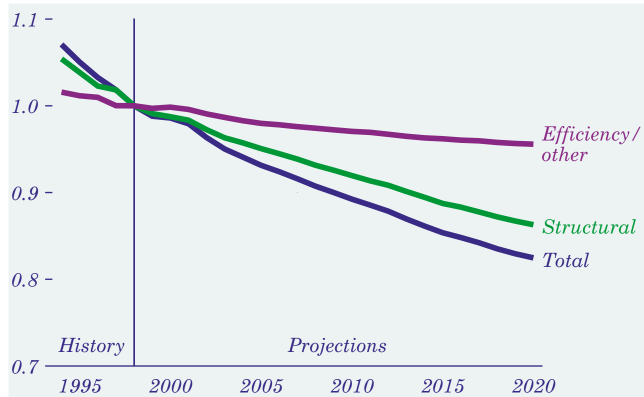
More than two-thirds of all the energy consumed in the industrial sector is used to provide heat and power for manufacturing; the remainder is approximately equally distributed between nonmanufacturing heat and power and consumption for nonfuel purposes, such as raw materials and asphalt (Figure 53).

Nonfuel use of energy grows more rapidly (1.2 percent annually) than does projected heat and power consumption (0.8 percent annually). The feedstock portion of nonfuel use is projected to grow at the same rate as the bulk chemical industry (1.1 percent annually) due to limited substitution possibilities. In 2020, feedstock consumption is projected to be 5.0 quadrillion Btu. Asphalt, the other component of nonfuel use, is projected to grow by 1.6 percent a year, to 1.8 quadrillion Btu in 2020. The growth rate for asphalt use is slightly less than the projected annual growth rate for the construction industry (1.7 percent), which is the principal consumer of asphalt for paving and roofing.

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 8.9 quadrillion Btu in 1998. 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.

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

Figure 54. Industrial delivered energy intensity by component, 1994-2020 (index, 1998 = 1)

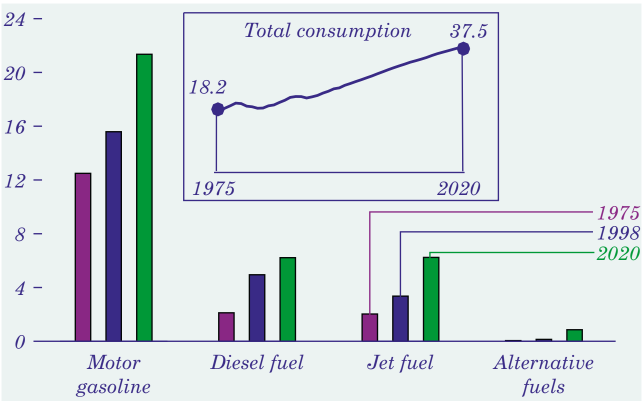


Changes in industrial energy intensity (consumption per unit of output) can be separated into two effects. One component reflects underlying increases in equipment and production efficiencies; the other arises from structural changes in the composition of manufacturing output. Since 1970, the use of more energy-efficient technologies, combined with relatively low growth in the energy-intensive industries, has dampened growth in industrial energy consumption. Thus, despite a 50-percent increase in industrial output, total energy use in the sector grew by only 12 percent between 1977 and 1998. These basic trends are expected to continue.

The share of total industrial output attributed to the energy-intensive industries is projected to fall from 23 percent to 19 percent from 1998 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 [*60*]. Over the forecast period, industrial delivered energy intensity drops by 17 percent, and the changing composition of industrial output alone results in approximately a 13-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.

Alternative Fuels Make Up 4 Percent of Light-Duty Vehicle Fuel Use in 2020

Figure 55. Transportation energy consumption by fuel, 1975, 1998, and 2020 (quadrillion Btu)



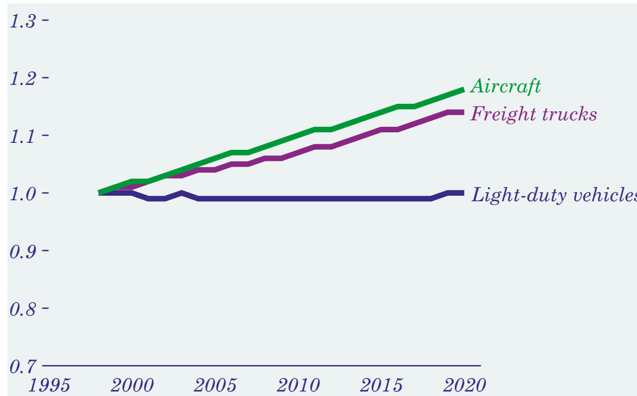
By 2020, total energy demand for transportation is expected to be 37.5 quadrillion Btu, compared with 25.9 quadrillion Btu in 1998 (Figure 55). Petroleum products dominate energy use in the sector. Motor gasoline use, increasing by 1.4 percent a year in the reference case, makes up more than half of transportation energy demand. Alternative fuels are projected to displace about 406,000 barrels of oil equivalent a day [*61*] by 2020 (about 4 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 by slower fuel efficiency gains for conventional light-duty vehicles (cars, vans, pickup trucks, and sport utility vehicles) than were achieved during the 1980s.

Assumed industrial output growth of 1.8 percent a year through 2020 leads to an increase in freight transport, with a corresponding 1.0-percent annual increase in diesel fuel use. Economic growth and low projected jet fuel prices yield a 4.0-percent annual increase in air travel, causing jet fuel use to increase by 2.9 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 1.3 percent a year, compared with 1.6 percent a year in the low oil price case.

Average Horsepower for New Cars Is Projected To Grow by 30 Percent

Figure 56. Transportation stock fuel efficiency by mode, 1998-2020 (index, 1998 = 1)



Fuel efficiency improves at a slower rate through 2020 than it did in the 1980s (Figure 56), with fuel efficiency standards for light-duty vehicles assumed to stay at current levels. Projected low fuel prices and higher personal income increase the demand for larger, more powerful vehicles. Average horsepower for new cars in 2020 is about 30 percent above the 1998 level (Table 8), 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.

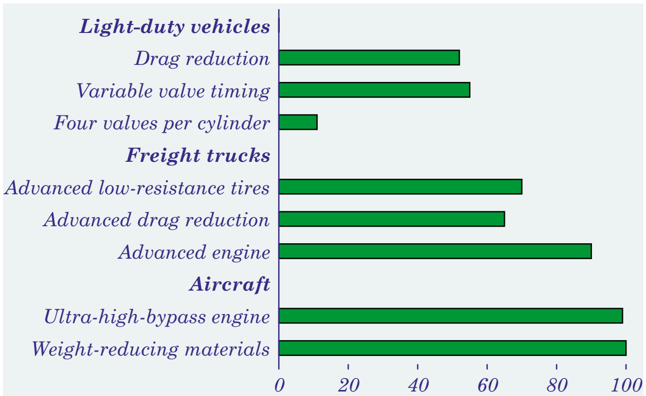
From 1990 to 1998, the horsepower of compact sport utility vehicles (medium light trucks) increased slightly faster than that of standard sport utility vehicles (large light trucks)—3.2 percent vs. 3.1 percent a year [*62*]. If it continues, this trend will lead to slightly higher horsepower for medium than for large light trucks by 2020.

Table 8. 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
1998						
Horsepower	164	193	208	191	213	224
Sales share	0.54	0.34	0.12	0.36	0.52	0.12
2010						
Horsepower	176	211	262	226	271	262
Sales share	0.56	0.31	0.13	0.33	0.50	0.16
2020						
Horsepower	211	246	298	274	307	304
Sales share	0.55	0.31	0.14	0.34	0.53	0.13

New Technologies Promise Better Vehicle Fuel Efficiency

Figure 57. Technology penetration by mode of travel, 2020 (percent)



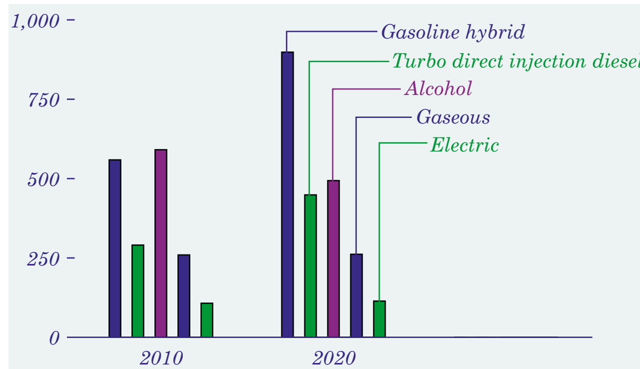
New automobile fuel economy is projected to reach approximately 31.6 miles per gallon by 2020, as a result of advances in fuel-saving technologies (Figure 57). Three of the most promising are advanced drag reduction, variable valve timing, and extension of four valve per cylinder technology to six-cylinder engines, each of which would provide between 7 and 10 percent higher fuel economy. Advanced drag reduction reduces air resistance over the vehicle; variable valve timing optimizes the timing of air intake into the cylinder with the spark ignition during combustion; and increasing the number of valves on the cylinder improves efficiency through more complete combustion of fuel in the engine.

It is more difficult for fuel-saving technology to penetrate the new truck market because of the higher marginal cost of the technologies; however, several technologies can increase fuel economy significantly, including advanced low-resistance tires (3 percent), advanced drag reduction (10 percent), and advanced low-emission high-efficiency diesel engines (10 percent). These technologies are anticipated to penetrate the heavy-duty truck market by 2020. Advanced technology penetration is projected to increase new freight truck fuel efficiency from 6.0 miles per gallon to 7.1 miles per gallon between 1998 and 2020.

New aircraft fuel efficiencies are projected to increase by more than 18 percent from 1998 levels by 2020. Ultra-high-bypass engine technology can potentially increase fuel efficiency by 10 percent, and increased use of weight-reducing materials may contribute up to a 15-percent improvement.

Advanced Technologies Could Reach Nearly 15 Percent of Sales by 2020

Figure 58. Advanced technology light-duty vehicle sales by fuel type, 2010 and 2020 (thousand vehicles sold)



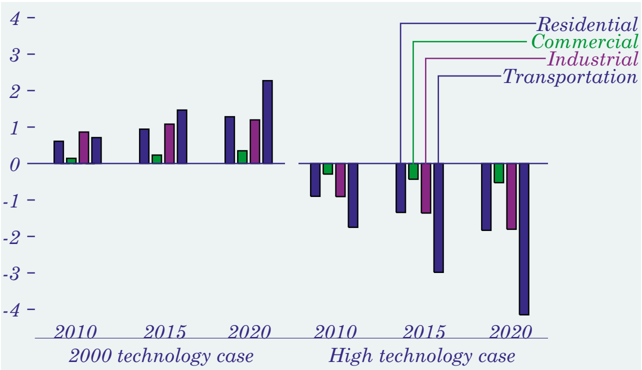
Advanced technology vehicles, representing automotive technologies that use alternative fuels or require advanced nonconventional engine technology, are projected to exceed 2.2 million vehicle sales or 14.6 percent of total light-duty vehicle sales by 2020 (Figure 58).

Gasoline hybrid electric vehicles, which will be introduced into the U.S. market by two manufacturers in 2000, are anticipated to lead advanced technology vehicle sales with almost 900,000 units by 2020. Both turbo direct injection diesels and alcohol flexible-fueled vehicles are expected to sell well in the personal vehicle market, reaching approximately 450,000 to 494,000 vehicle sales by 2020. All three of these advanced technologies will initially sell for less than $3,000 above an equivalent gasoline vehicle, but only the gasoline hybrid and the turbo direct injection diesel can achieve more than 35 to 45 percent better fuel economy than a comparable gasoline vehicle and vehicle ranges that exceed 600 miles.

About 68 percent of advanced technology sales are a result of Federal and State mandates for either fuel economy standards, emissions programs, or energy policy regulations. Alcohol flexible-fueled vehicles are currently being sold by manufacturers in order to receive fuel economy credits to comply with Corporate Average Fuel Economy regulations. The majority of the gasoline hybrid and electric vehicle sales will result from compliance with Low-Emission Vehicle programs in California, New York, and Massachusetts, which currently permit zero-emission vehicle credits for advanced technologies.

Alternative Cases Analyze Effects of Advances in Technology

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



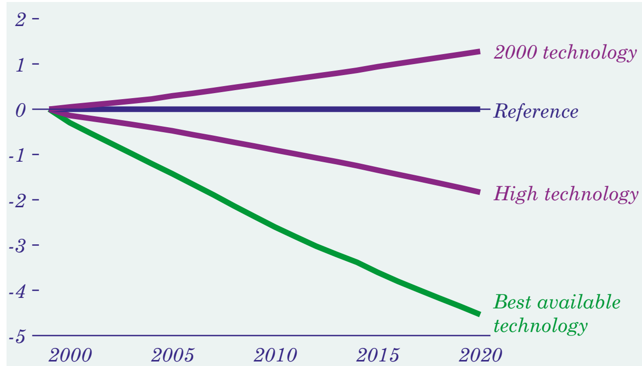
The availability and market penetration of new, more efficient technologies are uncertain. Alternative cases for each sector, based on a range of assumptions about technological progress, show the effects of these assumptions (Figure 59). The alternative cases assume that current equipment and building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

For the residential and commercial sectors, the 2000 technology case holds equipment and building shell efficiencies at 2000 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 2000 technology cases for the industrial and transportation sectors and the high technology case for the industrial sector use the same assumptions as the buildings sector cases. The high transportation technology case includes lower costs for advanced technologies and improved efficiencies, comparable to those assumed in a Department of Energy (DOE) interlaboratory study for air, rail, and marine travel and provided by the DOE Office of Energy Efficiency and Renewable Energy and American Council for an Energy-Efficient Economy for light-duty vehicles and by Argonne National Laboratory for freight trucks [*63*].

Advanced Technologies Could Reduce Residential Energy Use by 20 Percent

Figure 60. Variation from reference case primary residential energy use in three alternative cases, 1999-2020 (quadrillion Btu)



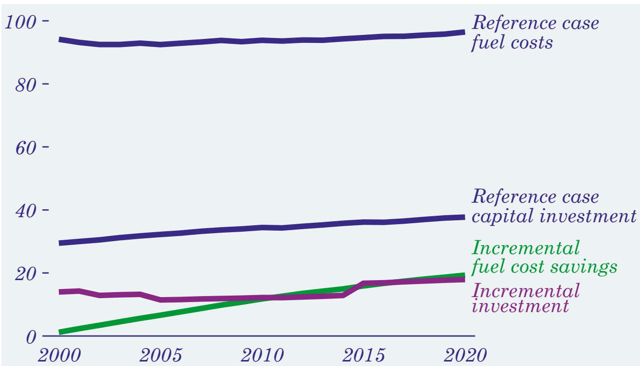
The *AEO2000* reference case forecast includes the projected effects of several different policies aimed at increasing residential end-use efficiency. Examples include minimum efficiency standards and voluntary energy savings programs designed to promote energy efficiency through innovations in manufacturing, building, and mortgage financing. In the 2000 technology case, which assumes no further increases in the efficiency of equipment or building shells beyond that available in 2000, 5.6 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 19.7 percent lower than in the reference case in 2020, and household primary energy use is 24.0 percent lower than in the 2000 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 8.0 percent in 2020; however, the savings are not as great as those in the best available technology case.

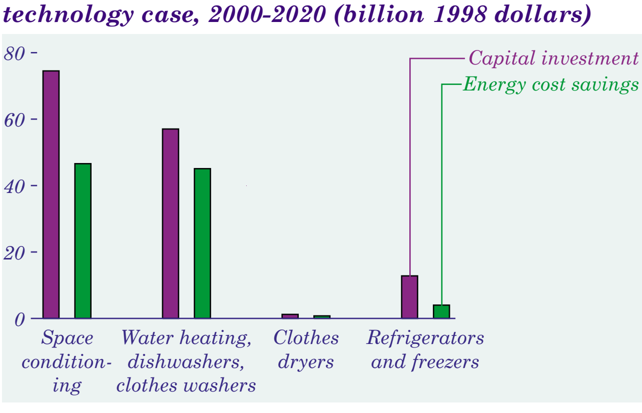
High Residential Energy Savings Would Require High Investment

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



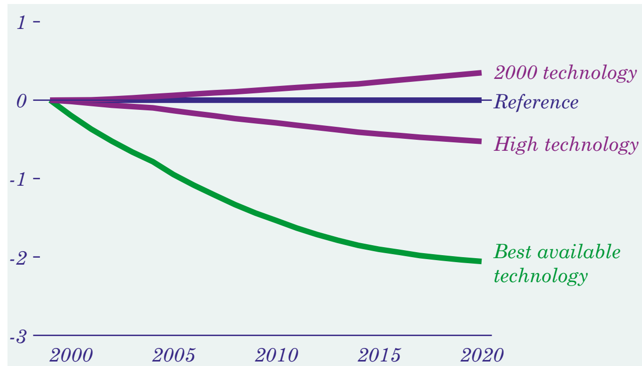
In the best available technology case, which requires the purchase of the most efficient equipment available, residential energy expenditures are lower but capital investment costs are higher (Figures 61 and 62). This case captures the effects of installing the most efficient (usually the most expensive) equipment at reference case turnover rates, regardless of economic considerations. An incremental investment of $145 billion [*64*] reduces residential delivered energy use by nearly 18 quadrillion Btu—saving consumers more than $96 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)



Advanced Technologies Could Reduce Commercial Energy Use by 10 Percent

Figure 63. Variation from reference case primary commercial energy use in three alternative cases, 1999-2020 (quadrillion Btu)

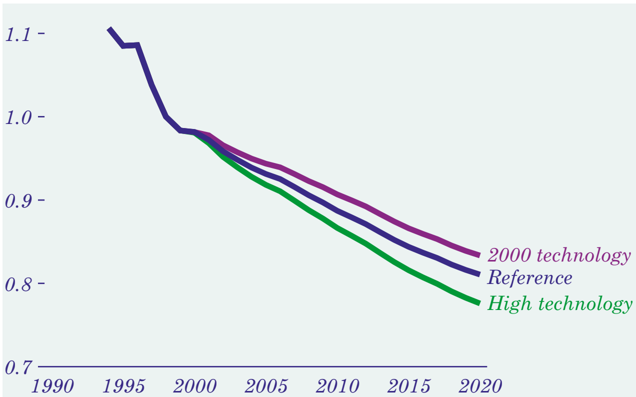


The *AEO2000* reference case incorporates efficiency improvements for commercial equipment and building shells, contributing to a 0.1-percent annual decline in commercial energy intensity over the forecast. The 2000 technology case assumes that future equipment and building shells will be no more efficient than those available in 2000. The high technology case assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment than in the reference case and more rapid improvement in building shells. The best available technology case assumes that only the most efficient technologies will be chosen, regardless of cost, and that building shells will improve at the rate assumed in the high technology case.

Energy use in the 2000 technology case is 1.9 percent higher than in the reference case by 2020 (Figure 63), with no change in commercial primary energy intensity. In the high technology case there is an additional 2.9-percent energy savings in 2020, and primary energy intensity falls by 0.2 percent a year from 1998 to 2020. Allowing the purchase of only the most efficient equipment in the best available technology case yields energy use that is 11.3 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. More optimistic assumptions result in additional energy savings from renewable technologies, as well as those using conventional fuels. Solar photovoltaic systems generate 9 percent more electricity in the high technology and best technology cases than in the reference case.

Alternative Technology Cases Show Range of Industrial Efficiency Gains

Figure 64. Industrial primary energy intensity in two alternative cases, 1994-2020 (index, 1998 = 1)



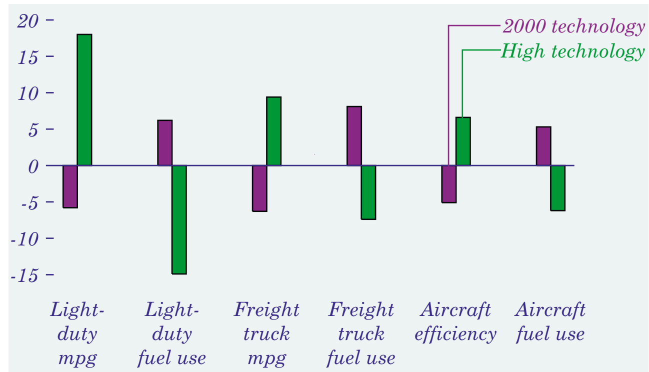
Projected efficiency gains in both energy-intensive and non-energy-intensive industries provide improvement in energy intensity. The growth in machinery and equipment production, driven primarily by investment and export-related demand, is a key factor: these less energy-intensive industries grow 56 percent faster than the industrial average in the reference case (2.9 percent vs. 1.8 percent a year).

In the high technology case, 1.8 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 1.1 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 is not as strongly affected, because the composition of industrial output is the same in the two cases.

In the 2000 technology case, industry consumes 1.2 quadrillion Btu more energy in 2020 than in the reference case. Energy efficiency remains at the level achieved new plants in 2000, but average efficiency still improves as old plants are retired. Aggregate industrial energy intensity declines by 0.8 percent a year because of reduced efficiency gains and changes in industrial structure. The composition of industrial output accounts for 87 percent of the change in aggregate industrial energy intensity in the 2000 technology case, compared with 76 percent in the reference case.

Vehicle Technology Improvements Would Lower Carbon Emissions

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



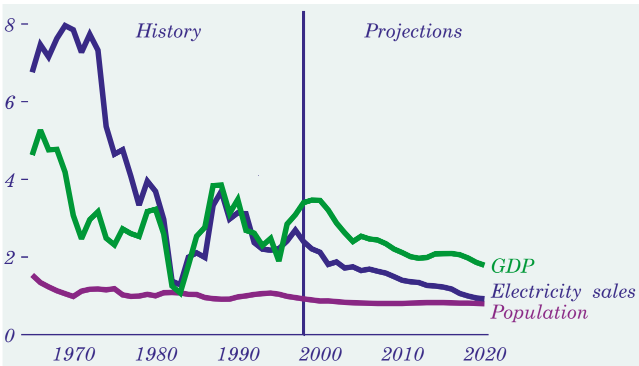
The transportation high technology case assumes lower costs, higher marginal efficiencies, and earlier introduction dates for new technologies. Demand is 4.2 quadrillion Btu (11 percent) lower in 2020 than in the reference case, reducing carbon emissions by 80 million metric tons. About 75 percent of the demand reduction in 2020 is for light-duty vehicles, where demand is reduced by 3.1 quadrillion Btu in 2020 as a result of advances in conventional technologies and in vehicle attributes for advanced technologies, which raise the average efficiency of the light-duty vehicle fleet to 24.3 miles per gallon, compared with 20.6 miles per gallon in the reference case (Figure 65).

In the high technology case, energy demand for freight trucks is reduced by 0.4 quadrillion Btu in 2020 relative to the reference case, as advanced technologies increase freight truck stock efficiency by 9.4 percent. Advanced aircraft technologies also reduce energy demand by 0.4 quadrillion Btu in 2020 in the high technology case, improving aircraft efficiency by 6.6 percent above the reference case.

In the 2000 technology case, with new technology efficiencies fixed at 2000 levels, efficiency improvements result only from stock turnover. In 2020, total transportation demand is 2.3 quadrillion Btu (6 percent) higher than in the reference case, and carbon emissions are 44 million metric tons higher. The fuel economy for new light-duty vehicles is 24.2 miles per gallon in 2020 in the 2000 technology case, 2.3 miles per gallon lower than in the reference case.

Parallel Growth Rates Are Projected for Electricity Use and GDP

Figure 66. Population, gross domestic product, and electricity sales, 1965-2020 (5-year moving average annual percent growth)



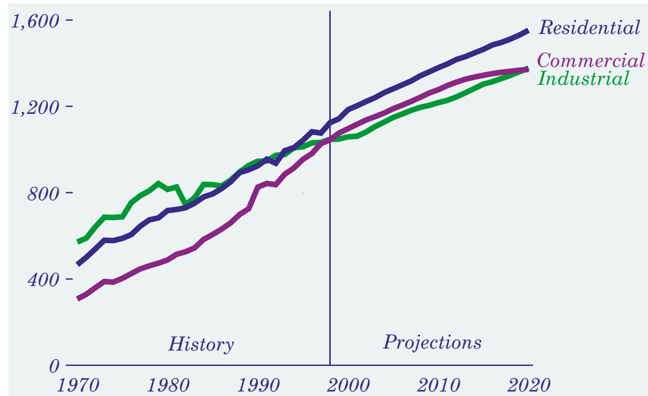
As generators and cogenerators try to adjust to the evolving structure of the electricity market, they also face slower growth in demand than in the past. Historically, the demand for electricity has been related to economic growth. That positive relationship is expected to continue, but the ratio is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

During the 1960s, electricity demand grew by more than 7 percent 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. Throughout the forecast, growth in demand for office equipment and personal computers, among other equipment, is dampened by slowing growth or reductions in demand for space heating and cooling, refrigeration, water heating, and lighting. The continuing saturation of electricity appliances, the availability and adoption of more efficient equipment, and efficiency standards are expected to hold the growth in electricity sales to an average of 1.4 percent a year between 1998 and 2020, compared with 2.2-percent annual growth in GDP.

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

Continued Growth in Electricity Use Is Expected in All Sectors

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



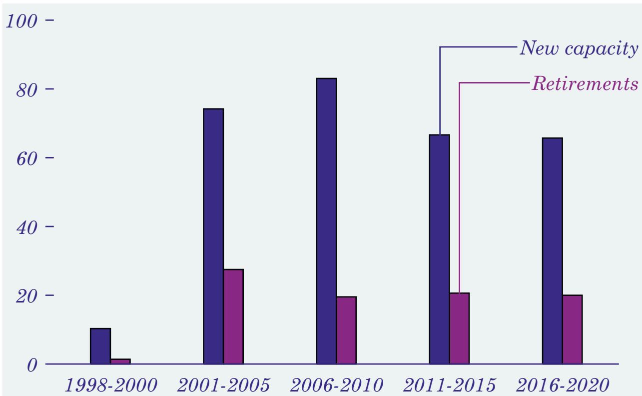
With the number of U.S. households projected to rise by 1.0 percent a year between 1998 and 2020, residential demand for electricity grows by 1.5 percent annually (Figure 67). Residential electricity demand changes as a function of the time of day, week, or year. During summer, residential demand peaks 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 1998 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 1.2 and 1.3 percent a year, respectively, between 1998 and 2020. Annual commercial floorspace growth of 0.9 percent and industrial output growth of 1.8 percent contribute to the increase.

In addition to sectoral sales, cogenerators in 1998 produced 165 billion kilowatthours for their own use in industrial and commercial processes, such as petroleum refining and paper manufacturing. By 2020, cogenerators are expected to see only a slight decline in their share of total generation, increasing their own-use generation to 184 billion kilowatthours as the demand for manufactured products increases.

Retirements of Nuclear Capacity Could Lead to Higher Fossil Fuel Use

Figure 68. New generating capacity and retirements, 1998-2020 (gigawatts)



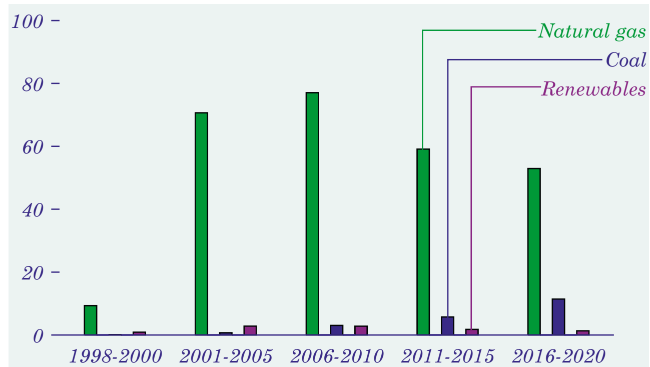
Despite slower demand growth, 300 gigawatts of new generating capacity will be needed by 2020 to meet growing demand and to replace retiring units. Between 1998 and 2020, 40 gigawatts (41 percent) of current nuclear capacity and 28 gigawatts (16 percent) of current fossil-steam capacity [*65*] are expected to be retired. Of the 132 gigawatts of new capacity needed after 2010 (Figure 68), 21 percent will replace retired nuclear capacity.

The reduction in baseload nuclear capacity has a marked impact on the electricity outlook after 2010: 46 percent of the new combined-cycle and 82 percent of the new coal-fired 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 with 49 percent for coal-steam units, and the construction costs for combined-cycle units are only about 41 percent of those for coal-steam plants.

As older nuclear power plants age and their operating costs rise, more than 40 percent 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.

A Thousand New Generating Plants Could Be Needed by 2020

Figure 69. Electricity generation and cogeneration capacity additions by fuel type, 1998-2020 (gigawatts)

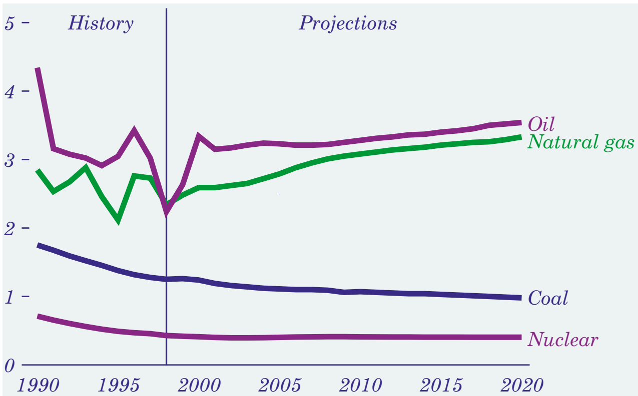


Before building new capacity, utilities are expected to use other options to meet demand growth—maintenance of existing plants, power imports from Canada and Mexico, and purchases from cogenerators. Even so, assuming an average plant capacity of 300 megawatts, a projected 1,000 new plants with a total of 300 gigawatts of capacity will be needed by 2020 to meet growing demand and to offset retirements. Of the new capacity, 90 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 21 gigawatts of new coal-fired capacity is projected to come on line between 1998 and 2020, accounting for almost 7 percent of all capacity expansion. Competition with low-cost gas-turbine-based technologies and the development of more efficient coal gasification systems have compelled vendors to standardize designs for coal-fired plants in efforts to reduce capital and operating costs in order to maintain a share of the market. Renewable technologies account for the remaining 3 percent of capacity expansion by 2020—primarily wind, biomass gasification, and municipal solid waste units. Oil-fired steam plants, with higher fuel costs and lower efficiencies, account for very little of the new capacity in the forecast. By 2020, annual investment in new capacity will be nearly $30 billion, assuming that the cost of new plants is recovered over a 20-year period.

Competition Is Expected To Reduce Electricity Generation Costs

Figure 70. Fuel prices to electricity generators, 1990-2020 (1998 dollars per million Btu)

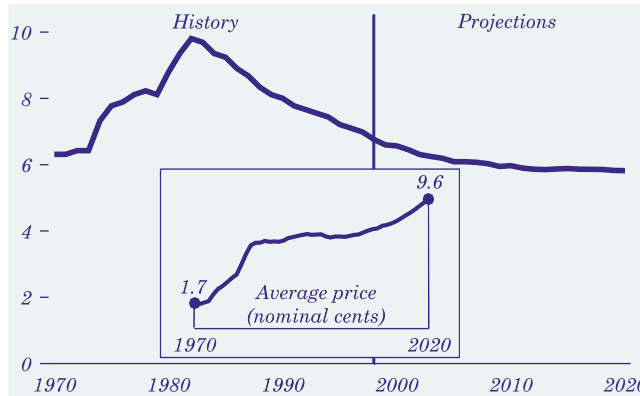


The cost of producing electricity is a function of fuel costs, operating and maintenance costs, and the cost of capital. In 1998, fuel costs for existing fossil plants typically represented $23 million annually—or 78 percent of the total operational costs (fuel and operating and maintenance)—for a 300-megawatt coal-fired plant, and $30 million annually—or 85 percent of the total operational costs—for a gas-fired combined-cycle plant of the same size. For nuclear plants, fuel costs are typically a much smaller portion of total production costs. Nonfuel operations and maintenance costs are a larger component of the operating costs for nuclear power plants than for fossil plants.

Over the projection period, the impact of rising gas prices is expected to be more than offset by the combination of falling coal prices and stable nuclear fuel costs. Natural gas prices to electricity suppliers rise by 1.6 percent a year in the forecast, from $2.40 per thousand cubic feet in 1998 to $3.41 in 2020 (Figure 70). Those increases are offset by declining coal prices, declining capital expenditures, and improved efficiencies for new plants. Sufficient supplies of uranium and fuel processing services are expected to keep nuclear fuel costs around $0.40 per million Btu (roughly 4 mills per kilowatthour) through 2020. Oil prices to utilities are expected to increase by 2.1 percent a year, leading to a decline in oil-fired generation of nearly 64 percent between 1998 and 2020. Oil currently accounts for only 3.4 percent of total generation, however, and that share is expected to decline to 0.9 percent by 2020 as oil-fired steam generators are replaced by gas turbine technologies.

Competitive Generation Markets Should Narrow Price Differences

Figure 71. Average U.S. retail electricity prices, 1970-2020 (1998 cents per kilowatthour)



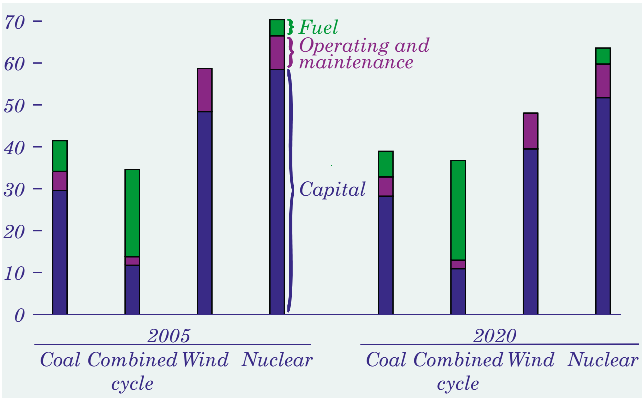
Between 1998 and 2020, the average price of electricity in real 1998 dollars is projected to decline by 0.6 percent a year as a result of competition among electricity suppliers (Figure 71). By sector, projected prices in 2020 are 10, 17, and 14 percent lower than 1998 prices for residential, commercial, and industrial customers, respectively.

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

Specific restructuring plans differ from State to State and utility to utility, but most call for a transition period during which customer access will be phased in. The transition period reflects the time needed for the establishment of competitive market institutions and the recovery of stranded costs as permitted by regulators. It is assumed that competition will be phased in between 1999 and 2007, with fully competitive prices beginning in 2008. In all the competitively priced regions, the generation price is set by the marginal cost of generation. Transmission and distribution prices are assumed to remain regulated.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 72. Electricity generation costs, 2005 and 2020 (1998 mills per kilowatthour)



Technology choices for new generating capacity are made to minimize cost while meeting local and Federal emissions constraints. The choice of technology for capacity additions is based on the least expensive option available (Figure 72). The reference case assumes a capital recovery period of 20 years. In addition, the cost of capital is based on competitive market rates, to account for the competitive risk of siting new units.

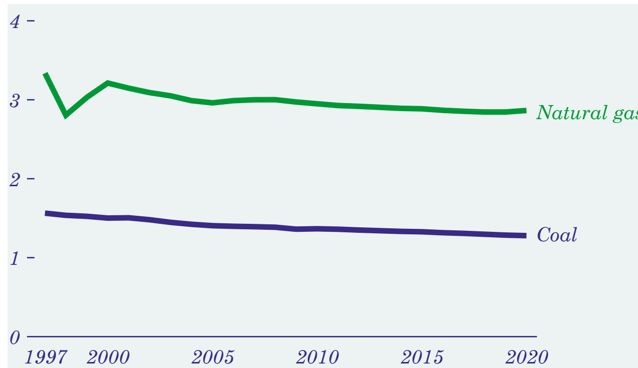
In the *AEO2000* projections, the costs and performance characteristics for new plants improve over time, at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, the costs are assumed to decline. The decline continues at a slower rate as more units are built. The performance (efficiency) of new plants is also assumed to improve, with heat rates declining by 5 to 18 percent between 1998 and 2010, depending on the technology (Table 9).

Table 9. Costs of producing electricity from new plants, 2005 and 2020

	2005		2020	
Item	Advanced coal	Advanced combined cycle	Advanced coal	Advanced combined cycle
	1998 mills per kilowatthour			
Capital	29.58	11.76	28.24	10.94
O&M	4.58	2.03	4.58	2.03
Fuel	7.32	20.82	6.12	23.77
Total	**41.48**	**34.61**	**38.94**	**36.74**
	Btu per kilowatthour			
Heat rate	9,253	6,639	9,087	6,350

Power Plant Operating Costs Are Expected To Continue Declining

Figure 73. Average operating costs for coal- and gas-fired generating plants, 1997-2020 (1998 cents per kilowatthour)

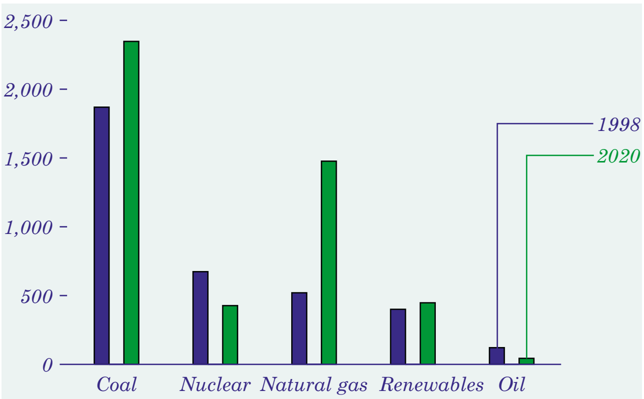


Since 1980, the per-kilowatthour operating costs for gas-fired and, particularly, coal-fired power plants have fallen significantly (Figure 73). For coal plants, fuel prices have been declining since the early 1980s. For gas plants, fuel prices rose in the early 1980s but declined sharply in 1986. Generating costs for coal-fired plants fell 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.

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

Figure 74. Electricity generation by fuel, 1998 and 2020 (billion kilowatthours)



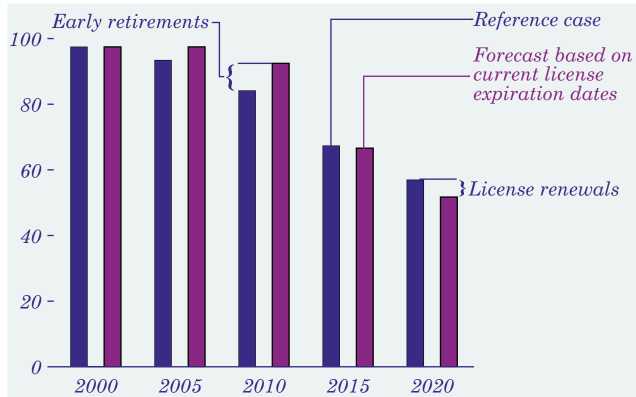
As they have since early in this century, coal-fired power plants are expected to remain the key source of electricity through 2020 (Figure 74). In 1998, coal accounted for 1,869 billion kilowatthours or 52 percent of total generation. Although coal-fired generation is projected to increase to 2,347 billion kilowatthours in 2020, increasing gas-fired generation reduces coal's share to 49 percent. Concerns about the environmental impacts of coal plants, their relatively long construction lead times, and the availability of economical natural gas make it unlikely that many new coal plants will be built before about 2005. Nevertheless, slow growth in other generating capacity, the huge investment in existing plants, and increasing utilization of those plants will keep coal in its dominant position. By 2020, it is projected that 21 gigawatts of coal-fired capacity will be retrofitted with scrubbers to meet the requirements of the Clean Air Act Amendments of 1990 (CAAA90).

The large investment in existing plants 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 shows the largest increase, from 14 percent of the 1998 total to 31 percent in 2020. As a result, by 2005, 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.

Some Nuclear Plants Are Expected To Operate Past Current License Dates

Figure 75. Nuclear capacity and license expiration dates, 2000-2020 (gigawatts)

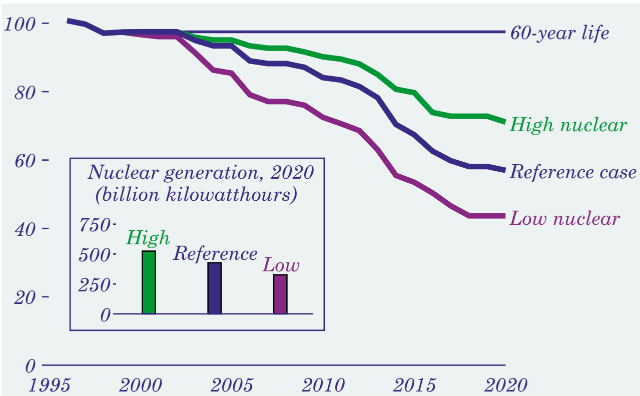


The United States currently has 104 operable nuclear units, which provided 19 percent of total electricity generation in 1998. In the reference case, 41 percent of current nuclear capacity is expected to be taken out of service by 2020, as operating licenses expire or units are retired early. Early retirements are based on the assumption that major aging-related investments will be needed after 30 years of operation and will be made only if they are more economical than building new capacity. Thirteen 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.

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. Utilities for 2 plants have submitted license renewal applications with the Nuclear Regulatory Commission, and as many as 12 more are scheduled to apply over the next 4 years. The forecast assumes that plants will continue to operate if further investments to combat aging effects after 40 and 50 years are more economical than building new capacity. The reference case projects that 12 units with license expiration dates before 2020 will continue operating after license renewals; as a result, the projections show more nuclear capacity on line in 2020 than would be operable if all units were retired at license expiration (Figure 75).

Nuclear Power Could Be Key to Reducing Carbon Emissions

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

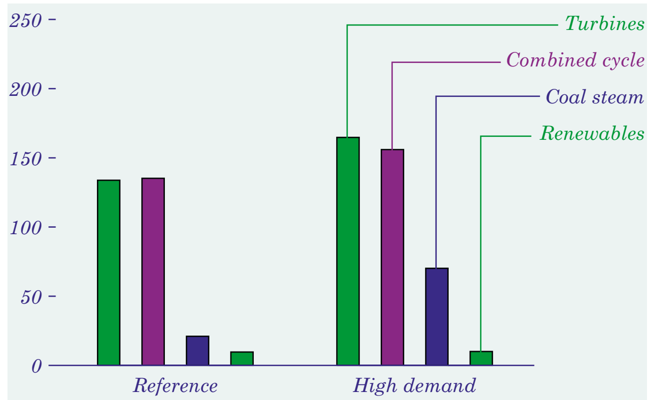


Two alternative cases—the high and low nuclear cases—show how nuclear plant retirement decisions affect the projections for capacity. If each plant operating today were able to operate for 20 years beyond its current license expiration date, nuclear capacity in 2020 would remain at the 1998 level (Figure 76). The high nuclear case assumes that the capital expenditures required after 40 years will be lower than in the reference case, 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. The low nuclear case assumes that the capital expenditures required for continued 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.

In the high nuclear case, 16 gigawatts of new fossil-fired capacity would not be needed, as compared with the reference case, and carbon emissions would be reduced by 5 million metric tons in 2010 and 14 million metric tons in 2020 (2 percent of total emissions by electricity generators). In the low nuclear case, more than 44 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 units (25 percent) and combined-cycle units (75 percent). The additional fossil-fueled capacity would produce 15 million metric tons of carbon emissions above those in the reference case in 2020.

High Demand Assumption Leads to Higher Fuel Prices for Generators

Figure 77. Cumulative new generating capacity by type in two cases, 1998-2020 (gigawatts)



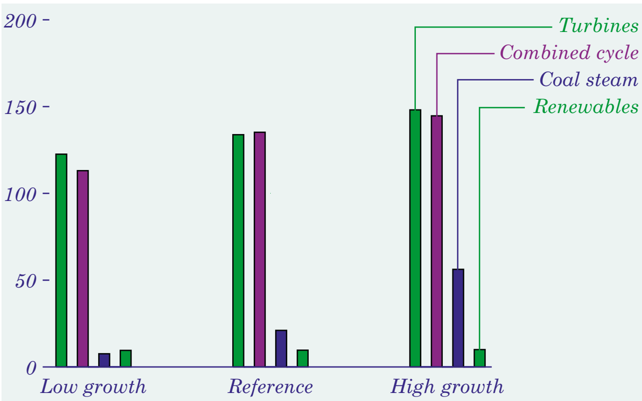
Electricity consumption grows in the forecast, but the rate of increase lags behind historical levels as a result of assumptions about efficiency improvements in end-use technologies, demand-side management programs, and population and economic growth. Deviations from the assumptions could result in substantial changes in electricity demand. In a high demand case, electricity demand is assumed to grow by 2.0 percent a year between 1998 and 2020, comparable to the growth rate of 2.2 percent a year between 1990 and 1998. In the reference case, electricity demand is projected to grow by 1.4 percent a year.

In the high demand case, an additional 101 gigawatts of new generating capacity—equivalent to 337 new 300-megawatt generating plants—is built between 1998 and 2020 as compared with the reference case (Figure 77). The shares of coal- and gas-fired (including non-coal steam, combustion turbine, combined cycle, and fuel cell) capacity additions change slightly: by 7 percent and 90 percent, respectively, in the reference case and by 18 percent and 80 percent in the high demand case. Relative to the reference case, there is a 13-percent increase in coal consumption and a 15-percent increase in natural gas consumption in the high demand case, and carbon emissions are 115 million metric tons (13 percent) higher.

More rapid growth in electricity demand also leads to higher prices. The price of electricity in 2020 is 6.5 cents per kilowatthour in the high demand case, compared with 5.8 cents in the reference case. Higher fuel prices, especially for natural gas, are the primary reason for the difference.

Rapid Economic Growth Would Boost Advanced Coal-Fired Capacity

Figure 78. Cumulative new generating capacity by type in three cases, 1998-2020 (gigawatts)



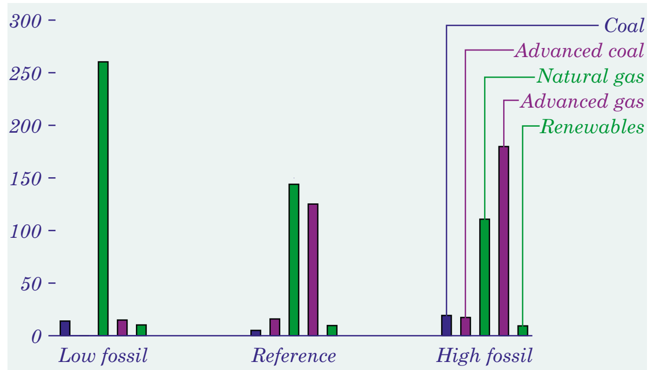
The annual average growth rate for GDP from 1998 to 2020 ranges from 2.6 percent in the high economic growth case to 1.7 percent in the low economic growth case. The difference of a percentage point in the economic growth rate leads to a 12-percent change in electricity demand in 2020, with a corresponding difference of 107 gigawatts of new capacity required in the high and low economic growth cases. Utilities are expected to retire about 12 percent of their current generating capacity (equivalent to 300 300-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 beyond that added in the reference case is expected to consist of new advanced coal-fired plants, which make up more than 59 percent of the projected new capacity in the high growth case. The stronger growth also stimulates additions of gas-fired plants, which account for 40 percent of the capacity increase in the high economic growth case over that projected in the reference case (Figure 78).

Current construction costs for a typical plant range from $450 per kilowatt for combined-cycle technologies to $1,100 per kilowatt for coal-steam technologies. Those costs, along with the difficulty of obtaining permits and developing new generating sites, make refurbishment of existing power plants a profitable option in some cases. Between 1998 and 2020, utilities are expected to maintain most of their older coal-fired plants while retiring many of their older, higher cost oil- and gas-fired generating plants.

Gas-Fired Technologies Lead New Additions of Generating Capacity

Figure 79. Cumulative new electricity generating capacity by technology type in three cases, 1998-2020 (gigawatts)

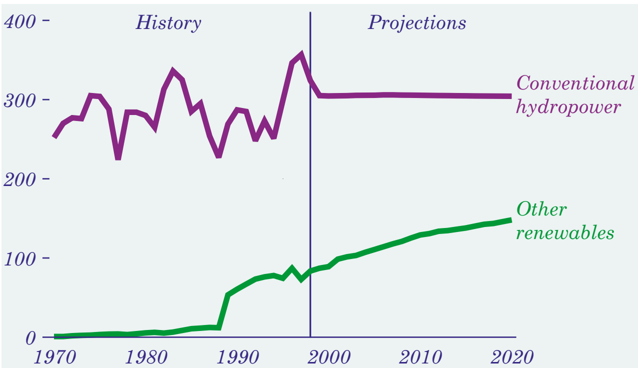


The *AEO2000* reference case uses the cost and performance characteristics of generating technologies to select the mix and amounts of new generating capacity for each year in the forecast. Numerical values for the characteristics of different technologies are determined in consultation with industry 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.

The basic story is the same in each of the three cases—gas technologies are expected to dominate new generating capacity additions (Figure 79). Across the cases the share of additions accounted for by gas technologies varies from 86 percent to 92 percent, and the mix between current and advanced gas technologies also varies across the cases. In the low fossil fuel case only 5 percent (15 gigawatts) of the gas plants added are advanced technology facilities, as compared with a 62-percent share (180 gigawatts) in the high fossil fuel case. Additions of coal-fired capacity increase slightly in the high fossil fuel case, but there is little change in additions of new renewable plants across the cases.

Renewable Generation Is Constrained by Relatively High Costs

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

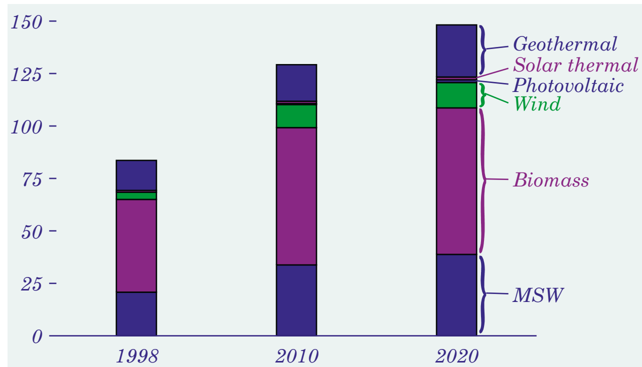


In the *AEO2000* reference case, projections are mixed for renewables in central station grid-connected U.S. electricity supply. State mandates produce substantial near-term growth for some renewable energy technologies, but generally higher costs are a disadvantage for renewables relative to fossil-fueled technologies over the forecast period as a whole. Total U.S. grid-connected electricity generation from renewable energy sources increases from 408 billion kilowatthours in 1998 to 452 billion kilowatthours in 2020, and generation from renewables other than hydroelectricity increases from 84 billion kilowatthours to 148 billion kilowatthours (Figure 80). Overall, renewables are projected to make up a smaller share of U.S. electricity generation, declining from 11.3 percent in 1998 to 9.5 percent in 2020.

Conventional hydroelectricity, which currently accounts for 80 percent of the electricity supply from renewables, declines slightly in the forecast. The expected addition of 620 megawatts of new capacity does not offset declines from existing hydroelectric facilities, as increasing environmental and other competing needs reduce their average productivity, and hydroelectric generation slips from 9.0 percent of the U.S. total in 1998 to 6.4 percent in 2020. The economic value of hydroelectric capacity is also likely to decline as environmental preferences shift generation to off-peak hours and seasons. If new legislation not assumed in the forecasts facilitates the removal of existing dams, hydroelectric generation will decline more sharply.

MSW and Biomass Lead the Increase in Renewable Fuel Use for Electricity

Figure 81. Nonhydroelectric renewable electricity generation by energy source, 1998, 2010, and 2020 (billion kilowatthours)



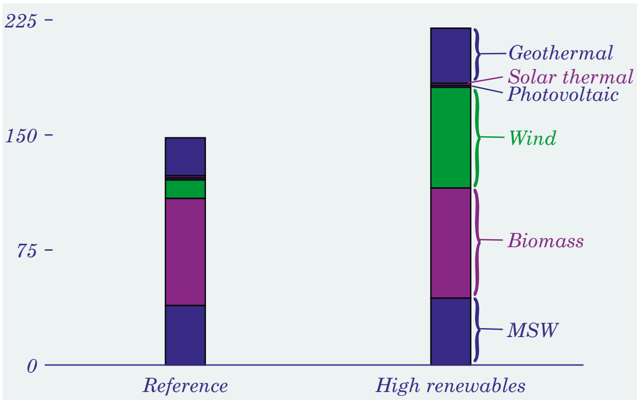
Most of the projected growth in renewable electricity generation is attributed to biomass, municipal solid waste (MSW), geothermal energy, and wind power (Figure 81). Generation from biomass and MSW increases the most, from a combined total of 65 billion kilowatthours in 1998 to 109 billion in 2020. Generation from biomass, particularly in the pulp and paper industries, grows by nearly 26 billion kilowatthours through 2020, more than half of which is from industrial cogeneration and the remainder either from plants using biomass strictly for electricity generation or from biomass co-firing in coal-fired plants, as co-firing is used increasingly to reduce emissions. Dedicated biomass-consuming capacity, with higher capital and fuel costs than fossil-fueled technologies, increases by only 1.2 gigawatts.

U.S. wind-powered generating capacity increased by a total of nearly 860 megawatts in 1998 and 1999, spurred by the now-expired Federal production tax credit. State mandates are estimated to yield nearly 2,400 megawatts of additional new wind capacity from 1999 through 2010, and more than 400 additional megawatts through 2020. Nevertheless, higher capital costs, lower output per kilowatt, and limited predictability put wind power at a disadvantage relative to natural gas and coal technologies.

Geothermal energy capacity is projected to increase by 860 megawatts between 1998 and 2020, contributing an additional 10 billion kilowatthours of generation in 2020. Solar technologies are not expected to add significantly to central station power generation, but off-grid and distributed applications for photovoltaics should continue robust growth.

Wind Energy Use Would Gain Most From Cost Reductions

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



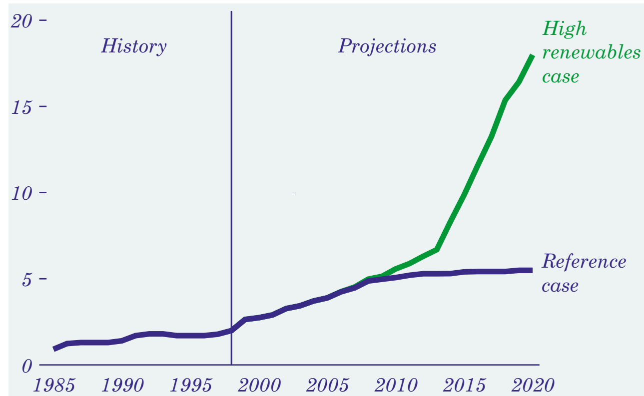
The *AEO2000* high renewables case assumes markedly more favorable cost and performance characteristics for renewable energy technologies than are assumed in the reference case, including capital costs that by 2020 average about 15 percent below costs in the reference case, reduced operations and maintenance costs, increased biomass fuel supplies, and higher capacity factors for solar and wind power plants. Fossil and nuclear technology characteristics remain unchanged from the reference case.

Results of the high renewables case suggest that greater technology improvements would accelerate some growth in renewable energy use, primarily after 2015, but would not significantly change the overall dominance of fossil-fueled technologies in U.S. electricity supply. Including cogeneration, total generation from nonhydroelectric renewables is projected to reach 220 billion kilowatthours in 2020 for the high renewables case compared with 148 billion for the reference case (Figure 82), increasing from 3.1 percent of total generation to 4.6 percent. Nearly 50 billion kilowatthours of the difference comes from an additional 12.5 gigawatts of wind capacity (Figure 83) and the remainder from geothermal, MSW, and biomass generation, whereas solar photovoltaic and thermal technologies remain too costly for central station generation.

The increase in renewable energy use in the high renewables case reduces the use of coal and natural gas, lowering carbon emissions from electricity generation by 12 million metric tons (1.6 percent). Retail electricity prices do not change significantly from those in the reference case.

State Mandates Call for More Generation From Renewable Energy

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

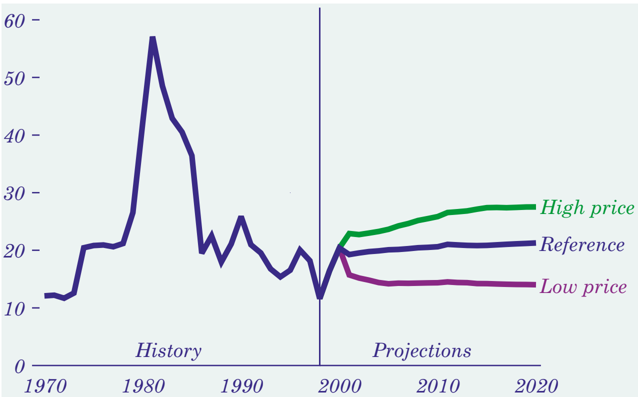


AEO2000 shows rapidly increasing State requirements to invest in renewable energy technologies. The requirements, reflecting both energy and environmental interests, ensure investment in renewables despite increasingly competitive electricity markets. Renewable portfolio standards, which require increasing percentages of electricity supplies from renewables, are the most common, although other mandates also exist. Requirements differ from State to State, reflecting varying renewable resources, supporting industries, and supply alternatives. In *AEO98,* no quantifiable State mandates existed. *AEO99* projected 2,010 megawatts of renewable capacity additions as a result of State mandates through 2020.

The implementation plans for most State renewable energy mandates are uncertain, and it is difficult to project the effects of renewable portfolio standards in some cases. Nevertheless, for *AEO2000,* it is estimated that State mandates will require additions of 5,168 megawatts of central station renewable generating capacity from 1999 through 2020, including 4,652 megawatts as a result of renewable portfolio standards. The resulting additions are expected to include 2,798 megawatts of wind capacity, 2,162 megawatts of MSW (primarily landfill gas) and biomass capacity, 163 megawatts of geothermal capacity, and 46 megawatts of central station solar (photovoltaic and thermal) capacity. Additions average a few hundred megawatts a year through 2012, needed to meet the increasing requirements. Less than 400 megawatts of renewable generating capacity is expected to be built after 2012, however, to maintain the required shares.

Oil Prices Are Expected To Remain Above Low 1998 Levels

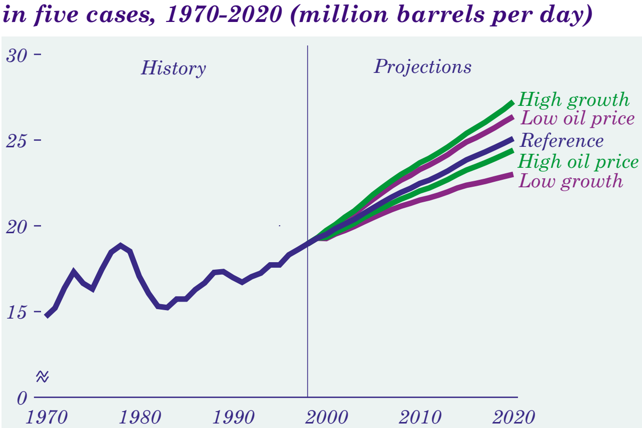
Figure 84. Lower 48 crude oil wellhead prices in three cases, 1970-2020 (1998 dollars per barrel)



Because domestic prices for crude oil are determined largely by the international market, the recovery from the 1998 decline in world oil prices causes a steep increase in wellhead prices for crude oil in the lower 48 States from 1998 through 2000 in all cases. After 2000, prices initially decline in the reference and low world oil price cases, then prices in all cases generally increase through the rest of the forecast. Prices remain above 1998 levels throughout the forecast in all cases, with wellhead prices projected to increase by 0.9, 2.8, and 4.0 percent a year from 1998 to 2020 in the low world oil price, reference, and high world oil price cases, respectively (Figure 84).

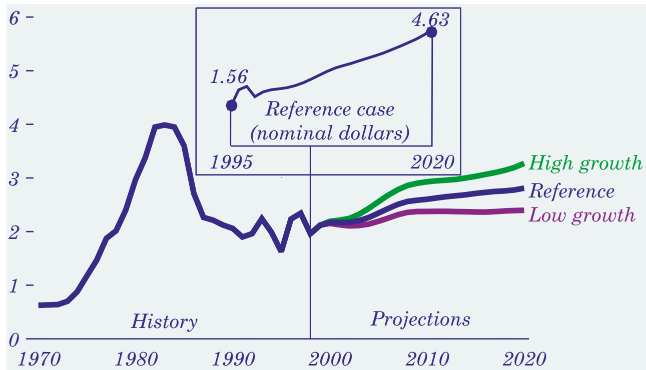
U.S. petroleum consumption continues to rise in all the *AEO2000* cases (Figure 85). Total petroleum product supplied ranges from 23.0 million barrels per day in the low economic growth case to 27.3 million in the high growth case, as compared with 18.9 million barrels per day in 1998.

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



Rising Demand Increases Natural Gas Prices in All Economic Growth Cases

Figure 86. Lower 48 natural gas wellhead prices in three cases, 1970-2020 (1998 dollars per thousand cubic feet)



Wellhead prices for natural gas in the lower 48 States increase on average by 0.9, 1.7, and 2.4 percent a year in the low economic growth, reference, and high economic growth cases, respectively (Figure 86). The reference case price increases from \$1.96 per thousand cubic feet in 1998 to \$2.81 in 2020. 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. Growth in lower 48 unconventional gas production ranges from 1.3 to 2.7 percent a year across cases, compared with a 2.1- to 2.2-percent range in annual growth for conventional sources across the cases. Despite the changes in sources of production, technically recoverable resources (Table 10) remain more than adequate overall to meet the production increases.

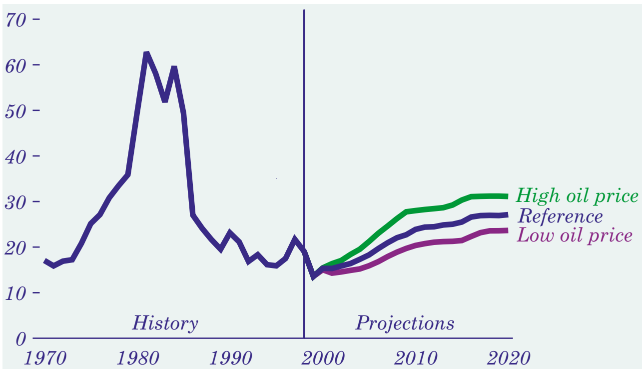
Although consumption, and thus production and price levels, for natural gas rise in all three cases, the price increases attributable to the rising demand are tempered by the beneficial impacts of technological progress on both the discovery process and production operations.

Table 10. Technically recoverable U.S. oil and gas resources as of January 1, 1998

Total U.S. resources	Crude oil (billion barrels)	Natural gas (trillion cubic feet)
Proved	24	167
Unproved	116	1,092
Total	**140**	**1,259**

Rising Gas Prices and Lower Drilling Costs Increase Well Completions

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



Both exploratory drilling 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 1.4 and 2.7 percent a year in the low and high oil price cases, respectively, compared with 2.1 percent in the reference case (Figure 87). Projected oil drilling varies more than gas drilling in the world oil price cases (Table 11), reflecting the relative sizes of the changes in prices for the two fuels.

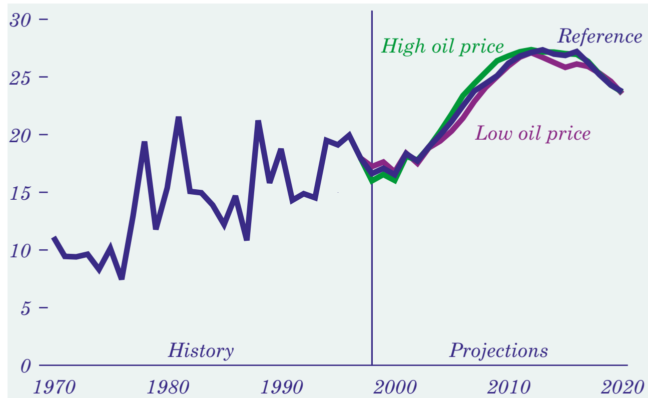
The productivity of natural gas drilling does not decline as much as that of oil drilling, in part because total recoverable gas resources are more abundant than oil resources. At the projected production levels, however, undiscovered recoverable resources of conventional natural gas decline rapidly in some areas, particularly in the onshore Gulf Coast 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 [*66*].

Table 11. Natural gas and crude oil drilling in three cases, 1998-2020 (thousand successful wells)

	1998	2000	2010	2020
Natural gas				
Low oil price case		10.7	14.5	16.5
Reference case	12.1	11.0	15.9	16.9
High oil price case		11.0	17.3	16.7
Crude oil				
Low oil price case		4.3	5.8	7.2
Reference case	7.0	4.4	7.9	10.2
High oil price case		4.4	10.7	14.4

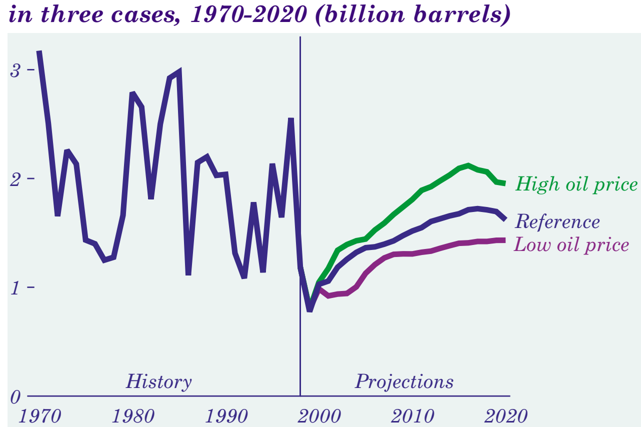
High Levels of Gas Reserve Additions Are Projected Through 2020

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



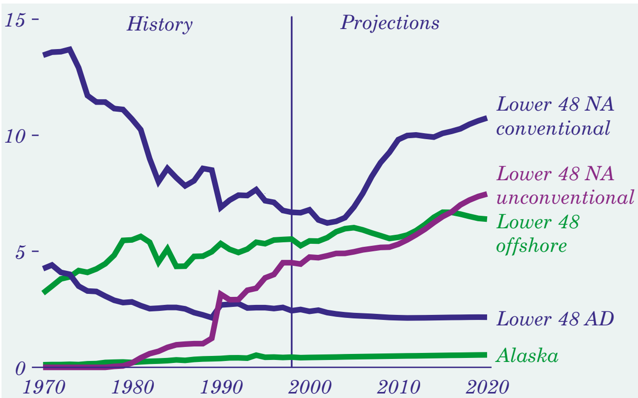
Although for most of the past two decades lower 48 production of both oil and natural gas has exceeded reserve additions, the pattern for natural gas reversed from 1994 through 1997. In 1998, falling prices caused production to exceed reserve additions again. After 2003, rising prices in the forecast cause natural gas reserve additions generally to exceed production until close to the end of the projection period (Figure 88), even with expected increases in demand. Relatively high levels of annual gas reserve additions through 2020 reflect increased exploratory and developmental drilling as a result of higher prices, as well as productivity gains from technology improvements comparable to those of recent years. 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)



Significant New Finds Are Likely To Continue Increases in Gas Production

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 35.7 percent of total U.S. domestic production in 1998, increases in share to 40.7 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.

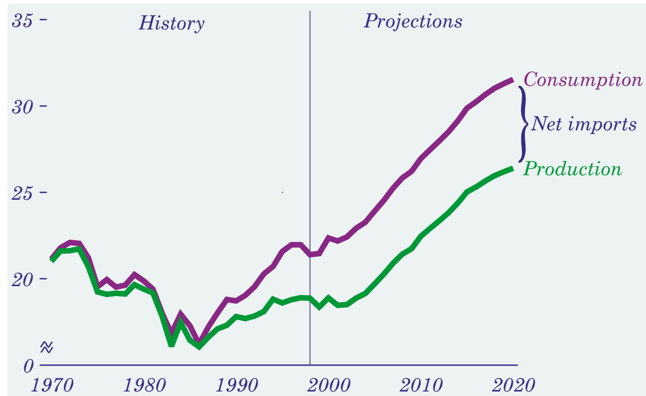
Production from conventional sources is projected to grow rapidly through 2010 in response to increasing demand. After 2010, slower growth of consumption and higher production from increasingly economical offshore and unconventional sources cause production from conventional sources to level off.

Natural gas production from Alaska grows by 0.9 percent a year in the forecast. Alaskan gas is not expected to be transported to the lower 48 States, however, because the projected lower 48 prices are not high enough in the forecast period to support the required transport system [*67*].

Production of associated-dissolved (AD) natural gas from lower 48 crude oil reservoirs generally declines in the projections, following the expected pattern of domestic crude oil production. AD gas accounts for 8.4 percent of total lower 48 production in 2020, compared with 13.3 percent in 1998.

Net Imports of Natural Gas Grow in the Projections

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



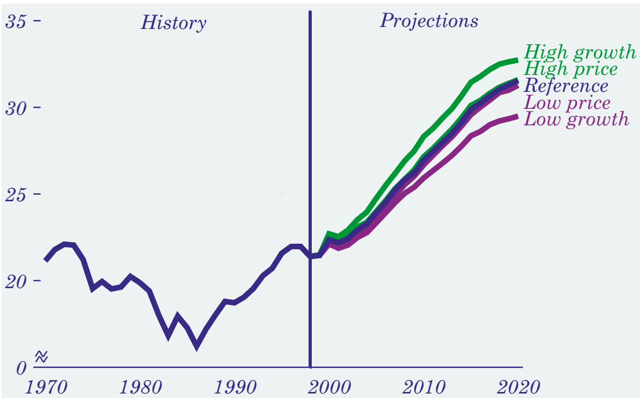
Net natural gas imports are expected to grow in the forecast (Figure 91) from 14.6 percent of total gas consumption in 1998 to 16.3 percent in 2020. Most of the increase is attributable to imports from Canada, which are projected to grow substantially. Although most of the additional imports come from western Canada, new pipeline capacity is also expected to provide access to eastern supplies. Natural gas from Sable Island, in the offshore Atlantic, is expected to begin flowing in late 1999.

Mexico has a considerable natural gas resource base, but its indigenous production is unlikely to increase sufficiently to satisfy rising demand. Since 1984, U.S. natural gas trade with Mexico has consisted primarily of exports. That trend is expected to continue throughout the forecast, especially in light of the recent elimination of the 4-percent import tariff and an increase in cross-border pipeline capacity. U.S. exports to Mexico are projected to grow from 50 billion cubic feet in 1998 to 240 billion cubic feet in 2020.

Imports of liquefied natural gas (LNG) are projected to grow at a rate of 7.2 percent a year, resulting in part from a 50-percent expansion of capacity at the Everett, Massachusetts, terminal and the projected reactivation of the Elba Island terminal in 2002. In spite of this activity, 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 are projected to reach a level of 0.39 trillion cubic feet in 2020, compared with 0.07 trillion cubic feet in 1998 [*68*].

Significant Increases in Natural Gas Use Are Seen in All Cases

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

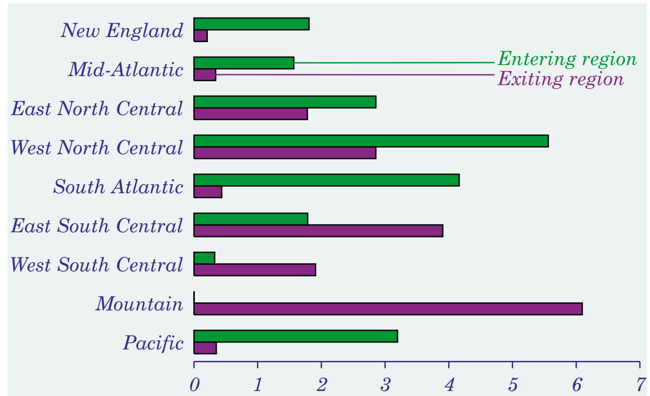


Natural gas consumption increases from 1998 to 2020 in all the *AEO2000* cases (Figure 92). Domestic consumption ranges from 29.5 trillion cubic feet per year in the low economic growth case to 32.7 trillion cubic feet in the high growth case in 2020, as compared with 21.4 trillion cubic feet in 1998. Growth is seen in all end-use sectors, and more than half the increase results from rising demand for electricity generation. Natural gas consumption in the electricity generation sector grows steadily throughout the forecast, as demand for electricity increases and retiring nuclear and older oil and gas steam plants are replaced by turbines and combined-cycle facilities.

In the reference case, natural gas consumption for electricity generation more than doubles, from 3.7 trillion cubic feet in 1998 to 9.3 trillion cubic feet in 2020. Although projected coal prices to the electricity generation sector fall throughout the forecast, the natural gas share of new capacity far outpaces the coal share. Lower capital costs, shorter construction lead times, higher efficiencies, and lower emissions give gas an advantage over coal for new generation in most regions of the United States. Natural-gas-fired facilities are less capital-intensive than coal, nuclear, or renewable electricity generation plants. Growth in natural gas use for electricity generation is also expected to be spurred by increased utilization of existing gas-fired power plants and by the environmental advantages of natural gas.

Gas Pipeline Capacity Expansion Is Needed To Serve New Markets

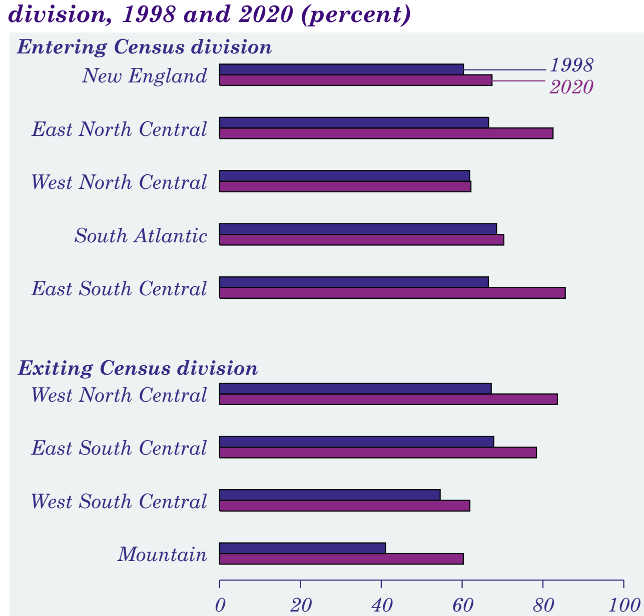
Figure 93. Pipeline capacity expansion by Census division, 1998-2020 (billion cubic feet per day)



Projected growth in natural gas consumption will require additional 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 an average rate of 0.8 percent a year in the forecast.

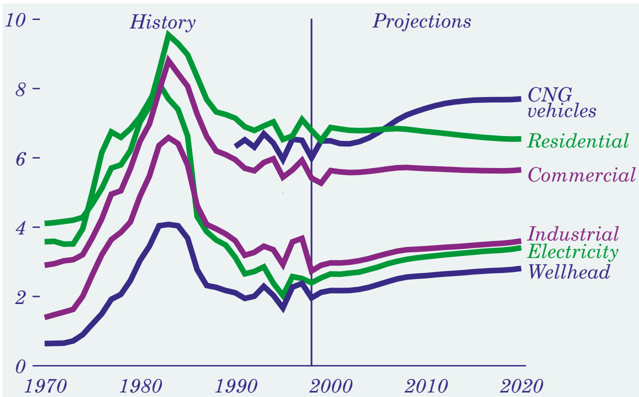
The greatest increases in capacity are expected along the corridors that provide access to Canadian, Gulf Coast, and Mountain region supplies and deliver them to the South Atlantic, Pacific, and Northeast regions. In all regions, growth in new pipeline construction is tempered by higher utilization of existing pipeline capacity (Figure 94).

Figure 94. Pipeline capacity utilization by Census division, 1998 and 2020 (percent)



Competitive Markets Keep Residential Gas Prices in Check

Figure 95. Natural gas end-use prices by sector, 1970-2020 (1998 dollars per thousand cubic feet)



While consumer prices to the industrial, electricity, and transportation sectors increase steadily throughout the forecast period, prices to the residential and commercial sectors remain within 5 percent of 1998 levels (Figure 95). The limited price fluctuations reflect declining distribution margins to these sectors due in part to anticipated efficiency improvements in an increasingly competitive market. Because industrial sector margins remain relatively constant, the growth in end-use prices results mainly from wellhead price increases. In the electricity generation sector, increases in pipeline margins and wellhead prices combine to yield an average 1.6-percent annual rise in end-use prices.

Compared with their rise and decline over the 1970 to 1998 period, transmission and distribution revenues in the natural gas industry are projected to grow steadily from 2002 forward, increasing overall at an average rate of 0.6 percent a year (Table 12). Declines in margins are balanced by higher volumes.

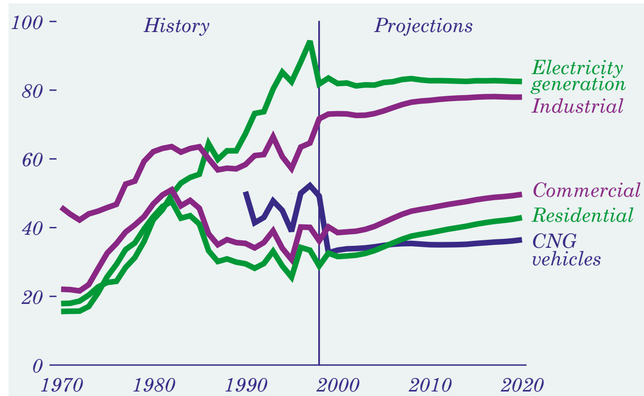
Table 12. Transmission and distribution revenues and margins, 1970-2020

	1970	1985	1998	2010	2015	2020
T&D revenues (billion 1998 dollars)	30.73	49.62	40.14	44.36	45.72	46.12
End-use consumption (trillion cubic feet)	19.21	15.97	19.42	24.68	27.39	28.90
Average margin* (1998 dollars per thousand cubic feet)	1.62	3.14	2.07	1.80	1.67	1.60

*Revenue divided by end-use consumption.

Distribution Costs Claim a Smaller Share of Residential Gas Prices

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.

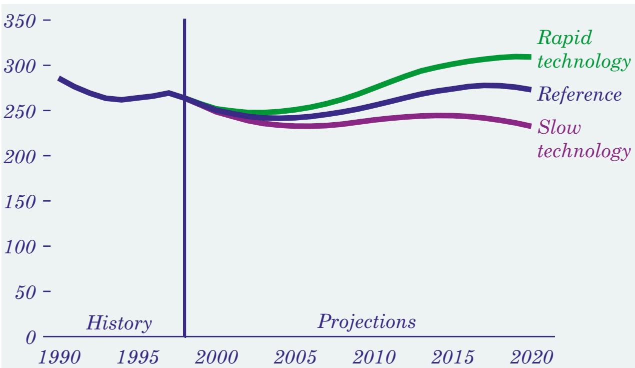
Changes have been seen historically in all components of end-use prices (Table 13). Pipeline margins decreased significantly between 1985 and 1998 with industry restructuring. Although the cost of interstate pipeline expansion causes margins to increase through 2000, modest decreases are projected to continue through the remainder of the forecast period. LDC margins in the residential sector are initially above 1985 levels, but efficiency improvements and other impacts of restructuring exert downward pressure on distribution costs, and reduced margins are projected for both the residential and commercial sectors.

Table 13. Components of residential and commercial natural gas end-use prices, 1985-2020 (1998 dollars per thousand cubic feet)

Price Component	1985	1998	2000	2010	2020
Wellhead price	3.60	1.96	2.17	2.60	2.81
Citygate price	5.38	3.02	3.34	3.76	3.93
Pipeline margin	1.78	1.06	1.17	1.16	1.12
LDC margin					
Residential	3.40	3.77	3.54	3.00	2.62
Commercial	2.51	2.40	2.29	1.93	1.73
End-use price					
Residential	8.78	6.79	6.88	6.76	6.55
Commercial	7.89	5.42	5.63	5.69	5.66

Total Oil and Gas Reserves Change Little Throughout the Forecast

Figure 97. Lower 48 crude oil and natural gas end-of-year reserves in three cases, 1990-2020 (quadrillion Btu)



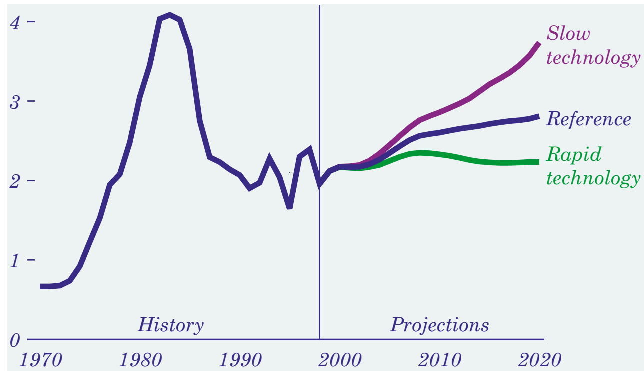
In the forecast, major advances in data acquisition, data processing, and the display and integration of seismic data with other geologic data—combined with lower cost computer power and experience gained with new techniques—continue to put downward pressure on costs while significantly improving finding 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 assess the sensitivity of the projections to changes in success rates, exploration and development costs, and finding rates as a result of technological progress. The assumed technology improvement rates increase and decrease by approximately one-third in the rapid and slow technology cases, which are analyzed as fully integrated model runs. All other parameters in the model are at their reference case values, including technology parameters in other energy markets, parameters affecting foreign oil supply, and assumptions about foreign natural gas trade, excluding Canada.

Although gas reserves make up 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 13.2 percent higher in the rapid technology case than in the reference case and 14.8 percent lower in the slow technology case.

Gas Price Projections Change With Technology Assumptions

Figure 98. Lower 48 natural gas wellhead prices in three cases, 1970-2020 (1998 dollars per thousand cubic feet)



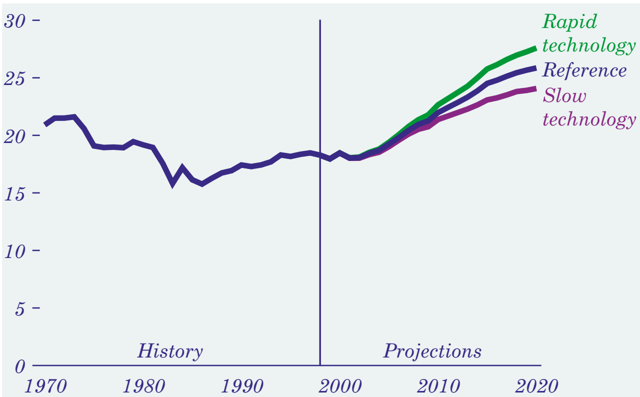
The natural gas price projections are highly sensitive to changes in assumptions about technological progress (Figure 98). Lower 48 wellhead prices increase at an average annual rate of 3.0 percent in the slow technology case, compared with only 1.7 percent in the reference case, over the projection period. In the rapid technology case, average natural gas wellhead prices are projected to remain below the 1997 average wellhead price of $2.39 per thousand cubic feet through 2020.

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 33.1 percent higher (at $3.74 per thousand cubic feet) in the slow technology case and 20.6 percent lower (at $2.23 per thousand cubic feet) in the rapid technology case than the reference case level of $2.81 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 19 cents lower in the rapid technology case and 6 cents higher in the slow technology case than the reference case price of $21.27 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.

Advances in Recovery Technologies Promote Increased Gas Production

Figure 99. Lower 48 natural gas production in three cases, 1970-2020 (trillion cubic feet)



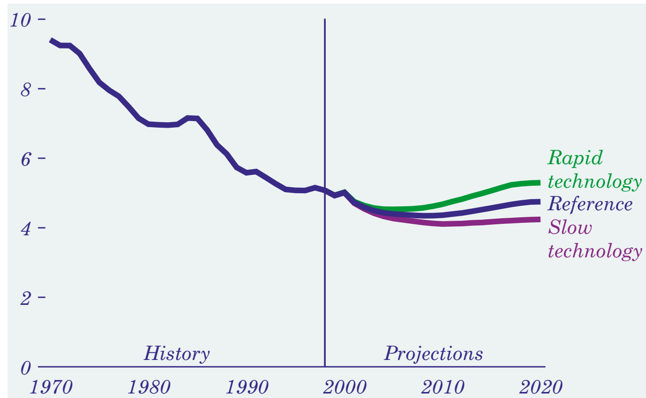
Changes in production in the alternative technology cases reflect the benefits of lower costs and higher finding rates for conventionally recoverable gas, as well as an array of technological enhancements for unconventional gas recovery. The changes in supply lead to price changes that affect new investment in all types of gas-fired technologies, especially in the more price-responsive 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 31.9 percent, compared with 22.3 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.

A slower rate of technology improvement is projected to have little effect on offshore production, whereas rapid technology improvement leads to an 18.9-percent increase in production relative to the reference case in 2020. The reverse is true for unconventional sources: rapid technology improvement has little impact, but slow improvement leads to a 14.2-percent decrease in production relative to the reference case in 2020.

Technology Advances Could Increase Offshore and Alaskan Oil Production

Figure 100. Lower 48 crude oil production in three cases, 1970-2020 (million barrels per day)



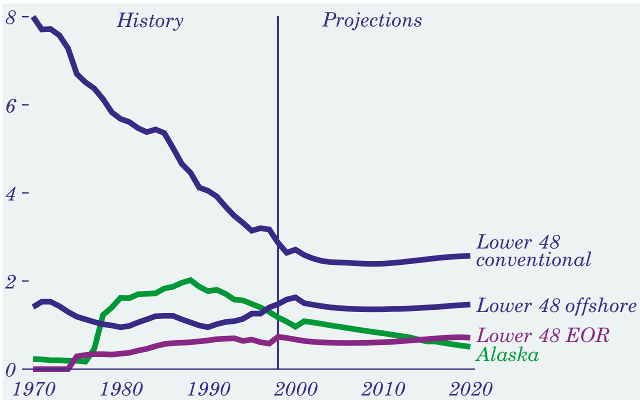
The projections for domestic oil production also are sensitive to changes in the technological progress assumptions (Figure 100). In comparison with the projected lower 48 production level of 4.8 million barrels per day in 2020 in the reference case, oil production increases to 5.3 million barrels per day in the rapid technology case and decreases to 4.2 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 11.0 million barrels per day in the rapid technology case to a high of 12.2 million barrels per day in the slow technology case.

Offshore oil production in the lower 48 States shows more sensitivity than onshore production to changes in technological progress assumptions, because large deepwater fields that are not economically feasible in the slow technology case become profitable in the rapid technology case. In the rapid technology case, offshore production in 2020 is about 250,000 barrels per day (17 percent) higher than in the reference case, and in the slow technology case it is 190,000 barrels per day (13 percent) lower. For onshore production, in contrast, the differences are only 9 percent and 10 percent. The projections for Alaskan production are even more sensitive to the technology assumptions, varying by more than 17 percent from the reference case in both the rapid and slow technology cases.

Domestic Crude Oil Production Continues To Decline

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



Projected domestic crude oil production continues its historic decline through 2005 (Figure 101). After 2005, technological improvements [*69*] and rising prices are projected to arrest the decline, leading to relatively stable lower 48 production in the remainder of the forecast. In 2020, the projected domestic production level of 5.3 million barrels per day is 1 million barrels per day less than the 1998 level. Conventional onshore production in the lower 48 States, which accounted for 45.9 percent of total U.S. crude oil production in 1998, is projected to increase to a 48.9-percent share in 2020.

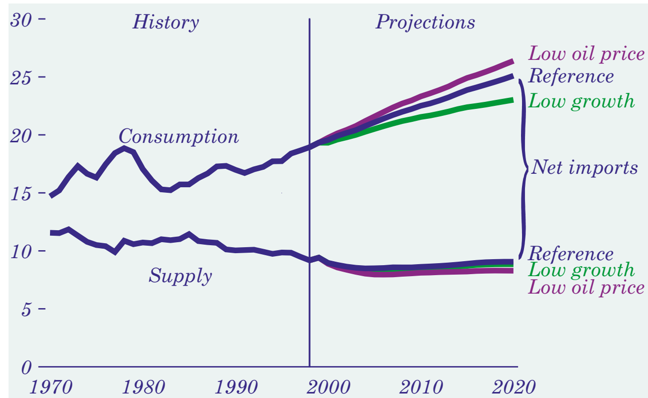
Crude oil production from Alaska is expected to decline at an average annual rate of 3.7 percent between 1998 and 2020. The overall decrease in Alaska's oil production results from a continuing decline in production from most of its oil fields and, in particular, from Prudhoe Bay, the largest producing field, which historically has accounted for more than 60 percent of total Alaskan production.

Offshore production ranges from 1.4 to 1.6 million barrels per day throughout the forecast. Technological advances and lower costs for deep exploration and production in the Gulf of Mexico help to offset a decline in production from shallow waters.

Production from enhanced oil recovery (EOR) [*70*], which becomes less profitable as oil prices fall, slows through 2006 and then increases along with world oil prices through the remainder of the forecast. The projected EOR production in 2020 is close to the 1998 level.

Imports Fill the Gap Between Domestic Supply and Demand

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



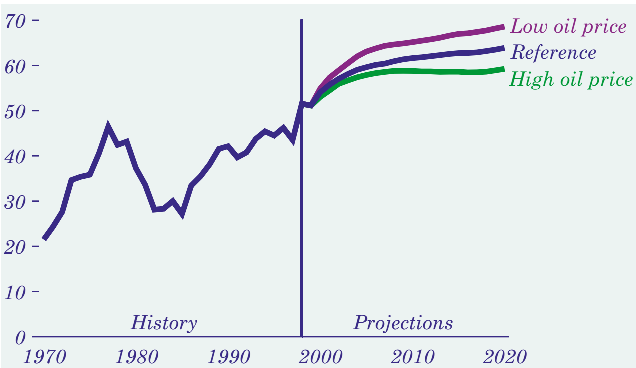
In the reference case, domestic petroleum supply declines slightly from its 1998 level of 9.2 million barrels per day to 9.1 million barrels per day in 2020 (Figure 102). As U.S. crude oil production falls off, refinery gain and production of natural gas plant liquids increase. In the low oil price case, domestic supply drops to 8.3 million barrels per day in 2020. In the high oil price case, domestic supply increases to 9.9 million barrels per day in 2020.

The greatest variation in petroleum consumption levels is seen across the economic growth cases, with an increase of 8.3 million barrels per day over the 1998 level in the high growth case, compared with an increase of only 4.1 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 18.1 million barrels per day in the low oil price case to a low of 14.2 million barrels per day in the low growth case, compared with the 1998 level of 9.8 million barrels per day. The value of petroleum imports in 2020 ranges from $108.3 billion in the low price case to $161.3 billion in the high economic growth case. Total annual U.S. expenditures for petroleum imports, which reached a historical peak of $133.7 billion (in 1998 dollars) in 1980 [*71*], were $46.6 billion in 1998.

Continued Dependence on Petroleum Imports Is Projected

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



In 1998, net imports of petroleum climbed to a record 52 percent of domestic petroleum consumption. Continued dependence on petroleum imports is projected, reaching 64 percent in 2020 in the reference case (Figure 103). The corresponding import shares of total consumption in 2020 are 59 percent in the high oil price case and 69 percent in the low price case.

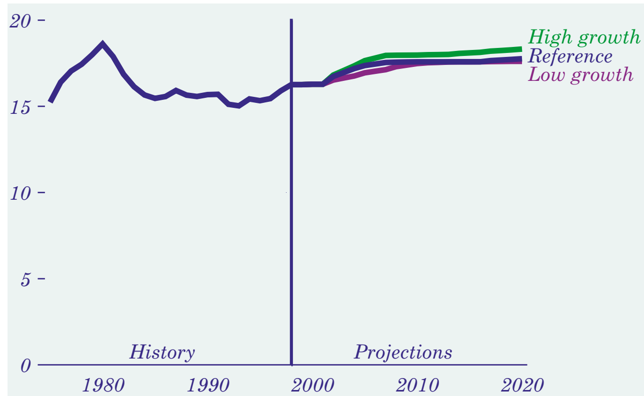
Although crude oil is expected to continue as the major component of petroleum imports, refined products represent a growing share. More imports will be needed as growth in demand for refined products exceeds the expansion of domestic refining capacity. Refined products make up 19 percent of net petroleum imports in 2020 in the low economic growth case and 34 percent in the high growth case, as compared with their 12-percent share in 1998 (Table 14).

Table 14. Petroleum consumption and net imports in five cases, 1998 and 2020 (million barrels per day)

Year and projection	Product supplied	Net imports	Net crude imports	Net product imports
1998	18.9	9.8	8.6	1.2
2020				
Reference	25.1	16.0	11.6	4.5
Low oil price	26.4	18.1	12.5	5.6
High oil price	24.4	14.5	10.9	3.6
Low growth	23.0	14.2	11.4	2.7
High growth	27.3	17.6	11.7	5.9

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

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



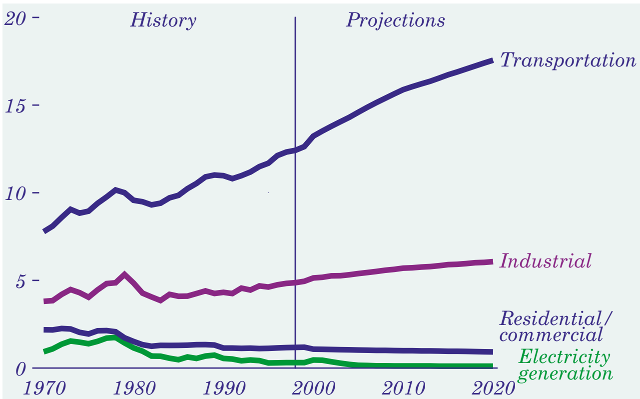
Falling demand for petroleum and the deregulation of the domestic refining industry in the 1980s led to 13 years of decline in U.S. refinery capacity. That trend was reversed in 1995, and 0.9 million barrels per day of distillation capacity had been added by 1999. Financial and legal considerations make 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 *AEO2000* cases (Figure 104).

Distillation capacity is projected to grow from the 1998 year-end level of 16.3 million barrels per day to 17.6 million in 2020 in the low economic growth case and 18.3 million in the high growth case, compared with the 1981 peak of 18.6 million barrels per day. Almost all the capacity additions are projected to occur on the Gulf Coast. Existing refineries will continue to be utilized intensively throughout the forecast, in a range from 93 percent to 96 percent of design capacity. In comparison, the 1998 utilization rate was 96 percent, well above the rates of the 1980s and early 1990s.

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

Petroleum Use Increases Mainly in the Transportation Sector

Figure 105. Petroleum consumption by sector, 1970-2020 (million barrels per day)



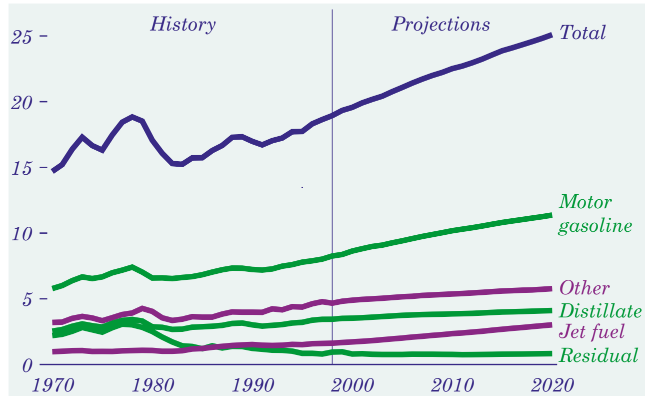
U.S. petroleum consumption is projected to increase by 6.2 million barrels per day between 1998 and 2020. Most of the increase in petroleum consumption occurs in the transportation sector, which accounted for two-thirds of U.S. petroleum use in 1998 (Figure 105). Petroleum use for transportation increases by 5.4 million barrels per day in the reference case, 4.0 million in the low economic growth case, and 6.7 million in the high economic growth case.

In the industrial sector, which accounts for more than a quarter of U.S. petroleum use, consumption in 2020 is higher than the 1998 level by 1.2 million barrels per day in the reference case, 0.6 million in the low economic growth case, and 1.9 million in the high economic growth case. More than half the growth is expected in the petrochemical, construction, and refining sectors.

Petroleum use is expected to decline in the residential, commercial, and electricity generator sectors, where oil gives ground to natural gas. Increased oil use for heating and electricity generation is seen only in the low oil price case. Natural gas use for home heating is growing in New England, the last stronghold of heating oil. Compared with 1998, heating oil use is 160,000 barrels a day lower in 2020 in the high price case and 30,000 barrels a day higher in the low price case. For electricity generation, oil-fired steam plants are being retired in favor of natural gas combined-cycle units. Oil use for electricity generation is 480,000 barrels a day lower in 2020 than in 1998 in the high price case and 360,000 barrels a day higher in the low price case.

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

Figure 106. Consumption of petroleum products, 1970-2020 (million barrels per day)



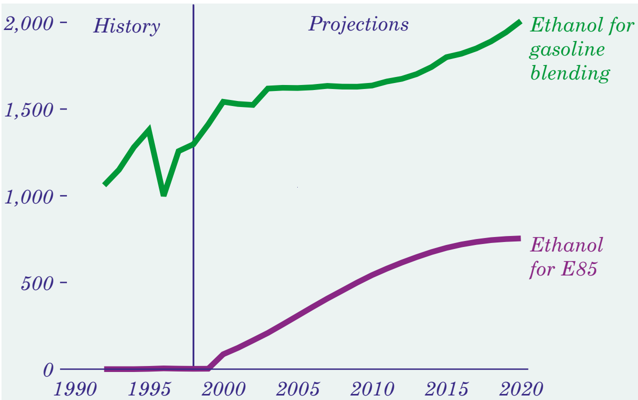
More than 90 percent of the projected growth in petroleum consumption stems from increased consumption of "light products," including gasoline, diesel, heating oil, jet fuel, and liquefied petroleum gases, which are more difficult and costly to produce than heavy products (Figure 106). Although refinery investments and enhancements are expected to increase the ability of domestic refineries to produce light products, they will compensate for less than half the additional demand; the remainder will be imported.

In the forecast, gasoline continues to account for about 45 percent of all the petroleum used in the United States. Between 1998 and 2020, U.S. gasoline consumption rises from 8.3 million barrels a day to 11.4 million barrels a day.

Increased air travel results in a near doubling of jet fuel consumption from 1.6 million barrels a day in 1998 to 3.0 million in 2020, accounting for 12 percent of total petroleum use in 2020 in the reference case, compared with 9 percent in 1998. Consumption of liquefied petroleum gases (LPGs)—primarily in the industrial sector—also increases, from 2.0 million barrels a day in 1998 to 2.5 million in 2020. Consumption of "other" petroleum products, mostly petrochemical feedstocks, still gas used to fuel refineries, and asphalt and road oil used in road construction, grows from 2.8 million to 3.3 million barrels a day. Diesel fuel consumption shows little change, whereas residual fuel use, mainly for electricity generation, declines by 250,000 barrels a day in the high oil price case but increases by 530,000 barrels a day in the low oil price case.

AEO2000 Projects an Expanded Role for Ethanol in Vehicle Fuels

Figure 107. U.S. ethanol consumption, 1992-2020 (million gallons)



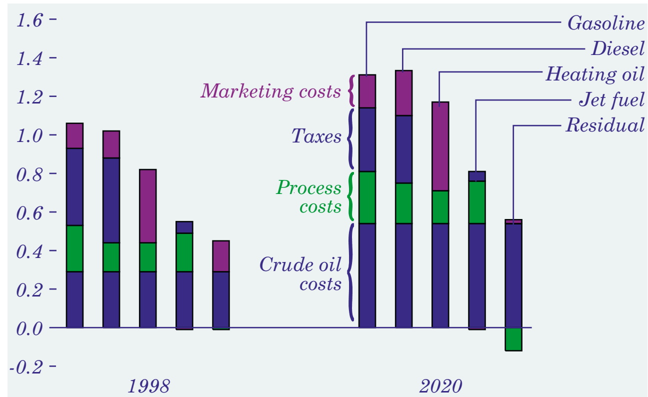
U.S. ethanol production, with corn as the primary feedstock, reached 1.4 billion gallons in 1998. Production is projected to increase to 2.7 billion gallons by 2020, with most of the growth coming from the conversion of cellulosic biomass to ethanol. Ethanol is used primarily in the Midwest as a gasoline volume extender and octane enhancer in a blend of 10 percent ethanol and 90 percent gasoline. It also serves as an oxygenate in areas that are required to use oxygenated fuels (with a minimum 2.7 percent oxygen content by volume) during the winter months to reduce carbon monoxide emissions.

AEO2000 projects an expanded role for ethanol, replacing MTBE as the oxygenate for reformulated gasoline (RFG) in California, where concerns about water quality in 1999 led to a State-wide ban on MTBE in gasoline by the end of 2002. To date, the U.S. Environmental Protection Agency (EPA) has not granted a waiver for the oxygen requirement in California RFG. In addition, ethanol consumption in E85 vehicles is projected to increase from the national total of 2.0 million gallons in 1998 to 754 million gallons in 2020 (Figure 107). E85 vehicles are currently in use as government fleet vehicles, flexible-fuel passenger vehicles (which run on either E85 or gasoline), and urban transit buses.

The Federal Highway Bill of 1998 extended the current tax credit for ethanol through 2007 but stipulated reductions from 54 cents a gallon to 53 cents in 2001, 52 cents in 2003, and 51 cents in 2005. *AEO2000* assumes that the credit will be extended at 51 cents per gallon through 2020.

Processing Costs for Gasoline and Jet Fuel Rise in the Forecast

Figure 108. Components of refined product costs, 1998 and 2020 (1998 dollars per gallon)



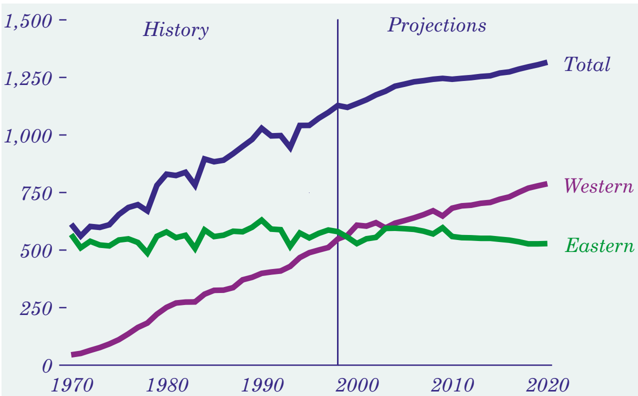
Refined product prices are determined by crude oil costs, refining process costs (including refiner profits), marketing costs, and taxes (Figure 108). In the *AEO2000* projections, crude oil costs continue to make the greatest contribution to product prices, and marketing costs remain stable, but the contributions of processing costs and taxes change considerably.

The processing costs for gasoline and jet fuel increase by 5 cents and 4 cents a gallon, respectively, between 1998 and 2020. The increases are attributed primarily to growth in demand for those products and also in part to investments related to compliance with refinery emissions, health, and safety regulations, which add 1 to 3 cents a gallon to the processing costs of light products (gasoline, distillate, jet fuel, kerosene, and LPGs).

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 *AEO2000* assumption of current laws and legislation, Federal motor fuels taxes are assumed to remain at nominal 1998 levels throughout the forecast, although Federal taxes have actually been raised sporadically in the past. State motor fuels taxes are assumed to keep up with inflation, as they have in the past. The net impact of the assumptions is a decrease in Federal taxes between 1998 and 2020—7 cents per gallon for gasoline, 9 cents for diesel fuel, and 1 cent for jet fuel.

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

Figure 109. Coal production by region, 1970-2020 (million short tons)



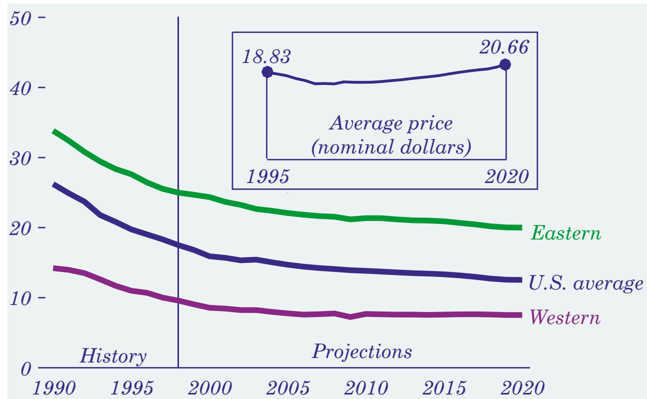
Continued improvements in mine productivity (averaging 6.7 percent a year since 1978) are projected to cause falling real minemouth prices throughout the forecast. Higher electricity demand and lower prices, in turn, yield increasing coal demand, but the demand is subject to a fixed sulfur emissions 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 lower 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 1998 to 2020, high- and medium-sulfur coal production declines from 636 to 533 million tons (0.8 percent a year), and low-sulfur coal production rises from 492 to 783 million tons (2.1 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 788 million tons in 2020 (Figure 109), but its annual growth rate falls from the 9.3 percent achieved between 1970 and 1998 to 1.7 percent in the forecast period.

Minemouth Coal Prices Continue To Fall in the Projections

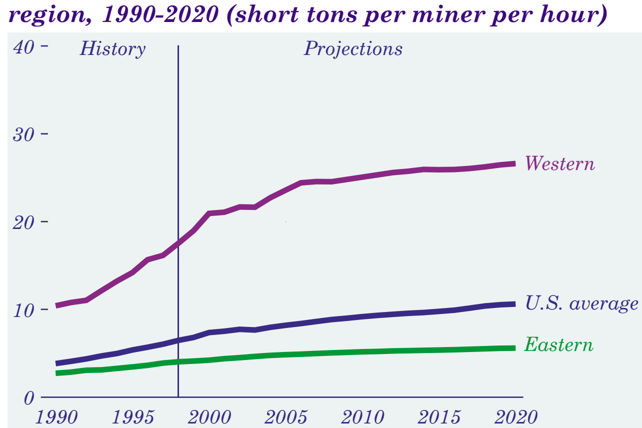
Figure 110. Average minemouth price of coal by region, 1990-2020 (1998 dollars per short ton)



Minemouth coal prices declined by $5.90 per ton in 1998 dollars between 1970 and 1998, and they are projected to decline by 1.5 percent a year, or $4.97 per ton, between 1998 and 2020 (Figure 110). The price of coal delivered to electricity generators, which declined by approximately 70 cents per ton between 1970 and 1998, falls to $20.01 per ton in 2020—a 1.1-percent annual decline.

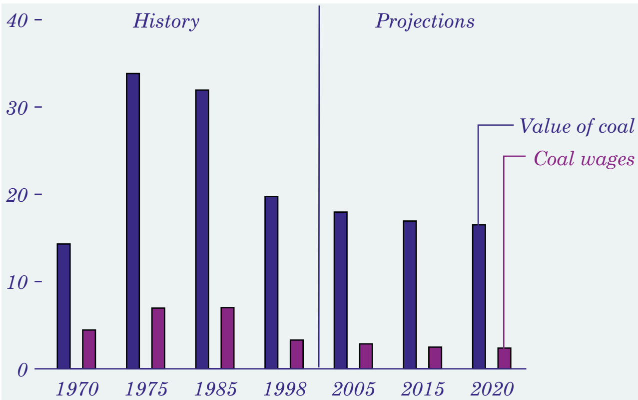
The mines of the Northern Great Plains, with thick seams and low overburden ratios, have had higher labor productivity than other coalfields, and their advantage is maintained throughout the forecast. Average U.S. labor productivity (Figure 111) follows the trend for eastern mines most closely, because eastern mining is more labor-intensive than western mining.

Figure 111. Coal mining labor productivity by region, 1990-2020 (short tons per miner per hour)



Labor Cost Contribution to Total Coal Prices Continues To Decline

Figure 112. Labor cost component of minemouth coal prices, 1970-2020 (billion 1998 dollars)



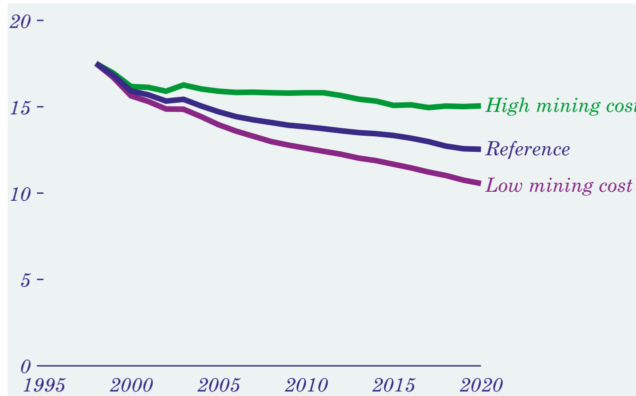
Gains in coal mine labor productivity result from technology improvements, economies of scale, and better mine design. At the national level, however, average labor productivity will also be influenced by changing regional production shares. Competition from very low sulfur, low-cost western and imported coals is projected to limit the growth of eastern low-sulfur coal mining. The boiler performance of western low-sulfur coal has been successfully tested in all U.S. Census divisions except New England and the Mid-Atlantic, and its 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 large volumes of coal 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 1998, the average number of miners working daily fell by 2.2 percent a year. With improvements continuing through 2020, a further decline of 1.5 percent a year in the number of miners is projected. The share of wages in minemouth coal prices [*72*], which fell from 31 percent to 17 percent between 1970 and 1998, is projected to decline to 14 percent by 2020 (Figure 112).

High Labor Cost Assumption Leads to Lower Production in the East

Figure 113. Average minemouth coal prices in three cases, 1998-2020 (1998 dollars per short ton)

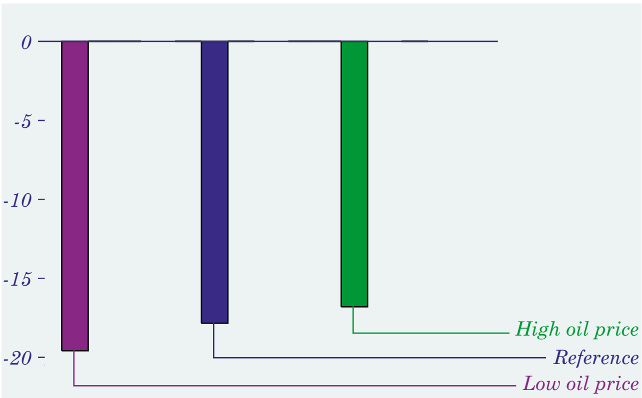


Alternative assumptions about future regional mining costs affect the market shares of eastern and western mines and the national average minemouth price of coal. In two alternative mining cost cases, demand for coal by electricity generators was allowed to respond to relative fuel prices, but coal demand from other sectors was held constant. Minemouth prices, delivered prices, and the resulting 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 1998 dollars. The national minemouth coal price declines by 1.5 percent a year to $12.54 per ton in 2020 (Figure 113). In the low mining cost case, productivity increases by 3.6 percent a year, and real wages decline by 0.5 percent a year [*73*]. The average minemouth price falls by 2.3 percent a year to $10.56 per ton in 2020 (15.8 percent less than in the reference case). Eastern coal production is 57 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 0.9 percent a year, and real wages increase by 0.5 percent a year. The average minemouth price of coal falls by 0.7 percent a year to $15.05 per ton in 2020 (20.0 percent higher than in the reference case). Eastern production in 2020 is 14 million tons lower in the high mining cost case than in the reference case.

Transportation Costs Are a Key Factor for Coal Markets

Figure 114. Percent change in coal transportation costs in three cases, 1998-2020

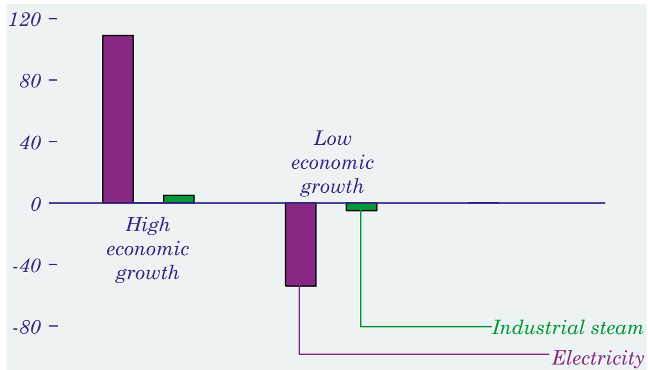


The competition between coal and other fuels, and among coalfields, is influenced by coal transportation costs. Changes in fuel costs affect transportation rates (Figure 114), but fuel efficiency also grows with other productivity improvements in the forecast. As a result, in the reference case, average coal transportation rates decline by 0.9 percent a year between 1998 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. Conditions have since improved, and, assuming that mines in the Powder River Basin complete needed expansion of their train-loading capacities, western coal should be able to meet the increase in demand expected with the advent of Phase 2 of CAAA90. The transition will require more low-sulfur coal than in *AEO99*, because scrubber retrofits are made at a slower pace in *AEO2000*. Any coal transportation problems associated with the increased shift to low-sulfur coal are expected to be temporary.

Higher Oil Prices Would Favor Coal Use for Electricity Generation

Figure 115. Variation from reference case projection of coal demand in two alternative cases, 2020 (million short tons)

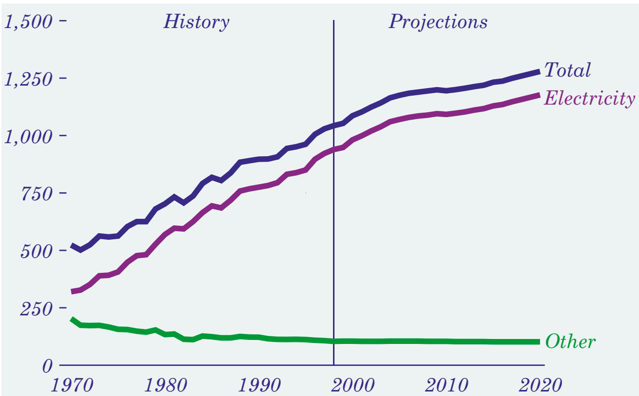


A strong correlation between economic growth and electricity use accounts for the variation in coal demand across the economic growth cases (Figure 115), with domestic coal consumption in 2020 ranging from 1,219 to 1,393 million tons. Of the difference, coal use for electricity generation makes up 163 million tons. The difference in total coal production between the two economic growth cases is 173 million tons, of which 111 million tons (64 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 essentially unchanged and 1.3 percent lower, respectively, in 2020 as compared with the reference case. The low world oil price case projects 24 million tons less coal use in 2020 than the high world oil price case. Low oil prices encourage electricity generation from oil, whereas high oil prices encourage coal consumption. The higher coal consumption in the high oil price case is attributable to the electricity generation sector, with electricity taking 26 million tons of the increase and consumption in the industrial sector declining slightly.

Coal Consumption for Electricity Continues To Rise in the Forecast

Figure 116. Electricity and other coal consumption, 1970-2020 (million short tons)



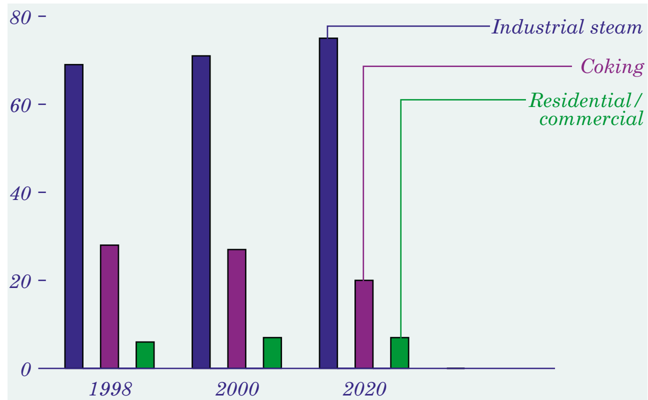
Domestic coal demand rises by 236 million tons in the forecast, from 1,043 million tons in 1998 to 1,279 million tons in 2020 (Figure 116), because of growth in coal use for electricity generation. Coal demand in other domestic end-use sectors declines, as reduced coking coal consumption is partially offset by increased coal demand for industrial cogeneration.

Coal consumption for electricity generation (excluding industrial cogeneration) rises from 939 million tons in 1998 to 1,177 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 68 percent to 83 percent between 1998 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 the midwestern and southeastern regions. In the East, generators shift from higher to lower sulfur Appalachian bituminous coals that contain more energy (Btu) per 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 Steam Coal Use Rises, But Demand for Coking Coal Declines

Figure 117. Non-electricity coal consumption by sector, 1998, 2000, and 2020 (million short tons)



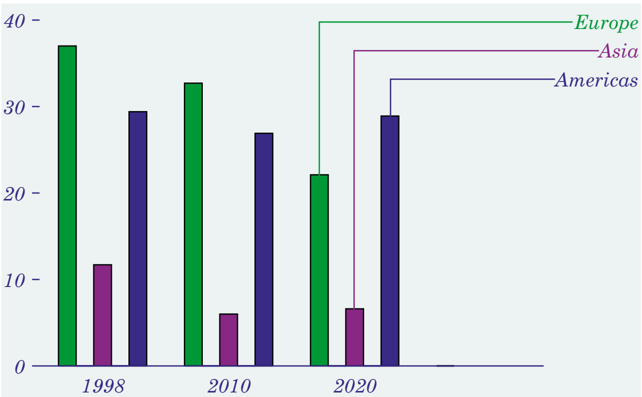
In the non-electricity sectors, an increase of 6 million tons in industrial steam coal consumption between 1998 and 2020 (0.4-percent annual growth) is offset by a decrease of 8 million tons in coking coal consumption (Figure 117). Increasing consumption of industrial steam coal results primarily from greater use of existing coal-fired boilers in energy-intensive industries.

The projected decline in domestic consumption of coking coal results from the 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 1.6 percent a year through 2020. Domestic production of coking coal is stabilized, in part, by sustained levels of export demand.

Although total energy consumption in the combined residential and commercial sectors grows by 0.9 percent a year, most of the growth is captured by electricity and natural gas. Coal consumption in the residential and commercial sectors remains constant, accounting for less than 1 percent of total U.S. coal demand.

U.S. Coal Exports to Europe and Asia Are Projected To Fall Sharply

Figure 118. U.S. coal exports by destination, 1998, 2010, and 2020 (million short tons)



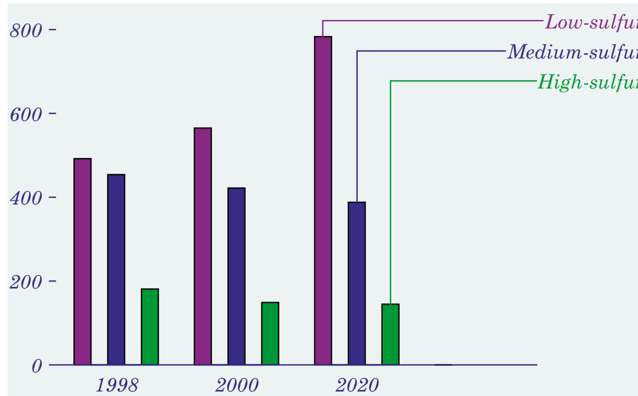
U.S. coal exports show a sharp decline between 1998 and 1999, falling from 78 million tons to 63 million tons, but are projected to remain relatively stable over the forecast horizon, settling at 58 million tons by 2020 (Figure 118). Australian and South African coal export prices dropped substantially in 1999, displacing U.S. coal exports to Europe and Asia. Price cuts by Australia, the world's leading coal exporter, were attributed to both strong productivity growth and a favorable exchange rate against the U.S. dollar.

Between 1999 and 2010, U.S. steam coal exports are projected to increase slightly, from 26 million tons to 29 million tons, as a result of increased coal imports by Europe, reflecting reduced subsidies for domestic coal production and some new generating capacity. During the same period, U.S. coking coal exports are projected to remain virtually unchanged. After 2010, however, both U.S. steam and coking coal exports decline slightly, as Europe shifts away from coal-fired generation and Australian coking coal becomes increasingly competitive, capturing a growing share of the world market.

Faced with strong competition from other coal-exporting countries and limited or negative growth in import demand in Europe and the Americas, the United States captures a decreasing share of both the world and regional coal markets. The U.S. share of total world coal trade is projected to decline from 14 percent in 1998 to 8 percent by 2020.

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

Figure 119. Coal production by sulfur content, 1998, 2000, and 2020 (million short tons)



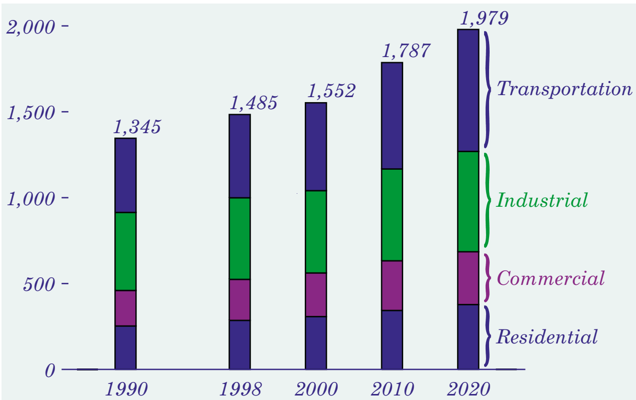
Phase 1 of CAAA90 required 261 coal-fired generating units to reduce sulfur dioxide emissions to about 2.5 pounds per million Btu of fuel. Phase 2, which begins in 2000, tightens the annual emissions limits imposed on these large, higher emitting plants and also sets restrictions on smaller, cleaner plants fired with coal, oil, and gas. The program affects existing utility units serving generators over 25 megawatts capacity and all new utility units [*74*].

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 119). Sulfur emissions from Phase 1 units were 24 percent (1.7 million tons) below the legally allowable limit in 1998 [*75*].

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

Higher Energy Consumption Forecast Increases Carbon Emissions

Figure 120. Carbon emissions by sector, 1990-2020 (million metric tons)



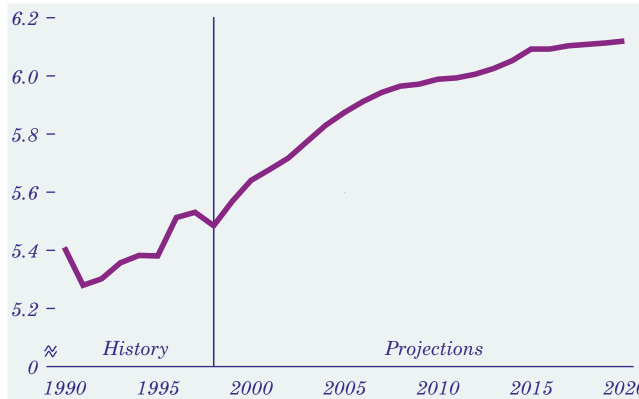
Carbon emissions from energy use are projected to increase by an average of 1.3 percent a year from 1998 to 2020, reaching 1,979 million metric tons (Figure 120). This projection is essentially the same as the *AEO99* projection of 1,975 million metric tons. In *AEO2000*, slightly higher energy consumption resulting from more rapid economic growth, more travel, and more fuel consumption for electricity generation is offset by more optimistic projections for nuclear generation and improvements in energy efficiency.

Increasing concentrations of carbon dioxide, methane, nitrous oxide, and other greenhouse gases may increase the Earth's temperature and affect the climate. The *AEO2000* 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 1,345 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.

Carbon Emissions From the Transportation Sector Grow Rapidly

Figure 121. 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 0.5 percent a year (Figure 121). To stabilize or reduce total emissions, population growth would need to be offset by reductions in per capita emissions.

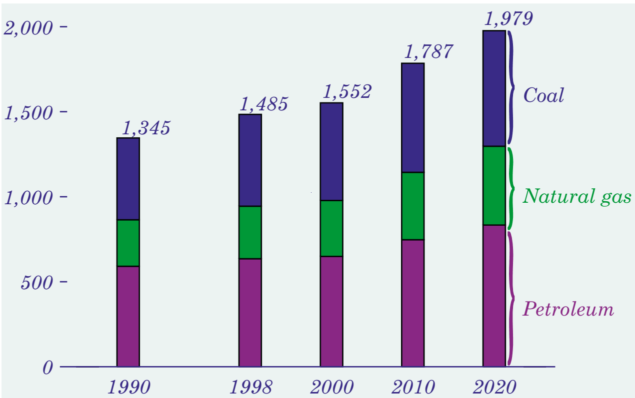
Emissions in the residential sector, including emissions from the generation of electricity used in the sector, are projected to increase by an average of 1.3 percent a year, reflecting the ongoing trends of electrification and penetration of new appliances and services. Significant growth in office equipment and other uses is also projected in the commercial sector, but growth in consumption—and in emissions, which increase by 1.2 percent a year—is likely to be moderated by slowing growth in floorspace.

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 stable 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.

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

Petroleum Products Lead Carbon Emissions From Energy Use

Figure 122. Carbon emissions by fuel, 1990-2020 (million metric tons)



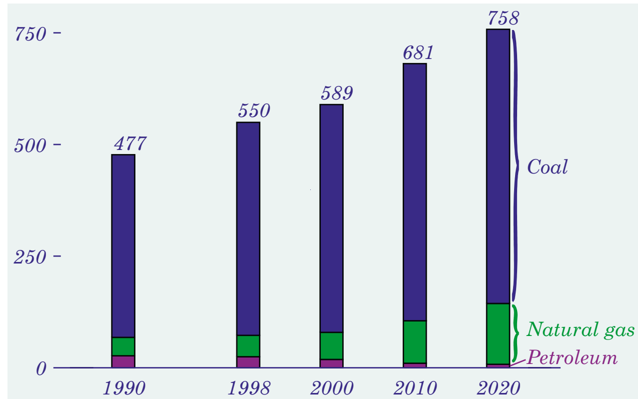
Petroleum products are the leading source of carbon emissions from energy use. In 2020, petroleum is projected to contribute 833 million metric tons of carbon to the total 1,979 million metric tons, a 42-percent share (Figure 122). About 82 percent (680 million metric tons) of the petroleum emissions 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 680 million metric tons in 2020, or 34 percent of the total. The share declines from 36 percent in 1998 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. In the industrial sector, there is a slight increase in emissions from steam coal use and a slight decline in emissions from coking coal.

In 2020, natural gas use is projected to produce 464 million metric tons of carbon emissions, a 23-percent share. Of the fossil fuels, natural gas consumption and emissions increase most rapidly through 2020, at an average annual rate of 1.8 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.

Electricity Use Is Another Major Cause of Carbon Emissions

Figure 123. Carbon emissions from electricity generation by fuel, 1990-2020 (million metric tons)



Electricity generation is a major cause of carbon emissions. Although electricity produces no emissions at the point of use, generation accounted for 37 percent of total carbon emissions in 1998, and its share is expected to increase to 38 percent in 2020. Coal accounts for about 52 percent of electricity generation in 2020 (excluding cogeneration) and produces 81 percent of electricity-related carbon emissions (Figure 123). In 2020, natural gas accounts for 28 percent of electricity generation but only 18 percent of electricity-related carbon emissions.

Between 1998 and 2020, 40 gigawatts of nuclear capacity are expected to be retired, resulting in a 37-percent decline in nuclear generation. To compensate for the loss of nuclear capacity and meet rising demand, 290 gigawatts of new fossil-fueled capacity (excluding cogeneration) will be needed. Increased generation from fossil fuels will raise electricity-related carbon emissions by 208 million metric tons, or 38 percent, from 1998 levels. Generation from renewable technologies, excluding cogenerators, increases by 33 billion kilowatthours, or 9 percent, between 1998 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, and improved technologies all could contribute to lower emissions than are projected here.

Scrubber Retrofits Will Be Needed To Meet Sulfur Emissions Caps

Figure 124. Sulfur dioxide emissions from electricity generation, 1990-2020 (million tons)

CAAA90 called for annual emissions of sulfur dioxide (SO_2) by electricity generators to be reduced to approximately 12 million tons in 1996, 9.48 million tons between 2000 and 2009, and 8.95 million tons a year thereafter. Because companies can bank allowances for future use, however, the long-term cap of 8.95 million tons per year may not be reached until after 2010. More than 95 percent of the SO_2 produced by generators results from coal combustion and the rest from residual oil.

CAAA90 called for the reductions to occur in two phases, with larger (more than 100 megawatts) and higher emitting (more than 2.5 pounds per million Btu) plants making reductions first. In Phase 1, 261 generating units at 110 plants were issued tradable emissions allowances permitting SO_2 emissions to reach a fixed amount per year—generally less than the plant's historical emissions. Allowances may also be banked for use in future years. Switching to lower sulfur subbituminous coal was the option chosen by more than half 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 11.6 million in 2000 (Figure 124). When the SO_2 emissions cap tightens in 2000 and after, the price of allowances is expected to rise, reaching $233 per ton by 2005. As the price rises, it is expected that 21 gigawatts of capacity—about 70 300-megawatt plants—will be retrofitted with scrubbers to meet the Phase 2 goal.

A Significant Drop in Nitrogen Oxide Emissions Is Expected in 2000

Figure 125. Nitrogen oxide emissions from electricity generation, 1995-2020 (million tons)

Nitrogen oxide (NO_x) emissions from electricity generation in the United States will fall significantly over the next 5 years as new legislation takes effect (Figure 125). The reductions are intended to reduce the formation of ground-level ozone, for which NO_x emissions are a major precursor. Together with volatile organic compounds and hot weather, NO_x emissions contribute to unhealthy air quality in many areas during the summer months. The CAAA90 NO_x reduction program calls for reductions at electric power plants in two phases, the first in 1995 and the second in 2000. The second phase of CAAA90 is expected to result in NO_x reductions of 0.8 million tons between 1999 and 2000.

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

The interpretation of ozone transport studies has been controversial. In September 1998 the EPA issued a rule, referred to as the ozone transport rule (OTR), to address the problem. The OTR calls for capping NO_x emissions in 22 midwestern and eastern States during the 5-month summer beginning in 2003. The OTR is currently being challenged in court, however, and its implementation has been stayed.

Forecast Comparisons

Forecast Comparisons

Three other organizations—Standard & Poor's DRI (DRI), the WEFA Group (WEFA), and the Gas Research Institute (GRI)—also produce comprehensive energy projections with a time horizon similar to that of *AEO2000*. The most recent projections from those organizations (DRI, Spring/Summer 1999; WEFA, 1999; GRI, August 1998), as well as other forecasts that concentrate on petroleum, natural gas, and international oil markets, are compared here with the *AEO2000* projections.

Economic Growth

Differences in long-run economic forecasts can be traced primarily to different views of the major supply-side determinants of growth in gross domestic product (GDP): labor force and productivity change (Table 15). In comparison with the *AEO2000* and DRI reference cases, the WEFA forecast shows the highest economic growth, including a higher growth rate for the labor force. The *AEO2000* long-run forecast of average annual economic growth from 1998 to 2020 in the reference case is 2.2 percent—0.2 percent higher than the *AEO99* forecast.

The 1999 *Economic Report of the President* projected real GDP growth of 2.2 percent a year between 1998 and 2005. *AEO2000* projects annual growth of 2.6 percent over the same period.

World Oil Prices

Comparisons with other oil price forecasts—including the International Energy Agency (IEA), Petroleum Economics Ltd. (PEL), Petroleum Industry Research Associates, Inc. (PIRA), Natural Resources Canada (NRCan), and Deutsche Banc Alex. Brown (DBAB)—are shown in Table 16 (IEA, 1998; PEL, December 1998; PIRA, October 1998; NRCan, April 1997; DBAB, June 1999). With the exception of IEA and PEL, the range between the *AEO2000* low and high world oil price cases spans the range of other published forecasts beyond 2005.

Total Energy Consumption

The *AEO2000* forecast of end-use sector energy consumption over the next two decades shows far less volatility than has occurred historically. Between 1974 and 1984, volatile world oil markets dampened domestic oil consumption. Consumers switched to electricity-based technologies in the buildings sector, while in the transportation sector new car fuel efficiency nearly doubled. Natural gas use declined as a result of high prices and limitations on new gas hookups. Between 1984 and 1995, however, both petroleum and natural gas consumption rebounded, bolstered by plentiful supplies and declining real energy prices. As a consequence, new car fuel efficiency in 1995 was less than 2 miles per gallon higher than in 1984, and natural gas use (residential, commercial, and industrial) was almost 25 percent higher than it was in 1984.

Given potentially different assumptions about, for example, technological developments over the next 20 years, the forecasts from DRI, GRI, and WEFA have remarkable similarities with the *AEO2000* projections. Electricity is expected to remain the fastest growing source of delivered energy (Table 17), although its rate of growth is down sharply from historical rates in each of the forecasts, because many traditional uses of electricity (such as for air conditioning) approach saturation while average equipment efficiencies rise. Petroleum consumption

Table 15. Forecasts of economic growth, 1998-2020

	Average annual percentage growth		
Forecast	**Real GDP**	**Labor force**	**Productivity**
AEO2000			
Low growth	1.7	0.6	1.0
Reference	2.2	0.9	1.3
High growth	2.6	1.1	1.5
DRI			
Low	1.8	0.7	1.1
Reference	2.2	0.9	1.3
High	2.7	1.1	1.6
WEFA			
Low	2.0	0.9	1.1
Reference	2.3	1.0	1.3
High	2.7	1.2	1.5

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

Table 16. Forecasts of world oil prices, 2000-2020

	1998 dollars per barrel				
Forecast	**2000**	**2005**	**2010**	**2015**	**2020**
AEO2000 reference	21.19	20.49	21.00	21.53	22.04
AEO2000 high price	24.23	24.16	26.31	27.86	28.04
AEO2000 low price	18.15	14.90	14.90	14.90	14.90
DRI	16.85	15.70	16.66	18.58	19.94
IEA	20.47	20.47	20.47	30.10	30.10
PEL	14.66	14.63	13.64	11.65	NA
PIRA	16.55	17.80	19.45	NA	NA
WEFA	13.46	16.54	18.62	19.28	19.77
GRI	18.31	18.37	19.06	19.59	NA
NRCan	20.97	20.97	20.97	20.97	20.97
DBAB	16.74	17.57	17.86	17.84	18.20

NA = not available.

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 for energy demand in the residential and commercial sectors are expected to decrease by more than 40 percent from the rates between 1984 and 1997, largely because of projected lower growth in population, housing starts, and commercial floorspace additions. Other contributing factors include increasing energy efficiency due to technical innovations and legislated standards; voluntary government efficiency programs; and reduced opportunities for additional market penetration of such end uses as air conditioning.

Differing views on the growth of new uses for energy contribute to variations among the forecasts. By fuel, electricity (excluding generation and transmission losses) remains the fastest growing energy source for both sectors across all forecasts (Table 18). All the forecasts project similar growth in electricity use through 2015; however, the *AEO2000*, DRI, and WEFA projections show slower growth toward the end of the forecast. GRI appears to have a higher projected growth rate, because its projections extend only through 2015. Natural gas use also grows but at lower rates, and petroleum use continues to fall. GRI projects a more rapid decline in oil use, particularly for commercial space and water heating, than the other forecasts.

Industrial Sector

In all the forecasts, the industrial sector shows slower growth in primary energy consumption than it did between 1984 and 1997 (Table 19). 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 1997 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. GRI generally projects higher growth in energy

Table 17. Forecasts of average annual growth rates for energy consumption (percent)

	History		Projections			
Energy use	1974-1984	1984-1997	AEO2000 (1998-2020)	DRI (1998-2020)	GRI (1997-2015)	WEFA (1998-2020)
Petroleum*	-0.1	1.4	1.4	1.2	1.1	1.2
Natural gas*	-1.7	1.9	1.0	1.1	1.4	1.1
Coal*	-3.0	-1.5	0.2	0.0	-0.4	0.1
Electricity	3.0	2.5	1.4	1.3	1.8	1.4
Delivered energy	-0.4	1.5	1.3	1.2	1.2	1.2
Electricity losses	2.5	1.7	0.7	0.4	1.0	0.4
Primary energy	0.2	1.6	1.1	1.0	1.2	1.0

*Excludes consumption by electric utilities.

Table 18. Forecasts of average annual growth in residential and commercial energy demand (percent)

	History	Projections			
Forecast	1984-1997	AEO2000 (1998-2020)	DRI (1998-2020)	GRI (1997-2015)	WEFA (1998-2020)
Residential					
Petroleum	0.5	-0.8	-0.1	-1.2	-0.9
Natural gas	0.7	1.1	1.1	0.7	1.0
Electricity	2.5	1.5	0.9	1.7	1.5
Delivered energy	1.5	1.0	0.9	0.7	1.0
Electricity losses	2.1	0.8	0.0	0.9	0.5
Primary energy	1.8	0.9	0.5	0.8	0.7
Commercial					
Petroleum	-4.2	-0.1	-0.5	-2.9	-0.9
Natural gas	1.9	0.9	0.7	1.0	1.1
Electricity	3.4	1.2	1.4	1.6	1.4
Delivered energy	1.7	1.0	0.9	1.0	1.1
Electricity losses	3.0	0.6	0.5	0.8	0.4
Primary energy	2.3	0.8	0.7	0.9	0.7

Table 19. Forecasts of average annual growth in industrial energy demand (percent)

	History	Projections			
Forecast	1984-1997	AEO2000 (1998-2020)	DRI (1998-2020)	GRI (1997-2015)	WEFA (1998-2020)
Petroleum	1.2	1.0	0.9	1.2	1.3
Natural gas	2.5	0.9	1.1	1.6	1.0
Coal	-1.4	0.1	0.2	-0.1	0.1
Electricity	1.6	1.3	1.6	2.2	1.4
Delivered energy	1.5	1.0	0.9	1.3	1.1
Electricity losses	0.9	0.6	0.7	1.2	0.4
Primary energy	1.4	0.9	0.8	1.3	0.9

demand than the other forecasts because of its relatively high projection for industrial output growth, averaging about 2.9 percent a year as compared with 2.0 percent in *AEO2000*.

Transportation Sector

Overall fuel consumption in the transportation sector is expected to grow slightly more slowly than in the recent past in each of the alternative forecasts (Table 20). Demand for diesel fuel grows more slowly in all the forecasts than it has in the past, whereas the projected growth of residual fuel demand exceeds recent historical rates. All the forecasts anticipate continued rapid growth in air travel and considerably slower growth in light-duty vehicle travel.

GRI projects slower growth in gasoline demand as a result of slower growth in light-duty vehicle travel and more rapid efficiency improvements. GRI also projects the slowest growth in air travel of all the forecasts, leading to slower growth in jet fuel demand. For diesel fuel, however, GRI shows the most rapid growth in demand of all the forecasts, because it projects relatively slow efficiency improvements, at about half the rate expected in *AEO2000*.

Electricity

Comparison across forecasts shows slight variation in projected electricity sales (Table 21). Sales projections for 2020 range from 1,375 billion kilowatthours (DRI) to 1,563 billion kilowatthours (WEFA) for the residential sector, as compared with the *AEO2000* reference case value of 1,553 billion kilowatthours. The forecasts for total electricity sales in 2020 range from 4,289 billion kilowatthours (DRI) to 4,413 billion kilowatthours (WEFA). All the projections for total electricity sales in 2020 fall within the range of the *AEO2000* low and high economic growth cases (4,087 and 4,653 billion kilowatthours, respectively). Different assumptions related to expected economic activity, coupled with diversity in the estimation of penetration rates for energy-efficient technologies, are the primary reasons for variation among the forecasts.

All the forecasts compared here agree that stable fuel prices and slow growth in electricity demand relative to GDP growth will tend to keep the price of electricity stable—or declining in real terms—until 2020.

Table 20. Forecasts of average annual growth in transportation energy demand (percent)

Forecast	History 1974-1984	History 1984-1996	Projections AEO2000 (1998-2020)	Projections DRI (1998-2020)	Projections GRI (1997-2015)	Projections WEFA (1998-2020)
Consumption						
Motor gasoline	0.1	1.4	1.4	1.4	0.5	0.9
Diesel fuel	4.5	3.1	1.0	0.8	1.9	1.3
Jet fuel	1.9	2.6	2.9	2.6	2.3	3.1
Residual fuel	1.4	0.6	2.7	1.8	3.3	2.0
All energy	0.9	1.8	1.7	1.5	1.4	1.4
Key indicators						
Car and light truck travel	2.8	3.1	1.7	1.6	1.4	1.6
Air travel (revenue passenger-miles)	7.0	5.3	4.0	3.6	2.8	3.5
Average new car fuel efficiency	4.5	0.5	0.5	0.5	0.9	0.5
Gasoline prices	1.8	-2.6	0.9	0.8	-0.1	0.6

NA = not available.

Both the DRI and GRI forecasts assume that the electric power industry will be fully restructured, resulting in average electricity prices that approach long-run marginal costs. *AEO2000* also assumes that competitive pressures will grow and continue to push prices down until the later years of the projections. *AEO2000* 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 *AEO2000* 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 combined-cycle technology than coal, oil, or gas steam capacity.

Table 21. Comparison of electricity forecasts (billion kilowatthours, except where noted)

Projection	AEO2000			Other forecasts		
	Reference	Low economic growth	High economic growth	WEFA	GRI	DRI
2015						
Average end-use price (1998 cents per kilowatthour)	**5.9**	**5.6**	**6.1**	**5.83**	**5.40**	**5.50**
Residential	7.3	7.0	7.6	7.22	7.00	7.00
Commercial	6.3	5.9	6.6	6.32	6.30	5.80
Industrial	3.9	3.6	4.1	3.89	3.10	3.80
Net energy for load	**4,404**	**4,220**	**4,625**	**4,650**	**4,733**	**4,641**
Coal	2,200	2,121	2,328	1,823	2,563	2,190
Oil	41	32	58	27	32	128
Natural gas	1,085	991	1,156	1,896	1,099	1,238
Nuclear	511	511	510	377	453	593
Hydroelectric/other [a]	385	386	388	486	407	449
Nonutility sales to grid [b]	162	161	164	NA	168	NA
Net imports	19	19	19	42	39	36
Electricity sales	**4,155**	**3,979**	**4,364**	**4,136**	**4,350**	**4,053**
Residential	1,464	1,438	1,486	1,459	1,456	1,296
Commercial/other [c]	1,388	1,340	1,436	1,325	1,363	1,348
Industrial	1,303	1,201	1,443	1,351	1,532	1,409
Capability (gigawatts) [d,e]	**970**	**936**	**1,016**	**929**	**881**	**968**
Coal	316	310	331	277	372	352
Oil and gas	462	435	492	477	345	405
Nuclear	67	67	67	47	64	94
Hydroelectric/other [a]	125	124	127	129	123	117
2020						
Average end-use price (1998 cents per kilowatthour)	**5.8**	**5.5**	**6.1**	**5.64**	**NA**	**5.30**
Residential	7.3	7.0	7.6	6.98	NA	6.80
Commercial	6.2	5.8	6.7	6.08	NA	5.70
Industrial	3.8	3.5	4.2	3.77	NA	3.70
Net energy for load	**4,598**	**4,321**	**4,917**	**4,962**	**NA**	**4902**
Coal	2,296	2,165	2,578	1,908	NA	2240
Oil	37	28	61	25	NA	142
Natural gas	1,256	1,122	1,251	2,143	NA	1,472
Nuclear	427	428	440	298	NA	560
Hydroelectric/other [a]	392	392	395	548	NA	449
Nonutility sales to grid [b]	169	166	172	NA	NA	NA
Net imports	20	20	20	42	NA	34
Electricity sales	**4,350**	**4,087**	**4,653**	**4,413**	**NA**	**4,289**
Residential	1,553	1,505	1,583	1,563	NA	1,375
Commercial/other [c]	1,420	1,350	1,490	1,418	NA	1,409
Industrial	1,378	1,232	1,580	1,432	NA	1,505
Capability (gigawatts) [d,e]	**1,018**	**967**	**1,079**	**986**	**NA**	**1,008**
Coal	326	311	362	284	NA	363
Oil and gas	508	473	529	526	NA	440
Nuclear	57	57	59	37	NA	88
Hydroelectric/other [a]	127	126	129	139	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 *AEO2000*, 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: ***AEO2000:*** AEO2000 National Energy Modeling System, runs AEO2K.D100199A (reference case), LMAC2K.D100199A (low economic growth case), and HMAC2K.D100199A (high economic growth case). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (1999). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1999 Edition (August 1998). **DRI:** Standard & Poor's DRI, *U.S. Energy Outlook* (Spring/Summer 1999).

Natural Gas

The differences among published forecasts of natural gas prices, production, consumption, and imports (Table 22) 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 32.55 trillion cubic feet in the WEFA forecast to a low of 28.35 trillion cubic feet in the *AEO2000* low economic growth case. The variation in the 2020 projections is even greater, with the highest projection only 15 percent above the lowest for 2015 but 17 percent above the lowest for 2020. The high projection for 2020 is 34.57 trillion cubic feet in the WEFA forecast, compared with a low of 29.49 trillion cubic feet in the *AEO2000* low economic growth case.

The American Gas Association (AGA) forecast for growth in both residential and commercial consumption relative to 1997 historical levels is significantly higher than the others, whereas the *AEO2000* low economic growth and reference case forecasts for growth in residential consumption are even lower than the rest. 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 projections of average lower 48 natural gas wellhead prices by 2015 in the *AEO2000* high economic growth and reference cases are higher than the other forecasts, with the lowest price across all forecasts coming from AGA at 14 percent below the *AEO2000* reference case and 1 percent below the low economic growth case. By 2020 the wellhead price forecasts from WEFA and DRI fall within the range of the *AEO2000* cases, with the *AEO2000* reference case slightly above both the WEFA and DRI forecasts. Excluding the *AEO2000* low economic growth case, the 2015 residential and commercial prices are highest in the *AEO2000* high economic growth case and lowest in the AGA forecast, differing by $0.94 and $1.15 per thousand cubic feet (16 and 24 percent), respectively, for the two sectors. The AGA prices, however, do not include some State and local taxes.

The price projections for the industrial and, to a lesser extent, electricity generation sectors are difficult to compare in absolute terms because of differences in definitions among the forecast groups. From 1997 to 2015, the *AEO2000* high economic growth and reference cases show slight increases in gas prices to the industrial sector. DRI, WEFA, and GRI project slight declines and AGA a more significant decline. The *AEO2000* high economic growth case projects a larger increase in industrial gas prices than the other forecasts from 2015 to 2020. There are significant differences in the projected growth rates for natural gas prices to electricity generators. GRI, WEFA, and AGA project slight declines through 2015, whereas DRI projects slight growth and *AEO2000* more significant growth, especially in the high economic growth case. Through 2020, the *AEO2000* high economic growth and reference cases and the DRI forecast show relatively rapid increases in gas prices to electricity generators, whereas the WEFA forecast and the *AEO2000* low economic growth case show moderate to no growth.

Petroleum

Projected prices for crude oil in the *AEO2000* low and high oil price cases (Table 23) bound the 2010 and 2020 projections in five other petroleum forecasts: the *AEO2000* reference case, WEFA, GRI, DRI, and the Independent Petroleum Association of America (IPAA, April 1999). Comparisons with GRI and IPAA forecasts, which do not extend to 2020, apply only to 2010. *AEO2000* shows the highest reference case price path of the five forecasts. The *AEO2000* reference case oil price for 2010 is $2.38 per barrel above the WEFA price, $3.50 above GRI, and $4.03 above DRI. After 2010, the *AEO2000* oil price growth slows relative to the other forecasts. By 2020 the *AEO2000* oil price is only $2.27 above the WEFA projection and $1.73 above the DRI projection.

All projections, including the *AEO2000* low and high oil price cases, reflect a decline in domestic oil production. The trend of the decline looks somewhat different in *AEO2000*, compared with the four other forecasts. *AEO2000* shows a sharper decline before 2010 than the other projections, resulting in a 2010 reference case projection for crude oil production that is at least 380,000 barrels per day below the other reference case forecasts. In fact, 2010 crude oil production levels in the four other forecasts are even higher than the *AEO2000* high oil price case. All three *AEO2000* projections show a slight recovery in production after 2015, resulting in 2020 production

Table 22. Comparison of natural gas forecasts (trillion cubic feet, except where noted)

Projection	AEO2000			Other forecasts			
	Reference	Low economic growth	High economic growth	WEFA	GRI	DRI	AGA
2015							
Lower 48 wellhead price (1998 dollars per thousand cubic feet)	2.71	2.36	3.03	2.51	2.39[a]	2.41	2.33[a]
Dry gas production[b]	25.03	23.85	26.32	27.24	27.31	24.74	26.75
Net imports	4.85	4.51	5.12	5.13	3.51[c]	5.25	4.15
Consumption	29.88	28.35	31.44	32.55	31.28	30.00	30.99
Residential	5.49	5.41	5.55	5.65	5.66	5.54	6.23
Commercial[d]	3.61	3.50	3.72	3.85	3.91	3.64[e]	4.01
Industrial[d]	9.64	9.07	10.36	9.74[h]	11.34	8.61[e]	10.84
Electricity generators[f]	8.37	7.70	8.93	10.66	7.19	9.28[d]	6.77
Other[g]	2.77	2.66	2.88	2.65	3.20	2.93	3.14
End-use prices (1998 dollars per thousand cubic feet)							
Residential	6.62	6.29	6.92	6.18	6.78	6.66	5.98[i]
Commercial[d]	5.64	5.30	5.95	5.39	5.78	5.69	4.80[i]
Industrial[d]	3.48	3.13	3.81	3.65[j]	2.96	3.64[j]	2.79[i,k]
Electricity generators[f]	3.28	2.93	3.57	2.81	2.64	2.84	2.64[i]
2020							
Lower 48 wellhead price (1998 dollars per thousand cubic feet)	2.81	2.40	3.27	2.66	NA	2.65	NA
Dry gas production[b]	26.40	25.00	27.22	28.74	NA	25.67	NA
Net imports	5.14	4.49	5.50	5.65	NA	5.57	NA
Consumption	31.53	29.49	32.73	34.57	NA	31.24	NA
Residential	5.69	5.57	5.76	5.76	NA	5.79	NA
Commercial[d]	3.65	3.50	3.79	3.98	NA	3.62[e]	NA
Industrial[d]	9.99	9.18	10.98	9.96[h]	NA	8.74[e]	NA
Electricity generators[f]	9.26	8.45	9.15	12.06	NA	10.02[d]	NA
Other[g]	2.95	2.81	3.05	2.81	NA	3.07	NA
End-use prices (1998 dollars per thousand cubic feet)							
Residential	6.55	6.18	6.99	5.95	NA	6.84	NA
Commercial[d]	5.66	5.26	6.10	5.24	NA	5.86	NA
Industrial[d]	3.60	3.16	4.08	3.69[j]	NA	3.85[j]	NA
Electricity generators[f]	3.41	2.95	3.85	2.94	NA	3.08	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 nonutility generation.
[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: ***AEO2000***: AEO2000 National Energy Modeling System, runs AEO2K.D100199A (reference case), LMAC2K.D100199A (low economic growth case), and HMAC2K.D100199A (high economic growth case). **WEFA:** The WEFA Group, *Natural Gas Outlook* (1999). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1999 Edition (August 1998). **DRI:** Standard & Poor's DRI, *U.S. Energy Outlook* (Spring/Summer 1999). **AGA:** American Gas Association, *1998 AGA-TERA Base Case* (July 1998).

Forecast Comparisons

Table 23. Comparison of petroleum forecasts (million barrels per day, except where noted)

Projection	AEO2000			Other forecasts			
	Reference	Low world oil price	High world oil price	WEFA	GRI	DRI	IPAA
2010							
World oil price (1998 dollars per barrel)	**21.00**	**14.90**	**26.31**	**18.62**	**17.50[a]**	**16.97**	**NA**
Crude oil and NGL production	**7.23**	**6.88**	**7.56**	**7.67**	**8.24**	**7.94**	**7.77**
Crude oil	5.18	4.84	5.50	5.58	5.56	5.68[b]	5.78
Natural gas liquids	2.05	2.04	2.06	2.09	2.68	2.26	1.99
Total net imports	**13.85**	**15.17**	**12.95**	**11.72**	**NA**	**13.03**	**11.92**
Crude oil	11.45	12.06	11.10	10.02	NA	9.96	NA
Petroleum products	2.40	3.11	1.85	1.70	NA	3.08	NA
Petroleum demand	**22.51**	**23.31**	**22.06**	**21.57**	**21.46**	**22.34**	**23.10**
Motor gasoline	10.18	10.38	10.01	9.16	8.72	10.08	NA
Jet fuel	2.35	2.37	2.33	2.31	2.24	2.20	NA
Distillate fuel	3.85	3.95	3.81	3.94	3.98	3.91	NA
Residual fuel	0.77	1.23	0.61	0.70	1.07	0.76	NA
Other	5.37	5.39	5.31	5.46	5.45	5.39	NA
Import share of product supplied (percent)	**62**	**65**	**59**	**54**	**NA**	**58**	**52**
2020							
World oil price (1998 dollars per barrel)	**22.04**	**14.90**	**28.04**	**19.77**	**NA**	**20.31**	**NA**
Crude oil and NGL production	**7.63**	**7.00**	**8.40**	**7.38**	**NA**	**7.54**	**NA**
Crude oil	5.26	4.65	6.02	5.00	NA	5.08[b]	NA
Natural gas liquids	2.37	2.35	2.38	2.38	NA	2.46	NA
Total net imports	**16.04**	**18.08**	**14.47**	**14.49**	**NA**	**15.69**	**NA**
Crude oil	11.59	12.47	10.88	11.80	NA	10.57	NA
Petroleum products	4.45	5.61	3.59	2.69	NA	5.12	NA
Petroleum demand	**25.10**	**26.38**	**24.42**	**24.21**	**NA**	**24.64**	**NA**
Motor gasoline	11.37	11.71	11.06	9.89	NA	10.85	NA
Jet fuel	3.02	3.04	2.94	3.10	NA	2.78	NA
Distillate fuel	4.11	4.33	4.04	4.31	NA	4.28	NA
Residual fuel	0.83	1.48	0.70	0.77	NA	0.69	NA
Other	5.77	5.83	5.68	6.14	NA	6.04	NA
Import share of product supplied (percent)	**64**	**69**	**59**	**60**	**NA**	**64**	**NA**

[a]Composite of U.S. refiners' acquisition cost.
[b]Includes shale and other.
NA = Not available.
Sources: ***AEO2000*:** AEO2000 National Energy Modeling System, runs AEO2K.D100199A (reference case), LWOP2K.D100199A (low world oil price case), and HWOP2K.D100199A (high world oil price case). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (1999). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1999 Edition (August 1998). **DRI:** Standard & Poor's DRI, *U.S. Energy Outlook* (Spring/Summer 1999). **IPAA:** Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Run Report* (April 1999).

above 2010 levels. As a result, the *AEO2000* high oil price and reference case production projections for 2020 are above the DRI and WEFA projections. The *AEO2000* projections for production of natural gas liquids are comparable to all but the GRI projections, which show an additional 630,000 barrels per day of production in 2010.

All three *AEO2000* cases project relatively high levels of petroleum consumption, which are mostly attributable to higher gasoline consumption than in the other forecasts. GRI and WEFA project the lowest petroleum consumption for 2010 at around 21.5 million barrels per day. The *AEO2000* low oil price case has the highest 2010 consumption, followed by IPAA, the *AEO2000* reference case, and DRI, which are similar. The *AEO2000* low oil price case also has the highest 2020 projection, followed by the *AEO2000* reference case. The DRI and WEFA consumption projections are significantly lower than the *AEO2000* reference case projection for 2020 but are more in line with the *AEO2000* high oil price. WEFA has the lowest 2020 projection for petroleum consumption, based on a lower level of demand for gasoline.

Net petroleum imports in the *AEO2000* reference and low oil 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 *AEO2000* low oil price case, followed by the reference case. For 2010 the import share of consumption ranges from 52 percent (IPAA) to 65 percent (*AEO2000* low oil price case). The low IPAA import share results from strong consumption projections that are second only to the *AEO2000* low oil price case and production levels that are above those in all three *AEO2000* cases.

The *AEO2000* high oil price case has the lowest share of imports in 2020 at 59 percent, because it projects relatively low petroleum consumption along with the highest level of domestic production. WEFA projects petroleum demand, imports, and the import share of consumption similar to those in the *AEO2000* high oil price case, despite a domestic production forecast that is more than 1 million barrels per day lower than that in the *AEO2000* high oil price case. The lower production in the WEFA forecast is counterbalanced by a refinery processing gain more than 1 million barrels per day higher than in any of the other forecasts. The relatively high processing gain in the WEFA forecast may reflect more optimistic assumptions about technological development.

Coal

The coal forecast by DRI is similar to the *AEO2000* coal forecasts, whereas those from WEFA and GRI/Hill [*76*] show lower production and consumption in the electricity and industrial sectors. The differences stem primarily from whether the forecast includes the effects of the NO_x and particulate emissions limits proposed by the U.S. Environmental Protection Agency, either of which could force the retirement of many older coal plants. Because the proposed standards must pass through several stages of State and judicial review before adoption, they are not included in the EIA projections. The DRI forecast projects relatively modest coal plant retirements after 2010 in response to the proposed environmental standards.

EIA expects growing domestic consumption but shrinking exports. DRI expects moderate expansion of electricity and industrial sector coal consumption, with exports remaining close to their 1997-1998 levels. WEFA projects sharply reduced electricity and industrial consumption but high exports, and GRI/Hill is the most pessimistic about consumption in the electricity generation and industrial sectors and export levels.

The differences among the forecasts for coal exports are significant. U.S. coal exports have declined from 90 million tons in 1996 to 78 in 1998, and net coal exports in 1998 (after adjustment for imports) were 69 million tons. EIA expects net exports to decline to 38 million tons in 2015 and remain at that level through 2020. GRI/Hill projects a similar decline to 31 million tons in 2015, followed by an increase to 35 million tons in 2020, as environmental restrictions on mining and coal burning suppress domestic coal consumption and imports. The long-term decline in exports results primarily from the inability of the U.S. mining industry to keep pace with strong productivity growth by competing exporters and the loss of markets as Europe moves away from coal for environmental reasons. Both DRI and WEFA, however, project strong growth in U.S. coal exports, at 80 million tons in 2015 and 83 million tons in 2020 (DRI) and 109 million tons in 2015 and 125 million tons in 2020 (WEFA).

Table 24. Comparison of coal forecasts (million short tons, except where noted)

Projection	AEO2000			Other forecasts		
	Reference	Low economic growth	High economic growth	WEFA	GRI/Hill	DRI
2015						
Production	**1,269**	**1,229**	**1,325**	**1,082**	**965**	**1,224**
Consumption by sector						
Electricity generation[a]	*1,129*	*1,094*	*1,182*	*887*	*855*	*1,033*
Coking plants	*21*	*22*	*21*	*24*	*19*	*24*
Industrial/other	*81*	*78*	*85*	*61*	*60*	*87*
Total	**1,232**	**1,193**	**1,288**	**972**	**934**	**1,144**
Net coal exports	**38**	**38**	**38**	**109**	**31**	**80**
Minemouth price						
(1998 dollars per short ton)	*13.34*	*13.09*	*13.52*	*13.30*	*NA*	*NA*
(1998 dollars per million Btu)	*0.64*	*0.62*	*0.64*	*0.61*	*NA*	*NA*
Average delivered price, electricity						
(1998 dollars per short ton)	*21.19*	*20.74*	*21.60*	*20.29[b]*	*21.88*	*21.11*
(1998 dollars per million Btu)	*1.03*	*1.01*	*1.05*	*0.99*	*NA*	*1.03*
2020						
Production	**1,316**	**1,256**	**1,429**	**1,129**	**786**	**1,210**
Consumption by sector						
Electricity generation[a]	*1,177*	*1,123*	*1,286*	*919*	*678*	*1,018*
Coking plants	*20*	*20*	*19*	*23*	*16*	*23*
Industrial/other	*82*	*77*	*87*	*63*	*57*	*88*
Total	**1,279**	**1,219**	**1,393**	**1,005**	**751**	**1,128**
Net coal exports	**38**	**38**	**38**	**125**	**35**	**83**
Minemouth price						
(1998 dollars per short ton)	*12.54*	*12.40*	*12.58*	*12.84*	*NA*	*NA*
(1998 dollars per million Btu)	*0.60*	*0.60*	*0.61*	*0.59*	*NA*	*NA*
Average delivered price, electricity						
(1998 dollars per short ton)	*20.01*	*19.61*	*20.32*	*19.47[b]*	*21.03*	*19.84*
(1998 dollars per million Btu)	*0.98*	*0.96*	*1.00*	*0.95*	*NA*	*0.97*

[a]The DRI and *AEO2000* 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.
[b]Computed using a conversion factor of 20.495 million Btu per short ton from the Technical Appendix.
NA = Not available.
Btu = British thermal unit.
Sources: ***AEO2000***: AEO2000 National Energy Modeling System, runs AEO2K.D100199A (reference case), LMAC2K.D100199A (low economic growth case), and HMAC2K.D100199A (high economic growth case). **WEFA:** The WEFA Group, *U.S. Energy Outlook* (1999). **GRI/Hill:** Gas Research Institute, *Final Report, Coal Demand and Price Projections*, Vol. I, GRI-99/0016.1 (January 1999). **DRI:** Standard & Poor's DRI, *U.S. Energy Outlook* (Spring/Summer 1999).

Only EIA and WEFA project national average minemouth coal prices, and they are in close agreement (all are shown in 1998 dollars). In dollars per million Btu, WEFA's slightly lower price at $0.61 indicates a slightly higher average Btu per ton conversion factor, which, in turn indicates a higher proportion of bituminous (over subbituminous) coal in the WEFA forecast.

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

List of Acronyms

ACEEE	American Council for an Energy-Efficient Economy
AD	Associated-dissolved (natural gas)
AEO	*Annual Energy Outlook*
AGA	American Gas Association
ANWR	Arctic National Wildlife Refuge
API	American Petroleum Institute
BRP	Blue Ribbon Panel
Btu	British thermal unit
CAAA90	Clean Air Act Amendments of 1990
CARB	California Air Resources Board
CCAP	Climate Change Action Plan
CDM	Clean Development Mechanism
CECA	Comprehensive Electricity Competition Act
CIDI	Compression ignition direct injection
CO	Carbon monoxide
DBAB	Deutsche Banc Alex. Brown
DOE	U.S. Department of Energy
DRI	Standard & Poor's DRI
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
FCC	Fluid catalytic cracking
FERC	Federal Energy Regulatory Commission
GDP	Gross domestic product
GRI	Gas Research Institute
HERS	Home energy rating system
IEA	International Energy Agency
IPAA	Independent Petroleum Association of America
LDC	Local distribution company
LEV	Low-emission vehicle
LEVP	Low-Emission Vehicle Program
LNG	Liquefied natural gas
LPGs	Liquefied petroleum gases
MMS	Minerals Management Service
MSW	Municipal solid waste
MTBE	Methyl tertiary butyl ether
NA	Nonassociated (natural gas)
NAAQS	National Ambient Air Quality Standards
NAECA	National Appliance Energy Conservation Act
NEMS	National Energy Modeling System
NO_x	Nitrogen oxides
NPC	National Petroleum Council
NPRM	Notice of Proposed Rulemaking
NRC	National Research Council
NRCan	Natural Resources Canada
OBD	On-board diagnostics
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of Petroleum Exporting Countries
OTR	Ozone Transport Rule
PEL	Petroleum Economics Ltd.
PIRA	Petroleum Industry Research Associates, Inc.
PM	Particulate matter
PNGV	Partnership for a New Generation of Vehicles
ppm	Parts per million
PUHCA	Public Utility Holding Company Act of 1935
PURPA	Public Utility Regulatory Policies Act of 1978
RFG	Reformulated gasoline
RPS	Renewable Portfolio Standard
Rvp	Reid vapor pressure
SO_2	Sulfur dioxide
SPR	Strategic Petroleum Reserve
SULEV	Super-ultra-low-emission vehicle
SUV	Sport utility vehicle
TAME	Tertiary amyl methyl ether
UGR	Unconventional gas recovery
ULEV	Ultra-low-emission vehicle
USGS	U.S. Geological Survey
VMT	Vehicle-miles traveled
VOCs	Volatile organic compounds
WEFA	The WEFA Group
ZEV	Zero-emission vehicle

Notes and Sources

Text Notes

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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, *Voluntary Reporting of Greenhouse Gases 1997*, DOE/EIA-0608(97) (Washington, DC, May 1999).

[*3*] The White House, Office of the Press Secretary, Executive Order 13134, "Developing and Promoting Biobased Products and Bioenergy" (Washington, DC, August 12, 1999).

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[*4*] U.S. Environmental Protection Agency, Office of Mobile Sources, *Proposed "Tier 2" Emission Standards for Vehicles and Gasoline Sulfur Standards for Refineries*, EPA 420-F-99-010 (Washington, DC, May 1999).

[*5*] See web site www.epa.gov/fedrgstr/EPA-AIR/1999/May/Day-13/a11384a.htm.

[*6*] U.S. Environmental Protection Agency, Office of Mobile Sources, *Exhaust Emission Certification Standards*, EPA 420-B-98-001 (Washington, DC, March 24, 1998).

[*7*] See web site www.epa.gov/oms/tr2home.htm.

[*8*] National Research Council, *Review of the Research Program of the Partnership for a New Generation of Vehicles: Fifth Report* (Washington, DC: National Academy Press, 1999).

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[*9*] U.S. Environmental Protection Agency, Office of Mobile Sources, *Diesel Fuel Quality: Advance Notice of Proposed Rulemaking*, EPA 420-F-99-011 (Washington, DC, May 1999).

[*10*] California Department of Health Services, *MTBE in California's Drinking Water* (Sacramento, CA, September 28, 1999), web site www.dhs.ca.gov/ps/ddwem/chemicals/MTBE/mtbeindex.html.

[*11*] Blue Ribbon Panel on Oxygenates in Gasoline, *Executive Summary and Recommendations* (Washington, DC, July 27, 1999).

[*12*] California Energy Commission, *Staff Report: Supply and Cost of Alternatives to MTBE in Gasoline*, P300-98-013D (Sacramento, CA, October 1998).

[*13*] Energy Information Administration, *Weekly Petroleum Status Report* (Washington, DC, various issues, 1998).

[*14*] Downstream Alternatives, Inc., *The Use of Ethanol in California Clean Burning Gasoline: Ethanol Supply and Demand* (Bremen, IN, February 5, 1999).

[*15*] California Energy Commission, *Staff Report: Supply and Cost of Alternatives to MTBE in Gasoline*, P300-98-013D (Sacramento, CA, October 1998).

[*16*] New Hampshire Joint Resolution 9 (July 16, 1999).

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[*17*] Cambridge Energy Research Associates, *Decision Brief: California Bans MTBE in Gasoline—A Signpost for National Action?* (Cambridge, MA, March 1999).

[*18*] Executive Order 13123 is available from the web site of the Federal Energy Management Program, www.eren.doe.gov/femp/aboutfemp/exec13123.html.

[*19*] Many solar photovoltaic systems have been installed or are planned that are not connected to the utility distribution network or "grid." Off-grid systems are not included in the *AEO2000* forecast for the commercial sector; however, they will count toward the goals of the Executive Order.

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

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

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[*22*] EIA estimation procedures yield 2.6 percent as the estimated 2000 share in the reference case in this report.

[*23*] The Department of Energy's *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), assumed that 61 percent of the generation from municipal solid waste facilities would qualify.

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[*24*] For a more detailed discussion of the costs of and investment in pipeline capacity expansion, see Energy Information Administration, *Natural Gas Issues and Trends*, DOE/EIA-0560(98) (Washington, DC, June 1999), pp. 121-126. For information on proposed projects, see Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Pipeline Construction Database, available at web site www.eia.doe.gov.

[*25*] Rates of technological improvement, estimated on the basis of historical data, are presented in *Assumptions for the Annual Energy Outlook 2000*, web site www.eia.doe.gov/oiaf/aeo/assumption/index.html. The estimation methodology is documented in Energy Information Administration, *Oil and Gas Supply Model (OGSM) Documentation*, DOE/EIA-M063(2000) (Washington, DC, December 1999).

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[*26*] Reed-Hycalog, *47th Annual Reed-Hycalog Rig Census* (Houston, TX, September 1999).

[*27*] "Deepwater Semi Upgrade Nearing Completion," *Oil and Gas Journal* (November 10, 1997), p. 40.

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

[*29*] Reed-Hycalog, *47th Annual Reed-Hycalog Rig Census* (Houston, TX, September 1999).

[*30*] U.S. Department of Energy, *Natural Gas Imports and Exports*, Fourth Quarter Report 1998, DOE/FE-0388 (Washington, DC), p. xi.

[*31*] "Touting Supply Diversity, Southern LNG Files to Recommission Elba Island," *Inside F.E.R.C.* (July 19, 1999).

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[*32*] U.S. Environmental Protection Agency, *Diesel Fuel Quality: Advance Notice of Proposed Rulemaking*, EPA 420-F-99-011 (Washington, DC, May 1999).

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[*33*] A.K. Rhodes, "U.S. Refiners Make Complex Model RFG as They Prepare for Next Hurdle," *Oil and Gas Journal* (January 5, 1998).

[*34*] U.S. Environmental Protection Agency, web site www.epa.gov/oms/regs/ld-hwy/tier-2/nprm/ria/ch-v.pdf.

[*35*] MathPro, Inc., *Cost of Meeting a 40 ppm Standard for Gasoline*, report prepared for the American Petroleum Institute (Bethesda, MD, February 26, 1999).

[*36*] Oak Ridge National Laboratory, Center for Transportation Analysis, *Low Sulfur Gasoline Impacts on Mid-capability Refinery* (Oak Ridge, TN, July 20, 1999).

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[*37*] Blue Ribbon Panel on Oxygenates in Gasoline, *Executive Summary and Recommendations* (Washington, DC, July 27, 1999).

[*38*] Blue Ribbon Panel on Oxygenates in Gasoline, *Executive Summary and Recommendations* (Washington, DC, July 27, 1999).

[*39*] Recommended in H.R. 1367 IH and H.R. 1705 IH.

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[*40*] J. Vautrain, "California Refiners Anticipate Broad Effects of Possible State MTBE Ban," *Oil and Gas Journal* (January 18, 1999).

[*41*] Downstream Alternatives, Inc., *The Use of Ethanol in California Clean Burning Gasoline: Ethanol Supply and Demand* (Bremen, IN, February 5, 1999).

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[*42*] American Council for an Energy-Efficient Economy, *Approaching the Kyoto Targets: Five Key Strategies for the United States* (Washington, DC, August 1998).

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[*43*] **Buildings:** Energy Information Administration (EIA), *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Arthur D. Little, Inc., September 1998). **Industrial:** EIA, *Aggressive Technology Strategy for the NEMS Model* (Arthur D. Little, Inc., September 1998). **Transportation:** U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond*, ORNL/CON-444 (Washington, DC, September 1997); Office of Energy Efficiency and Renewable Energy, Office of Transportation Technologies, *OTT Program Analysis Methodology: Quality Metrics 2000* (November 1998); J. DeCicco and M. Ross, *An Updated Assessment of the Near-Term Potential for Improving Automotive Fuel Economy* (Washington, DC: American Council for an Energy-Efficient Economy, November 1993); and F. Stodolsky, A. Vyas, and R. Cuenca, *Heavy and Medium Duty Truck Fuel Economy and Market Penetration Analysis*, Draft Report (Chicago, IL: Argonne National Laboratory, August 1999). **Fossil-fired generating technologies:** U.S. Department of Energy, Office of Fossil Energy. **Renewable Generating Technologies:** U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, and Electric Power Research Institute, *Renewable Energy Technology Characterizations*, EPRI-TR-109496 (Washington, DC, December 1997).

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[*44*] Australia, Austria, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, Estonia, European Community, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, United Kingdom of Great Britain and Northern Ireland, and United States of America. Turkey and Belarus are Annex I nations that have not ratified the Framework Convention and did not commit to quantifiable emissions targets.

[*45*] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1998*, DOE/EIA-0573(98) (Washington, DC, October 1999).

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[*46*] 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.

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

[*48*] Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998), web site www.eia.doe.gov/oiaf/kyoto/kyotorpt.html.

[*49*] Energy Information Administration, *What Does the Kyoto Protocol Mean to U.S. Energy Markets and the U.S. Economy?*, SR/OIAF/98-03(S) (Washington, DC, October 1998), web site www.eia.doe.gov/oiaf/kyoto/kyotobrf.html.

[*50*] Energy Information Administration, *Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol*, SR/OIAF/99-02 (Washington, DC, July 1999), web site www.eia.doe.gov/oiaf/kyoto3/kyoto3rpt.html.

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[*51*] The loss in potential GDP measures the loss in productive capacity of the economy that is attributable to the reduction in energy resources available to the economy. The loss in actual GDP incorporates the adjustment cost to the economy and reflects

short-term economic dislocations that result from higher energy prices.

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[*52*] These Articles provide for joint implementation, the Clean Development Mechanism, and Annex I trading of emissions permits, respectively.

[*53*] This Article defines the emissions limits, base year, commitment period, and carbon sources and sinks from land-use and forestry activities.

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[*54*] The input-output matrix was updated for *AEO2000* to reflect the Department of Commerce benchmark table expressed in fixed-weighted 1992 dollars.

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[*55*] Standard & Poor's DRI, Simulation T250899 (August 1999).

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[*56*] 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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[*57*] 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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[*58*] 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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[*59*] The definition of the commercial sector for *AEO2000* is based on data from the 1995 Commercial Buildings Energy Consumption Survey (CBECS). See Energy Information Administration, 1995 CBECS Micro-Data Files (February 17, 1998), web site www.eia.doe.gov/emeu/cbecs/. Nonsampling and sampling errors (found in any statistical sample survey) and a change in the target building population resulted in a lower commercial floorspace estimate than found with the previous CBECS. In addition, 1995 CBECS energy intensities for specific end uses varied from earlier estimates, providing a different composition of end-use consumption. These factors contribute to the pattern of commercial energy use projected for *AEO2000*. Further discussion is provided in Appendix G.

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[*60*] 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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[*61*] Estimated as consumption of alternative transportation fuels in crude oil Btu equivalence.

[*62*] 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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[*63*] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond*, ORNL/CON-444 (Washington, DC, September 1997); Office of Energy Efficiency and Renewable Energy, Office of Transportation Technologies, *OTT Program Analysis Methodology: Quality Metrics 2000* (November 1998); J. DeCicco and M. Ross, *An Updated Assessment of the Near-Term Potential for Improving Automotive Fuel Economy* (Washington, DC: American Council for an Energy-Efficient Economy, November 1993); and F. Stodolsky, A. Vyas, and R. Cuenca, *Heavy-Duty and Medium-Duty Truck Fuel Economy and Market Penetration Analysis*, Draft Report (Chicago, IL: Argonne National Laboratory, August 1999).

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[*64*] Values for incremental investments and energy expenditure savings are discounted back to 1999 at a 7-percent real discount rate.

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

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[*66*] 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. *AEO2000* 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

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[*67*] Currently, all production in Alaska is either consumed in the State, reinjected, or exported to Japan as liquefied natural gas (LNG). 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. Substantial uncertainty surrounds the ultimate use of North Slope gas; however, projected low gas prices in the lower 48 markets justify the *AEO2000* perspective that does not consider it a significant factor affecting domestic energy markets, especially natural gas markets. An additional option being considered for North Slope gas is conversion into synthetic petroleum products that will use the Trans Alaska Pipeline System (TAPS) to reach world markets.

[*68*] An additional LNG import facility located at Cove Point, MD, is currently idle and is not projected to be reopened in the reference case. Although LNG imports have until recently all come from Algeria, new sources of supply include Australia, Trinidad and Tobago, and Qatar. Other potential new sources include Abu Dhabi and Norway.

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[*69*] 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.

[*70*] 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.

[*71*] Energy Information Administration, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999), Table 3.7.

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[*72*] Total labor costs are estimated by multiplying the average hourly earnings of coal mine production workers by total annual labor hours worked. Average hourly earnings do not represent total labor costs per hour for the employer, because they exclude retroactive payments and irregular bonuses, employee benefits, and the employer's share of payroll taxes. Labor hours of office workers are excluded from the calculation.

[*73*] 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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[*74*] U.S. Environmental Protection Agency, web site www.epa.gov/acidrain/overview.html (September 1997).

[*75*] U.S. Environmental Protection Agency, web site www.epa.gov/acidrain/cmprpt98/summary.pdf.

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[*76*] 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.

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Appendixes

Table A1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Production							
Crude Oil and Lease Condensate	13.66	13.23	11.35	10.96	11.01	11.13	-0.8%
Natural Gas Plant Liquids	2.57	2.49	2.57	2.90	3.21	3.36	1.4%
Dry Natural Gas	19.43	19.40	20.25	23.09	25.73	27.13	1.5%
Coal	23.28	23.89	25.79	26.18	26.63	27.36	0.6%
Nuclear Power	6.71	7.19	7.20	6.70	5.45	4.56	-2.1%
Renewable Energy[1]	7.00	6.67	7.07	7.39	7.70	7.98	0.8%
Other[2]	0.66	0.57	0.62	0.59	0.63	0.66	0.7%
Total	**73.30**	**73.46**	**74.85**	**77.81**	**80.35**	**82.18**	**0.5%**
Imports							
Crude Oil[3]	17.86	18.90	23.49	24.91	24.97	25.22	1.3%
Petroleum Products[4]	3.89	3.99	5.37	6.80	8.98	10.87	4.7%
Natural Gas	3.06	3.37	4.52	4.91	5.31	5.61	2.3%
Other Imports[5]	0.54	0.59	0.99	0.89	0.89	0.97	2.3%
Total	**25.34**	**26.85**	**34.38**	**37.50**	**40.16**	**42.67**	**2.1%**
Exports							
Petroleum[6]	2.09	1.94	1.94	1.97	1.95	1.93	-0.0%
Natural Gas	0.16	0.17	0.24	0.29	0.35	0.36	3.5%
Coal	2.19	2.05	1.59	1.63	1.44	1.46	-1.5%
Total	**4.45**	**4.16**	**3.76**	**3.89**	**3.75**	**3.76**	**-0.5%**
Discrepancy[7]	**-0.22**	**1.27**	**0.18**	**0.16**	**0.10**	**0.14**	**N/A**
Consumption							
Petroleum Products[8]	36.43	37.21	41.21	43.98	46.65	49.05	1.3%
Natural Gas	22.60	21.99	24.57	27.69	30.68	32.38	1.8%
Coal	21.34	21.50	24.72	25.12	25.84	26.60	1.0%
Nuclear Power	6.71	7.19	7.20	6.70	5.45	4.56	-2.1%
Renewable Energy[1]	7.00	6.67	7.08	7.41	7.71	7.99	0.8%
Other[9]	0.33	0.32	0.50	0.36	0.33	0.36	0.6%
Total	**94.41**	**94.88**	**105.28**	**111.26**	**116.66**	**120.95**	**1.1%**
Net Imports - Petroleum	**19.65**	**20.95**	**26.92**	**29.73**	**32.00**	**34.15**	**2.2%**
Prices (1998 dollars per unit)							
World Oil Price (dollars per barrel)[10]	18.71	12.10	20.49	21.00	21.53	22.04	2.8%
Gas Wellhead Price (dollars per Mcf)[11]	2.39	1.96	2.34	2.60	2.71	2.81	1.7%
Coal Minemouth Price (dollars per ton)	18.32	17.51	14.71	13.84	13.34	12.54	-1.5%
Average Electric Price (cents per kilowatthour)	6.9	6.7	6.1	6.0	5.9	5.8	-0.6%

[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 A18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Mcf = Thousand cubic feet.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1997 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1997*, DOE/EIA-0131(97) (Washington, DC, October 1998). 1997 coal minemouth prices: EIA, *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998). Other 1997 values: EIA, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). 1998 natural gas values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(99/06) (Washington, DC, June 1999). 1998 petroleum values: EIA, *Petroleum Supply Annual 1998,* DOE/EIA-0340(98/1) (Washington, DC, June 1999). Other 1998 values: EIA, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(99/1Q) (Washington, DC, August 1999). **Projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

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

Sector and Source	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Energy Consumption							
Residential							
Distillate Fuel	0.90	0.84	0.79	0.73	0.69	0.65	-1.2%
Kerosene	0.09	0.10	0.09	0.09	0.09	0.09	-0.9%
Liquefied Petroleum Gas	0.44	0.41	0.44	0.43	0.42	0.41	0.0%
Petroleum Subtotal	1.43	1.36	1.31	1.25	1.19	1.15	-0.8%
Natural Gas	5.12	4.61	5.22	5.46	5.65	5.86	1.1%
Coal	0.06	0.06	0.06	0.05	0.05	0.05	-0.4%
Renewable Energy[1]	0.42	0.38	0.44	0.44	0.45	0.45	0.8%
Electricity	3.67	3.84	4.37	4.70	5.00	5.30	1.5%
Delivered Energy	**10.70**	**10.24**	**11.40**	**11.91**	**12.34**	**12.81**	**1.0%**
Electricity Related Losses	8.14	8.53	9.42	9.76	9.96	10.18	0.8%
Total	**18.84**	**18.77**	**20.82**	**21.66**	**22.30**	**22.99**	**0.9%**
Commercial							
Distillate Fuel	0.45	0.38	0.38	0.38	0.37	0.36	-0.2%
Residual Fuel	0.11	0.11	0.10	0.10	0.10	0.10	-0.2%
Kerosene	0.03	0.03	0.03	0.03	0.03	0.03	-0.1%
Liquefied Petroleum Gas	0.08	0.07	0.08	0.08	0.09	0.09	0.9%
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.03	-0.3%
Petroleum Subtotal	0.69	0.61	0.62	0.62	0.62	0.60	-0.1%
Natural Gas	3.31	3.11	3.43	3.58	3.71	3.75	0.9%
Coal	0.09	0.09	0.10	0.10	0.10	0.10	0.9%
Renewable Energy[3]	0.08	0.08	0.08	0.08	0.08	0.08	0.0%
Electricity	3.50	3.56	4.06	4.36	4.58	4.68	1.2%
Delivered Energy	**7.67**	**7.46**	**8.28**	**8.74**	**9.10**	**9.22**	**1.0%**
Electricity Related Losses	7.77	7.93	8.75	9.04	9.14	8.98	0.6%
Total	**15.43**	**15.38**	**17.03**	**17.78**	**18.24**	**18.20**	**0.8%**
Industrial[4]							
Distillate Fuel	1.14	1.08	1.22	1.29	1.38	1.46	1.3%
Liquefied Petroleum Gas	2.16	2.06	2.27	2.40	2.53	2.64	1.1%
Petrochemical Feedstock	1.40	1.39	1.48	1.58	1.66	1.73	1.0%
Residual Fuel	0.30	0.27	0.25	0.29	0.30	0.31	0.7%
Motor Gasoline[2]	0.20	0.21	0.23	0.25	0.27	0.28	1.4%
Other Petroleum[5]	4.11	4.11	4.61	4.72	4.91	5.03	0.9%
Petroleum Subtotal	9.30	9.13	10.05	10.53	11.04	11.45	1.0%
Natural Gas[6]	9.95	9.75	10.36	10.96	11.53	11.99	0.9%
Metallurgical Coal	0.81	0.76	0.68	0.63	0.58	0.53	-1.6%
Steam Coal	1.57	1.54	1.58	1.59	1.61	1.63	0.3%
Net Coal Coke Imports	0.02	0.07	0.17	0.21	0.24	0.27	6.6%
Coal Subtotal	2.39	2.36	2.43	2.42	2.42	2.43	0.1%
Renewable Energy[7]	2.03	2.08	2.30	2.40	2.53	2.63	1.1%
Electricity	3.52	3.57	3.92	4.15	4.45	4.70	1.3%
Delivered Energy	**27.20**	**26.89**	**29.06**	**30.46**	**31.96**	**33.20**	**1.0%**
Electricity Related Losses	7.81	7.95	8.45	8.61	8.87	9.03	0.6%
Total	**35.01**	**34.84**	**37.51**	**39.08**	**40.83**	**42.23**	**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 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Transportation							
Distillate Fuel	4.73	4.95	5.53	5.76	6.02	6.22	1.0%
Jet Fuel[8]	3.31	3.36	4.16	4.85	5.55	6.24	2.9%
Motor Gasoline[2]	15.08	15.59	17.69	19.12	20.30	21.35	1.4%
Residual Fuel	0.73	0.65	0.80	0.92	1.05	1.18	2.7%
Liquefied Petroleum Gas	0.04	0.05	0.09	0.11	0.12	0.13	5.0%
Other Petroleum[9]	0.24	0.30	0.33	0.34	0.36	0.37	0.9%
Petroleum Subtotal	24.13	24.89	28.59	31.10	33.39	35.49	1.6%
Pipeline Fuel Natural Gas	0.77	0.75	0.77	0.87	0.95	0.99	1.3%
Compressed Natural Gas	0.01	0.02	0.16	0.23	0.29	0.33	13.0%
Renewable Energy (E85)[10]	0.00	0.00	0.03	0.06	0.07	0.08	16.3%
Methanol (M85)[11]	0.00	0.01	0.06	0.10	0.13	0.15	14.3%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	0.07	0.07	0.10	0.12	0.15	0.17	4.2%
Delivered Energy	**24.99**	**25.74**	**29.71**	**32.48**	**34.99**	**37.20**	**1.7%**
Electricity Related Losses	0.15	0.15	0.21	0.26	0.30	0.32	3.5%
Total	**25.13**	**25.89**	**29.92**	**32.74**	**35.28**	**37.53**	**1.7%**
Delivered Energy Consumption for All Sectors							
Distillate Fuel	7.22	7.25	7.91	8.16	8.45	8.68	0.8%
Kerosene	0.14	0.16	0.14	0.14	0.14	0.14	-0.7%
Jet Fuel[8]	3.31	3.36	4.16	4.85	5.55	6.24	2.9%
Liquefied Petroleum Gas	2.71	2.59	2.88	3.03	3.16	3.27	1.1%
Motor Gasoline[2]	15.31	15.82	17.95	19.39	20.59	21.65	1.4%
Petrochemical Feedstock	1.40	1.39	1.48	1.58	1.66	1.73	1.0%
Residual Fuel	1.14	1.02	1.15	1.31	1.45	1.59	2.0%
Other Petroleum[12]	4.34	4.39	4.91	5.04	5.24	5.38	0.9%
Petroleum Subtotal	35.55	35.98	40.57	43.50	46.24	48.69	1.4%
Natural Gas[6]	19.16	18.24	19.94	21.09	22.13	22.92	1.0%
Metallurgical Coal	0.81	0.76	0.68	0.63	0.58	0.53	-1.6%
Steam Coal	1.71	1.68	1.73	1.75	1.77	1.79	0.3%
Net Coal Coke Imports	0.02	0.07	0.17	0.21	0.24	0.27	6.6%
Coal Subtotal	2.54	2.50	2.59	2.58	2.58	2.59	0.2%
Renewable Energy[13]	2.53	2.55	2.84	2.98	3.12	3.24	1.1%
Methanol (M85)[11]	0.00	0.01	0.06	0.10	0.13	0.15	14.3%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	10.76	11.04	12.44	13.34	14.18	14.84	1.4%
Delivered Energy	**70.55**	**70.32**	**78.46**	**83.59**	**88.38**	**92.44**	**1.3%**
Electricity Related Losses	23.86	24.56	26.82	27.67	28.27	28.51	0.7%
Total	**94.41**	**94.88**	**105.28**	**111.26**	**116.66**	**120.95**	**1.1%**
Electric Generators[14]							
Distillate Fuel	0.05	0.08	0.04	0.04	0.05	0.05	-2.4%
Residual Fuel	0.83	1.15	0.60	0.45	0.36	0.32	-5.6%
Petroleum Subtotal	0.88	1.23	0.64	0.48	0.41	0.37	-5.3%
Natural Gas	3.44	3.75	4.62	6.60	8.55	9.46	4.3%
Steam Coal	18.80	19.00	22.13	22.54	23.26	24.01	1.1%
Nuclear Power	6.71	7.19	7.20	6.70	5.45	4.56	-2.1%
Renewable Energy[15]	4.46	4.12	4.23	4.43	4.59	4.75	0.6%
Electricity Imports[16]	0.33	0.31	0.44	0.26	0.19	0.21	-1.8%
Total	**34.62**	**35.60**	**39.27**	**41.00**	**42.45**	**43.35**	**0.9%**

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

Sector and Source	Reference Case 1997	1998	2005	2010	2015	2020	Annual Growth 1998-2020 (percent)
Total Energy Consumption							
Distillate Fuel	7.27	7.32	7.95	8.19	8.50	8.73	0.8%
Kerosene	0.14	0.16	0.14	0.14	0.14	0.14	-0.7%
Jet Fuel[8]	3.31	3.36	4.16	4.85	5.55	6.24	2.9%
Liquefied Petroleum Gas	2.71	2.59	2.88	3.03	3.16	3.27	1.1%
Motor Gasoline[2]	15.31	15.82	17.95	19.39	20.59	21.65	1.4%
Petrochemical Feedstock	1.40	1.39	1.48	1.58	1.66	1.73	1.0%
Residual Fuel	1.96	2.17	1.75	1.76	1.81	1.91	-0.6%
Other Petroleum[12]	4.34	4.39	4.91	5.04	5.24	5.38	0.9%
Petroleum Subtotal	36.43	37.21	41.21	43.98	46.65	49.05	1.3%
Natural Gas	22.60	21.99	24.57	27.69	30.68	32.38	1.8%
Metallurgical Coal	0.81	0.76	0.68	0.63	0.58	0.53	-1.6%
Steam Coal	20.51	20.68	23.86	24.28	25.02	25.80	1.0%
Net Coal Coke Imports	0.02	0.07	0.17	0.21	0.24	0.27	6.6%
Coal Subtotal	21.34	21.50	24.72	25.12	25.84	26.60	1.0%
Nuclear Power	6.71	7.19	7.20	6.70	5.45	4.56	-2.1%
Renewable Energy[17]	7.00	6.67	7.08	7.41	7.71	7.99	0.8%
Methanol (M85)[11]	0.00	0.01	0.06	0.10	0.13	0.15	14.3%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity Imports[16]	0.33	0.31	0.44	0.26	0.19	0.21	-1.8%
Total	**94.41**	**94.88**	**105.28**	**111.26**	**116.66**	**120.95**	**1.1%**
Energy Use and Related Statistics							
Delivered Energy Use	70.55	70.32	78.46	83.59	88.38	92.44	1.3%
Total Energy Use	94.41	94.88	105.28	111.26	116.66	120.95	1.1%
Population (millions)	268.20	270.58	286.57	298.34	310.78	323.40	0.8%
Gross Domestic Product (billion 1992 dollars)	7,270	7,552	9,056	10,054	11,147	12,179	2.2%
Total Carbon Emissions (million metric tons)	1,478.9	1,485.4	1,683.4	1,786.6	1,893.4	1,979.2	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, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector electricity cogenerated by using wood and wood waste, landfill gas, municipal solid waste, and other biomass. See Table A18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Fuel consumption includes consumption for cogeneration.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Includes lease and plant fuel and consumption by cogenerators, excludes consumption by nonutility generators.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass; includes cogeneration, both for sale to the grid and for own use.
[8]Includes naphtha and kerosene type.
[9]Includes aviation gas and lubricants.
[10]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[11]M85 is 85 percent methanol and 15 percent motor gasoline.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes cogeneration. Excludes net electricity imports.
[16]In 1998 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[17]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1997 natural gas lease, plant, and pipeline fuel values: Energy Information Administration (EIA), *Natural Gas Annual 1997*, DOE/EIA-0131(97) (Washington, DC, October 1998). 1997 and 1998 electric utility fuel consumption: EIA, *Electric Power Annual 1998, Volume 1,* DOE/EIA-0348(98)/1 (Washington, DC, April 1999). 1997 and 1998 nonutility consumption estimates: Form EIA-867, "Annual Nonutility Power Producer Report, 1997." Other 1997 values: EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A. Other 1998 values: EIA, *Short-Term Energy Outlook, September 1999.* Online. http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999). **Projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Table A3. Energy Prices by Sector and Source
(1998 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Residential	**13.38**	**13.30**	**13.03**	**13.09**	**13.08**	**13.10**	**-0.1%**
Primary Energy[1]	7.17	6.75	7.15	7.11	6.99	6.92	0.1%
Petroleum Products[2]	8.64	7.48	9.48	9.73	9.88	10.04	1.3%
Distillate Fuel	7.14	6.12	7.55	7.74	7.82	7.88	1.2%
Liquefied Petroleum Gas	11.82	10.42	13.06	13.21	13.37	13.62	1.2%
Natural Gas	6.83	6.60	6.62	6.57	6.43	6.36	-0.2%
Electricity	24.56	23.58	21.90	21.67	21.50	21.33	-0.5%
Commercial	**13.33**	**13.13**	**12.32**	**12.14**	**12.04**	**12.00**	**-0.4%**
Primary Energy[1]	5.60	5.06	5.49	5.54	5.51	5.53	0.4%
Petroleum Products[2]	5.62	4.55	6.12	6.27	6.36	6.49	1.6%
Distillate Fuel	5.03	3.93	5.38	5.56	5.63	5.73	1.7%
Residual Fuel	3.50	2.49	3.70	3.74	3.79	3.87	2.0%
Natural Gas[3]	5.71	5.26	5.48	5.53	5.48	5.50	0.2%
Electricity	22.32	21.76	19.31	18.65	18.37	18.17	-0.8%
Industrial[4]	**5.54**	**4.88**	**5.38**	**5.48**	**5.55**	**5.65**	**0.7%**
Primary Energy	4.15	3.41	4.18	4.32	4.42	4.55	1.3%
Petroleum Products[2]	5.81	4.58	5.79	5.88	5.97	6.11	1.3%
Distillate Fuel	5.19	4.02	5.49	5.66	5.71	5.89	1.7%
Liquefied Petroleum Gas	8.81	7.11	7.79	7.87	8.00	8.25	0.7%
Residual Fuel	3.13	2.49	3.17	3.23	3.30	3.38	1.4%
Natural Gas[5]	3.08	2.66	3.08	3.28	3.38	3.50	1.3%
Metallurgical Coal	1.78	1.72	1.66	1.60	1.56	1.50	-0.6%
Steam Coal	1.48	1.45	1.32	1.26	1.21	1.16	-1.0%
Electricity	13.58	13.09	11.92	11.66	11.43	11.27	-0.7%
Transportation	**8.89**	**7.53**	**9.08**	**9.13**	**9.11**	**9.04**	**0.8%**
Primary Energy	8.87	7.51	9.06	9.11	9.09	9.02	0.8%
Petroleum Products[2]	8.87	7.51	9.06	9.11	9.08	9.01	0.8%
Distillate Fuel[6]	8.71	7.51	8.90	9.01	9.02	8.97	0.8%
Jet Fuel[7]	5.30	4.06	5.39	5.74	5.89	5.91	1.7%
Motor Gasoline[8]	10.07	8.54	10.33	10.35	10.35	10.30	0.9%
Residual Fuel	3.10	2.22	3.13	3.21	3.30	3.39	1.9%
Liquid Petroleum Gas[9]	12.28	11.01	13.52	13.48	13.47	13.50	0.9%
Natural Gas[10]	6.32	5.83	6.54	7.22	7.45	7.49	1.1%
Ethanol (E85)[11]	16.44	14.35	17.54	17.66	17.74	17.79	1.0%
Methanol (M85)[12]	13.39	8.99	14.01	14.32	14.38	14.42	2.2%
Electricity	16.56	16.46	14.62	14.15	13.68	13.38	-0.9%
Average End-Use Energy	**8.89**	**8.08**	**8.76**	**8.81**	**8.81**	**8.81**	**0.4%**
Primary Energy	8.52	7.59	8.43	8.49	8.49	8.49	0.5%
Electricity	20.19	19.56	17.85	17.50	17.24	17.06	-0.6%
Electric Generators[13]							
Fossil Fuel Average	1.57	1.48	1.44	1.55	1.64	1.67	0.6%
Petroleum Products	3.02	2.24	3.23	3.28	3.40	3.54	2.1%
Distillate Fuel	4.62	3.19	4.98	5.12	5.10	5.23	2.3%
Residual Fuel	2.92	2.17	3.11	3.13	3.19	3.30	1.9%
Natural Gas	2.73	2.34	2.79	3.08	3.21	3.33	1.6%
Steam Coal	1.28	1.25	1.11	1.07	1.03	0.98	-1.1%

Table A3. Energy Prices by Sector and Source (Continued)
(1998 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Average Price to All Users[14]							
Petroleum Products[2]	7.96	6.64	8.22	8.32	8.35	8.35	1.0%
Distillate Fuel	7.71	6.60	8.06	8.19	8.22	8.22	1.0%
Jet Fuel	5.30	4.06	5.39	5.74	5.89	5.91	1.7%
Liquefied Petroleum Gas	9.39	7.76	8.86	8.93	9.02	9.22	0.8%
Motor Gasoline[8]	10.07	8.54	10.33	10.35	10.35	10.30	0.9%
Residual Fuel	3.05	2.24	3.16	3.23	3.31	3.40	1.9%
Natural Gas	4.38	3.92	4.23	4.29	4.26	4.31	0.4%
Coal	1.32	1.29	1.13	1.09	1.04	0.99	-1.2%
Ethanol (E85)[11]	16.44	14.35	17.54	17.66	17.74	17.79	1.0%
Methanol (M85)[12]	13.39	8.99	14.01	14.32	14.38	14.42	2.2%
Electricity	20.19	19.56	17.85	17.50	17.24	17.06	-0.6%
Non-Renewable Energy Expenditures by Sector (billion 1998 dollars)							
Residential	137.55	131.06	142.85	150.04	155.58	161.86	1.0%
Commercial	101.11	96.86	101.07	105.14	108.63	109.62	0.6%
Industrial	116.22	101.24	118.54	126.14	134.52	142.83	1.6%
Transportation	215.26	188.11	262.19	287.60	308.82	325.96	2.5%
Total Non-Renewable Expenditures	570.14	517.27	624.65	668.93	707.54	740.27	1.6%
Transportation Renewable Expenditures	0.01	0.04	0.57	1.01	1.31	1.41	17.5%
Total Expenditures	**570.15**	**517.31**	**625.22**	**669.94**	**708.85**	**741.68**	**1.7%**

[1]Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Excludes independent power producers.
[4]Includes cogenerators.
[5]Excludes uses for lease and plant fuel.
[6] Low sulfur diesel fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[8]Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[9]Includes Federal and State taxes while excluding county and local taxes.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]M85 is 85 percent methanol and 15 percent motor gasoline.
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[14]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1997 prices for gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1997* . Online. ftp://ftp.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/historical/1997/pdf/pmaall.pdf (September 1, 1999). 1998 prices for gasoline, distillate, and jet fuel are based on prices in various issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380 (98/03-99/04) (Washington, DC, 1998-99). 1997 and 1998 prices for all other petroleum products are derived from the EIA,*State Energy Price and Expenditure Report 1995*, DOE/EIA-0376(95) (Washington, DC, August 1998). 1997 residential, commercial, and transportation natural gas delivered prices: EIA,*Natural Gas Annual 1997*, DOE/EIA-0131(97) (Washington, DC, October 1998). 1997 electric generators natural gas delivered prices: Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 1997 and 1998 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1994*. 1998 residential and commercial natural gas delivered prices: EIA *Natural Gas Monthly*, DOE/EIA-0130(99/06) (Washington, DC, June 1999). 1997 and 1998 coal prices based on EIA, *Quarterly Coal Report* , DOE/EIA-0121(99/1Q) (Washington, DC, August 1999), and EIA, AEO 2000 National Energy Modeling System run AEO2K.D100199A.1997 residential electricity prices derived from EIA, *Short-Term Energy Outlook, September 1999.* Online.http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999). 1997 and 1998 electricity prices for commercial, industrial, and transportation: EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A. **Projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

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

Key Indicators and Consumption	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Key Indicators							
Households (millions)							
Single-Family	73.74	74.69	80.61	84.38	87.61	90.55	0.9%
Multifamily	21.43	21.68	23.42	24.94	26.60	28.23	1.2%
Mobile Homes	6.32	6.47	7.28	7.81	8.31	8.77	1.4%
Total	**101.48**	**102.84**	**111.31**	**117.13**	**122.52**	**127.54**	**1.0%**
Average House Square Footage	**1663**	**1667**	**1689**	**1698**	**1704**	**1707**	**0.1%**
Energy Intensity (million Btu consumed per household)							
Delivered Energy Consumption	105.48	99.54	102.43	101.65	100.69	100.44	0.0%
Electricity Related Losses	80.18	82.95	84.67	83.31	81.33	79.78	-0.2%
Total Energy Consumption	185.66	182.49	187.10	184.95	182.02	180.22	-0.1%
Delivered Energy Consumption by Fuel							
Electricity							
Space Heating	0.42	0.38	0.44	0.46	0.48	0.50	1.3%
Space Cooling	0.45	0.56	0.55	0.58	0.62	0.67	0.8%
Water Heating	0.40	0.40	0.42	0.43	0.44	0.44	0.4%
Refrigeration	0.46	0.45	0.38	0.34	0.32	0.32	-1.5%
Cooking	0.10	0.10	0.11	0.12	0.12	0.13	1.0%
Clothes Dryers	0.22	0.22	0.24	0.26	0.27	0.29	1.2%
Freezers	0.13	0.12	0.10	0.09	0.08	0.08	-1.8%
Lighting	0.33	0.33	0.38	0.40	0.42	0.44	1.3%
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.04	0.04	1.0%
Dishwashers[1]	0.05	0.05	0.05	0.05	0.05	0.06	0.9%
Color Televisions	0.11	0.12	0.15	0.16	0.16	0.17	1.7%
Personal Computers	0.03	0.05	0.08	0.09	0.10	0.11	3.2%
Furnace Fans	0.08	0.07	0.08	0.08	0.09	0.10	1.8%
Other Uses[2]	0.87	0.96	1.37	1.60	1.80	1.97	3.4%
Delivered Energy	**3.67**	**3.83**	**4.37**	**4.70**	**5.00**	**5.30**	**1.5%**
Natural Gas							
Space Heating	3.49	3.01	3.53	3.67	3.79	3.93	1.2%
Space Cooling	0.00	0.00	0.00	0.01	0.01	0.02	16.0%
Water Heating	1.26	1.23	1.28	1.34	1.38	1.42	0.6%
Cooking	0.19	0.18	0.20	0.22	0.23	0.24	1.2%
Clothes Dryers	0.06	0.06	0.08	0.09	0.09	0.10	2.2%
Other Uses[3]	0.12	0.11	0.12	0.13	0.14	0.14	1.1%
Delivered Energy	**5.12**	**4.61**	**5.22**	**5.46**	**5.65**	**5.86**	**1.1%**
Distillate							
Space Heating	0.78	0.71	0.67	0.62	0.58	0.55	-1.1%
Water Heating	0.12	0.13	0.11	0.11	0.10	0.10	-1.4%
Other Uses[4]	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Delivered Energy	**0.90**	**0.84**	**0.79**	**0.73**	**0.69**	**0.65**	**-1.2%**
Liquefied Petroleum Gas							
Space Heating	0.30	0.27	0.30	0.29	0.28	0.28	0.1%
Water Heating	0.10	0.10	0.10	0.10	0.10	0.09	-0.4%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.3%
Other Uses[3]	0.01	0.01	0.01	0.01	0.01	0.01	0.7%
Delivered Energy	**0.44**	**0.41**	**0.44**	**0.43**	**0.42**	**0.41**	**0.0%**
Marketed Renewables (wood)[5]	0.42	0.38	0.44	0.44	0.45	0.45	0.8%
Other Fuels[6]	0.15	0.16	0.15	0.14	0.14	0.14	-0.7%

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

Key Indicators and Consumption	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Delivered Energy Consumption by End-Use							
Space Heating	5.56	4.91	5.52	5.62	5.72	5.85	0.8%
Space Cooling	0.45	0.56	0.55	0.59	0.64	0.68	0.9%
Water Heating	1.88	1.87	1.92	1.98	2.02	2.05	0.4%
Refrigeration	0.46	0.45	0.38	0.34	0.32	0.32	-1.5%
Cooking	0.32	0.32	0.35	0.37	0.39	0.40	1.1%
Clothes Dryers	0.28	0.28	0.32	0.34	0.37	0.39	1.5%
Freezers	0.13	0.12	0.10	0.09	0.08	0.08	-1.8%
Lighting	0.33	0.33	0.38	0.40	0.42	0.44	1.3%
Clothes Washers	0.03	0.03	0.03	0.03	0.04	0.04	1.0%
Dishwashers	0.05	0.05	0.05	0.05	0.05	0.06	0.9%
Color Televisions	0.11	0.12	0.15	0.16	0.16	0.17	1.7%
Personal Computers	0.03	0.05	0.08	0.09	0.10	0.11	3.2%
Furnace Fans	0.08	0.07	0.08	0.08	0.09	0.10	1.8%
Other Uses[7]	0.99	1.08	1.51	1.74	1.95	2.13	3.1%
Delivered Energy	**10.70**	**10.24**	**11.40**	**11.91**	**12.34**	**12.81**	**1.0%**
Electricity Related Losses	**8.14**	**8.53**	**9.42**	**9.76**	**9.96**	**10.18**	**0.8%**
Total Energy Consumption by End-Use							
Space Heating	6.48	5.75	6.48	6.58	6.67	6.80	0.8%
Space Cooling	1.44	1.81	1.73	1.80	1.88	1.96	0.4%
Water Heating	2.77	2.76	2.82	2.88	2.89	2.89	0.2%
Refrigeration	1.49	1.45	1.20	1.06	0.96	0.93	-2.0%
Cooking	0.55	0.55	0.59	0.62	0.64	0.65	0.8%
Clothes Dryers	0.76	0.77	0.84	0.88	0.91	0.94	0.9%
Freezers	0.42	0.40	0.31	0.27	0.25	0.25	-2.2%
Lighting	1.06	1.06	1.18	1.24	1.26	1.27	0.8%
Clothes Washers	0.10	0.10	0.10	0.11	0.11	0.11	0.5%
Dishwashers	0.14	0.15	0.15	0.15	0.16	0.16	0.5%
Color Televisions	0.36	0.38	0.48	0.49	0.48	0.50	1.2%
Personal Computers	0.11	0.18	0.26	0.28	0.29	0.32	2.7%
Furnace Fans	0.25	0.21	0.24	0.26	0.27	0.28	1.3%
Other Uses[7]	2.92	3.21	4.46	5.05	5.53	5.92	2.8%
Total	**18.84**	**18.77**	**20.82**	**21.66**	**22.30**	**22.99**	**0.9%**
Non-Marketed Renewables							
Geothermal[8]	0.01	0.01	0.02	0.03	0.04	0.05	5.5%
Solar[9]	0.01	0.01	0.01	0.01	0.01	0.01	2.3%
Total	**0.02**	**0.02**	**0.03**	**0.04**	**0.05**	**0.06**	**4.9%**

[1]Does not include electric water heating portion of load.
[2]Includes small electric devices, heating elements, and motors.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as swimming pool and hot tub heaters.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1997*.
[6]Includes kerosene and coal.
[7]Includes all other uses listed above.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports.
Source: 1997 and 1998: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1999.* Online. http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999). **Projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

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

Key Indicators and Consumption	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Key Indicators							
Total Floor Space (billion square feet)							
Surviving	58.8	59.6	65.5	69.3	72.1	72.9	0.9%
New Additions	1.6	1.7	1.6	1.6	1.2	0.9	-2.7%
Total	**60.3**	**61.2**	**67.1**	**70.9**	**73.3**	**73.8**	**0.9%**
Energy Consumption Intensity (thousand Btu per square foot)							
Delivered Energy Consumption	127.1	121.7	123.4	123.3	124.1	124.8	0.1%
Electricity Related Losses	128.8	129.4	130.3	127.5	124.7	121.7	-0.3%
Total Energy Consumption	255.9	251.2	253.7	250.8	248.8	246.5	-0.1%
Delivered Energy Consumption by Fuel							
Purchased Electricity							
Space Heating	0.11	0.10	0.11	0.11	0.11	0.10	-0.1%
Space Cooling	0.37	0.45	0.42	0.43	0.43	0.42	-0.3%
Water Heating	0.12	0.12	0.12	0.12	0.12	0.11	-0.3%
Ventilation	0.17	0.17	0.18	0.19	0.19	0.19	0.5%
Cooking	0.03	0.03	0.03	0.03	0.03	0.02	-0.9%
Lighting	1.16	1.17	1.21	1.24	1.26	1.23	0.2%
Refrigeration	0.18	0.18	0.19	0.20	0.20	0.20	0.6%
Office Equipment (PC)	0.08	0.08	0.12	0.13	0.15	0.16	2.9%
Office Equipment (non-PC)	0.25	0.26	0.33	0.37	0.42	0.46	2.6%
Other Uses[1]	1.05	1.00	1.35	1.54	1.69	1.78	2.6%
Delivered Energy	**3.50**	**3.56**	**4.06**	**4.36**	**4.58**	**4.68**	**1.2%**
Natural Gas[2]							
Space Heating	1.25	1.10	1.28	1.31	1.34	1.33	0.8%
Space Cooling	0.01	0.01	0.02	0.02	0.02	0.02	2.5%
Water Heating	0.48	0.49	0.53	0.56	0.58	0.59	0.8%
Cooking	0.20	0.20	0.23	0.24	0.25	0.26	1.1%
Other Uses[3]	1.37	1.30	1.38	1.45	1.52	1.56	0.8%
Delivered Energy	**3.31**	**3.11**	**3.43**	**3.58**	**3.71**	**3.75**	**0.9%**
Distillate							
Space Heating	0.17	0.16	0.17	0.17	0.16	0.15	-0.5%
Water Heating	0.06	0.06	0.06	0.05	0.05	0.05	-1.2%
Other Uses[4]	0.21	0.15	0.15	0.15	0.16	0.16	0.3%
Delivered Energy	**0.45**	**0.38**	**0.38**	**0.38**	**0.37**	**0.36**	**-0.2%**
Other Fuels[5]	**0.33**	**0.32**	**0.33**	**0.35**	**0.35**	**0.35**	**0.4%**
Marketed Renewable Fuels							
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	N/A
Delivered Energy	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**N/A**
Delivered Energy Consumption by End-Use							
Space Heating	1.54	1.37	1.57	1.59	1.60	1.57	0.6%
Space Cooling	0.38	0.46	0.44	0.45	0.45	0.44	-0.2%
Water Heating	0.65	0.67	0.70	0.73	0.75	0.75	0.5%
Ventilation	0.17	0.17	0.18	0.19	0.19	0.19	0.5%
Cooking	0.23	0.23	0.25	0.27	0.28	0.28	0.8%
Lighting	1.16	1.17	1.21	1.24	1.26	1.23	0.2%
Refrigeration	0.18	0.18	0.19	0.20	0.20	0.20	0.6%
Office Equipment (PC)	0.08	0.08	0.12	0.13	0.15	0.16	2.9%
Office Equipment (non-PC)	0.25	0.26	0.33	0.37	0.42	0.46	2.6%
Other Uses[6]	3.04	2.86	3.29	3.57	3.80	3.93	1.5%
Delivered Energy	**7.67**	**7.46**	**8.28**	**8.74**	**9.10**	**9.22**	**1.0%**

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

Key Indicators and Consumption	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Electricity Related Losses	**7.77**	**7.93**	**8.75**	**9.04**	**9.14**	**8.98**	**0.6%**
Total Energy Consumption by End-Use							
Space Heating	1.79	1.60	1.81	1.82	1.81	1.76	0.5%
Space Cooling	1.19	1.46	1.35	1.33	1.31	1.25	-0.7%
Water Heating	0.92	0.94	0.97	0.98	0.99	0.96	0.1%
Ventilation	0.54	0.54	0.57	0.58	0.57	0.55	0.0%
Cooking	0.29	0.30	0.32	0.33	0.33	0.33	0.4%
Lighting	3.72	3.76	3.81	3.80	3.76	3.60	-0.2%
Refrigeration	0.57	0.57	0.60	0.61	0.61	0.60	0.2%
Office Equipment (PC)	0.25	0.27	0.38	0.41	0.44	0.46	2.4%
Office Equipment (non-PC)	0.81	0.84	1.03	1.15	1.26	1.33	2.1%
Other Uses[6]	5.36	5.09	6.20	6.77	7.17	7.35	1.7%
Total	**15.43**	**15.38**	**17.03**	**17.78**	**18.24**	**18.20**	**0.8%**
Non-Marketed Renewable Fuels							
Solar[7]	0.02	0.02	0.03	0.04	0.04	0.04	3.1%
Total	**0.02**	**0.02**	**0.03**	**0.04**	**0.04**	**0.04**	**3.1%**

[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, cogeneration in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, district services, emergency electric generators, and cogeneration in commercial buildings.
[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, cogeneration in commercial buildings, 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, and electricity generation by solar photovoltaic systems.
N/A = Not applicable.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports.
Source: 1997 and 1998 Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1999.* Online. http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999). **Projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

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

Key Indicators and Consumption	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Key Indicators							
Value of Gross Output (billion 1987 dollars)							
Manufacturing	3,184	3,291	3,838	4,227	4,663	5,040	2.0%
Nonmanufacturing	810	835	932	989	1,067	1,131	1.4%
Total	**3,993**	**4,126**	**4,770**	**5,216**	**5,730**	**6,171**	**1.8%**
Energy Prices (1998 dollars per million Btu)							
Electricity	13.58	13.09	11.92	11.66	11.43	11.27	-0.7%
Natural Gas	3.08	2.66	3.08	3.28	3.38	3.50	1.3%
Steam Coal	1.48	1.45	1.32	1.26	1.21	1.16	-1.0%
Residual Oil	3.13	2.49	3.17	3.23	3.30	3.38	1.4%
Distillate Oil	5.19	4.02	5.49	5.66	5.71	5.89	1.7%
Liquefied Petroleum Gas	8.81	7.11	7.79	7.87	8.00	8.25	0.7%
Motor Gasoline	10.05	8.54	10.30	10.32	10.32	10.28	0.8%
Metallurgical Coal	1.78	1.72	1.66	1.60	1.56	1.50	-0.6%
Energy Consumption							
Consumption[1]							
Purchased Electricity	3.52	3.57	3.92	4.15	4.45	4.70	1.3%
Natural Gas[2]	9.95	9.75	10.36	10.96	11.53	11.99	0.9%
Steam Coal	1.57	1.54	1.58	1.59	1.61	1.63	0.3%
Metallurgical Coal and Coke[3]	0.83	0.82	0.85	0.83	0.82	0.80	-0.1%
Residual Fuel	0.30	0.27	0.25	0.29	0.30	0.31	0.7%
Distillate	1.14	1.08	1.21	1.29	1.38	1.46	1.3%
Liquefied Petroleum Gas	2.16	2.06	2.27	2.40	2.53	2.64	1.1%
Petrochemical Feedstocks	1.40	1.39	1.47	1.58	1.66	1.73	1.0%
Other Petroleum[4]	4.31	4.32	4.84	4.97	5.17	5.31	0.9%
Renewables[5]	2.03	2.08	2.30	2.40	2.53	2.63	1.1%
Delivered Energy	**27.20**	**26.89**	**29.06**	**30.46**	**31.96**	**33.20**	**1.0%**
Electricity Related Losses	7.81	7.95	8.45	8.61	8.87	9.03	0.6%
Total	**35.01**	**34.84**	**37.51**	**39.08**	**40.83**	**42.23**	**0.9%**
Consumption per Unit of Output[1] (thousand Btu per 1987 dollars)							
Purchased Electricity	0.88	0.87	0.82	0.80	0.78	0.76	-0.6%
Natural Gas[2]	2.49	2.36	2.17	2.10	2.01	1.94	-0.9%
Steam Coal	0.39	0.37	0.33	0.30	0.28	0.26	-1.5%
Metallurgical Coal and Coke[3]	0.21	0.20	0.18	0.16	0.14	0.13	-1.9%
Residual Fuel	0.07	0.06	0.05	0.05	0.05	0.05	-1.2%
Distillate	0.28	0.26	0.25	0.25	0.24	0.24	-0.5%
Liquefied Petroleum Gas	0.54	0.50	0.48	0.46	0.44	0.43	-0.7%
Petrochemical Feedstocks	0.35	0.34	0.31	0.30	0.29	0.28	-0.8%
Other Petroleum[4]	1.08	1.05	1.01	0.95	0.90	0.86	-0.9%
Renewables[5]	0.51	0.51	0.48	0.46	0.44	0.43	-0.8%
Delivered Energy	**6.81**	**6.52**	**6.09**	**5.84**	**5.58**	**5.38**	**-0.9%**
Electricity Related Losses	1.96	1.93	1.77	1.65	1.55	1.46	-1.2%
Total	**8.77**	**8.44**	**7.86**	**7.49**	**7.13**	**6.84**	**-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. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports.

Sources: 1997 prices for gasoline and distillate are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1997* . Online. ftp://ftp.eia.doe.gov/pub/ oil_gas/petroleum/data_publications/petroleum_marketing_annual/historical/1997/pdf/pmaall.pdf (September 1, 1999). 1998 prices for gasoline and distillate are based on prices in various issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380 (98/03-99/04) (Washington, DC, 1998-99). 1997 and 1998 coal prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(99/08) (Washington, DC, August 1999). 1997 and 1998 electricity prices: EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A. Other 1997 values and other 1998 prices derived from EIA, *State Energy Data Report 1996* , DOE/EIA-0214(96) (Washington, DC, February 1999). Other 1998 values: EIA, *Short-Term Energy Outlook, September 1999.* Online. http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999). **Projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Key Indicators							
Level of Travel (billions)							
Light-Duty Vehicles <8,500 pounds (VMT)	2272	2403	2791	3048	3282	3498	1.7%
Commercial Light Trucks (VMT)[1]	70	72	83	90	98	105	1.7%
Freight Trucks >10,000 pounds (VMT)	161	184	215	228	243	256	1.5%
Air (seat miles available)	1044	1061	1439	1765	2118	2495	4.0%
Rail (ton miles traveled)	1316	1246	1403	1489	1581	1672	1.3%
Marine (ton miles traveled)	693	692	741	781	827	861	1.0%
Energy Efficiency Indicators							
New Light-Duty Vehicle (miles per gallon)[2]	23.9	24.2	24.9	25.6	26.2	26.5	0.4%
New Car (miles per gallon)[2]	27.9	28.2	30.1	31.4	31.7	31.6	0.5%
New Light Truck (miles per gallon)[2]	20.2	20.6	21.1	21.6	22.3	22.8	0.5%
Light-Duty Fleet (miles per gallon)[3]	20.6	20.7	20.5	20.4	20.5	20.6	-0.0%
New Commercial Light Truck (MPG)[1]	19.9	20.4	20.5	21.0	21.6	22.1	0.4%
Stock Commercial Light Truck (MPG)[1]	14.6	14.7	15.4	15.8	16.2	16.5	0.5%
Aircraft Efficiency (seat miles per gallon)	51.0	51.4	54.3	56.4	58.4	60.5	0.7%
Freight Truck Efficiency (miles per gallon)	5.1	5.6	5.9	6.0	6.2	6.4	0.6%
Rail Efficiency (ton miles per thousand Btu)	2.7	2.7	2.9	3.1	3.2	3.4	1.0%
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.4	2.4	2.7	2.8	3.0	3.2	1.2%
Energy Use by Mode (quadrillion Btu)							
Light-Duty Vehicles	14.16	14.64	16.97	18.54	19.87	21.03	1.7%
Commercial Light Trucks[1]	0.60	0.61	0.67	0.71	0.76	0.79	1.2%
Freight Trucks[4]	4.06	4.35	4.84	5.01	5.16	5.24	0.9%
Air	3.35	3.40	4.21	4.91	5.61	6.32	2.9%
Rail[5]	0.59	0.56	0.59	0.61	0.62	0.64	0.6%
Marine[6]	1.25	1.17	1.34	1.50	1.65	1.81	2.0%
Pipeline Fuel	0.77	0.75	0.77	0.87	0.95	0.99	1.3%
Other[7]	0.20	0.26	0.28	0.30	0.31	0.33	1.1%
Total	**24.99**	**25.74**	**29.71**	**32.48**	**34.99**	**37.20**	**1.7%**
Energy Use by Mode[8] (million barrels per day)							
Light-Duty Vehicles	7.38	7.63	8.94	9.79	10.50	11.12	1.7%
Commercial Light Trucks[1]	0.32	0.32	0.35	0.37	0.40	0.42	1.2%
Freight Trucks[4]	1.83	1.97	2.19	2.27	2.34	2.38	0.9%
Railroad	0.23	0.21	0.23	0.23	0.23	0.23	0.3%
Domestic Shipping	0.13	0.13	0.13	0.13	0.13	0.12	-0.2%
International Shipping	0.31	0.28	0.35	0.41	0.48	0.54	3.1%
Air Transportation	1.39	1.42	1.82	2.15	2.48	2.82	3.2%
Military Use	0.26	0.25	0.25	0.26	0.26	0.27	0.3%
Bus Transportation	0.08	0.07	0.07	0.07	0.07	0.07	0.0%
Rail Transportation[5]	0.05	0.05	0.05	0.06	0.06	0.07	1.6%
Recreational Boats	0.13	0.13	0.14	0.14	0.15	0.15	0.8%
Lubricants	0.09	0.12	0.13	0.14	0.15	0.15	1.1%
Pipeline Fuel	0.39	0.38	0.39	0.44	0.48	0.50	1.3%
Total	**12.58**	**12.97**	**15.04**	**16.46**	**17.73**	**18.85**	**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.
[8]Nonpetroleum fuels converted to crude oil equivalent.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.

Note: Totals may not equal sum of components due to independent rounding. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports.

Sources: 1997: Energy Information Administration (EIA), *Natural Gas Annual 1997*, DOE/EIA-0131(97) (Washington, DC, October 1998); Federal Highway Administration, *Highway Statistics 1997* (Washington, DC, 1997); Oak Ridge National Laboratory, *Transportation Energy Data Book: 12, 13, 14, 15, 16, 17, and 18*, (Oak Ridge, TN, August 1998); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance*, (Washington, DC, February 1998); 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 1996*, DOE/EIA-0214(96) (Washington, DC, February 1999). 1998: U.S. Department of Transportation, Bureau of Transportation Statisitics, *Air Carrier Statistics Monthly, December 1998/1997*, (Washington, DC, 1998); EIA, *Short-Term Energy Outlook, September 1999.* Online. http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999); 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, AEO2000 National Energy Modeling System run AEO2K.D100199A.

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

Supply, Disposition, and Prices	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Generation by Fuel Type							
Electric Generators[1]							
Coal	1798	1817	2076	2121	2200	2296	1.1%
Petroleum	81	114	62	48	41	37	-5.0%
Natural Gas	299	325	517	796	1085	1256	6.3%
Nuclear Power	629	674	674	627	511	427	-2.1%
Pumped Storage	-3	-2	-1	-1	-1	-1	-3.8%
Renewable Sources[2]	394	360	366	381	386	393	0.4%
Total	**3198**	**3288**	**3695**	**3973**	**4222**	**4409**	**1.3%**
Non-Utility Generation for Own Use	8	10	15	16	16	16	2.2%
Cogenerators[3]							
Coal	52	52	51	51	51	51	-0.1%
Petroleum	8	8	6	6	6	7	-0.7%
Natural Gas	194	195	200	205	212	220	0.6%
Other Gaseous Fuels[4]	3	3	6	6	7	7	3.9%
Renewable Sources[2]	40	40	45	48	51	54	1.3%
Other[5]	7	8	8	8	8	8	0.2%
Total	**304**	**306**	**316**	**325**	**336**	**348**	**0.6%**
Sales to Utilities	146	148	151	156	162	169	0.6%
Generation for Own Use	166	165	171	174	179	184	0.5%
Other Generators[6]	**7**	**7**	**5**	**5**	**5**	**5**	**-1.3%**
Net Imports[7]	**32**	**30**	**43**	**26**	**19**	**20**	**-1.8%**
Electricity Sales by Sector							
Residential	1076	1124	1281	1379	1464	1553	1.5%
Commercial	1027	1045	1189	1277	1344	1371	1.2%
Industrial	1033	1047	1149	1217	1303	1378	1.3%
Transportation	19	20	28	36	44	49	4.2%
Total	**3155**	**3236**	**3647**	**3909**	**4155**	**4350**	**1.4%**
End-Use Prices (1998 cents per kilowatthour)[8]							
Residential	8.4	8.0	7.5	7.4	7.3	7.3	-0.5%
Commercial	7.6	7.4	6.6	6.4	6.3	6.2	-0.8%
Industrial	4.6	4.5	4.1	4.0	3.9	3.8	-0.7%
Transportation	5.6	5.6	5.0	4.8	4.7	4.6	-0.9%
All Sectors Average	**6.9**	**6.7**	**6.1**	**6.0**	**5.9**	**5.8**	**-0.6%**
Emissions (million short tons)							
Sulfur Dioxide	12.79	13.04	10.38	9.15	8.95	8.95	-1.7%
Nitrogen Oxide	5.96	5.98	5.50	5.66	5.87	5.93	-0.0%

[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]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[7]In 1998 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[8]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1997 and 1998 commercial and transportation sales derived from: Energy Information Administration (EIA), *State Energy Data Report 1996* , DOE/EIA-0214(96) (Washington, DC, February 1999), 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. 1997 and 1998 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: EIA, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). 1997 and 1998 residential electricity prices derived from EIA, *Short-Term Energy Outlook, September 1999.* Online. http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999). **1997 and 1998 electricity prices for commercial, industrial, and transportation; emissions; and projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Table A9. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	Reference Case 1997	1998	2005	2010	2015	2020	Annual Growth 1998-2020 (percent)
Electric Generators[2]							
Capability							
Coal Steam	305.1	305.2	301.6	301.7	306.8	317.0	0.2%
Other Fossil Steam[3]	137.5	138.2	125.3	119.5	117.1	109.9	-1.0%
Combined Cycle	18.3	19.5	55.8	93.1	124.7	154.6	9.9%
Combustion Turbine/Diesel	66.3	73.2	115.0	153.5	180.4	202.3	4.7%
Nuclear Power	99.7	97.1	93.4	84.1	67.4	57.0	-2.4%
Pumped Storage	19.6	19.9	20.0	20.0	20.0	20.0	0.0%
Fuel Cells	0.0	0.0	0.0	0.0	0.1	0.1	26.6%
Renewable Sources[4]	86.7	87.2	91.1	93.8	95.3	96.7	0.5%
Total	**733.2**	**740.2**	**802.2**	**865.7**	**911.8**	**957.5**	**1.2%**
Cumulative Planned Additions[5]							
Coal Steam	0.0	0.0	0.1	0.1	0.1	0.1	N/A
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combined Cycle	0.0	0.0	4.7	4.7	4.7	4.7	N/A
Combustion Turbine/Diesel	0.0	0.0	1.5	1.5	1.5	1.5	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.1	N/A
Renewable Sources[4]	0.0	0.0	2.7	4.8	5.7	5.9	N/A
Total	**0.0**	**0.0**	**8.9**	**11.1**	**12.0**	**12.2**	**N/A**
Cumulative Unplanned Additions[5]							
Coal Steam	0.0	0.0	0.7	3.8	9.5	21.0	N/A
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combined Cycle	0.0	0.0	31.6	68.9	100.6	130.5	N/A
Combustion Turbine/Diesel	0.0	0.0	42.2	81.9	109.4	132.3	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[4]	0.0	0.0	1.1	1.8	2.6	3.8	N/A
Total	**0.0**	**0.0**	**75.6**	**156.4**	**222.1**	**287.6**	**N/A**
Cumulative Total Additions	**0.0**	**0.0**	**84.5**	**167.4**	**234.1**	**299.8**	**N/A**
Cumulative Retirements[6]	**0.0**	**0.0**	**28.9**	**48.4**	**69.0**	**89.0**	**N/A**
Cogenerators[7]							
Capability							
Coal	8.8	8.8	9.0	9.0	9.0	9.0	0.1%
Petroleum	1.4	1.4	1.4	1.4	1.4	1.4	0.1%
Natural Gas	30.9	31.8	35.7	36.4	37.3	38.4	0.9%
Other Gaseous Fuels	0.4	0.4	0.8	0.8	0.9	1.0	3.7%
Renewable Sources[4]	6.5	6.6	7.4	7.9	8.5	9.0	1.4%
Other	1.2	1.3	1.4	1.4	1.4	1.4	0.3%
Total	**49.2**	**50.3**	**55.6**	**56.8**	**58.4**	**60.2**	**0.8%**
Cumulative Additions[5]	**0.0**	**0.0**	**5.3**	**6.6**	**8.1**	**9.9**	**N/A**

Table A9. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Other Generators[8]							
Capability	1.1	1.1	1.2	1.4	1.5	1.8	2.4%
Cumulative Additions	0.0	0.0	0.1	0.3	0.4	0.7	N/A

[1]Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes grid-connected utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[3]Includes oil-, gas-, and dual-fired capability.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar and wind power.
[5]Cumulative additions after December 31, 1998.
[6]Cumulative total retirements after December 31, 1998.
[7]Nameplate capacity is reported for nonutilities on Form EIA-867, “Annual Nonutility Power Producer Report, 1997.” Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.
[8]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
N/A = Not applicable.
Notes: Totals may not equal sum of components due to independent rounding. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators for AEO2000. Net summer capacity is used to be consistent with electric utility capacity estimates.
Sources: 1997 and 1998 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 1998 and planned additions estimated based on EIA, Form EIA-867, “Annual Nonutility Power Producer Report, 1997.” **Projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

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

Electricity Trade	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Interregional Electricity Trade							
Gross Domestic Firm Power Trade	190.3	202.4	143.1	102.4	48.5	0.0	N/A
Gross Domestic Economy Trade	208.8	144.1	206.5	199.7	182.4	186.1	1.2%
Gross Domestic Trade	**399.1**	**346.4**	**349.6**	**302.1**	**230.9**	**186.1**	**-2.8%**
Gross Domestic Firm Power Sales (million 1998 dollars)	9,033.3	9,607.3	6,792.9	4,862.3	2,303.2	0.0	N/A
Gross Domestic Economy Sales (million 1998 dollars)	7,264.3	4,260.3	6,204.4	6,218.7	5,728.2	5,832.9	1.4%
Gross Domestic Sales (million 1998 dollars)	**16,297.6**	**13,867.6**	**12,997.3**	**11,081.0**	**8,031.4**	**5,832.9**	**-3.9%**
International Electricity Trade							
Firm Power Imports From Canada and Mexico[1]	18.9	19.0	7.2	4.6	2.2	0.0	N/A
Economy Imports From Canada and Mexico[1]	29.0	26.5	56.3	39.3	29.4	27.9	0.2%
Gross Imports From Canada and Mexico[1]	**47.8**	**45.4**	**63.5**	**43.8**	**31.6**	**27.9**	**-2.2%**
Firm Power Exports To Canada and Mexico	0.3	0.3	13.7	10.4	4.9	0.0	N/A
Economy Exports To Canada and Mexico	15.2	15.0	7.0	7.7	7.7	7.7	-3.0%
Gross Exports To Canada and Mexico	**15.6**	**15.4**	**20.7**	**18.1**	**12.6**	**7.7**	**-3.1%**

[1]Historically electricity imports were primarily from renewable resources, principally hydroelectric.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.
Sources: 1997 and 1998 interregional firm electricity trade data: North America Electricity Reliability Council (NERC), Electricity Sales and Demand Database 1998. 1997 and 1998 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 1997 and 1998 firm/economy share: National Energy Board, *Annual Report 1998*. **Projections:** Energy Information Administration, AEO2000 National Energy Modeling System run AEO2K.D100199A.

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

Supply and Disposition	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Crude Oil							
Domestic Crude Production[1]	6.45	6.25	5.36	5.18	5.20	5.26	-0.8%
Alaska	1.30	1.18	0.96	0.81	0.63	0.51	-3.7%
Lower 48 States	5.15	5.08	4.40	4.36	4.57	4.75	-0.3%
Net Imports	8.12	8.60	10.79	11.45	11.48	11.59	1.4%
Gross Imports	8.23	8.70	10.82	11.47	11.50	11.62	1.3%
Exports	0.11	0.11	0.03	0.03	0.03	0.03	-5.8%
Other Crude Supply[2]	0.09	0.04	0.00	0.00	0.00	0.00	N/A
Total Crude Supply	**14.66**	**14.89**	**16.15**	**16.62**	**16.68**	**16.84**	**0.6%**
Natural Gas Plant Liquids	**1.82**	**1.76**	**1.81**	**2.05**	**2.26**	**2.37**	**1.4%**
Other Inputs[3]	**0.29**	**0.25**	**0.29**	**0.29**	**0.30**	**0.32**	**1.1%**
Refinery Processing Gain[4]	**0.85**	**0.89**	**1.03**	**1.11**	**1.12**	**1.12**	**1.1%**
Net Product Imports[5]	**1.04**	**1.17**	**1.76**	**2.40**	**3.48**	**4.45**	**6.3%**
Gross Refined Product Imports[6]	1.52	1.63	2.08	2.65	3.68	4.60	4.8%
Unfinished Oil Imports	0.35	0.30	0.57	0.67	0.72	0.74	4.2%
Ether Imports	0.06	0.07	0.00	0.00	0.00	0.00	-28.9%
Exports	0.90	0.83	0.89	0.92	0.91	0.90	0.4%
Total Primary Supply[7]	**18.65**	**18.95**	**21.04**	**22.47**	**23.85**	**25.09**	**1.3%**
Refined Petroleum Products Supplied							
Motor Gasoline[8]	7.98	8.25	9.41	10.18	10.81	11.37	1.5%
Jet Fuel[9]	1.60	1.62	2.01	2.35	2.68	3.02	2.9%
Distillate Fuel[10]	3.42	3.45	3.74	3.85	4.00	4.11	0.8%
Residual Fuel	0.86	0.95	0.76	0.77	0.79	0.83	-0.6%
Other[11]	4.74	4.67	5.15	5.37	5.60	5.77	1.0%
Total	**18.59**	**18.94**	**21.08**	**22.51**	**23.87**	**25.10**	**1.3%**
Refined Petroleum Products Supplied							
Residential and Commercial	1.14	1.06	1.06	1.03	1.00	0.96	-0.4%
Industrial[12]	4.91	4.80	5.28	5.54	5.81	6.03	1.0%
Transportation	12.15	12.54	14.46	15.73	16.89	17.94	1.6%
Electric Generators[13]	0.38	0.54	0.28	0.21	0.18	0.16	-5.3%
Total	**18.59**	**18.94**	**21.08**	**22.51**	**23.87**	**25.10**	**1.3%**
Discrepancy[14]	**0.06**	**0.01**	**-0.04**	**-0.04**	**-0.03**	**-0.01**	**N/A**
World Oil Price (1998 dollars per barrel)[15]	**18.71**	**12.10**	**20.49**	**21.00**	**21.53**	**22.04**	**2.8%**
Import Share of Product Supplied	**0.49**	**0.52**	**0.60**	**0.62**	**0.63**	**0.64**	**1.0%**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 1998 dollars)	**61.40**	**46.55**	**95.36**	**109.73**	**124.19**	**138.16**	**5.1%**
Domestic Refinery Distillation Capacity[16]	**15.9**	**16.3**	**17.4**	**17.6**	**17.6**	**17.8**	**0.4%**
Capacity Utilization Rate (percent)	**96.0**	**96.0**	**93.2**	**94.8**	**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.
[16]End-of-year capacity.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1997 and 1998 product supplied data from Table A2. Other 1997 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1997,* DOE/EIA-0340(97/1) (Washington, DC, June 1998). Other 1998 data: EIA, *Petroleum Supply Annual 1998,* DOE/EIA-0340(98/1) (Washington, DC, June 1999). **Projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Table A12. Petroleum Product Prices
(1998 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
World Oil Price (1998 dollars per barrel)	**18.71**	**12.10**	**20.49**	**21.00**	**21.53**	**22.04**	**2.8%**
Delivered Sector Product Prices							
Residential							
Distillate Fuel	99.0	84.9	104.7	107.3	108.5	109.3	1.2%
Liquefied Petroleum Gas	102.0	90.0	112.7	114.0	115.4	117.6	1.2%
Commercial							
Distillate Fuel	69.7	54.4	74.7	77.1	78.0	79.5	1.7%
Residual Fuel	52.3	37.3	55.4	56.0	56.8	57.9	2.0%
Residual Fuel (1998 dollars per barrel)	21.98	15.65	23.26	23.51	23.85	24.33	2.0%
Industrial[1]							
Distillate Fuel	72.0	55.7	76.1	78.5	79.1	81.6	1.7%
Liquefied Petroleum Gas	76.1	61.4	67.2	68.0	69.0	71.2	0.7%
Residual Fuel	46.8	37.2	47.4	48.4	49.4	50.6	1.4%
Residual Fuel (1998 dollars per barrel)	19.67	15.64	19.92	20.32	20.76	21.24	1.4%
Transportation							
Diesel Fuel (distillate)[2]	120.7	104.1	123.4	125.0	125.1	124.3	0.8%
Jet Fuel[3]	71.5	54.7	72.8	77.5	79.5	79.8	1.7%
Motor Gasoline[4]	126.0	106.9	128.6	128.8	128.7	128.2	0.8%
Liquid Petroleum Gas	106.0	95.0	116.7	116.3	116.3	116.6	0.9%
Residual Fuel	46.4	33.3	46.8	48.1	49.4	50.7	1.9%
Residual Fuel (1998 dollars per barrel)	19.47	13.98	19.66	20.20	20.75	21.29	1.9%
Ethanol (E85)	147.3	128.6	157.0	158.1	158.8	159.2	1.0%
Methanol (M85)	98.3	66.0	102.7	105.0	105.4	105.7	2.2%
Electric Generators[5]							
Distillate Fuel	64.0	44.2	69.0	70.9	70.7	72.5	2.3%
Residual Fuel	43.8	32.5	46.6	46.9	47.7	49.4	1.9%
Residual Fuel (1998 dollars per barrel)	18.38	13.67	19.58	19.69	20.05	20.76	1.9%
Refined Petroleum Product Prices[6]							
Distillate Fuel	106.9	91.6	111.8	113.6	114.0	114.0	1.0%
Jet Fuel[3]	71.5	54.7	72.8	77.5	79.5	79.8	1.7%
Liquefied Petroleum Gas	81.1	67.0	76.4	77.0	77.8	79.6	0.8%
Motor Gasoline[4]	126.0	106.9	128.6	128.8	128.7	128.2	0.8%
Residual Fuel	45.7	33.6	47.3	48.3	49.5	50.8	1.9%
Residual Fuel (1998 dollars per barrel)	19.19	14.10	19.88	20.28	20.79	21.35	1.9%
Average	**104.6**	**87.4**	**107.7**	**108.9**	**109.2**	**109.1**	**1.0%**

[1]Includes cogenerators. Includes Federal and State taxes while excluding county and state taxes.
[2] Low sulfur diesel fuel. Includes Federal and State taxes while excluding county and local taxes.
[3]Kerosene-type jet fuel.
[4]Sales weighted-average price for all grades. Includes Federal and State taxes while excluding county and local taxes.
[5]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1997 prices for gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1997* . Online. ftp://ftp.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/historical/1997/pdf/pmaall.pdf (September 1, 1999). 1998 prices for gasoline, distillate, and jet fuel are based on prices in various issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380 (98/03-99/04) (Washington, DC, 1998-99). 1997 and 1998 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditure Report 1995*, DOE/EIA-0376(95) (Washington, DC, August 1998). **Projections**: EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

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

Supply and Disposition	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Production							
Dry Gas Production[1]	18.90	18.88	19.70	22.46	25.03	26.40	1.5%
Supplemental Natural Gas[2]	0.10	0.12	0.11	0.06	0.06	0.06	-3.2%
Net Imports	**2.84**	**3.13**	**4.19**	**4.52**	**4.85**	**5.14**	**2.3%**
Canada	2.84	3.15	3.98	4.32	4.72	5.01	2.1%
Mexico	-0.02	-0.04	-0.08	-0.13	-0.19	-0.20	7.7%
Liquefied Natural Gas	0.02	0.02	0.29	0.33	0.33	0.33	13.7%
Total Supply	**21.84**	**22.13**	**24.00**	**27.03**	**29.94**	**31.59**	**1.6%**
Consumption by Sector							
Residential	4.97	4.48	5.07	5.30	5.49	5.69	1.1%
Commercial	3.21	3.03	3.34	3.48	3.61	3.65	0.9%
Industrial[3]	8.47	8.23	8.81	9.22	9.64	9.99	0.9%
Electric Generators[4]	3.36	3.67	4.53	6.45	8.37	9.26	4.3%
Lease and Plant Fuel[5]	1.20	1.24	1.26	1.43	1.57	1.67	1.3%
Pipeline Fuel	0.75	0.73	0.75	0.84	0.92	0.96	1.3%
Transportation[6]	0.01	0.02	0.15	0.22	0.28	0.32	13.0%
Total	**21.99**	**21.39**	**23.91**	**26.95**	**29.88**	**31.53**	**1.8%**
Discrepancy[7]	**-0.15**	**0.73**	**0.09**	**0.08**	**0.06**	**0.05**	**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, 1997 and 1998 values include net storage injections.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1997 supply values and consumption as lease, plant, and pipeline fuel: Energy Information Administration (EIA), *Natural Gas Annual 1997*, DOE/EIA-0131(97) (Washington, DC, October 1998). Other 1997 consumption derived from: EIA, *State Energy Data Report 1996* , DOE/EIA-0214(96) (Washington, DC, February 1999). 1998 supplemental natural gas: EIA, *Natural Gas Monthly*, DOE/EIA-0130(99/06) (Washington, DC, June 1999). 1997 imports and dry gas production derived from: EIA, *Natural Gas Annual 1997*, DOE/EIA-0131(97) (Washington, DC, October 1998). 1998 transportation sector consumption: EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A. Other 1998 consumption: EIA, *Short-Term Energy Outlook, September 1999. Online.* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf *(October 12, 1999)* with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A. **Projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Table A14. Natural Gas Prices, Margins, and Revenues
(1998 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Source Price							
Average Lower 48 Wellhead Price[1]	2.39	1.96	2.34	2.60	2.71	2.81	1.7%
Average Import Price	2.18	1.96	2.59	2.64	2.67	2.92	1.8%
Average[2]	**2.36**	**1.96**	**2.39**	**2.61**	**2.70**	**2.83**	**1.7%**
Delivered Prices							
Residential	7.02	6.79	6.81	6.76	6.62	6.55	-0.2%
Commercial	5.87	5.42	5.64	5.69	5.64	5.66	0.2%
Industrial[3]	3.17	2.73	3.17	3.38	3.48	3.60	1.3%
Electric Generators[4]	2.79	2.40	2.85	3.14	3.28	3.41	1.6%
Transportation[5]	6.51	6.00	6.73	7.43	7.66	7.70	1.1%
Average[6]	**4.50**	**4.03**	**4.35**	**4.41**	**4.38**	**4.43**	**0.4%**
Transmission and Distribution Margins[7]							
Residential	4.66	4.83	4.42	4.15	3.91	3.72	-1.2%
Commercial	3.51	3.46	3.25	3.08	2.93	2.83	-0.9%
Industrial[3]	0.81	0.77	0.78	0.77	0.77	0.77	-0.0%
Electric Generators[4]	0.43	0.44	0.46	0.54	0.57	0.58	1.3%
Transportation[5]	4.14	4.04	4.34	4.82	4.96	4.87	0.9%
Average[6]	**2.14**	**2.07**	**1.96**	**1.80**	**1.67**	**1.60**	**-1.2%**
Transmission and Distribution Revenue (billion 1998 dollars)							
Residential	23.19	21.62	22.45	22.01	21.48	21.18	-0.1%
Commercial	11.27	10.46	10.85	10.73	10.59	10.31	-0.1%
Industrial[3]	6.82	6.37	6.87	7.09	7.46	7.73	0.9%
Electric Generators[4]	1.44	1.60	2.08	3.45	4.80	5.34	5.6%
Transportation[5]	0.06	0.09	0.67	1.08	1.40	1.55	14.0%
Total	**42.78**	**40.14**	**42.93**	**44.36**	**45.72**	**46.12**	**0.6%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.
Note: Totals may not equal sum of components due to independent rounding. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports.

Sources: 1997 residential, commercial, and transportation delivered prices; average lower 48 wellhead price; and average import price: Energy Information Administration (EIA), *Natural Gas Annual 1997*, DOE/EIA-0131(97) (Washington, DC, October 1998). 1997 electric generators delivered price: Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants". 1997 and 1998 industrial delivered prices based on EIA, *Manufacturing Energy Consumption Survey 1994*. 1998 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(99/06) (Washington, DC, June 1999). **Other 1997 values, other 1998 values, and projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Table A15. Oil and Gas Supply

Production and Supply	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Crude Oil							
Lower 48 Average Wellhead Price[1] (1998 dollars per barrel)	**18.19**	**11.60**	**20.08**	**20.62**	**20.86**	**21.27**	**2.8%**
Production (million barrels per day)[2]							
U.S. Total	**6.45**	**6.25**	**5.36**	**5.18**	**5.20**	**5.26**	**-0.8%**
Lower 48 Onshore	3.75	3.60	3.01	3.00	3.17	3.28	-0.4%
Conventional	3.06	2.87	2.42	2.39	2.49	2.57	-0.5%
Enhanced Oil Recovery	0.69	0.73	0.59	0.61	0.68	0.71	-0.1%
Lower 48 Offshore	1.40	1.47	1.38	1.36	1.40	1.47	-0.0%
Alaska	1.30	1.18	0.96	0.81	0.63	0.51	-3.7%
Lower 48 End of Year Reserves (billion barrels)[2]	**18.73**	**18.05**	**14.15**	**13.38**	**13.32**	**13.21**	**-1.4%**
Natural Gas							
Lower 48 Average Wellhead Price[1] (1998 dollars per thousand cubic feet)	**2.39**	**1.96**	**2.34**	**2.60**	**2.71**	**2.81**	**1.7%**
Production (trillion cubic feet)[3]							
U.S. Total	**18.90**	**18.72**	**19.70**	**22.46**	**25.03**	**26.40**	**1.6%**
Lower 48 Onshore	12.96	12.75	13.22	16.37	17.83	19.47	1.9%
Associated-Dissolved[4]	1.70	1.56	1.34	1.25	1.25	1.25	-1.0%
Non-Associated	11.27	11.19	11.88	15.12	16.58	18.22	2.2%
Conventional	6.76	6.68	6.91	9.81	10.09	10.75	2.2%
Unconventional	4.51	4.51	4.98	5.30	6.49	7.47	2.3%
Lower 48 Offshore	5.51	5.53	6.02	5.60	6.68	6.39	0.7%
Associated-Dissolved[4]	0.88	0.88	0.89	0.88	0.89	0.91	0.1%
Non-Associated	4.63	4.65	5.12	4.72	5.79	5.48	0.8%
Alaska	0.43	0.44	0.46	0.49	0.51	0.54	0.9%
Lower 48 End of Year Reserves (trillion cubic feet)	**156.66**	**155.00**	**155.85**	**173.45**	**191.59**	**191.37**	**1.0%**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.12**	**0.12**	**0.11**	**0.05**	**0.05**	**0.05**	**-3.9%**
Total Lower 48 Wells (thousands)	**27.39**	**23.96**	**24.92**	**32.86**	**35.69**	**38.66**	**2.2%**

[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.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1997 lower 48 onshore, lower 48 offshore, Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 1997,* DOE/EIA-0340(97/1) (Washington, DC. June 1998). 1997 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). 1997 natural gas lower 48 average wellhead price and total natural gas production: EIA, *Natural Gas Annual 1997*, DOE/EIA-0131(97) (Washington, DC, October 1998). 1998 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 1998,* DOE/EIA-0340(98/1) (Washington, DC. June 1999). 1998 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(99/06) (Washington, DC, June 1999). Other 1997 and 1998 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

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

Supply, Disposition, and Prices	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Production[1]							
Appalachia	476	470	449	427	412	385	-0.9%
Interior	171	168	169	146	147	155	-0.4%
West	451	489	603	669	710	776	2.1%
East of the Mississippi	587	580	593	559	547	528	-0.4%
West of the Mississippi	511	548	628	682	721	788	1.7%
Total	**1098**	**1128**	**1221**	**1242**	**1269**	**1316**	**0.7%**
Net Imports							
Imports	7	9	15	17	18	20	3.7%
Exports	84	78	62	64	57	58	-1.4%
Total	**-76**	**-69**	**-47**	**-47**	**-38**	**-38**	**-2.7%**
Total Supply[2]	**1022**	**1058**	**1174**	**1195**	**1230**	**1278**	**0.9%**
Consumption by Sector							
Residential and Commercial	6	6	7	7	7	7	0.4%
Industrial[3]	71	69	73	73	74	75	0.4%
Coke Plants	30	28	26	23	21	20	-1.6%
Electric Generators[4]	922	939	1070	1092	1129	1177	1.0%
Total	**1029**	**1043**	**1175**	**1195**	**1232**	**1279**	**0.9%**
Discrepancy and Stock Change[5].	**-7**	**16**	**-1**	**-1**	**-1**	**-1**	**N/A**
Average Minemouth Price							
(1998 dollars per short ton)	18.32	17.51	14.71	13.84	13.34	12.54	-1.5%
(1998 dollars per million Btu)	0.86	0.83	0.70	0.66	0.64	0.60	-1.4%
Delivered Prices (1998 dollars per short ton)[6]							
Industrial	32.73	32.26	28.71	27.44	26.27	25.24	-1.1%
Coke Plants	48.08	46.06	44.57	42.93	41.72	40.19	-0.6%
Electric Generators							
(1998 dollars per short ton)	26.42	25.64	22.96	22.13	21.19	20.01	-1.1%
(1998 dollars per million Btu)	1.28	1.25	1.11	1.07	1.03	0.98	-1.1%
Average	**27.50**	**26.65**	**23.79**	**22.86**	**21.86**	**20.63**	**-1.2%**
Exports[7]	40.95	38.89	38.14	36.05	35.08	33.91	-0.6%

[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, 8.8 million tons in 1996, 8.1 million tons in 1997, and are projected to reach 9.5 million tons in 1998, and 11.6 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. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1997: Energy Information Administration (EIA), *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998). 1998 data based on EIA, *Quarterly Coal Report* , DOE/EIA-0121(99/1Q) (Washington, DC, August 1999), and EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A. **Projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

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

Capacity and Generation	Reference Case 1997	1998	2005	2010	2015	2020	Annual Growth 1998-2020 (percent)
Electric Generators[1]							
(excluding cogenerators)							
Net Summer Capability							
Conventional Hydropower	77.43	77.71	78.21	78.33	78.33	78.33	0.0%
Geothermal[2]	2.87	2.89	2.89	2.98	3.11	3.75	1.2%
Municipal Solid Waste[3]	2.49	2.49	3.70	4.47	5.00	5.17	3.4%
Wood and Other Biomass[4]	1.76	1.76	2.01	2.41	2.71	2.93	2.3%
Solar Thermal	0.33	0.33	0.35	0.40	0.44	0.48	1.7%
Solar Photovoltaic	0.01	0.01	0.07	0.19	0.35	0.52	18.4%
Wind	1.78	1.99	3.89	5.07	5.40	5.49	4.7%
Total	**86.68**	**87.19**	**91.13**	**93.84**	**95.33**	**96.67**	**0.5%**
Generation (billion kilowatthours)							
Conventional Hydropower	350.45	316.79	300.62	300.50	299.90	299.35	-0.3%
Geothermal[2]	14.58	14.29	15.55	17.35	19.62	24.70	2.5%
Municipal Solid Waste[3]	17.72	17.78	25.48	30.63	34.55	35.71	3.2%
Wood and Other Biomass[4]	6.88	6.86	15.18	20.35	18.23	18.80	4.7%
Dedicated Plants	6.88	6.86	8.38	11.00	13.03	14.55	3.5%
Cofiring	0.00	0.00	6.80	9.34	5.20	4.25	N/A
Solar Thermal	0.89	0.89	0.95	1.09	1.22	1.35	1.9%
Solar Photovoltaic	0.00	0.00	0.18	0.46	0.86	1.30	31.8%
Wind	3.39	3.39	8.18	10.95	11.87	12.09	6.0%
Total	**393.91**	**360.00**	**366.13**	**381.33**	**386.26**	**393.32**	**0.4%**
Cogenerators[5]							
Net Summer Capability							
Municipal Solid Waste	0.52	0.52	0.52	0.52	0.52	0.52	0.0%
Biomass	6.00	6.04	6.85	7.37	7.94	8.46	1.5%
Total	**6.52**	**6.56**	**7.37**	**7.89**	**8.46**	**8.98**	**1.4%**
Generation (billion kilowatthours)							
Municipal Solid Waste	2.99	3.00	3.13	3.13	3.13	3.13	0.2%
Biomass	37.13	37.34	41.96	45.06	48.28	51.02	1.4%
Total	**40.13**	**40.34**	**45.09**	**48.19**	**51.41**	**54.15**	**1.3%**
Other Generators[6]							
Net Summer Capability							
Conventional Hydropower[7]	1.10	1.10	1.10	1.10	1.10	1.10	-0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Solar Photovoltaic	0.01	0.01	0.09	0.35	0.42	0.74	23.5%
Total	**1.10**	**1.10**	**1.19**	**1.44**	**1.52**	**1.84**	**2.4%**
Generation (billion kilowatthours)							
Conventional Hydropower[7]	7.25	7.25	4.86	4.85	4.84	4.83	-1.8%
Geothermal	0.00	0.00	0.07	0.07	0.07	0.07	13.9%
Solar Photovoltaic	0.01	0.01	0.16	0.46	0.47	0.50	21.8%
Total	**7.26**	**7.26**	**5.09**	**5.38**	**5.37**	**5.40**	**-1.3%**

[1]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.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Cogenerators produce electricity and other useful thermal energy.
[6]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[7]Represents own-use industrial hydroelectric power.
N/A = Not applicable.
Notes: Totals may not equal sum of components due to independent rounding. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators for AEO2000. Net summer capability is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.
Sources: 1997 and 1998 electric utility capability: Energy Information Administration (EIA), Form EIA-860. “Annual Electric Generator Report.” 1997 and 1998 nonutility and cogenerator capability: EIA, Form EIA-867, “Annual Nonutility Power Producer Report, 1997.” 1997 and 1998 generation: EIA, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Table A18. Renewable Energy, Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Marketed Renewable Energy[2]							
Residential	**0.42**	**0.38**	**0.44**	**0.44**	**0.45**	**0.45**	**0.8%**
Wood	0.42	0.38	0.44	0.44	0.45	0.45	0.8%
Commercial	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**N/A**
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	N/A
Industrial[3]	**2.03**	**2.08**	**2.30**	**2.40**	**2.53**	**2.63**	**1.1%**
Conventional Hydroelectric	0.17	0.17	0.17	0.17	0.17	0.17	N/A
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	-0.0%
Biomass	1.86	1.91	2.13	2.23	2.35	2.46	1.1%
Transportation	**0.10**	**0.12**	**0.16**	**0.18**	**0.21**	**0.23**	**3.2%**
Ethanol used in E85[4]	0.00	0.00	0.03	0.05	0.06	0.06	N/A
Ethanol used in Gasoline Blending	0.10	0.12	0.14	0.14	0.15	0.17	1.7%
Electric Generators[5]	**4.46**	**4.12**	**4.23**	**4.43**	**4.59**	**4.75**	**0.6%**
Conventional Hydroelectric	3.68	3.33	3.10	3.09	3.09	3.08	-0.4%
Geothermal	0.40	0.40	0.49	0.52	0.64	0.77	3.0%
Municipal Solid Waste	0.27	0.27	0.41	0.49	0.55	0.57	3.4%
Biomass	0.06	0.06	0.14	0.19	0.17	0.17	4.8%
Dedicated Plants	0.06	0.06	0.08	0.10	0.12	0.13	3.6%
Cofiring	0.00	0.00	0.06	0.09	0.05	0.04	N/A
Solar Thermal	0.01	0.01	0.01	0.02	0.02	0.03	4.9%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Wind	0.04	0.04	0.08	0.11	0.12	0.12	5.0%
Total Marketed Renewable Energy	**7.10**	**6.79**	**7.21**	**7.53**	**7.85**	**8.14**	**0.8%**
Non-Marketed Renewable Energy[6]							
Selected Consumption							
Residential	**0.02**	**0.02**	**0.03**	**0.04**	**0.05**	**0.06**	**4.9%**
Solar Hot Water Heating	0.01	0.01	0.00	0.00	0.00	0.00	-0.4%
Geothermal Heat Pumps	0.01	0.01	0.02	0.03	0.04	0.05	5.5%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	28.8%
Commercial	**0.02**	**0.02**	**0.03**	**0.04**	**0.04**	**0.04**	**3.1%**
Solar Thermal	0.02	0.02	0.03	0.03	0.03	0.03	1.6%
Solar Photovoltaic	0.00	0.00	0.00	0.01	0.01	0.01	24.1%
Ethanol							
From Corn	0.10	0.12	0.15	0.16	0.16	0.16	1.5%
From Cellulose	0.00	0.00	0.01	0.02	0.05	0.07	N/A
Total	**0.10**	**0.12**	**0.16**	**0.18**	**0.21**	**0.23**	**3.2%**

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table A8.
[3]Includes all electricity production by industrial and other cogenerators for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes renewable energy delivered to the grid from electric utilities and nonutilities other than cogenerators. Renewable energy used in generating electricity for own use is included in the individual sectoral electricity energy consumption values.
[6]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. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1997 and 1998 ethanol: Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). 1997 and 1998 electric generators: EIA, Form EIA-860, “Annual Electric Generator Report,” and EIA, Form EIA-867, “Annual Nonutility Power Producer Report, 1997.” Other 1997 and 1998: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Table A19. Carbon Emissions by Sector and Source
(Million Metric Tons per Year)

Sector and Source	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Residential							
Petroleum	27.1	24.8	24.8	23.5	22.4	21.5	-0.6%
Natural Gas	73.7	66.3	75.2	78.6	81.3	84.4	1.1%
Coal	1.5	1.5	1.5	1.4	1.4	1.3	-0.4%
Electricity	181.6	191.0	226.8	240.2	255.8	270.5	1.6%
Total	**283.9**	**283.5**	**328.2**	**343.7**	**361.0**	**377.7**	**1.3%**
Commercial							
Petroleum	13.9	12.9	12.1	12.2	12.1	11.8	-0.4%
Natural Gas	47.6	44.9	49.4	51.6	53.5	54.1	0.8%
Coal	2.2	2.2	2.5	2.6	2.7	2.7	0.9%
Electricity	173.4	177.5	210.4	222.5	234.8	238.8	1.4%
Total	**237.1**	**237.5**	**274.5**	**288.8**	**303.0**	**307.3**	**1.2%**
Industrial[1]							
Petroleum	105.6	100.8	102.0	105.6	109.2	112.4	0.5%
Natural Gas[2]	142.9	140.0	147.0	155.4	163.5	170.1	0.9%
Coal	59.3	58.0	61.6	61.4	61.4	61.6	0.3%
Electricity	174.3	178.0	203.3	212.0	227.6	240.0	1.4%
Total	**482.0**	**476.8**	**513.9**	**534.4**	**561.8**	**584.1**	**0.9%**
Transportation							
Petroleum[3]	461.5	473.4	547.5	595.8	639.7	679.9	1.7%
Natural Gas[4]	11.2	10.8	13.3	15.8	17.8	18.9	2.6%
Other[5]	0.0	0.0	1.1	1.8	2.3	2.7	N/A
Electricity	3.2	3.4	5.0	6.3	7.7	8.6	4.3%
Total[3]	**475.9**	**487.5**	**566.9**	**619.7**	**667.5**	**710.0**	**1.7%**
Total Carbon Emissions by Delivered Fuel							
Petroleum[3]	608.0	611.9	686.3	737.1	783.5	825.6	1.4%
Natural Gas	275.4	262.0	285.0	301.3	316.1	327.4	1.0%
Coal	63.0	61.7	65.6	65.4	65.5	65.6	0.3%
Other[5]	0.0	0.0	1.1	1.8	2.3	2.7	N/A
Electricity	532.5	549.8	645.5	681.0	725.9	757.8	1.5%
Total[3]	**1478.9**	**1485.4**	**1683.4**	**1786.6**	**1893.4**	**1979.2**	**1.3%**
Electric Generators[6]							
Petroleum	17.5	24.8	13.6	10.2	8.6	7.7	-5.2%
Natural Gas	43.5	47.8	66.6	95.0	123.1	136.2	4.9%
Coal	471.5	477.3	565.3	575.8	594.2	613.9	1.2%
Total	**532.5**	**549.8**	**645.5**	**681.0**	**725.9**	**757.8**	**1.5%**
Total Carbon Emissions by Primary Fuel[7]							
Petroleum[3]	625.5	636.7	699.9	747.3	792.1	833.3	1.2%
Natural Gas	318.9	309.8	351.5	396.3	439.3	463.7	1.8%
Coal	534.5	538.9	630.9	641.2	659.7	679.5	1.1%
Other[5]	0.0	0.0	1.1	1.8	2.3	2.7	N/A
Total[3]	**1478.9**	**1485.4**	**1683.4**	**1786.6**	**1893.4**	**1979.2**	**1.3%**
Carbon Emissions (tons per person)	**5.5**	**5.5**	**5.9**	**6.0**	**6.1**	**6.1**	**0.5%**

[1]Includes consumption by cogenerators.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel which, by convention are excluded from the international accounting of carbon 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. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1997 and 1998 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 1998,* DOE/EIA-0573(98), (Washington, DC, October 1999). **Projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Table A20. Macroeconomic Indicators
(Billion 1992 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	Reference Case 1997	1998	2005	2010	2015	2020	Annual Growth 1998-2020 (percent)
GDP Chain-Type Price Index (1992=1.000)	**1.116**	**1.127**	**1.278**	**1.423**	**1.591**	**1.857**	**2.3%**
Real Gross Domestic Product	**7,270**	**7,552**	**9,056**	**10,054**	**11,147**	**12,179**	**2.2%**
Real Consumption	4,914	5,153	6,188	6,906	7,743	8,585	2.3%
Real Investment	1,206	1,330	1,746	1,937	2,239	2,489	2.9%
Real Government Spending	1,285	1,297	1,458	1,575	1,666	1,779	1.4%
Real Exports	970	985	1,569	2,233	2,931	3,669	6.2%
Real Imports	1,106	1,223	1,910	2,623	3,522	4,610	6.2%
Real Disposable Personal Income	**5,183**	**5,348**	**6,406**	**7,204**	**8,083**	**9,008**	**2.4%**
Index of Manufacturing Gross Output (index 1987=1.000)	**1.365**	**1.411**	**1.645**	**1.812**	**1.999**	**2.160**	**2.0%**
AA Utility Bond Rate (percent)	7.54	6.91	6.86	7.72	8.14	8.81	N/A
Real Yield on Government 10 Year Bonds (percent)	4.94	4.29	3.95	4.59	4.91	4.69	N/A
Real Utility Bond Rate (percent)	5.53	5.33	4.80	5.55	5.79	5.43	N/A
Energy Intensity (thousand Btu per 1992 dollar of GDP)							
Delivered Energy	9.71	9.32	8.67	8.32	7.94	7.60	-0.9%
Total Energy	12.99	12.57	11.63	11.07	10.47	9.94	-1.1%
Consumer Price Index (1982-84=1.00)	1.61	1.63	1.94	2.20	2.48	2.90	2.7%
Unemployment Rate (percent)	4.94	4.48	5.05	5.72	5.30	5.10	N/A
Unit Sales of Light-Duty Vehicles (millions)	**15.05**	**15.64**	**15.80**	**16.02**	**17.06**	**17.09**	**0.4%**
Millions of People							
Population with Armed Forces Overseas	268.2	270.6	286.6	298.3	310.8	323.4	0.8%
Population (aged 16 and over)	206.4	208.6	223.7	235.2	245.6	255.3	0.9%
Employment, Non-Agriculture	121.8	126.2	135.3	140.1	144.6	147.8	0.7%
Employment, Manufacturing	18.7	19.0	17.9	17.2	16.6	15.9	-0.8%
Labor Force	136.3	137.7	149.8	157.3	162.6	167.0	0.9%

GDP = Gross domestic product.
Btu = British thermal unit.
N/A = Not applicable.
Sources: 1997 and 1998: Standard & Poor's DRI, Simulation T250899. **Projections:** Energy Information Administration, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Table A21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
World Oil Price (1998 dollars per barrel)[1]	**18.71**	**12.10**	**20.49**	**21.00**	**21.53**	**22.04**	**2.8%**
Production[2]							
OECD							
U.S. (50 states)	9.40	9.14	8.50	8.62	8.89	9.06	-0.0%
Canada	2.59	2.70	3.03	3.22	3.39	3.43	1.1%
Mexico	3.44	3.52	3.78	3.99	3.90	3.80	0.3%
OECD Europe[3]	7.02	6.95	7.94	7.72	7.03	6.52	-0.3%
Other OECD	0.83	0.77	0.90	0.92	0.88	0.82	0.3%
Total OECD	**23.27**	**23.09**	**24.15**	**24.48**	**24.09**	**23.63**	**0.1%**
Developing Countries							
Other South & Central America	3.40	3.64	4.07	4.43	4.79	4.99	1.4%
Pacific Rim	2.17	2.19	2.46	3.00	3.17	3.27	1.8%
OPEC	30.96	31.70	38.23	42.02	47.56	55.47	2.6%
Other Developing Countries	4.62	4.69	4.87	5.50	6.61	7.57	2.2%
Total Developing Countries	**41.14**	**42.23**	**49.63**	**54.96**	**62.13**	**71.30**	**2.4%**
Eurasia							
Former Soviet Union	7.13	7.24	7.70	10.14	12.08	13.05	2.7%
Eastern Europe	0.25	0.25	0.32	0.39	0.42	0.45	2.7%
China	3.20	3.20	3.33	3.52	3.62	3.63	0.6%
Total Eurasia	**10.58**	**10.69**	**11.35**	**14.05**	**16.12**	**17.13**	**2.2%**
Total Production	**74.99**	**76.01**	**85.14**	**93.48**	**102.33**	**112.06**	**1.8%**
Consumption							
OECD							
U.S. (50 states)	18.59	18.94	21.08	22.51	23.87	25.10	1.3%
U.S. Territories	0.28	0.28	0.32	0.34	0.36	0.38	1.4%
Canada	1.86	1.88	2.05	2.14	2.22	2.29	0.9%
Mexico	1.77	1.78	2.11	2.47	2.87	3.33	2.9%
Japan	5.71	5.51	5.80	6.04	6.30	6.59	0.8%
Australia and New Zealand	0.95	0.94	1.06	1.13	1.21	1.29	1.4%
OECD Europe[3]	14.47	14.74	15.82	16.37	16.90	17.46	0.8%
Total OECD	**43.62**	**44.07**	**48.24**	**51.01**	**53.74**	**56.43**	**1.1%**
Developing Countries							
Other South and Central America	4.44	4.67	5.74	6.78	7.95	9.30	3.2%
Pacific Rim	7.48	7.47	9.39	10.88	12.52	14.37	3.0%
OPEC	5.44	5.47	6.34	7.19	8.06	9.07	2.3%
Other Developing Countries	3.69	3.71	4.39	5.06	5.79	6.65	2.7%
Total Developing Countries	**21.05**	**21.32**	**25.85**	**29.92**	**34.33**	**39.39**	**2.8%**
Eurasia							
Former Soviet Union	4.26	4.23	4.50	4.91	5.39	5.93	1.5%
Eastern Europe	1.41	1.47	1.66	1.70	1.75	1.79	0.9%
China	3.79	3.91	5.18	6.23	7.43	8.82	3.8%
Total Eurasia	**9.46**	**9.62**	**11.34**	**12.85**	**14.57**	**16.55**	**2.5%**

Table A21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Total Consumption	**74.16**	**74.99**	**85.44**	**93.78**	**102.63**	**112.36**	**1.9%**
Non-OPEC Production	44.04	44.31	46.90	51.46	54.77	56.60	1.1%
Net Eurasia Exports	1.12	1.08	0.01	1.20	1.55	0.58	-2.7%
OPEC Market Share	0.41	0.42	0.45	0.45	0.46	0.49	0.8%

[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. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1997 and 1998 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1999.* Online.http://www.eia.doe.gov /pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999). **Projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Economic Growth Case Comparisons

Table B1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1998	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	13.23	10.83	10.96	11.26	10.85	11.01	11.67	10.95	11.13	11.98
Natural Gas Plant Liquids	2.49	2.80	2.90	3.05	3.06	3.21	3.36	3.19	3.36	3.46
Dry Natural Gas	19.40	22.28	23.09	24.31	24.52	25.73	27.06	25.70	27.13	27.98
Coal	23.89	25.68	26.18	26.80	25.79	26.63	27.79	26.14	27.36	29.62
Nuclear Power	7.19	6.70	6.70	6.70	5.45	5.45	5.45	4.56	4.56	4.70
Renewable Energy[1]	6.67	7.27	7.39	7.60	7.51	7.70	8.01	7.77	7.98	8.40
Other[2]	0.57	0.60	0.59	0.58	0.65	0.63	0.64	0.66	0.66	0.68
Total	**73.46**	**76.16**	**77.81**	**80.30**	**77.84**	**80.35**	**83.97**	**78.98**	**82.18**	**86.82**
Imports										
Crude Oil[3]	18.90	24.52	24.91	25.57	24.90	24.97	25.35	24.85	25.22	25.53
Petroleum Products[4]	3.99	5.58	6.80	8.00	6.52	8.98	10.66	7.64	10.87	13.73
Natural Gas	3.37	4.66	4.91	5.08	4.97	5.31	5.59	4.95	5.61	5.99
Other Imports[5]	0.59	0.87	0.89	0.95	0.85	0.89	0.97	0.92	0.97	1.08
Total	**26.85**	**35.62**	**37.50**	**39.61**	**37.24**	**40.16**	**42.57**	**38.36**	**42.67**	**46.33**
Exports										
Petroleum[6]	1.94	2.03	1.97	1.89	2.10	1.95	1.80	2.19	1.93	1.90
Natural Gas	0.17	0.29	0.29	0.29	0.35	0.35	0.35	0.36	0.36	0.36
Coal	2.05	1.60	1.63	1.60	1.44	1.44	1.44	1.46	1.46	1.46
Total	**4.16**	**3.92**	**3.89**	**3.78**	**3.89**	**3.75**	**3.59**	**4.01**	**3.76**	**3.73**
Discrepancy[7]	**1.27**	**0.17**	**0.16**	**0.17**	**0.07**	**0.10**	**0.12**	**0.04**	**0.14**	**0.06**
Consumption										
Petroleum Products[8]	37.21	42.08	43.98	46.33	43.73	46.65	49.65	44.99	49.05	53.27
Natural Gas	21.99	26.63	27.69	29.08	29.12	30.68	32.29	30.28	32.38	33.61
Coal	21.50	24.64	25.12	25.85	24.97	25.84	27.08	25.32	26.60	28.98
Nuclear Power	7.19	6.70	6.70	6.70	5.45	5.45	5.45	4.56	4.56	4.70
Renewable Energy[1]	6.67	7.28	7.41	7.61	7.53	7.71	8.03	7.78	7.99	8.42
Other[9]	0.32	0.36	0.36	0.37	0.31	0.33	0.34	0.34	0.36	0.38
Total	**94.88**	**107.68**	**111.26**	**115.95**	**111.12**	**116.66**	**122.83**	**113.28**	**120.95**	**129.36**
Net Imports - Petroleum	**20.95**	**28.07**	**29.73**	**31.68**	**29.32**	**32.00**	**34.21**	**30.30**	**34.15**	**37.36**
Prices (1998 dollars per unit)										
World Oil Price (dollars per barrel)[10]	12.10	20.44	21.00	21.56	20.74	21.53	22.32	20.99	22.04	23.11
Gas Wellhead Price (dollars per Mcf)[11]	1.96	2.38	2.60	2.93	2.36	2.71	3.03	2.40	2.81	3.27
Coal Minemouth Price (dollars per ton)	17.51	13.63	13.84	14.13	13.09	13.34	13.52	12.40	12.54	12.58
Average Electric Price (cents per Kwh)	6.7	5.7	6.0	6.3	5.6	5.9	6.1	5.5	5.8	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. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(99/06) (Washington, DC, June 1999). 1998 petroleum values: EIA, *Petroleum Supply Annual 1998,* DOE/EIA-0340(98/1) (Washington, DC, June 1999). Other 1998 values: EIA, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999) and EIA, *Quarterly Coal Report* , DOE/EIA-0121(99/1Q) (Washington, DC, August 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1998	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	0.84	0.73	0.73	0.73	0.69	0.69	0.68	0.65	0.65	0.65
Kerosene	0.10	0.09	0.09	0.09	0.08	0.09	0.09	0.08	0.09	0.09
Liquefied Petroleum Gas	0.41	0.43	0.43	0.44	0.42	0.42	0.42	0.41	0.41	0.41
Petroleum Subtotal	1.36	1.25	1.25	1.26	1.19	1.19	1.19	1.14	1.15	1.15
Natural Gas	4.61	5.41	5.46	5.48	5.57	5.65	5.71	5.73	5.86	5.92
Coal	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.38	0.44	0.44	0.44	0.44	0.45	0.45	0.44	0.45	0.46
Electricity	3.83	4.66	4.70	4.75	4.91	5.00	5.07	5.14	5.30	5.40
Delivered Energy	**10.24**	**11.82**	**11.91**	**11.99**	**12.16**	**12.34**	**12.48**	**12.50**	**12.81**	**12.99**
Electricity Related Losses	8.53	9.71	9.76	9.86	9.89	9.96	10.03	10.11	10.18	10.19
Total	**18.77**	**21.52**	**21.66**	**21.85**	**22.05**	**22.30**	**22.51**	**22.61**	**22.99**	**23.18**
Commercial										
Distillate Fuel	0.38	0.37	0.38	0.39	0.36	0.37	0.38	0.35	0.36	0.37
Residual Fuel	0.11	0.10	0.10	0.11	0.10	0.10	0.11	0.10	0.10	0.11
Kerosene	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.07	0.08	0.08	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	0.03	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.61	0.61	0.62	0.64	0.60	0.62	0.64	0.58	0.60	0.63
Natural Gas	3.11	3.52	3.58	3.64	3.61	3.71	3.83	3.60	3.75	3.90
Coal	0.09	0.10	0.10	0.10	0.10	0.10	0.11	0.10	0.10	0.11
Renewable Energy[3]	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Electricity	3.56	4.27	4.36	4.44	4.43	4.58	4.74	4.44	4.68	4.91
Delivered Energy	**7.46**	**8.57**	**8.74**	**8.90**	**8.81**	**9.10**	**9.40**	**8.80**	**9.22**	**9.63**
Electricity Related Losses	7.93	8.88	9.04	9.22	8.92	9.14	9.39	8.75	8.98	9.27
Total	**15.38**	**17.45**	**17.78**	**18.12**	**17.73**	**18.24**	**18.79**	**17.55**	**18.20**	**18.90**
Industrial[4]										
Distillate Fuel	1.08	1.22	1.29	1.38	1.26	1.38	1.49	1.29	1.46	1.61
Liquefied Petroleum Gas	2.06	2.25	2.40	2.60	2.30	2.53	2.80	2.32	2.64	3.02
Petrochemical Feedstock	1.39	1.49	1.58	1.72	1.52	1.66	1.84	1.52	1.73	1.98
Residual Fuel	0.27	0.27	0.29	0.31	0.27	0.30	0.33	0.27	0.31	0.36
Motor Gasoline[2]	0.21	0.23	0.25	0.26	0.24	0.26	0.28	0.25	0.28	0.31
Other Petroleum[5]	4.11	4.52	4.72	4.95	4.59	4.91	5.19	4.61	5.03	5.46
Petroleum Subtotal	9.12	9.98	10.53	11.22	10.17	11.04	11.94	10.25	11.45	12.74
Natural Gas[6]	9.75	10.53	10.96	11.56	10.89	11.53	12.33	11.08	11.99	13.06
Metallurgical Coal	0.76	0.63	0.63	0.63	0.58	0.58	0.57	0.53	0.53	0.52
Steam Coal	1.54	1.54	1.59	1.65	1.53	1.61	1.68	1.53	1.63	1.74
Net Coal Coke Imports	0.07	0.18	0.21	0.27	0.20	0.24	0.32	0.22	0.27	0.39
Coal Subtotal	2.36	2.34	2.42	2.54	2.31	2.42	2.57	2.28	2.43	2.65
Renewable Energy[7]	2.08	2.29	2.40	2.58	2.34	2.53	2.77	2.37	2.63	2.98
Electricity	3.57	3.93	4.15	4.51	4.10	4.45	4.92	4.20	4.70	5.39
Delivered Energy	**26.89**	**29.07**	**30.46**	**32.41**	**29.82**	**31.96**	**34.53**	**30.18**	**33.20**	**36.82**
Electricity Related Losses	7.95	8.18	8.61	9.36	8.26	8.87	9.74	8.27	9.03	10.17
Total	**34.84**	**37.25**	**39.08**	**41.78**	**38.07**	**40.83**	**44.27**	**38.46**	**42.23**	**47.00**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1998	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	4.95	5.47	5.76	6.13	5.58	6.02	6.51	5.62	6.22	6.91
Jet Fuel[8]	3.36	4.58	4.85	5.19	5.07	5.55	6.01	5.52	6.24	6.91
Motor Gasoline[2]	15.59	18.51	19.12	19.76	19.37	20.30	21.16	20.08	21.35	22.53
Residual Fuel	0.65	0.89	0.92	0.96	0.98	1.05	1.10	1.07	1.18	1.24
Liquefied Petroleum Gas	0.05	0.10	0.11	0.11	0.11	0.12	0.13	0.12	0.13	0.14
Other Petroleum[9]	0.30	0.32	0.34	0.36	0.33	0.36	0.38	0.33	0.37	0.40
Petroleum Subtotal	24.89	29.87	31.10	32.50	31.45	33.39	35.29	32.74	35.49	38.15
Pipeline Fuel Natural Gas	0.75	0.84	0.87	0.90	0.91	0.95	0.98	0.94	0.99	1.02
Compressed Natural Gas	0.02	0.22	0.23	0.24	0.27	0.29	0.31	0.30	0.33	0.36
Renewable Energy (E85)[10]	0.00	0.05	0.06	0.06	0.06	0.07	0.08	0.07	0.08	0.09
Methanol (M85)[11]	0.01	0.09	0.10	0.11	0.12	0.13	0.15	0.14	0.15	0.17
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.07	0.12	0.12	0.13	0.15	0.15	0.15	0.16	0.17	0.17
Delivered Energy	**25.74**	**31.20**	**32.48**	**33.94**	**32.97**	**34.99**	**36.96**	**34.34**	**37.20**	**39.96**
Electricity Related Losses	0.15	0.25	0.26	0.26	0.29	0.30	0.30	0.32	0.32	0.33
Total	**25.89**	**31.45**	**32.74**	**34.20**	**33.26**	**35.28**	**37.27**	**34.66**	**37.53**	**40.29**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.25	7.79	8.16	8.63	7.89	8.45	9.06	7.90	8.68	9.55
Kerosene	0.16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Jet Fuel[8]	3.36	4.58	4.85	5.19	5.07	5.55	6.01	5.52	6.24	6.91
Liquefied Petroleum Gas	2.59	2.87	3.03	3.24	2.92	3.16	3.45	2.93	3.27	3.67
Motor Gasoline[2]	15.82	18.77	19.39	20.04	19.64	20.59	21.47	20.35	21.65	22.86
Petrochemical Feedstock	1.39	1.49	1.58	1.72	1.52	1.66	1.84	1.52	1.73	1.98
Residual Fuel	1.02	1.26	1.31	1.38	1.35	1.45	1.53	1.43	1.59	1.71
Other Petroleum[12]	4.39	4.82	5.04	5.29	4.90	5.24	5.55	4.92	5.38	5.84
Petroleum Subtotal	35.98	41.71	43.50	45.62	43.42	46.24	49.06	44.71	48.69	52.66
Natural Gas[6]	18.24	20.52	21.09	21.82	21.25	22.13	23.16	21.65	22.92	24.26
Metallurgical Coal	0.76	0.63	0.63	0.63	0.58	0.58	0.57	0.53	0.53	0.52
Steam Coal	1.68	1.69	1.75	1.81	1.69	1.77	1.84	1.68	1.79	1.91
Net Coal Coke Imports	0.07	0.18	0.21	0.27	0.20	0.24	0.32	0.22	0.27	0.39
Coal Subtotal	2.50	2.50	2.58	2.70	2.47	2.58	2.73	2.43	2.59	2.81
Renewable Energy[13]	2.55	2.86	2.98	3.17	2.92	3.12	3.38	2.96	3.24	3.62
Methanol (M85)[11]	0.01	0.09	0.10	0.11	0.12	0.13	0.15	0.14	0.15	0.17
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.04	12.98	13.34	13.82	13.58	14.18	14.89	13.94	14.84	15.88
Delivered Energy	**70.32**	**80.66**	**83.59**	**87.24**	**83.76**	**88.38**	**93.37**	**85.83**	**92.44**	**99.40**
Electricity Related Losses	24.56	27.03	27.67	28.71	27.36	28.27	29.46	27.45	28.51	29.96
Total	**94.88**	**107.68**	**111.26**	**115.95**	**111.12**	**116.66**	**122.83**	**113.28**	**120.95**	**129.36**
Electric Generators[14]										
Distillate Fuel	0.08	0.03	0.04	0.04	0.04	0.05	0.04	0.04	0.05	0.08
Residual Fuel	1.15	0.34	0.45	0.67	0.27	0.36	0.55	0.23	0.32	0.53
Petroleum Subtotal	1.23	0.37	0.48	0.71	0.31	0.41	0.59	0.28	0.37	0.60
Natural Gas	3.75	6.11	6.60	7.26	7.87	8.55	9.13	8.63	9.46	9.35
Steam Coal	19.00	22.15	22.54	23.15	22.50	23.26	24.35	22.90	24.01	26.17
Nuclear Power	7.19	6.70	6.70	6.70	5.45	5.45	5.45	4.56	4.56	4.70
Renewable Energy[15]	4.12	4.42	4.43	4.44	4.60	4.59	4.65	4.82	4.75	4.80
Electricity Imports[16]	0.31	0.26	0.26	0.26	0.19	0.19	0.19	0.21	0.21	0.21
Total	**35.60**	**40.01**	**41.00**	**42.53**	**40.93**	**42.45**	**44.35**	**41.39**	**43.35**	**45.84**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1998	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Total Energy Consumption										
Distillate Fuel	7.32	7.82	8.19	8.67	7.93	8.50	9.10	7.94	8.73	9.62
Kerosene	0.16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Jet Fuel[8]	3.36	4.58	4.85	5.19	5.07	5.55	6.01	5.52	6.24	6.91
Liquefied Petroleum Gas	2.59	2.87	3.03	3.24	2.92	3.16	3.45	2.93	3.27	3.67
Motor Gasoline[2]	15.82	18.77	19.39	20.04	19.64	20.59	21.47	20.35	21.65	22.86
Petrochemical Feedstock	1.39	1.49	1.58	1.72	1.52	1.66	1.84	1.52	1.73	1.98
Residual Fuel	2.17	1.59	1.76	2.05	1.62	1.81	2.08	1.67	1.91	2.24
Other Petroleum[12]	4.39	4.82	5.04	5.29	4.90	5.24	5.55	4.92	5.38	5.84
Petroleum Subtotal	37.21	42.08	43.98	46.33	43.73	46.65	49.65	44.99	49.05	53.27
Natural Gas	21.99	26.63	27.69	29.08	29.12	30.68	32.29	30.28	32.38	33.61
Metallurgical Coal	0.76	0.63	0.63	0.63	0.58	0.58	0.57	0.53	0.53	0.52
Steam Coal	20.68	23.84	24.28	24.96	24.19	25.02	26.19	24.57	25.80	28.08
Net Coal Coke Imports	0.07	0.18	0.21	0.27	0.20	0.24	0.32	0.22	0.27	0.39
Coal Subtotal	21.50	24.64	25.12	25.85	24.97	25.84	27.08	25.32	26.60	28.98
Nuclear Power	7.19	6.70	6.70	6.70	5.45	5.45	5.45	4.56	4.56	4.70
Renewable Energy[17]	6.67	7.28	7.41	7.61	7.53	7.71	8.03	7.78	7.99	8.42
Methanol (M85)[11]	0.01	0.09	0.10	0.11	0.12	0.13	0.15	0.14	0.15	0.17
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports[16]	0.31	0.26	0.26	0.26	0.19	0.19	0.19	0.21	0.21	0.21
Total	**94.88**	**107.68**	**111.26**	**115.95**	**111.12**	**116.66**	**122.83**	**113.28**	**120.95**	**129.36**
Energy Use and Related Statistics										
Delivered Energy Use	70.32	80.66	83.59	87.24	83.76	88.38	93.37	85.83	92.44	99.40
Total Energy Use	94.88	107.68	111.26	115.95	111.12	116.66	122.83	113.28	120.95	129.36
Population (millions)	270.58	290.88	298.34	305.81	299.85	310.78	321.72	308.90	323.40	337.89
Gross Domestic Product (billion 1992 dollars)	7,552	9,524	10,054	10,680	10,265	11,147	11,984	10,870	12,179	13,413
Total Carbon Emissions (million metric tons)	1,485.4	1,728.0	1,786.6	1,863.3	1,801.5	1,893.4	1,996.7	1,850.6	1,979.2	2,125.9

[1]Includes wood used for residential heating. See Table B18 estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector electricity cogenerated by using wood and wood waste, landfill gas, municipal solid waste, and other biomass. See Table B18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Fuel consumption includes consumption for cogeneration.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Includes lease and plant fuel and consumption by cogenerators, excludes consumption by nonutility generators.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass; includes cogeneration, both for sale to the grid and for own use.
[8]Includes naphtha and kerosene type.
[9]Includes aviation gas and lubricants.
[10]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[11]M85 is 85 percent methanol and 15 percent motor gasoline.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes cogeneration. Excludes net electricity imports.
[16]In 1998 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[17]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1998 electric utility fuel consumption: Energy Information Administration, (EIA) *Electric Power Annual 1998, Volume 1,* DOE/EIA-0348(98)/1 (Washington, DC, April 1999). 1998 nonutility consumption estimates: Form EIA-867, "Annual Nonutility Power Producer Report, 1997." Other 1998 values: EIA, *Short-Term Energy Outlook, September 1999.* Online. http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B3. Energy Prices by Sector and Source
(1998 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1998	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	**13.30**	**12.62**	**13.09**	**13.65**	**12.49**	**13.08**	**13.63**	**12.50**	**13.10**	**13.79**
Primary Energy[1]	6.75	6.88	7.11	7.40	6.67	6.99	7.28	6.56	6.92	7.33
Petroleum Products[2]	7.48	9.49	9.73	9.93	9.52	9.88	10.20	9.59	10.04	10.37
Distillate Fuel	6.12	7.53	7.74	7.89	7.55	7.82	8.12	7.57	7.88	8.15
Liquefied Petroleum Gas	10.42	12.95	13.21	13.47	12.90	13.37	13.70	12.98	13.62	14.04
Natural Gas	6.60	6.34	6.57	6.88	6.11	6.43	6.72	6.01	6.36	6.79
Electricity	23.58	20.89	21.67	22.59	20.57	21.50	22.35	20.50	21.33	22.31
Commercial	**13.13**	**11.57**	**12.14**	**12.87**	**11.31**	**12.04**	**12.75**	**11.20**	**12.00**	**12.91**
Primary Energy[1]	5.06	5.32	5.54	5.82	5.20	5.51	5.80	5.16	5.53	5.94
Petroleum Products[2]	4.55	6.07	6.27	6.42	6.08	6.36	6.66	6.12	6.49	6.78
Distillate Fuel	3.93	5.35	5.56	5.70	5.35	5.63	5.97	5.36	5.73	6.03
Residual Fuel	2.49	3.64	3.74	3.85	3.67	3.79	3.94	3.70	3.87	4.06
Natural Gas[3]	5.26	5.30	5.53	5.84	5.16	5.48	5.78	5.11	5.50	5.93
Electricity	21.76	17.75	18.65	19.83	17.26	18.37	19.45	17.01	18.17	19.50
Industrial[4]	**4.88**	**5.20**	**5.48**	**5.82**	**5.14**	**5.55**	**5.94**	**5.13**	**5.65**	**6.16**
Primary Energy	3.41	4.11	4.32	4.56	4.10	4.42	4.72	4.12	4.55	4.93
Petroleum Products[2]	4.58	5.67	5.88	6.05	5.65	5.97	6.26	5.66	6.11	6.43
Distillate Fuel	4.02	5.45	5.66	5.80	5.43	5.71	6.12	5.42	5.89	6.24
Liquefied Petroleum Gas	7.11	7.59	7.87	8.11	7.55	8.00	8.30	7.61	8.25	8.63
Residual Fuel	2.49	3.14	3.23	3.33	3.18	3.30	3.43	3.21	3.38	3.55
Natural Gas[5]	2.66	3.06	3.28	3.61	3.04	3.38	3.70	3.07	3.50	3.97
Metallurgical Coal	1.72	1.60	1.60	1.62	1.54	1.56	1.57	1.48	1.50	1.52
Steam Coal	1.45	1.26	1.26	1.28	1.20	1.21	1.23	1.15	1.16	1.19
Electricity	13.09	11.07	11.66	12.43	10.68	11.43	12.14	10.38	11.27	12.17
Transportation	**7.53**	**8.90**	**9.13**	**9.34**	**8.81**	**9.11**	**9.37**	**8.70**	**9.04**	**9.34**
Primary Energy	7.51	8.88	9.11	9.32	8.79	9.09	9.35	8.68	9.02	9.32
Petroleum Products[2]	7.51	8.88	9.11	9.31	8.78	9.08	9.34	8.67	9.01	9.31
Distillate Fuel[6]	7.51	8.67	9.01	9.27	8.62	9.02	9.42	8.51	8.97	9.38
Jet Fuel[7]	4.06	5.46	5.74	5.94	5.56	5.89	6.07	5.55	5.91	6.08
Motor Gasoline[8]	8.54	10.14	10.35	10.58	10.03	10.35	10.63	9.93	10.30	10.66
Residual Fuel	2.22	3.12	3.21	3.31	3.17	3.30	3.43	3.21	3.39	3.56
Liquid Petroleum Gas[9]	11.01	13.16	13.48	13.84	12.91	13.47	13.92	12.79	13.50	14.06
Natural Gas[10]	6.10	6.90	7.22	7.63	7.00	7.45	7.88	6.98	7.49	8.04
Ethanol (E85)[11]	14.35	17.36	17.66	17.98	17.28	17.74	18.17	17.23	17.79	18.34
Methanol (M85)[12]	8.99	14.07	14.32	14.59	14.02	14.38	14.75	13.97	14.42	14.88
Electricity	16.46	13.67	14.15	14.63	13.25	13.68	14.01	13.28	13.38	13.69
Average End-Use Energy	**8.08**	**8.53**	**8.81**	**9.12**	**8.43**	**8.81**	**9.15**	**8.39**	**8.81**	**9.22**
Primary Energy	7.59	8.22	8.49	8.78	8.13	8.49	8.82	8.08	8.49	8.88
Electricity	19.56	16.81	17.50	18.32	16.43	17.24	17.96	16.25	17.06	17.90
Electric Generators[13]										
Fossil Fuel Average	1.48	1.46	1.55	1.68	1.51	1.64	1.75	1.51	1.67	1.76
Petroleum Products	2.24	3.25	3.28	3.31	3.38	3.40	3.45	3.47	3.54	3.66
Distillate Fuel	3.19	4.92	5.12	5.22	4.84	5.10	5.49	4.82	5.23	5.31
Residual Fuel	2.17	3.08	3.13	3.20	3.17	3.19	3.29	3.23	3.30	3.42
Natural Gas	2.34	2.84	3.08	3.37	2.86	3.21	3.50	2.89	3.33	3.76
Steam Coal	1.25	1.05	1.07	1.10	1.01	1.03	1.05	0.96	0.98	1.00

Table B3. Energy Prices by Sector and Source (Continued)

(1998 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1998	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]	6.64	8.12	8.32	8.48	8.07	8.35	8.59	8.01	8.35	8.61
Distillate Fuel	6.60	7.89	8.19	8.42	7.86	8.22	8.62	7.78	8.22	8.61
Jet Fuel	4.06	5.46	5.74	5.94	5.56	5.89	6.07	5.55	5.91	6.08
Liquefied Petroleum Gas	7.76	8.68	8.93	9.11	8.62	9.02	9.26	8.66	9.22	9.53
Motor Gasoline[8]	8.54	10.14	10.35	10.58	10.03	10.35	10.63	9.93	10.30	10.66
Residual Fuel	2.24	3.15	3.23	3.31	3.20	3.31	3.42	3.24	3.40	3.55
Natural Gas	3.92	4.09	4.29	4.55	3.96	4.26	4.53	3.93	4.31	4.74
Coal	1.29	1.07	1.09	1.11	1.02	1.04	1.06	0.98	0.99	1.01
Ethanol (E85)[11]	14.35	17.36	17.66	17.98	17.28	17.74	18.17	17.23	17.79	18.34
Methanol (M85)[12]	8.99	14.07	14.32	14.59	14.02	14.38	14.75	13.97	14.42	14.88
Electricity	19.56	16.81	17.50	18.32	16.43	17.24	17.96	16.25	17.06	17.90
Non-Renewable Energy Expenditures by Sector (billion 1998 dollars)										
Residential	131.06	143.64	150.04	157.51	146.36	155.58	163.96	150.72	161.86	172.66
Commercial	96.86	98.22	105.14	113.53	98.80	108.63	118.80	97.65	109.62	123.34
Industrial	101.24	113.57	126.14	144.01	115.33	134.52	157.06	116.40	142.83	174.89
Transportation	188.11	269.35	287.60	307.46	281.21	308.82	335.71	289.49	325.96	362.06
Total Non-Renewable Expenditures	517.28	624.77	668.93	722.53	641.71	707.54	775.53	654.26	740.27	832.95
Transportation Renewable Expenditures	0.04	0.91	1.01	1.13	1.12	1.31	1.52	1.17	1.41	1.72
Total Expenditures	**517.32**	**625.68**	**669.94**	**723.65**	**642.83**	**708.85**	**777.05**	**655.43**	**741.68**	**834.67**

[1]Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Excludes independent power producers.
[4]Includes cogenerators.
[5]Excludes uses for lease and plant fuel.
[6] Low sulfur diesel fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[8]Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[9]Includes Federal and State taxes while excluding county and local taxes.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]M85 is 85 percent methanol and 15 percent motor gasoline.
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[14]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 1998 are model results and may differ slightly from official EIA data reports.

Sources: 1998 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380 (98/03-99/04) (Washington, DC, 1998-99). 1998 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1995*, DOE/EIA-0376(95) (Washington, DC, August 1998). 1998 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1994*. 1998 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(99/06) (Washington, DC, June 1999). 1998 coal prices based on EIA, *Quarterly Coal Report* , DOE/EIA-0121(99/1Q) (Washington, DC, August 1999), and EIA, AEO 2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A. 1998 electricity prices for commercial, industrial, and transportation: EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A. **Projections:** EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B4. Residential Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1998	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	74.69	83.02	84.38	85.71	85.32	87.61	89.44	87.21	90.55	92.92
Multifamily	21.68	24.47	24.94	25.73	25.83	26.60	27.71	27.09	28.23	29.72
Mobile Homes	6.47	7.67	7.81	7.92	8.06	8.31	8.40	8.39	8.77	8.85
Total	**102.84**	**115.16**	**117.13**	**119.37**	**119.21**	**122.52**	**125.55**	**122.68**	**127.54**	**131.50**
Average House Square Footage	**1667**	**1696**	**1698**	**1699**	**1701**	**1704**	**1704**	**1703**	**1707**	**1707**
Energy Intensity (million Btu consumed per household)										
Delivered Energy Consumption	99.54	102.61	101.65	100.40	102.00	100.69	99.37	101.92	100.44	98.73
Electricity Related Losses	82.95	84.28	83.31	82.61	82.94	81.33	79.90	82.40	79.78	77.49
Total Energy Consumption	182.49	186.90	184.95	183.01	184.94	182.02	179.27	184.32	180.22	176.22
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.38	0.46	0.46	0.47	0.47	0.48	0.49	0.48	0.50	0.51
Space Cooling	0.56	0.58	0.58	0.59	0.61	0.62	0.63	0.65	0.67	0.68
Water Heating	0.40	0.43	0.43	0.43	0.43	0.44	0.44	0.43	0.44	0.45
Refrigeration	0.45	0.34	0.34	0.35	0.31	0.32	0.33	0.31	0.32	0.33
Cooking	0.10	0.12	0.12	0.12	0.12	0.12	0.13	0.12	0.13	0.14
Clothes Dryers	0.22	0.26	0.26	0.26	0.27	0.27	0.27	0.28	0.29	0.29
Freezers	0.12	0.09	0.09	0.09	0.08	0.08	0.09	0.08	0.08	0.09
Lighting	0.33	0.40	0.40	0.40	0.42	0.42	0.42	0.43	0.44	0.44
Clothes Washers[1]	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Dishwashers[1]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06
Color Televisions	0.12	0.16	0.16	0.16	0.16	0.16	0.16	0.17	0.17	0.17
Personal Computers	0.05	0.09	0.09	0.09	0.09	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.10
Other Uses[2]	0.96	1.58	1.60	1.61	1.77	1.80	1.82	1.92	1.97	2.01
Delivered Energy	**3.83**	**4.66**	**4.70**	**4.75**	**4.91**	**5.00**	**5.07**	**5.14**	**5.30**	**5.40**
Natural Gas										
Space Heating	3.01	3.64	3.67	3.68	3.74	3.79	3.82	3.85	3.93	3.97
Space Cooling	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02
Water Heating	1.23	1.33	1.34	1.35	1.36	1.38	1.40	1.38	1.42	1.44
Cooking	0.18	0.22	0.22	0.22	0.23	0.23	0.23	0.24	0.24	0.25
Clothes Dryers	0.06	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10
Other Uses[3]	0.11	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.15
Delivered Energy	**4.61**	**5.41**	**5.46**	**5.48**	**5.57**	**5.65**	**5.71**	**5.73**	**5.86**	**5.92**
Distillate										
Space Heating	0.71	0.62	0.62	0.62	0.58	0.58	0.58	0.55	0.55	0.55
Water Heating	0.13	0.11	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10
Other Uses[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	**0.84**	**0.73**	**0.73**	**0.73**	**0.69**	**0.69**	**0.68**	**0.65**	**0.65**	**0.65**
Liquefied Petroleum Gas										
Space Heating	0.27	0.29	0.29	0.29	0.28	0.28	0.28	0.27	0.28	0.28
Water Heating	0.10	0.10	0.10	0.10	0.09	0.10	0.10	0.09	0.09	0.09
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Other Uses[3]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Delivered Energy	**0.41**	**0.43**	**0.43**	**0.44**	**0.42**	**0.42**	**0.42**	**0.41**	**0.41**	**0.41**
Marketed Renewables (wood)[5]	0.38	0.44	0.44	0.44	0.44	0.45	0.45	0.44	0.45	0.46
Other Fuels[6]	0.16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14

Table B4. Residential Sector Key Indicators and End-Use Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1998	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	4.91	5.59	5.62	5.65	5.65	5.72	5.76	5.74	5.85	5.90
Space Cooling	0.56	0.59	0.59	0.60	0.62	0.64	0.65	0.66	0.68	0.70
Water Heating	1.87	1.97	1.98	2.00	1.99	2.02	2.05	2.00	2.05	2.08
Refrigeration	0.45	0.34	0.34	0.35	0.31	0.32	0.33	0.31	0.32	0.33
Cooking	0.32	0.36	0.37	0.38	0.38	0.39	0.40	0.39	0.40	0.41
Clothes Dryers	0.28	0.34	0.34	0.35	0.36	0.37	0.37	0.38	0.39	0.39
Freezers	0.12	0.09	0.09	0.09	0.08	0.08	0.09	0.08	0.08	0.09
Lighting	0.33	0.40	0.40	0.40	0.42	0.42	0.42	0.43	0.44	0.44
Clothes Washers	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Dishwashers	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06
Color Televisions	0.12	0.16	0.16	0.16	0.16	0.16	0.16	0.17	0.17	0.17
Personal Computers	0.05	0.09	0.09	0.09	0.09	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.10
Other Uses[7]	1.08	1.73	1.74	1.76	1.92	1.95	1.97	2.07	2.13	2.17
Delivered Energy	**10.24**	**11.82**	**11.91**	**11.98**	**12.16**	**12.34**	**12.48**	**12.50**	**12.81**	**12.98**
Electricity Related Losses	**8.53**	**9.71**	**9.76**	**9.86**	**9.89**	**9.96**	**10.03**	**10.11**	**10.18**	**10.19**
Total Energy Consumption by End-Use										
Space Heating	5.75	6.54	6.58	6.62	6.60	6.67	6.73	6.68	6.80	6.86
Space Cooling	1.81	1.79	1.80	1.82	1.85	1.88	1.90	1.93	1.96	1.97
Water Heating	2.76	2.86	2.88	2.90	2.86	2.89	2.92	2.84	2.89	2.92
Refrigeration	1.45	1.04	1.06	1.07	0.95	0.96	0.98	0.91	0.93	0.95
Cooking	0.55	0.61	0.62	0.63	0.62	0.64	0.65	0.64	0.65	0.67
Clothes Dryers	0.77	0.87	0.88	0.88	0.90	0.91	0.91	0.92	0.94	0.94
Freezers	0.40	0.27	0.27	0.28	0.25	0.25	0.26	0.24	0.25	0.25
Lighting	1.06	1.24	1.24	1.24	1.26	1.26	1.26	1.27	1.27	1.27
Clothes Washers	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Dishwashers	0.15	0.15	0.15	0.16	0.15	0.16	0.16	0.16	0.16	0.17
Color Televisions	0.38	0.48	0.49	0.49	0.48	0.48	0.49	0.49	0.50	0.50
Personal Computers	0.18	0.28	0.28	0.28	0.29	0.29	0.29	0.31	0.32	0.32
Furnace Fans	0.21	0.25	0.26	0.26	0.26	0.27	0.27	0.27	0.28	0.28
Other Uses[7]	3.21	5.03	5.05	5.10	5.48	5.53	5.57	5.85	5.92	5.96
Total	**18.77**	**21.52**	**21.66**	**21.85**	**22.05**	**22.30**	**22.51**	**22.61**	**22.99**	**23.17**
Non-Marketed Renewables										
Geothermal[8]	0.01	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.05	0.05
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**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**

[1]Does not include electric water heating portion of load.
[2]Includes small electric devices, heating elements, and motors.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as swimming pool and hot tub heaters.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1997*.
[6]Includes kerosene and coal.
[7]Includes all other uses listed above.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Source: 1998: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1999.* Online.http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B5. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1998	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2015 Low Economic Growth	2015 Reference	2015 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth
Key Indicators										
Total Floor Space (billion square feet)										
Surviving	59.6	67.5	69.3	71.3	69.2	72.1	75.2	68.8	72.9	77.2
New Additions	1.7	1.3	1.6	1.8	1.0	1.2	1.4	0.7	0.9	1.2
Total	**61.2**	**68.8**	**70.9**	**73.1**	**70.2**	**73.3**	**76.7**	**69.5**	**73.8**	**78.5**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	121.7	124.5	123.3	121.7	125.6	124.1	122.5	126.7	124.8	122.8
Electricity Related Losses	129.4	129.0	127.5	126.1	127.1	124.7	122.4	125.9	121.7	118.1
Total Energy Consumption	251.2	253.5	250.8	247.9	252.7	248.8	245.0	252.6	246.5	240.9
Delivered Energy Consumption by Fuel										
Purchased Electricity										
Space Heating	0.10	0.11	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10
Space Cooling	0.45	0.42	0.43	0.44	0.41	0.43	0.45	0.40	0.42	0.45
Water Heating	0.12	0.12	0.12	0.12	0.11	0.12	0.12	0.11	0.11	0.12
Ventilation	0.17	0.18	0.19	0.19	0.18	0.19	0.20	0.18	0.19	0.20
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.03
Lighting	1.17	1.21	1.24	1.26	1.22	1.26	1.29	1.18	1.23	1.29
Refrigeration	0.18	0.19	0.20	0.21	0.20	0.20	0.21	0.19	0.20	0.22
Office Equipment (PC)	0.08	0.13	0.13	0.14	0.14	0.15	0.15	0.15	0.16	0.17
Office Equipment (non-PC)	0.26	0.37	0.37	0.38	0.40	0.42	0.44	0.43	0.46	0.48
Other Uses[1]	1.00	1.51	1.54	1.57	1.63	1.69	1.75	1.69	1.78	1.87
Delivered Energy	**3.56**	**4.27**	**4.36**	**4.44**	**4.43**	**4.58**	**4.74**	**4.44**	**4.68**	**4.91**
Natural Gas[2]										
Space Heating	1.10	1.30	1.31	1.33	1.31	1.34	1.37	1.28	1.33	1.37
Space Cooling	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Water Heating	0.49	0.54	0.56	0.57	0.56	0.58	0.61	0.56	0.59	0.62
Cooking	0.20	0.23	0.24	0.24	0.24	0.25	0.26	0.24	0.26	0.27
Other Uses[3]	1.30	1.43	1.45	1.48	1.48	1.52	1.57	1.50	1.56	1.63
Delivered Energy	**3.11**	**3.52**	**3.58**	**3.64**	**3.61**	**3.71**	**3.83**	**3.60**	**3.75**	**3.90**
Distillate										
Space Heating	0.16	0.17	0.17	0.17	0.16	0.16	0.16	0.14	0.15	0.15
Water Heating	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Other Uses[4]	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.17
Delivered Energy	**0.38**	**0.37**	**0.38**	**0.39**	**0.36**	**0.37**	**0.38**	**0.35**	**0.36**	**0.37**
Other Fuels[5]	**0.32**	**0.34**	**0.35**	**0.36**	**0.34**	**0.35**	**0.37**	**0.33**	**0.35**	**0.37**
Marketed Renewable Fuels										
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Delivered Energy	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Delivered Energy Consumption by End-Use										
Space Heating	1.37	1.57	1.59	1.61	1.56	1.60	1.64	1.52	1.57	1.62
Space Cooling	0.46	0.44	0.45	0.46	0.43	0.45	0.47	0.42	0.44	0.47
Water Heating	0.67	0.71	0.73	0.75	0.72	0.75	0.78	0.71	0.75	0.78
Ventilation	0.17	0.18	0.19	0.19	0.18	0.19	0.20	0.18	0.19	0.20
Cooking	0.23	0.26	0.27	0.27	0.27	0.28	0.29	0.27	0.28	0.30
Lighting	1.17	1.21	1.24	1.26	1.22	1.26	1.29	1.18	1.23	1.29
Refrigeration	0.18	0.19	0.20	0.21	0.20	0.20	0.21	0.19	0.20	0.22
Office Equipment (PC)	0.08	0.13	0.13	0.14	0.14	0.15	0.15	0.15	0.16	0.17
Office Equipment (non-PC)	0.26	0.37	0.37	0.38	0.40	0.42	0.44	0.43	0.46	0.48
Other Uses[6]	2.86	3.50	3.57	3.64	3.68	3.80	3.93	3.76	3.93	4.11
Delivered Energy	**7.46**	**8.57**	**8.74**	**8.90**	**8.81**	**9.10**	**9.40**	**8.80**	**9.22**	**9.63**

Table B5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1998	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
Electricity Related Losses	**7.93**	**8.88**	**9.04**	**9.22**	**8.92**	**9.14**	**9.39**	**8.75**	**8.98**	**9.27**
Total Energy Consumption by End-Use										
Space Heating	1.60	1.79	1.82	1.84	1.77	1.81	1.85	1.70	1.76	1.82
Space Cooling	1.46	1.31	1.33	1.36	1.27	1.31	1.35	1.21	1.25	1.31
Water Heating	0.94	0.96	0.98	1.00	0.95	0.99	1.02	0.92	0.96	1.00
Ventilation	0.54	0.57	0.58	0.59	0.55	0.57	0.58	0.53	0.55	0.57
Cooking	0.30	0.32	0.33	0.33	0.32	0.33	0.34	0.31	0.33	0.34
Lighting	3.76	3.74	3.80	3.87	3.66	3.76	3.85	3.49	3.60	3.71
Refrigeration	0.57	0.60	0.61	0.63	0.59	0.61	0.64	0.57	0.60	0.63
Office Equipment (PC)	0.27	0.40	0.41	0.42	0.42	0.44	0.45	0.45	0.46	0.48
Office Equipment (non-PC)	0.84	1.13	1.15	1.18	1.22	1.26	1.30	1.28	1.33	1.39
Other Uses[6]	5.09	6.64	6.77	6.91	6.97	7.17	7.40	7.09	7.35	7.64
Total	**15.38**	**17.45**	**17.78**	**18.12**	**17.73**	**18.24**	**18.79**	**17.55**	**18.20**	**18.90**
Non-Marketed Renewable Fuels										
Solar[7]	0.02	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Total	**0.02**	**0.03**	**0.04**	**0.04**	**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, cogeneration in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, district services, emergency electric generators, and cogeneration in commercial buildings.
[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, cogeneration in commercial buildings, 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, and electricity generation by solar photovoltaic systems.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Source: 1998 Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1999.* Online. http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1998	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	3,291	4,030	4,227	4,593	4,354	4,663	5,178	4,601	5,040	5,794
Nonmanufacturing	835	930	989	1,054	977	1,067	1,153	1,000	1,131	1,253
Total	**4,126**	**4,960**	**5,216**	**5,647**	**5,331**	**5,730**	**6,331**	**5,602**	**6,171**	**7,046**
Energy Prices (1998 dollars per million Btu)										
Electricity	13.09	11.07	11.66	12.43	10.68	11.43	12.14	10.38	11.27	12.17
Natural Gas	2.66	3.06	3.28	3.61	3.04	3.38	3.70	3.07	3.50	3.97
Steam Coal	1.45	1.26	1.26	1.28	1.20	1.21	1.23	1.15	1.16	1.19
Residual Oil	2.49	3.14	3.23	3.33	3.18	3.30	3.43	3.21	3.38	3.55
Distillate Oil	4.02	5.45	5.66	5.80	5.43	5.71	6.12	5.42	5.89	6.24
Liquefied Petroleum Gas	7.11	7.59	7.87	8.11	7.55	8.00	8.30	7.61	8.25	8.63
Motor Gasoline	8.54	10.11	10.32	10.55	10.01	10.32	10.61	9.91	10.28	10.64
Metallurgical Coal	1.72	1.60	1.60	1.62	1.54	1.56	1.57	1.48	1.50	1.52
Energy Consumption										
Consumption[1]										
Purchased Electricity	3.57	3.93	4.15	4.51	4.10	4.45	4.92	4.20	4.70	5.39
Natural Gas[2]	9.75	10.53	10.96	11.56	10.89	11.53	12.33	11.08	11.99	13.06
Steam Coal	1.54	1.54	1.59	1.65	1.53	1.61	1.68	1.53	1.63	1.74
Metallurgical Coal and Coke[3]	0.82	0.81	0.83	0.89	0.78	0.82	0.89	0.75	0.80	0.90
Residual Fuel	0.27	0.27	0.29	0.31	0.27	0.30	0.33	0.27	0.31	0.36
Distillate	1.08	1.22	1.29	1.38	1.26	1.38	1.49	1.29	1.46	1.61
Liquefied Petroleum Gas	2.06	2.25	2.40	2.60	2.30	2.53	2.80	2.32	2.64	3.02
Petrochemical Feedstocks	1.39	1.49	1.58	1.72	1.52	1.66	1.84	1.52	1.73	1.98
Other Petroleum[4]	4.32	4.75	4.97	5.21	4.83	5.17	5.48	4.85	5.31	5.77
Renewables[5]	2.08	2.29	2.40	2.58	2.34	2.53	2.77	2.37	2.63	2.98
Delivered Energy	**26.89**	**29.07**	**30.46**	**32.41**	**29.82**	**31.96**	**34.53**	**30.18**	**33.20**	**36.82**
Electricity Related Losses	7.95	8.18	8.61	9.36	8.26	8.87	9.74	8.27	9.03	10.17
Total	**34.84**	**37.25**	**39.08**	**41.78**	**38.07**	**40.83**	**44.27**	**38.46**	**42.23**	**47.00**
Consumption per Unit of Output[1] (thousand Btu per 1987 dollars)										
Purchased Electricity	0.87	0.79	0.80	0.80	0.77	0.78	0.78	0.75	0.76	0.77
Natural Gas[2]	2.36	2.12	2.10	2.05	2.04	2.01	1.95	1.98	1.94	1.85
Steam Coal	0.37	0.31	0.30	0.29	0.29	0.28	0.27	0.27	0.26	0.25
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	0.06	0.05	0.05	0.06	0.05	0.05	0.05	0.05	0.05	0.05
Distillate	0.26	0.25	0.25	0.24	0.24	0.24	0.23	0.23	0.24	0.23
Liquefied Petroleum Gas	0.50	0.45	0.46	0.46	0.43	0.44	0.44	0.41	0.43	0.43
Petrochemical Feedstocks	0.34	0.30	0.30	0.30	0.28	0.29	0.29	0.27	0.28	0.28
Other Petroleum[4]	1.05	0.96	0.95	0.92	0.91	0.90	0.87	0.87	0.86	0.82
Renewables[5]	0.51	0.46	0.46	0.46	0.44	0.44	0.44	0.42	0.43	0.42
Delivered Energy	**6.52**	**5.86**	**5.84**	**5.74**	**5.59**	**5.58**	**5.45**	**5.39**	**5.38**	**5.23**
Electricity Related Losses	1.93	1.65	1.65	1.66	1.55	1.55	1.54	1.48	1.46	1.44
Total	**8.44**	**7.51**	**7.49**	**7.40**	**7.14**	**7.13**	**6.99**	**6.86**	**6.84**	**6.67**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net coke coal imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.

Sources: 1998 prices for gasoline and distillate are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380 (98/03-99/04) (Washington, DC, 1998-99). 1998 coal prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(99/08) (Washington, DC, August 1999). 1998 electricity prices: EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A. Other 1998 prices derived from EIA, *State Energy Data Report 1996* , DOE/EIA-0214(96) (Washington, DC, February 1999). Other 1998 values: EIA, *Short-Term Energy Outlook, September 1999.* Online. http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	1998	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Key Indicators										
Level of Travel (billions)										
Light-Duty Vehicles <8,500 pounds (VMT)	2403	2953	3048	3148	3134	3282	3423	3290	3498	3693
Commercial Light Trucks (VMT)[1]	72	87	90	95	92	98	105	96	105	115
Freight Trucks >10,000 pounds (VMT)	184	215	228	245	224	243	265	229	256	288
Air (seat miles available)	1061	1654	1765	1899	1919	2118	2313	2178	2495	2790
Rail (ton miles traveled)	1246	1423	1489	1576	1481	1581	1701	1530	1672	1861
Marine (ton miles traveled)	692	748	781	828	775	827	888	791	861	940
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[2]	24.2	25.7	25.6	25.6	26.3	26.2	26.1	26.6	26.5	26.4
New Car (miles per gallon)[2]	28.2	31.5	31.4	31.3	31.9	31.7	31.6	31.8	31.6	31.5
New Light Truck (miles per gallon)[2]	20.6	21.7	21.6	21.6	22.4	22.3	22.3	22.9	22.8	22.8
Light-Duty Fleet (miles per gallon)[3]	20.7	20.5	20.4	20.4	20.5	20.5	20.5	20.6	20.6	20.6
New Commercial Light Truck (MPG)[1]	20.4	21.1	21.0	21.0	21.7	21.6	21.6	22.2	22.1	22.0
Stock Commercial Light Truck (MPG)[1]	14.7	15.9	15.8	15.8	16.2	16.2	16.2	16.6	16.5	16.5
Aircraft Efficiency (seat miles per gallon)	51.4	56.2	56.4	56.6	58.2	58.4	58.7	60.1	60.5	60.8
Freight Truck Efficiency (miles per gallon)	5.6	6.0	6.0	6.0	6.2	6.2	6.2	6.4	6.4	6.5
Rail Efficiency (ton miles per thousand Btu)	2.7	3.1	3.1	3.1	3.2	3.2	3.2	3.4	3.4	3.4
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.4	2.8	2.8	2.8	3.0	3.0	3.0	3.2	3.2	3.2
Energy Use by Mode (quadrillion Btu)										
Light-Duty Vehicles	14.64	17.94	18.54	19.16	18.94	19.87	20.73	19.75	21.03	22.21
Commercial Light Trucks[1]	0.61	0.68	0.71	0.75	0.71	0.76	0.81	0.73	0.79	0.87
Freight Trucks[4]	4.35	4.75	5.01	5.34	4.77	5.16	5.59	4.73	5.24	5.85
Air	3.40	4.63	4.91	5.24	5.13	5.61	6.07	5.58	6.32	7.00
Rail[5]	0.56	0.59	0.61	0.64	0.59	0.62	0.66	0.59	0.64	0.69
Marine[6]	1.17	1.44	1.50	1.55	1.56	1.65	1.72	1.66	1.81	1.90
Pipeline Fuel	0.75	0.84	0.87	0.90	0.91	0.95	0.98	0.94	0.99	1.02
Other[7]	0.26	0.28	0.30	0.32	0.29	0.31	0.34	0.29	0.33	0.36
Total	**25.74**	**31.20**	**32.48**	**33.94**	**32.97**	**34.99**	**36.96**	**34.34**	**37.20**	**39.96**
Energy Use by Mode[8] (million barrels per day)										
Light-Duty Vehicles	7.63	9.47	9.79	10.12	10.01	10.50	10.96	10.44	11.12	11.75
Commercial Light Trucks[1]	0.32	0.36	0.37	0.39	0.37	0.40	0.42	0.38	0.42	0.45
Freight Trucks[4]	1.97	2.15	2.27	2.43	2.16	2.34	2.54	2.14	2.38	2.66
Railroad	0.21	0.22	0.23	0.24	0.22	0.23	0.25	0.21	0.23	0.26
Domestic Shipping	0.13	0.12	0.13	0.14	0.12	0.13	0.14	0.11	0.12	0.14
International Shipping	0.28	0.40	0.41	0.43	0.44	0.48	0.50	0.49	0.54	0.57
Air Transportation	1.42	2.02	2.15	2.30	2.26	2.48	2.69	2.48	2.82	3.13
Military Use	0.25	0.25	0.26	0.27	0.25	0.26	0.28	0.25	0.27	0.29
Bus Transportation	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Rail Transportation[5]	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07
Recreational Boats	0.13	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.15	0.16
Lubricants	0.12	0.13	0.14	0.15	0.14	0.15	0.16	0.14	0.15	0.17
Pipeline Fuel	0.38	0.43	0.44	0.45	0.46	0.48	0.50	0.48	0.50	0.51
Total	**12.97**	**15.81**	**16.46**	**17.19**	**16.71**	**17.73**	**18.72**	**17.41**	**18.85**	**20.23**

[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.
[8]Nonpetroleum fuels converted to crude oil equivalent.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998: U.S. Department of Transportation, Bureau of Transportation Statisitics, *Air Carrier Statistics Monthly, December 1998/1997*, (Washington, DC, 1998); Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1999.* Online. http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999); 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, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B8. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1998	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	1817	2083	2121	2180	2121	2200	2328	2165	2296	2578
Petroleum	114	37	48	70	32	41	58	28	37	61
Natural Gas	325	737	796	864	991	1085	1156	1122	1256	1251
Nuclear Power	674	627	627	627	511	511	510	428	427	440
Pumped Storage	-2	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[2]	360	379	381	382	386	386	389	393	393	396
Total	**3288**	**3863**	**3973**	**4121**	**4040**	**4222**	**4441**	**4134**	**4409**	**4725**
Non-Utility Generation for Own Use	10	16	16	16	16	16	16	16	16	16
Cogenerators[3]										
Coal	52	51	51	51	51	51	51	51	51	51
Petroleum	8	6	6	6	6	6	7	6	7	7
Natural Gas	195	203	205	208	209	212	217	215	220	227
Other Gaseous Fuels[4]	3	6	6	7	6	7	7	7	7	8
Renewable Sources[2]	40	46	48	53	47	51	57	48	54	63
Other[5]	8	8	8	8	8	8	8	8	8	8
Total	**306**	**319**	**325**	**333**	**328**	**336**	**348**	**335**	**348**	**364**
Sales to Utilities	148	155	156	157	161	162	164	166	169	172
Generation for Own Use	165	169	174	181	172	179	189	174	184	197
Other Generators[6]	**7**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
Net Imports[7]	**30**	**26**	**26**	**26**	**19**	**19**	**19**	**20**	**20**	**20**
Electricity Sales by Sector										
Residential	1124	1366	1379	1391	1438	1464	1486	1505	1553	1583
Commercial	1045	1251	1277	1301	1298	1344	1391	1302	1371	1439
Industrial	1047	1152	1217	1321	1201	1303	1443	1232	1378	1580
Transportation	20	36	36	37	43	44	45	48	49	51
Total	**3236**	**3805**	**3909**	**4051**	**3979**	**4155**	**4364**	**4087**	**4350**	**4653**
End-Use Prices (1998 cents per kwh)[8]										
Residential	8.0	7.1	7.4	7.7	7.0	7.3	7.6	7.0	7.3	7.6
Commercial	7.4	6.1	6.4	6.8	5.9	6.3	6.6	5.8	6.2	6.7
Industrial	4.5	3.8	4.0	4.2	3.6	3.9	4.1	3.5	3.8	4.2
Transportation	5.6	4.7	4.8	5.0	4.5	4.7	4.8	4.5	4.6	4.7
All Sectors Average	**6.7**	**5.7**	**6.0**	**6.3**	**5.6**	**5.9**	**6.1**	**5.5**	**5.8**	**6.1**
Emissions (million short tons)										
Sulfur Dioxide	13.04	9.41	9.15	8.95	8.95	8.95	8.95	8.95	8.95	8.95
Nitrogen Oxide	5.98	5.53	5.66	5.86	5.69	5.87	6.01	5.77	5.93	6.02

[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]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[7]In 1998 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[8]Prices represent average revenue per kilowatthour.

Kwh = Kilowatthour.

Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.

Sources: 1998 commercial and transportation sales derived from: Energy Information Administration (EIA), *State Energy Data Report 1996* , DOE/EIA-0214(96) (Washington, DC, February 1999), 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. 1998 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: EIA, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). 1998 residential electricity prices derived from EIA, *Short-Term Energy Outlook, September 1999.* Online.http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999). **1998 electricity prices for commercial, industrial, and transportation; emissions; and projections**: EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B9. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1998	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	305.2	299.1	301.7	306.4	300.6	306.8	321.9	302.5	317.0	353.0
Other Fossil Steam[3]	138.2	119.1	119.5	120.3	114.0	117.1	118.7	109.3	109.9	107.7
Combined Cycle	19.5	88.0	93.1	94.3	113.2	124.7	132.1	132.5	154.6	164.1
Combustion Turbine/Diesel	73.2	143.5	153.5	174.2	168.5	180.4	200.5	190.8	202.3	215.7
Nuclear Power	97.1	84.1	84.1	84.1	67.4	67.4	67.4	57.0	57.0	58.7
Pumped Storage	19.9	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Fuel Cells	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Renewable Sources[4]	87.2	93.7	93.8	94.0	95.3	95.3	95.6	96.5	96.7	97.0
Total	**740.2**	**847.7**	**865.7**	**893.3**	**879.0**	**911.8**	**956.1**	**908.8**	**957.5**	**1016.3**
Cumulative Planned Additions[5]										
Coal Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Combustion Turbine/Diesel	0.0	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
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	0.1	0.1	0.1
Renewable Sources[4]	0.0	4.8	4.8	4.8	5.7	5.7	5.7	5.9	5.9	5.9
Total	**0.0**	**11.1**	**11.1**	**11.1**	**12.0**	**12.0**	**12.0**	**12.2**	**12.2**	**12.2**
Cumulative Unplanned Additions[5]										
Coal Steam	0.0	2.2	3.8	6.9	4.3	9.5	23.8	7.5	21.0	56.1
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	63.9	68.9	70.2	89.1	100.6	108.0	108.4	130.5	140.0
Combustion Turbine/Diesel	0.0	72.2	81.9	102.1	97.6	109.4	129.1	121.1	132.3	146.6
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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.0	1.6	1.8	1.9	2.6	2.6	2.9	3.6	3.8	4.1
Total	**0.0**	**139.9**	**156.4**	**181.1**	**193.5**	**222.1**	**263.8**	**240.7**	**287.6**	**346.9**
Cumulative Total Additions	**0.0**	**151.0**	**167.4**	**192.1**	**205.6**	**234.1**	**275.8**	**252.9**	**299.8**	**359.1**
Cumulative Retirements[6]	**0.0**	**50.0**	**48.4**	**45.5**	**73.3**	**69.0**	**66.4**	**90.8**	**89.0**	**89.5**
Cogenerators[7]										
Capability										
Coal	8.8	8.9	9.0	9.0	8.9	9.0	9.0	8.9	9.0	9.0
Petroleum	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Natural Gas	31.8	36.2	36.4	36.8	37.0	37.3	38.0	37.7	38.4	39.3
Other Gaseous Fuels	0.4	0.8	0.8	0.9	0.8	0.9	1.0	0.9	1.0	1.0
Renewable Sources[4]	6.6	7.5	7.9	8.7	7.7	8.5	9.5	7.9	9.0	10.5
Other	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Total	**50.3**	**56.1**	**56.8**	**58.1**	**57.2**	**58.4**	**60.3**	**58.2**	**60.2**	**62.6**
Cumulative Additions[5]	**0.0**	**5.8**	**6.6**	**7.8**	**6.9**	**8.1**	**10.0**	**7.9**	**9.9**	**12.3**

Table B9. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1998	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
Other Generators[8]										
Capability	1.1	1.4	1.4	1.4	1.5	1.5	1.6	1.6	1.8	2.1
Cumulative Additions	0.0	0.3	0.3	0.3	0.4	0.4	0.5	0.5	0.7	1.0

[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, 1998.
[6]Cumulative total retirements after December 31, 1998.
[7]Nameplate capacity is reported for nonutilities on Form EIA-867, "Annual Nonutility Power Producer Report, 1997." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.
[8]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
Notes: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators for AEO2000. Net summer capacity is used to be consistent with electric utility capacity estimates.
Sources: 1998 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 1998 and planned additions based on EIA, Form EIA-867, "Annual Nonutility Power Producer Report, 1997." **Projections:** EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1998	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Interregional Electricity Trade										
Gross Domestic Firm Power Trade	202.4	102.4	102.4	102.4	48.5	48.5	48.5	0.0	0.0	0.0
Gross Domestic Economy Trade	144.1	194.5	199.7	212.1	193.1	182.4	190.3	201.1	186.1	200.5
Gross Domestic Trade	**346.4**	**296.9**	**302.1**	**314.5**	**241.6**	**230.9**	**238.8**	**201.1**	**186.1**	**200.5**
Gross Domestic Firm Power Sales (million 1998 dollars)	9,607.3	4,862.3	4,862.3	4,862.3	2,303.2	2,303.2	2,303.2	0.0	0.0	0.0
Gross Domestic Economy Sales (million 1998 dollars)	4,260.3	5,714.7	6,218.7	7,188.3	5,711.7	5,728.2	6,366.4	5,804.1	5,832.9	6,813.2
Gross Domestic Sales (million 1998 dollars)	**13,867.6**	**10,577.0**	**11,081.0**	**12,050.6**	**8,014.9**	**8,031.4**	**8,669.6**	**5,804.1**	**5,832.9**	**6,813.2**
International Electricity Trade										
Firm Power Imports From Canada and Mexico[1]	19.0	4.6	4.6	4.6	2.2	2.2	2.2	0.0	0.0	0.0
Economy Imports From Canada and Mexico[1]	26.5	39.3	39.3	39.2	29.4	29.4	29.4	27.9	27.9	27.9
Gross Imports From Canada and Mexico[1]	**45.4**	**43.8**	**43.8**	**43.8**	**31.6**	**31.6**	**31.6**	**27.9**	**27.9**	**27.9**
Firm Power Exports To Canada and Mexico	0.3	10.4	10.4	10.4	4.9	4.9	4.9	0.0	0.0	0.0
Economy Exports To Canada and Mexico	15.0	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**15.4**	**18.1**	**18.1**	**18.1**	**12.6**	**12.6**	**12.6**	**7.7**	**7.7**	**7.7**

[1]Historically electricity imports were primarily from renewable resources, principally hydroelectric.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.
Sources: 1998 interregional firm electricity trade data: North American Electricity Reliability Council (NERC), Electricity Sales and Demand Database 1998. 1998 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 1998 firm/economy share: National Energy Board, *Annual Report 1998*.
Projections: Energy Information Administration, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1998	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
Crude Oil										
Domestic Crude Production[1]	6.25	5.12	5.18	5.32	5.13	5.20	5.51	5.17	5.26	5.66
Alaska	1.18	0.81	0.81	0.81	0.63	0.63	0.63	0.51	0.51	0.51
Lower 48 States	5.08	4.30	4.36	4.50	4.50	4.57	4.88	4.67	4.75	5.15
Net Imports	8.60	11.27	11.45	11.75	11.45	11.48	11.64	11.42	11.59	11.71
Gross Imports	8.70	11.29	11.47	11.78	11.47	11.50	11.68	11.45	11.62	11.76
Exports	0.11	0.02	0.03	0.03	0.02	0.03	0.04	0.03	0.03	0.05
Other Crude Supply[2]	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**14.89**	**16.39**	**16.62**	**17.06**	**16.57**	**16.68**	**17.15**	**16.59**	**16.84**	**17.37**
Natural Gas Plant Liquids	**1.76**	**1.98**	**2.05**	**2.15**	**2.16**	**2.26**	**2.37**	**2.25**	**2.37**	**2.44**
Other Inputs[3]	**0.25**	**0.30**	**0.29**	**0.28**	**0.32**	**0.30**	**0.30**	**0.33**	**0.32**	**0.32**
Refinery Processing Gain[4]	**0.89**	**1.07**	**1.11**	**1.14**	**1.10**	**1.12**	**1.18**	**1.10**	**1.12**	**1.20**
Net Product Imports[5]	**1.17**	**1.77**	**2.40**	**3.03**	**2.21**	**3.48**	**4.39**	**2.73**	**4.45**	**5.91**
Gross Refined Product Imports[6]	1.63	2.16	2.65	3.18	2.52	3.68	4.44	3.08	4.60	6.00
Unfinished Oil Imports	0.30	0.56	0.67	0.73	0.67	0.72	0.78	0.67	0.74	0.79
Ether Imports	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Exports	0.83	0.95	0.92	0.88	0.98	0.91	0.83	1.02	0.90	0.87
Total Primary Supply[7]	**18.95**	**21.50**	**22.47**	**23.67**	**22.37**	**23.85**	**25.39**	**23.01**	**25.09**	**27.24**
Refined Petroleum Products Supplied										
Motor Gasoline[8]	8.25	9.85	10.18	10.52	10.31	10.81	11.27	10.69	11.37	12.01
Jet Fuel[9]	1.62	2.21	2.35	2.51	2.45	2.68	2.90	2.67	3.02	3.34
Distillate Fuel[10]	3.45	3.68	3.85	4.08	3.73	4.00	4.28	3.74	4.11	4.53
Residual Fuel	0.95	0.69	0.77	0.89	0.71	0.79	0.91	0.73	0.83	0.97
Other[11]	4.67	5.11	5.37	5.71	5.19	5.60	6.04	5.21	5.77	6.40
Total	**18.94**	**21.54**	**22.51**	**23.71**	**22.39**	**23.87**	**25.40**	**23.02**	**25.10**	**27.25**
Refined Petroleum Products Supplied										
Residential and Commercial	1.06	1.02	1.03	1.04	0.99	1.00	1.01	0.95	0.96	0.98
Industrial[12]	4.80	5.24	5.54	5.92	5.35	5.81	6.31	5.38	6.03	6.74
Transportation	12.54	15.12	15.73	16.43	15.92	16.89	17.83	16.57	17.94	19.26
Electric Generators[13]	0.54	0.16	0.21	0.31	0.14	0.18	0.26	0.12	0.16	0.27
Total	**18.94**	**21.54**	**22.51**	**23.71**	**22.39**	**23.87**	**25.40**	**23.02**	**25.10**	**27.25**
Discrepancy[14]	**0.01**	**-0.04**	**-0.04**	**-0.03**	**-0.02**	**-0.03**	**-0.01**	**-0.02**	**-0.01**	**-0.01**
World Oil Price (1998 dollars per barrel)[15]	**12.10**	**20.44**	**21.00**	**21.56**	**20.74**	**21.53**	**22.32**	**20.99**	**22.04**	**23.11**
Import Share of Product Supplied	**0.52**	**0.61**	**0.62**	**0.62**	**0.61**	**0.63**	**0.63**	**0.61**	**0.64**	**0.65**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 1998 dollars)	**46.55**	**99.68**	**109.73**	**121.12**	**107.07**	**124.19**	**139.16**	**113.51**	**138.16**	**161.35**
Domestic Refinery Distillation Capacity[16]	**16.3**	**17.5**	**17.6**	**18.0**	**17.6**	**17.6**	**18.1**	**17.6**	**17.8**	**18.3**
Capacity Utilization Rate (percent)	**96.0**	**94.0**	**94.8**	**95.3**	**94.6**	**95.1**	**95.1**	**94.5**	**95.2**	**95.3**

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.
[3]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, and other hydrocarbons.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[6]Includes blending components.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net petroleum imports.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes naphtha and kerosene types.
[10]Includes distillate and kerosene.
[11]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[12]Includes consumption by cogenerators.
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses and gains.
[15]Average refiner acquisition cost for imported crude oil.
[16]End-of-year capacity.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 product supplied data from Table B2. Other 1998 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1998,* DOE/EIA-0340(98/1) (Washington, DC, June 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B12. Petroleum Product Prices
(1998 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	1998	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 (1998 dollars per barrel)	**12.10**	**20.44**	**21.00**	**21.56**	**20.74**	**21.53**	**22.32**	**20.99**	**22.04**	**23.11**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	84.9	104.4	107.3	109.4	104.7	108.5	112.6	105.0	109.3	113.0
Liquefied Petroleum Gas	90.0	111.7	114.0	116.2	111.4	115.4	118.2	112.1	117.6	121.2
Commercial										
Distillate Fuel	54.4	74.2	77.1	79.1	74.2	78.0	82.8	74.3	79.5	83.7
Residual Fuel	37.3	54.5	56.0	57.6	55.0	56.8	58.9	55.4	57.9	60.7
Residual Fuel (1998 dollars per barrel)	15.65	22.87	23.51	24.19	23.08	23.85	24.75	23.27	24.33	25.51
Industrial[1]										
Distillate Fuel	55.7	75.5	78.5	80.4	75.3	79.1	84.9	75.2	81.6	86.6
Liquefied Petroleum Gas	61.4	65.5	68.0	70.0	65.2	69.0	71.6	65.7	71.2	74.4
Residual Fuel	37.2	47.0	48.4	49.9	47.6	49.4	51.4	48.1	50.6	53.2
Residual Fuel (1998 dollars per barrel)	15.64	19.73	20.32	20.97	19.98	20.76	21.59	20.21	21.24	22.33
Transportation										
Diesel Fuel (distillate)[2]	104.1	120.2	125.0	128.6	119.6	125.1	130.6	118.1	124.3	130.1
Jet Fuel[3]	54.7	73.7	77.5	80.2	75.0	79.5	81.9	74.9	79.8	82.1
Motor Gasoline[4]	106.9	126.2	128.8	131.7	124.8	128.7	132.3	123.5	128.2	132.6
Liquid Petroleum Gas	95.0	113.6	116.3	119.5	111.4	116.3	120.1	110.4	116.6	121.4
Residual Fuel	33.3	46.7	48.1	49.6	47.4	49.4	51.4	48.1	50.7	53.3
Residual Fuel (1998 dollars per barrel)	13.98	19.60	20.20	20.82	19.93	20.75	21.58	20.19	21.29	22.38
Ethanol (E85)	128.6	155.4	158.1	161.0	154.7	158.8	162.7	154.2	159.2	164.2
Methanol (M85)	66.0	103.2	105.0	107.0	102.8	105.4	108.1	102.4	105.7	109.1
Electric Generators[5]										
Distillate Fuel	44.2	68.2	70.9	72.3	67.2	70.7	76.2	66.8	72.5	73.6
Residual Fuel	32.5	46.2	46.9	47.9	47.4	47.7	49.2	48.4	49.4	51.2
Residual Fuel (1998 dollars per barrel)	13.67	19.39	19.69	20.11	19.90	20.05	20.66	20.34	20.76	21.51
Refined Petroleum Product Prices[6]										
Distillate Fuel	91.6	109.4	113.6	116.8	109.0	114.0	119.6	107.9	114.0	119.4
Jet Fuel[3]	54.7	73.7	77.5	80.2	75.0	79.5	81.9	74.9	79.8	82.1
Liquefied Petroleum Gas	67.0	75.0	77.0	78.7	74.4	77.8	79.9	74.7	79.6	82.2
Motor Gasoline[4]	106.9	126.2	128.8	131.7	124.8	128.7	132.3	123.5	128.2	132.6
Residual Fuel	33.6	47.1	48.3	49.5	47.9	49.5	51.2	48.5	50.8	53.1
Residual Fuel (1998 dollars per barrel)	14.10	19.79	20.28	20.78	20.13	20.79	21.51	20.39	21.35	22.32
Average	**87.4**	**106.3**	**108.9**	**111.0**	**105.5**	**109.2**	**112.2**	**104.7**	**109.1**	**112.4**

[1]Includes cogenerators. Includes Federal and State taxes while excluding county and state taxes.
[2] Low sulfur diesel fuel. Includes Federal and State taxes while excluding county and local taxes.
[3]Kerosene-type jet fuel.
[4]Sales weighted-average price for all grades. Includes Federal and State taxes while excluding county and local taxes.
[5]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380 (98/03-99/04) (Washington, DC, 1998-99). 1998 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditure Report 1995*, DOE/EIA-0376(95) (Washington, DC, August 1998). **Projections**: EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1998	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production										
Dry Gas Production[1]	18.88	21.67	22.46	23.65	23.85	25.03	26.32	25.00	26.40	27.22
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	**3.13**	**4.27**	**4.52**	**4.69**	**4.51**	**4.85**	**5.12**	**4.49**	**5.14**	**5.50**
Canada	3.15	4.08	4.32	4.50	4.38	4.72	4.99	4.37	5.01	5.38
Mexico	-0.04	-0.13	-0.13	-0.13	-0.19	-0.19	-0.19	-0.20	-0.20	-0.20
Liquefied Natural Gas	0.02	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Total Supply	**22.13**	**26.00**	**27.03**	**28.39**	**28.42**	**29.94**	**31.50**	**29.55**	**31.59**	**32.78**
Consumption by Sector										
Residential	4.48	5.26	5.30	5.33	5.41	5.49	5.55	5.57	5.69	5.76
Commercial	3.03	3.42	3.48	3.54	3.50	3.61	3.72	3.50	3.65	3.79
Industrial[3]	8.23	8.85	9.22	9.75	9.07	9.64	10.36	9.18	9.99	10.98
Electric Generators[4]	3.67	5.98	6.45	7.10	7.70	8.37	8.93	8.45	9.26	9.15
Lease and Plant Fuel[5]	1.24	1.39	1.43	1.48	1.51	1.57	1.63	1.60	1.67	1.71
Pipeline Fuel	0.73	0.82	0.84	0.87	0.89	0.92	0.96	0.92	0.96	0.99
Transportation[6]	0.02	0.21	0.22	0.23	0.26	0.28	0.30	0.29	0.32	0.35
Total	**21.39**	**25.92**	**26.95**	**28.31**	**28.35**	**29.88**	**31.44**	**29.49**	**31.53**	**32.73**
Discrepancy[7]	**0.73**	**0.08**	**0.08**	**0.08**	**0.07**	**0.06**	**0.06**	**0.06**	**0.05**	**0.05**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 1998 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(99/06) (Washington, DC, June 1999). 1998 transportation sector consumption: EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A. Other 1998 consumption: EIA, *Short-Term Energy Outlook, September 1999. Online.* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf *(October 12, 1999)* with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A. **Projections:** EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B14. Natural Gas Prices, Margins, and Revenue
(1998 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1998	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]	1.96	2.38	2.60	2.93	2.36	2.71	3.03	2.40	2.81	3.27
Average Import Price	1.96	2.45	2.64	2.87	2.47	2.67	2.91	2.58	2.92	3.22
Average[2]	**1.96**	**2.39**	**2.61**	**2.92**	**2.38**	**2.70**	**3.01**	**2.43**	**2.83**	**3.26**
Delivered Prices										
Residential	6.79	6.52	6.76	7.08	6.29	6.62	6.92	6.18	6.55	6.99
Commercial	5.42	5.46	5.69	6.01	5.30	5.64	5.95	5.26	5.66	6.10
Industrial[3]	2.73	3.14	3.38	3.71	3.13	3.48	3.81	3.16	3.60	4.08
Electric Generators[4]	2.40	2.91	3.14	3.44	2.93	3.28	3.57	2.95	3.41	3.85
Transportation[5]	6.27	7.10	7.43	7.85	7.20	7.66	8.11	7.19	7.70	8.28
Average[6]	**4.03**	**4.21**	**4.41**	**4.68**	**4.07**	**4.38**	**4.66**	**4.04**	**4.43**	**4.88**
Transmission & Distribution Margins[7]										
Residential	4.83	4.13	4.15	4.16	3.91	3.91	3.91	3.76	3.72	3.72
Commercial	3.46	3.07	3.08	3.09	2.92	2.93	2.94	2.84	2.83	2.84
Industrial[3]	0.77	0.76	0.77	0.79	0.74	0.77	0.80	0.73	0.77	0.82
Electric Generators[4]	0.44	0.52	0.54	0.52	0.54	0.57	0.56	0.52	0.58	0.58
Transportation[5]	4.31	4.71	4.82	4.93	4.82	4.96	5.10	4.76	4.87	5.01
Average[6]	**2.07**	**1.82**	**1.80**	**1.76**	**1.68**	**1.67**	**1.65**	**1.61**	**1.60**	**1.61**
Transmission & Distribution Revenue (billion 1998 dollars)										
Residential	21.62	21.75	22.01	22.15	21.14	21.48	21.68	20.91	21.18	21.42
Commercial	10.46	10.48	10.73	10.92	10.24	10.59	10.93	9.92	10.31	10.77
Industrial[3]	6.37	6.68	7.09	7.72	6.76	7.46	8.29	6.74	7.73	9.00
Electric Generators[4]	1.60	3.09	3.45	3.70	4.19	4.80	5.03	4.41	5.34	5.33
Transportation[5]	0.09	1.00	1.08	1.16	1.27	1.40	1.52	1.38	1.55	1.73
Total	**40.15**	**43.01**	**44.36**	**45.65**	**43.60**	**45.72**	**47.45**	**43.36**	**46.12**	**48.26**

[1]Represents lower 48 onshore and offshore supplies.
[2]Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1994*. 1998 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(99/06) (Washington, DC, June 1999). **Other 1998 values, and projections:** EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B15. Oil and Gas Supply

Production and Supply	1998	Projections 2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2015 Low Economic Growth	2015 Reference	2015 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth
Crude Oil										
Lower 48 Average Wellhead Price[1] (1998 dollars per barrel)	**11.60**	**20.09**	**20.62**	**21.17**	**20.31**	**20.86**	**21.35**	**20.46**	**21.27**	**22.20**
Production (million barrels per day)[2]										
U.S. Total	**6.25**	**5.12**	**5.18**	**5.32**	**5.13**	**5.20**	**5.51**	**5.17**	**5.26**	**5.66**
Lower 48 Onshore	3.60	2.94	3.00	3.10	3.06	3.17	3.35	3.11	3.28	3.51
Conventional	2.87	2.35	2.39	2.49	2.39	2.49	2.65	2.43	2.57	2.77
Enhanced Oil Recovery	0.73	0.60	0.61	0.61	0.67	0.68	0.70	0.68	0.71	0.75
Lower 48 Offshore	1.47	1.36	1.36	1.41	1.44	1.40	1.53	1.56	1.47	1.64
Alaska	1.18	0.81	0.81	0.81	0.63	0.63	0.63	0.51	0.51	0.51
Lower 48 End of Year Reserves (billion barrels)[2]	**18.05**	**13.19**	**13.38**	**13.82**	**13.13**	**13.32**	**14.19**	**12.93**	**13.21**	**14.22**
Natural Gas										
Lower 48 Average Wellhead Price[1] (1998 dollars per thousand cubic feet)	**1.96**	**2.38**	**2.60**	**2.93**	**2.36**	**2.71**	**3.03**	**2.40**	**2.81**	**3.27**
Production (trillion cubic feet)[3]										
U.S. Total	**18.72**	**21.67**	**22.46**	**23.65**	**23.85**	**25.03**	**26.32**	**25.00**	**26.40**	**27.22**
Lower 48 Onshore	12.75	15.64	16.37	17.54	16.89	17.83	19.16	18.06	19.47	19.99
Associated-Dissolved[4]	1.56	1.25	1.25	1.28	1.23	1.25	1.31	1.22	1.25	1.32
Non-Associated	11.19	14.39	15.12	16.26	15.66	16.58	17.86	16.84	18.22	18.68
Conventional	6.68	9.60	9.81	9.94	10.12	10.09	9.97	10.79	10.75	10.60
Unconventional	4.51	4.79	5.30	6.32	5.54	6.49	7.89	6.04	7.47	8.08
Lower 48 Offshore	5.53	5.55	5.60	5.62	6.45	6.68	6.64	6.41	6.39	6.69
Associated-Dissolved[4]	0.88	0.88	0.88	0.89	0.90	0.89	0.92	0.93	0.91	0.95
Non-Associated	4.65	4.66	4.72	4.72	5.55	5.79	5.72	5.48	5.48	5.74
Alaska	0.44	0.48	0.49	0.49	0.51	0.51	0.52	0.53	0.54	0.54
Lower 48 End of Year Reserves (trillion cubic feet)	**155.00**	**170.01**	**173.45**	**183.15**	**185.66**	**191.59**	**198.47**	**185.52**	**191.37**	**189.54**
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)	**23.96**	**29.26**	**32.86**	**39.96**	**30.38**	**35.69**	**41.81**	**33.35**	**38.66**	**46.61**

[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.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 1998,* DOE/EIA-0340(98/1) (Washington, DC. June 1999). 1998 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(99/06) (Washington, DC, June 1999). Other 1998 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1998	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production[1]										
Appalachia	470	421	427	437	404	412	424	379	385	397
Interior	168	156	146	145	140	147	163	141	155	186
West	489	645	669	690	685	710	738	737	776	846
East of the Mississippi	580	560	559	569	533	547	575	507	528	569
West of the Mississippi	548	662	682	702	697	721	749	749	788	860
Total	**1128**	**1222**	**1242**	**1271**	**1229**	**1269**	**1325**	**1256**	**1316**	**1429**
Net Imports										
Imports	9	17	17	17	18	18	18	20	20	20
Exports	78	63	64	63	57	57	57	58	58	58
Total	**-69**	**-46**	**-47**	**-46**	**-38**	**-38**	**-38**	**-38**	**-38**	**-38**
Total Supply[2]	**1058**	**1176**	**1195**	**1225**	**1191**	**1230**	**1286**	**1218**	**1278**	**1391**
Consumption by Sector										
Residential and Commercial	6	7	7	7	7	7	7	7	7	7
Industrial[3]	69	71	73	76	71	74	78	70	75	80
Coke Plants	28	23	23	23	22	21	21	20	20	19
Electric Generators[4]	939	1077	1092	1120	1094	1129	1182	1123	1177	1286
Total	**1043**	**1178**	**1195**	**1226**	**1193**	**1232**	**1288**	**1219**	**1279**	**1393**
Discrepancy and Stock Change[5]	**16**	**-2**	**-1**	**-1**	**-2**	**-1**	**-1**	**-1**	**-1**	**-2**
Average Minemouth Price										
(1998 dollars per short ton)	17.51	13.63	13.84	14.13	13.09	13.34	13.52	12.40	12.54	12.58
(1998 dollars per million Btu)	0.83	0.65	0.66	0.67	0.62	0.64	0.64	0.60	0.60	0.61
Delivered Prices (1998 dollars per short ton)[6]										
Industrial	32.26	27.34	27.44	27.78	26.00	26.27	26.77	24.93	25.24	25.76
Coke Plants	46.06	42.79	42.93	43.33	41.17	41.72	42.03	39.66	40.19	40.62
Electric Generators										
(1998 dollars per short ton)	25.64	21.64	22.13	22.69	20.74	21.19	21.60	19.61	20.01	20.32
(1998 dollars per million Btu)	1.25	1.05	1.07	1.10	1.01	1.03	1.05	0.96	0.98	1.00
Average	**26.65**	**22.41**	**22.86**	**23.40**	**21.43**	**21.86**	**22.25**	**20.25**	**20.63**	**20.92**
Exports[7]	38.89	35.95	36.05	36.52	34.66	35.08	35.55	33.51	33.91	34.30

[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, 8.8 million tons in 1996, 8.1 million tons in 1997, and are projected to reach 9.5 million tons in 1998, and 11.6 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. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 data based on Energy Information Administration (EIA), *Quarterly Coal Report* , DOE/EIA-0121(99/1Q) (Washington, DC, August 1999), and EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A. **Projections:** EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B17. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1998	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	77.71	78.33	78.33	78.33	78.33	78.33	78.33	78.33	78.33	78.33
Geothermal[2]	2.89	2.95	2.98	3.02	3.26	3.11	3.20	3.98	3.75	3.78
Municipal Solid Waste[3]	2.49	4.38	4.47	4.59	4.86	5.00	5.15	4.97	5.17	5.36
Wood and Other Biomass[4]	1.76	2.41	2.41	2.41	2.70	2.71	2.76	2.77	2.93	3.04
Solar Thermal	0.33	0.40	0.40	0.40	0.44	0.44	0.44	0.48	0.48	0.48
Solar Photovoltaic	0.01	0.19	0.19	0.19	0.35	0.35	0.35	0.52	0.52	0.52
Wind	1.99	5.07	5.07	5.07	5.40	5.40	5.40	5.49	5.49	5.50
Total	**87.19**	**93.72**	**93.84**	**94.00**	**95.33**	**95.33**	**95.61**	**96.53**	**96.67**	**97.02**
Generation (billion kilowatthours)										
Conventional Hydropower	316.79	300.47	300.50	300.53	299.86	299.90	299.97	299.27	299.35	299.44
Geothermal[2]	14.29	17.13	17.35	17.68	20.81	19.62	20.32	26.49	24.70	24.97
Municipal Solid Waste[3]	17.78	30.00	30.63	31.46	33.59	34.55	35.56	34.34	35.71	37.07
Wood and Other Biomass[4]	6.86	18.77	20.35	19.37	18.26	18.23	19.48	18.17	18.80	19.34
Dedicated Plants	6.86	11.00	11.00	11.00	12.94	13.03	13.40	13.45	14.55	15.36
Cofiring	0.00	7.76	9.34	8.36	5.32	5.20	6.09	4.72	4.25	3.98
Solar Thermal	0.89	1.09	1.09	1.09	1.22	1.22	1.22	1.35	1.35	1.35
Solar Photovoltaic	0.00	0.46	0.46	0.46	0.86	0.86	0.86	1.30	1.30	1.30
Wind	3.39	10.95	10.95	10.95	11.87	11.87	11.87	12.09	12.09	12.14
Total	**360.00**	**378.88**	**381.33**	**381.54**	**386.47**	**386.26**	**389.29**	**393.03**	**393.32**	**395.62**
Cogenerators[5]										
Net Summer Capability										
Municipal Solid Waste	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Biomass	6.04	6.93	7.37	8.14	7.20	7.94	8.98	7.38	8.46	9.96
Total	**6.56**	**7.45**	**7.89**	**8.66**	**7.72**	**8.46**	**9.51**	**7.90**	**8.98**	**10.48**
Generation (billion kilowatthours)										
Municipal Solid Waste	3.00	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13
Biomass	37.34	42.37	45.06	49.51	43.79	48.28	54.16	44.57	51.02	59.46
Total	**40.34**	**45.50**	**48.19**	**52.64**	**46.92**	**51.41**	**57.30**	**47.70**	**54.15**	**62.59**
Other Generators[6]										
Net Summer Capability										
Conventional Hydropower[7]	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.01	0.35	0.35	0.35	0.38	0.42	0.47	0.47	0.74	1.03
Total	**1.10**	**1.44**	**1.44**	**1.44**	**1.47**	**1.52**	**1.56**	**1.56**	**1.84**	**2.13**
Generation (billion Kilowatthours)										
Conventional Hydropower[7]	7.25	4.85	4.85	4.85	4.84	4.84	4.84	4.83	4.83	4.83
Geothermal	0.00	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Solar Photovoltaic	0.01	0.46	0.46	0.46	0.46	0.47	0.47	0.47	0.50	0.53
Total	**7.26**	**5.38**	**5.38**	**5.38**	**5.37**	**5.37**	**5.38**	**5.37**	**5.40**	**5.43**

[1]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.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Cogenerators produce electricity and other useful thermal energy.
[6]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[7]Represents own-use industrial hydroelectric power.
Notes: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators for AEO2000. Net summer capability is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.
Sources: 1998 electric utility capability: Energy Information Administration (EIA), Form EIA-860, “Annual Electric Generator Report.” 1998 nonutility and cogenerator capability: EIA, Form EIA-867, “Annual Nonutility Power Producer Report, 1997.” 1998 generation: EIA, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B18. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1998	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
Marketed Renewable Energy[2]										
Residential	**0.38**	**0.44**	**0.44**	**0.44**	**0.44**	**0.45**	**0.45**	**0.44**	**0.45**	**0.46**
Wood	0.38	0.44	0.44	0.44	0.44	0.45	0.45	0.44	0.45	0.46
Commercial	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Industrial[3]	**2.08**	**2.29**	**2.40**	**2.58**	**2.34**	**2.53**	**2.77**	**2.37**	**2.63**	**2.98**
Conventional Hydroelectric	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	1.91	2.12	2.23	2.41	2.17	2.35	2.60	2.20	2.46	2.81
Transportation	**0.12**	**0.18**	**0.18**	**0.18**	**0.21**	**0.21**	**0.21**	**0.23**	**0.23**	**0.24**
Ethanol used in E85[4]	0.00	0.04	0.05	0.05	0.05	0.06	0.07	0.05	0.06	0.07
Ethanol used in Gasoline Blending	0.12	0.14	0.14	0.13	0.16	0.15	0.15	0.17	0.17	0.17
Electric Generators[5]	**4.12**	**4.42**	**4.43**	**4.44**	**4.60**	**4.59**	**4.65**	**4.82**	**4.75**	**4.80**
Conventional Hydroelectric	3.33	3.09	3.09	3.09	3.09	3.09	3.09	3.08	3.08	3.08
Geothermal	0.40	0.54	0.52	0.54	0.66	0.64	0.67	0.87	0.77	0.80
Municipal Solid Waste	0.27	0.48	0.49	0.50	0.54	0.55	0.57	0.55	0.57	0.59
Biomass	0.06	0.18	0.19	0.18	0.17	0.17	0.18	0.17	0.17	0.18
Dedicated Plants	0.06	0.10	0.10	0.10	0.12	0.12	0.12	0.12	0.13	0.14
Cofiring	0.00	0.07	0.09	0.08	0.05	0.05	0.06	0.04	0.04	0.04
Solar Thermal	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.04	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.12
Total Marketed Renewable Energy	**6.79**	**7.41**	**7.53**	**7.73**	**7.67**	**7.85**	**8.15**	**7.94**	**8.14**	**8.56**
Non-Marketed Renewable Energy[6]										
Selected Consumption										
Residential	**0.02**	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**
Solar Hot Water Heating	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal Heat Pumps	0.01	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.05	0.05
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Commercial	**0.02**	**0.03**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**
Solar Thermal	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Ethanol										
From Corn	0.12	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
From Cellulose	0.00	0.02	0.02	0.02	0.05	0.05	0.05	0.07	0.07	0.08
Total	**0.12**	**0.18**	**0.18**	**0.18**	**0.21**	**0.21**	**0.21**	**0.23**	**0.23**	**0.24**

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table B8.
[3]Includes all electricity production by industrial and other cogenerators for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes renewable energy delivered to the grid from electric utilities and nonutilities other than cogenerators. Renewable energy used in generating electricity for own use is included in the individual sectoral electricity energy consumption values.
[6]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. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 ethanol: Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). 1998 electric generators: EIA, Form EIA-860, "Annual Electric Generator Report," and EIA, Form EIA-867, "Annual Nonutility Power Producer Report, 1997." Other 1998: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B19. Carbon Emissions by Sector and Source
(Million Metric Tons per Year)

Sector and Source	1998	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential										
Petroleum	24.8	23.5	23.5	23.6	22.4	22.4	22.4	21.5	21.5	21.6
Natural Gas	66.3	78.0	78.6	79.0	80.2	81.3	82.2	82.5	84.4	85.3
Coal	1.5	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3
Electricity	191.0	237.6	240.2	244.2	251.2	255.8	260.8	263.5	270.5	277.8
Total	**283.5**	**340.5**	**343.7**	**348.2**	**355.2**	**361.0**	**366.8**	**368.8**	**377.7**	**385.9**
Commercial										
Petroleum	12.9	12.0	12.2	12.5	11.8	12.1	12.5	11.4	11.8	12.3
Natural Gas	44.9	50.6	51.6	52.4	51.9	53.5	55.2	51.8	54.1	56.2
Coal	2.2	2.5	2.6	2.7	2.6	2.7	2.8	2.5	2.7	2.8
Electricity	177.5	217.5	222.5	228.4	226.7	234.8	244.1	228.0	238.8	252.6
Total	**237.5**	**282.6**	**288.8**	**296.0**	**292.9**	**303.0**	**314.5**	**293.8**	**307.3**	**324.0**
Industrial[1]										
Petroleum	100.8	100.6	105.6	111.4	101.7	109.2	117.0	102.1	112.4	123.8
Natural Gas[2]	140.0	149.4	155.4	163.8	154.5	163.5	174.8	157.3	170.1	185.1
Coal	58.0	59.4	61.4	64.4	58.6	61.4	65.2	57.7	61.6	67.0
Electricity	178.0	200.3	212.0	231.8	209.7	227.6	253.2	215.7	240.0	277.4
Total	**476.8**	**509.7**	**534.4**	**571.5**	**524.6**	**561.8**	**610.1**	**532.8**	**584.1**	**653.2**
Transportation										
Petroleum[3]	473.4	572.0	595.8	622.8	602.2	639.7	676.4	626.7	679.9	731.0
Natural Gas[4]	10.8	15.3	15.8	16.4	17.0	17.8	18.6	17.9	18.9	19.8
Other[5]	0.0	1.6	1.8	1.9	2.1	2.3	2.6	2.4	2.7	3.0
Electricity	3.4	6.2	6.3	6.5	7.4	7.7	7.9	8.3	8.6	8.9
Total[3]	**487.5**	**595.1**	**619.7**	**647.7**	**628.8**	**667.5**	**705.4**	**655.2**	**710.0**	**762.7**
Total Carbon Emissions by Delivered Fuel										
Petroleum[3]	611.9	708.2	737.1	770.4	738.1	783.5	828.2	761.6	825.6	888.7
Natural Gas	262.0	293.2	301.3	311.6	303.7	316.1	330.7	309.5	327.4	346.4
Coal	61.7	63.3	65.4	68.4	62.5	65.5	69.3	61.6	65.6	71.2
Other[5]	0.0	1.6	1.8	1.9	2.1	2.3	2.6	2.4	2.7	3.0
Electricity	549.8	661.6	681.0	711.0	695.0	725.9	765.9	715.5	757.8	816.6
Total[3]	**1485.4**	**1728.0**	**1786.6**	**1863.3**	**1801.5**	**1893.4**	**1996.7**	**1850.6**	**1979.2**	**2125.9**
Electric Generators[6]										
Petroleum	24.8	7.8	10.2	15.1	6.6	8.6	12.5	5.8	7.7	12.8
Natural Gas	47.8	87.9	95.0	104.5	113.3	123.1	131.4	124.3	136.2	134.6
Coal	477.3	565.9	575.8	591.3	575.1	594.2	622.0	585.4	613.9	669.2
Total	**549.8**	**661.6**	**681.0**	**711.0**	**695.0**	**725.9**	**765.9**	**715.5**	**757.8**	**816.6**
Total Carbon Emissions by Primary Fuel[7]										
Petroleum[3]	636.7	716.0	747.3	785.5	744.7	792.1	840.7	767.4	833.3	901.4
Natural Gas	309.8	381.2	396.3	416.1	417.0	439.3	462.2	433.8	463.7	481.0
Coal	538.9	629.2	641.2	659.8	637.6	659.7	691.3	647.0	679.5	740.4
Other[5]	0.0	1.6	1.8	1.9	2.1	2.3	2.6	2.4	2.7	3.0
Total[3]	**1485.4**	**1728.0**	**1786.6**	**1863.3**	**1801.5**	**1893.4**	**1996.7**	**1850.6**	**1979.2**	**2125.9**
Carbon Emissions										
(tons per person)	**5.5**	**5.9**	**6.0**	**6.1**	**6.0**	**6.1**	**6.2**	**6.0**	**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 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.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 1998,* DOE/EIA-0573(98), (Washington, DC, October 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B20. Macroeconomic Indicators
(Billion 1992 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	1998	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)	**1.127**	**1.519**	**1.423**	**1.314**	**1.762**	**1.591**	**1.440**	**2.109**	**1.857**	**1.627**
Real Gross Domestic Product	**7,552**	**9,524**	**10,054**	**10,680**	**10,265**	**11,147**	**11,984**	**10,870**	**12,179**	**13,413**
Real Consumption	5,153	6,588	6,906	7,205	7,175	7,743	8,132	7,728	8,585	9,207
Real Investment	1,330	1,750	1,937	2,132	1,928	2,239	2,488	1,991	2,489	2,878
Real Government Spending	1,297	1,483	1,575	1,628	1,533	1,666	1,747	1,601	1,779	1,896
Real Exports	985	2,080	2,233	2,462	2,620	2,931	3,303	3,115	3,669	4,231
Real Imports	1,223	2,382	2,623	2,698	3,014	3,522	3,649	3,679	4,610	4,881
Real Disposable Personal Income	**5,348**	**6,887**	**7,204**	**7,543**	**7,572**	**8,083**	**8,555**	**8,281**	**9,008**	**9,679**
Index of Manufacturing Gross Output (index 1987=1.000)	**1.411**	**1.727**	**1.812**	**1.969**	**1.866**	**1.999**	**2.220**	**1.972**	**2.160**	**2.483**
AA Utility Bond Rate (percent)	6.91	8.73	7.72	7.03	9.34	8.14	7.18	11.14	8.81	7.38
Real Yield on Government 10 Year Bonds (percent)	4.29	4.45	4.59	4.55	4.98	4.91	4.59	6.08	4.69	4.23
Real Utility Bond Rate (percent)	5.33	5.78	5.55	5.23	6.21	5.79	5.28	7.27	5.43	4.74
Energy Intensity (thousand Btu per 1992 dollar of GDP)										
Delivered Energy	9.32	8.48	8.32	8.18	8.17	7.94	7.80	7.90	7.60	7.42
Total Energy	12.57	11.31	11.07	10.86	10.83	10.47	10.26	10.43	9.94	9.65
Consumer Price Index (1982-84=1.00)	1.63	2.35	2.20	2.03	2.78	2.48	2.25	3.38	2.90	2.55
Unemployment Rate (percent)	4.48	6.25	5.72	5.12	6.00	5.30	5.29	6.00	5.10	4.95
Unit Sales of Light-Duty Vehicles (millions)	**15.64**	**15.22**	**16.02**	**16.84**	**15.79**	**17.06**	**18.09**	**14.84**	**17.09**	**19.26**
Millions of People										
Population with Armed Forces Overseas	270.6	290.9	298.3	305.8	299.8	310.8	321.7	308.9	323.4	337.9
Population (aged 16 and over)	208.6	229.8	235.2	240.6	237.6	245.6	253.5	244.6	255.3	266.0
Employment, Non-Agriculture	126.2	136.2	140.1	145.1	138.0	144.6	150.2	138.1	147.8	156.2
Employment, Manufacturing	19.0	16.6	17.2	18.3	15.7	16.6	17.7	14.7	15.9	17.4
Labor Force	137.7	153.0	157.3	162.2	156.2	162.6	169.2	158.3	167.0	175.9

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 1998: Standard & Poor's DRI, Simulation T250899. **Projections:** Energy Information Administration, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Table B21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1998	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 (1998 dollars per barrel)[1]	**12.10**	**20.44**	**21.00**	**21.56**	**20.74**	**21.53**	**22.32**	**20.99**	**22.04**	**23.11**
Production[2]										
OECD										
U.S. (50 states)	9.14	8.46	8.62	8.89	8.71	8.89	9.37	8.85	9.06	9.61
Canada	2.70	3.22	3.22	3.22	3.38	3.39	3.39	3.42	3.43	3.44
Mexico	3.52	3.98	3.99	4.00	3.89	3.90	3.91	3.78	3.80	3.81
OECD Europe[3]	6.95	7.71	7.72	7.73	7.02	7.03	7.04	6.51	6.52	6.53
Other OECD	0.77	0.92	0.92	0.92	0.88	0.88	0.88	0.82	0.82	0.82
Total OECD	**23.09**	**24.29**	**24.48**	**24.76**	**23.88**	**24.09**	**24.59**	**23.38**	**23.63**	**24.22**
Developing Countries										
Other South & Central America	3.64	4.42	4.43	4.44	4.77	4.79	4.80	4.97	4.99	5.01
Pacific Rim	2.19	3.00	3.00	3.01	3.16	3.17	3.18	3.26	3.27	3.28
OPEC	31.70	41.52	42.02	42.65	46.81	47.56	48.09	54.43	55.47	56.26
Other Developing Countries	4.69	5.49	5.50	5.51	6.59	6.61	6.63	7.54	7.57	7.60
Total Developing Countries	**42.23**	**54.43**	**54.96**	**55.60**	**61.34**	**62.13**	**62.70**	**70.21**	**71.30**	**72.16**
Eurasia										
Former Soviet Union	7.24	10.13	10.14	10.16	12.05	12.08	12.12	13.00	13.05	13.10
Eastern Europe	0.25	0.39	0.39	0.39	0.42	0.42	0.42	0.45	0.45	0.45
China	3.20	3.51	3.52	3.52	3.61	3.62	3.63	3.61	3.63	3.64
Total Eurasia	**10.69**	**14.02**	**14.05**	**14.07**	**16.07**	**16.12**	**16.16**	**17.06**	**17.13**	**17.20**
Total Production	**76.01**	**92.75**	**93.48**	**94.44**	**101.28**	**102.33**	**103.45**	**110.65**	**112.06**	**113.58**
Consumption										
OECD										
U.S. (50 states)	18.94	21.54	22.51	23.71	22.39	23.87	25.40	23.02	25.10	27.25
U.S. Territories	0.28	0.35	0.34	0.34	0.37	0.36	0.36	0.39	0.38	0.38
Canada	1.88	2.16	2.14	2.13	2.25	2.22	2.20	2.32	2.29	2.26
Mexico	1.78	2.48	2.47	2.46	2.90	2.87	2.85	3.37	3.33	3.29
Japan	5.51	6.09	6.04	6.00	6.39	6.30	6.22	6.72	6.59	6.46
Australia and New Zealand	0.94	1.13	1.13	1.13	1.21	1.21	1.20	1.30	1.29	1.28
OECD Europe[3]	14.74	16.42	16.37	16.32	16.99	16.90	16.81	17.58	17.46	17.34
Total OECD	**44.07**	**50.18**	**51.01**	**52.07**	**52.49**	**53.74**	**55.04**	**54.70**	**56.43**	**58.25**
Developing Countries										
Other South and Central America	4.67	6.80	6.78	6.77	7.98	7.95	7.93	9.34	9.30	9.26
Pacific Rim	7.47	10.91	10.88	10.86	12.57	12.52	12.48	14.44	14.37	14.30
OPEC	5.47	7.19	7.19	7.19	8.06	8.06	8.06	9.07	9.07	9.07
Other Developing Countries	3.71	5.08	5.06	5.04	5.84	5.79	5.75	6.73	6.65	6.57
Total Developing Countries	**21.32**	**29.98**	**29.92**	**29.86**	**34.45**	**34.33**	**34.22**	**39.58**	**39.39**	**39.21**
Eurasia										
Former Soviet Union	4.23	4.93	4.91	4.90	5.41	5.39	5.37	5.97	5.93	5.90
Eastern Europe	1.47	1.71	1.70	1.70	1.75	1.75	1.74	1.80	1.79	1.79
China	3.91	6.26	6.23	6.21	7.48	7.43	7.38	8.91	8.82	8.74
Total Eurasia	**9.62**	**12.90**	**12.85**	**12.81**	**14.65**	**14.57**	**14.49**	**16.67**	**16.55**	**16.43**

Table B21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1998	Projections								
		2010			2015			2020		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Total Consumption	**74.99**	**93.05**	**93.78**	**94.74**	**101.58**	**102.63**	**103.75**	**110.95**	**112.36**	**113.88**
Non-OPEC Production	44.31	51.23	51.46	51.79	54.47	54.77	55.36	56.22	56.60	57.32
Net Eurasia Exports	1.08	1.13	1.20	1.27	1.42	1.55	1.67	0.39	0.58	0.77
OPEC Market Share	0.42	0.45	0.45	0.45	0.46	0.46	0.46	0.49	0.49	0.50

[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. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1999.* Online. http://www.eia.doe.gov /pub/forecasting/steo/ oldsteos/sep99.pdf (October 12, 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LMAC2K.D100199A, AEO2K.D100199A, and HMAC2K.D100199A.

Oil Price Case Comparisons

Table C1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1998	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2015 Low World Oil Price	2015 Reference	2015 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price
Production										
Crude Oil and Lease Condensate	13.23	10.25	10.96	11.64	9.94	11.01	12.29	9.84	11.13	12.74
Natural Gas Plant Liquids	2.49	2.89	2.90	2.92	3.18	3.21	3.23	3.34	3.36	3.37
Dry Natural Gas	19.40	22.95	23.09	23.24	25.51	25.73	25.98	26.97	27.13	27.26
Coal	23.89	26.09	26.18	26.07	26.37	26.63	26.61	26.90	27.36	27.43
Nuclear Power	7.19	6.70	6.70	6.70	5.41	5.45	5.45	4.51	4.56	4.63
Renewable Energy[1]	6.67	7.33	7.39	7.45	7.62	7.70	7.78	7.90	7.98	8.06
Other[2]	0.57	0.49	0.59	0.70	0.56	0.63	0.71	0.59	0.66	0.73
Total	**73.46**	**76.70**	**77.81**	**78.71**	**78.57**	**80.35**	**82.05**	**80.06**	**82.18**	**84.23**
Imports										
Crude Oil[3]	18.90	26.20	24.91	24.19	26.83	24.97	23.87	27.10	25.22	23.76
Petroleum Products[4]	3.99	8.06	6.80	5.71	10.48	8.98	7.52	12.94	10.87	9.44
Natural Gas	3.37	4.76	4.91	4.96	5.23	5.31	5.30	5.51	5.61	5.54
Other Imports[5]	0.59	0.89	0.89	0.90	0.89	0.89	0.90	0.97	0.97	0.98
Total	**26.85**	**39.93**	**37.50**	**35.75**	**43.44**	**40.16**	**37.58**	**46.51**	**42.67**	**39.72**
Exports										
Petroleum[6]	1.94	1.88	1.97	2.03	1.78	1.95	2.17	1.69	1.93	2.33
Natural Gas	0.17	0.29	0.29	0.29	0.35	0.35	0.35	0.36	0.36	0.36
Coal	2.05	1.60	1.63	1.63	1.44	1.44	1.44	1.46	1.46	1.46
Total	**4.16**	**3.77**	**3.89**	**3.95**	**3.58**	**3.75**	**3.96**	**3.52**	**3.76**	**4.15**
Discrepancy[7]	**1.27**	**0.29**	**0.16**	**0.02**	**0.27**	**0.10**	**-0.10**	**0.26**	**0.14**	**N/A**
Consumption										
Petroleum Products[8]	37.21	45.68	43.98	43.06	48.82	46.65	45.46	51.73	49.05	47.71
Natural Gas	21.99	27.40	27.69	27.89	30.37	30.68	30.91	32.11	32.38	32.44
Coal	21.50	25.07	25.12	25.02	25.59	25.84	25.83	26.15	26.60	26.68
Nuclear Power	7.19	6.70	6.70	6.70	5.41	5.45	5.45	4.51	4.56	4.63
Renewable Energy[1]	6.67	7.34	7.41	7.46	7.64	7.71	7.79	7.92	7.99	8.08
Other[9]	0.32	0.37	0.36	0.36	0.34	0.33	0.31	0.37	0.36	0.34
Total	**94.88**	**112.56**	**111.26**	**110.48**	**118.16**	**116.66**	**115.76**	**122.79**	**120.95**	**119.88**
Net Imports - Petroleum	**20.95**	**32.39**	**29.73**	**27.87**	**35.53**	**32.00**	**29.22**	**38.35**	**34.15**	**30.87**
Prices (1998 dollars per unit)										
World Oil Price (dollars per barrel)[10]	12.10	14.90	21.00	26.31	14.90	21.53	27.86	14.90	22.04	28.04
Gas Wellhead Price (dollars per Mcf)[11]	1.96	2.44	2.60	2.72	2.56	2.71	2.78	2.68	2.81	2.87
Coal Minemouth Price (dollars per ton)	17.51	13.82	13.84	13.99	13.31	13.34	13.39	12.38	12.54	12.53
Average Electric Price (cents per Kwh)	6.7	5.9	6.0	6.1	5.8	5.9	5.9	5.8	5.8	5.9

[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 C18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Mcf = Thousand cubic feet.
Kwh = Kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(99/06) (Washington, DC, June 1999). 1998 petroleum values: *Petroleum Supply Annual 1998,* DOE/EIA-0340(98/1) (Washington, DC, June 1999). Other 1998 values: EIA, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999) and EIA, *Quarterly Coal Report* , DOE/EIA-0121(99/1Q) (Washington, DC, August 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1998	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	0.84	0.78	0.73	0.70	0.74	0.69	0.64	0.70	0.65	0.61
Kerosene	0.10	0.09	0.09	0.08	0.09	0.09	0.08	0.09	0.09	0.08
Liquefied Petroleum Gas	0.41	0.48	0.43	0.41	0.48	0.42	0.39	0.48	0.41	0.37
Petroleum Subtotal	1.36	1.34	1.25	1.19	1.31	1.19	1.12	1.27	1.15	1.06
Natural Gas	4.61	5.47	5.46	5.44	5.65	5.65	5.64	5.86	5.86	5.86
Coal	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.38	0.44	0.44	0.44	0.45	0.45	0.44	0.46	0.45	0.45
Electricity	3.83	4.72	4.70	4.69	5.00	5.00	4.99	5.30	5.30	5.29
Delivered Energy	**10.24**	**12.03**	**11.91**	**11.81**	**12.46**	**12.34**	**12.25**	**12.94**	**12.81**	**12.73**
Electricity Related Losses	8.53	9.97	9.76	9.71	10.20	9.96	9.95	10.50	10.18	10.17
Total	**18.77**	**21.99**	**21.66**	**21.53**	**22.66**	**22.30**	**22.20**	**23.44**	**22.99**	**22.89**
Commercial										
Distillate Fuel	0.38	0.43	0.38	0.35	0.44	0.37	0.33	0.44	0.36	0.32
Residual Fuel	0.11	0.10	0.10	0.10	0.11	0.10	0.10	0.10	0.10	0.10
Kerosene	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.07	0.09	0.08	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	0.03	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.61	0.68	0.62	0.59	0.69	0.62	0.58	0.69	0.60	0.57
Natural Gas	3.11	3.59	3.58	3.57	3.70	3.71	3.71	3.73	3.75	3.75
Coal	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.10	0.10
Renewable Energy[3]	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Electricity	3.56	4.38	4.36	4.33	4.60	4.58	4.57	4.68	4.68	4.66
Delivered Energy	**7.46**	**8.82**	**8.74**	**8.67**	**9.17**	**9.10**	**9.04**	**9.28**	**9.22**	**9.16**
Electricity Related Losses	7.93	9.25	9.04	8.97	9.38	9.14	9.11	9.28	8.98	8.96
Total	**15.38**	**18.07**	**17.78**	**17.64**	**18.55**	**18.24**	**18.15**	**18.57**	**18.20**	**18.12**
Industrial[4]										
Distillate Fuel	1.08	1.32	1.29	1.27	1.41	1.38	1.35	1.49	1.46	1.42
Liquefied Petroleum Gas	2.06	2.41	2.40	2.38	2.55	2.53	2.51	2.67	2.64	2.62
Petrochemical Feedstock	1.39	1.58	1.58	1.58	1.67	1.66	1.66	1.74	1.73	1.73
Residual Fuel	0.27	0.32	0.29	0.23	0.33	0.30	0.26	0.36	0.31	0.25
Motor Gasoline[2]	0.21	0.25	0.25	0.24	0.27	0.26	0.26	0.28	0.28	0.28
Other Petroleum[5]	4.11	4.66	4.72	4.67	4.83	4.91	4.82	4.97	5.03	4.95
Petroleum Subtotal	9.12	10.54	10.53	10.37	11.05	11.04	10.86	11.51	11.45	11.25
Natural Gas[6]	9.75	10.97	10.96	11.00	11.52	11.53	11.63	11.92	11.99	12.07
Metallurgical Coal	0.76	0.63	0.63	0.62	0.58	0.58	0.57	0.53	0.53	0.52
Steam Coal	1.54	1.61	1.59	1.58	1.64	1.61	1.60	1.66	1.63	1.62
Net Coal Coke Imports	0.07	0.20	0.21	0.21	0.24	0.24	0.25	0.27	0.27	0.28
Coal Subtotal	2.36	2.45	2.42	2.41	2.46	2.42	2.41	2.46	2.43	2.42
Renewable Energy[7]	2.08	2.37	2.40	2.43	2.48	2.53	2.57	2.57	2.63	2.69
Electricity	3.57	4.16	4.15	4.15	4.45	4.45	4.44	4.71	4.70	4.70
Delivered Energy	**26.89**	**30.49**	**30.46**	**30.37**	**31.96**	**31.96**	**31.92**	**33.17**	**33.20**	**33.13**
Electricity Related Losses	7.95	8.80	8.61	8.60	9.09	8.87	8.86	9.34	9.03	9.02
Total	**34.84**	**39.29**	**39.08**	**38.97**	**41.05**	**40.83**	**40.78**	**42.51**	**42.23**	**42.16**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1998	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	4.95	5.79	5.76	5.75	6.07	6.02	6.01	6.27	6.22	6.20
Jet Fuel[8]	3.36	4.91	4.85	4.81	5.60	5.55	5.46	6.29	6.24	6.09
Motor Gasoline[2]	15.59	19.49	19.12	18.80	20.78	20.30	19.78	21.96	21.35	20.75
Residual Fuel	0.65	0.93	0.92	0.92	1.05	1.05	1.05	1.18	1.18	1.17
Liquefied Petroleum Gas	0.05	0.11	0.11	0.11	0.13	0.12	0.12	0.14	0.13	0.13
Other Petroleum[9]	0.30	0.34	0.34	0.34	0.36	0.36	0.35	0.37	0.37	0.36
Petroleum Subtotal	24.89	31.57	31.10	30.73	33.99	33.39	32.77	36.22	35.49	34.70
Pipeline Fuel Natural Gas	0.75	0.85	0.87	0.87	0.93	0.95	0.95	0.97	0.99	0.99
Compressed Natural Gas	0.02	0.23	0.23	0.23	0.29	0.29	0.29	0.33	0.33	0.33
Renewable Energy (E85)[10]	0.00	0.06	0.06	0.05	0.08	0.07	0.07	0.09	0.08	0.07
Methanol (M85)[11]	0.01	0.11	0.10	0.09	0.14	0.13	0.12	0.17	0.15	0.14
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.07	0.12	0.12	0.12	0.15	0.15	0.15	0.17	0.17	0.17
Delivered Energy	**25.74**	**32.95**	**32.48**	**32.10**	**35.59**	**34.99**	**34.34**	**37.94**	**37.20**	**36.39**
Electricity Related Losses	0.15	0.26	0.26	0.25	0.31	0.30	0.29	0.34	0.32	0.32
Total	**25.89**	**33.21**	**32.74**	**32.35**	**35.90**	**35.28**	**34.64**	**38.28**	**37.53**	**36.71**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.25	8.32	8.16	8.06	8.65	8.45	8.33	8.91	8.68	8.55
Kerosene	0.16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.13
Jet Fuel[8]	3.36	4.91	4.85	4.81	5.60	5.55	5.46	6.29	6.24	6.09
Liquefied Petroleum Gas	2.59	3.08	3.03	2.98	3.24	3.16	3.10	3.37	3.27	3.21
Motor Gasoline[2]	15.82	19.76	19.39	19.08	21.08	20.59	20.07	22.27	21.65	21.05
Petrochemical Feedstock	1.39	1.58	1.58	1.58	1.67	1.66	1.66	1.74	1.73	1.73
Residual Fuel	1.02	1.35	1.31	1.25	1.49	1.45	1.41	1.64	1.59	1.52
Other Petroleum[12]	4.39	4.99	5.04	4.98	5.17	5.24	5.15	5.32	5.38	5.29
Petroleum Subtotal	35.98	44.13	43.50	42.88	47.04	46.24	45.33	49.69	48.69	47.58
Natural Gas[6]	18.24	21.11	21.09	21.10	22.10	22.13	22.22	22.80	22.92	23.00
Metallurgical Coal	0.76	0.63	0.63	0.62	0.58	0.58	0.57	0.53	0.53	0.52
Steam Coal	1.68	1.77	1.75	1.74	1.79	1.77	1.76	1.82	1.79	1.78
Net Coal Coke Imports	0.07	0.20	0.21	0.21	0.24	0.24	0.25	0.27	0.27	0.28
Coal Subtotal	2.50	2.60	2.58	2.57	2.61	2.58	2.57	2.62	2.59	2.58
Renewable Energy[13]	2.55	2.96	2.98	3.01	3.09	3.12	3.16	3.20	3.24	3.30
Methanol (M85)[11]	0.01	0.11	0.10	0.09	0.14	0.13	0.12	0.17	0.15	0.14
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.04	13.38	13.34	13.30	14.20	14.18	14.15	14.86	14.84	14.82
Delivered Energy	**70.32**	**84.29**	**83.59**	**82.94**	**89.18**	**88.38**	**87.54**	**93.33**	**92.44**	**91.41**
Electricity Related Losses	24.56	28.28	27.67	27.54	28.98	28.27	28.22	29.46	28.51	28.47
Total	**94.88**	**112.56**	**111.26**	**110.48**	**118.16**	**116.66**	**115.76**	**122.79**	**120.95**	**119.88**
Electric Generators[14]										
Distillate Fuel	0.08	0.09	0.04	0.03	0.19	0.05	0.04	0.30	0.05	0.04
Residual Fuel	1.15	1.46	0.45	0.15	1.59	0.36	0.10	1.75	0.32	0.09
Petroleum Subtotal	1.23	1.55	0.48	0.19	1.78	0.41	0.14	2.05	0.37	0.13
Natural Gas	3.75	6.29	6.60	6.79	8.27	8.55	8.70	9.31	9.46	9.44
Steam Coal	19.00	22.47	22.54	22.45	22.97	23.26	23.26	23.52	24.01	24.11
Nuclear Power	7.19	6.70	6.70	6.70	5.41	5.45	5.45	4.51	4.56	4.63
Renewable Energy[15]	4.12	4.39	4.43	4.45	4.55	4.59	4.63	4.72	4.75	4.78
Electricity Imports[16]	0.31	0.26	0.26	0.26	0.19	0.19	0.19	0.21	0.21	0.21
Total	**35.60**	**41.66**	**41.00**	**40.84**	**43.18**	**42.45**	**42.37**	**44.32**	**43.35**	**43.29**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1998	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Total Energy Consumption										
Distillate Fuel	7.32	8.40	8.19	8.09	8.85	8.50	8.37	9.21	8.73	8.59
Kerosene	0.16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.13
Jet Fuel[8]	3.36	4.91	4.85	4.81	5.60	5.55	5.46	6.29	6.24	6.09
Liquefied Petroleum Gas	2.59	3.08	3.03	2.98	3.24	3.16	3.10	3.37	3.27	3.21
Motor Gasoline[2]	15.82	19.76	19.39	19.08	21.08	20.59	20.07	22.27	21.65	21.05
Petrochemical Feedstock	1.39	1.58	1.58	1.58	1.67	1.66	1.66	1.74	1.73	1.73
Residual Fuel	2.17	2.81	1.76	1.41	3.08	1.81	1.51	3.39	1.91	1.62
Other Petroleum[12]	4.39	4.99	5.04	4.98	5.17	5.24	5.15	5.32	5.38	5.29
Petroleum Subtotal	37.21	45.68	43.98	43.06	48.82	46.65	45.46	51.73	49.05	47.71
Natural Gas	21.99	27.40	27.69	27.89	30.37	30.68	30.91	32.11	32.38	32.44
Metallurgical Coal	0.76	0.63	0.63	0.62	0.58	0.58	0.57	0.53	0.53	0.52
Steam Coal	20.68	24.24	24.28	24.19	24.77	25.02	25.02	25.34	25.80	25.89
Net Coal Coke Imports	0.07	0.20	0.21	0.21	0.24	0.24	0.25	0.27	0.27	0.28
Coal Subtotal	21.50	25.07	25.12	25.02	25.59	25.84	25.83	26.15	26.60	26.68
Nuclear Power	7.19	6.70	6.70	6.70	5.41	5.45	5.45	4.51	4.56	4.63
Renewable Energy[17]	6.67	7.34	7.41	7.46	7.64	7.71	7.79	7.92	7.99	8.08
Methanol (M85)[11]	0.01	0.11	0.10	0.09	0.14	0.13	0.12	0.17	0.15	0.14
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports[16]	0.31	0.26	0.26	0.26	0.19	0.19	0.19	0.21	0.21	0.21
Total	**94.88**	**112.56**	**111.26**	**110.48**	**118.16**	**116.66**	**115.76**	**122.79**	**120.95**	**119.88**
Energy Use and Related Statistics										
Delivered Energy Use	70.32	84.29	83.59	82.94	89.18	88.38	87.54	93.33	92.44	91.41
Total Energy Use	94.88	112.56	111.26	110.48	118.16	116.66	115.76	122.79	120.95	119.88
Population (millions)	270.58	298.34	298.34	298.34	310.78	310.78	310.78	323.40	323.40	323.40
Gross Domestic Product (billion 1992 dollars)	7,552	10,097	10,054	10,031	11,179	11,147	11,124	12,205	12,179	12,151
Total Carbon Emissions (million metric tons)	1,485.4	1,816.0	1,786.6	1,768.9	1,927.1	1,893.4	1,873.7	2,019.1	1,979.2	1,956.3

[1]Includes wood used for residential heating. See Table C18 estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector electricity cogenerated by using wood and wood waste, landfill gas, municipal solid waste, and other biomass. See Table C18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Fuel consumption includes consumption for cogeneration.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Includes lease and plant fuel and consumption by cogenerators, excludes consumption by nonutility generators.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass; includes cogeneration, both for sale to the grid and for own use.
[8]Includes naphtha and kerosene type.
[9]Includes aviation gas and lubricants.
[10]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[11]M85 is 85 percent methanol and 15 percent motor gasoline.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes cogeneration. Excludes net electricity imports.
[16]In 1998 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[17]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1998 electric utility fuel consumption: Energy Information Administration (EIA), *Electric Power Annual 1998, Volume 1,* DOE/EIA-0348(98)/1 (Washington, DC, April 1999). 1998 nonutility consumption estimates: Form EIA-867, "Annual Nonutility Power Producer Report, 1997." Other 1998 values: EIA, *Short-Term Energy Outlook, September 1999.* Online. http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C3. Energy Prices by Sector and Source
(1998 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1998	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	**13.30**	**12.74**	**13.09**	**13.40**	**12.79**	**13.08**	**13.33**	**12.83**	**13.10**	**13.32**
Primary Energy[1]	6.75	6.77	7.11	7.38	6.66	6.99	7.23	6.63	6.92	7.13
Petroleum Products[2]	7.48	8.51	9.73	10.75	8.58	9.88	11.12	8.75	10.04	11.25
Distillate Fuel	6.12	6.63	7.74	8.65	6.72	7.82	8.97	6.83	7.88	9.00
Liquefied Petroleum Gas	10.42	11.66	13.21	14.46	11.55	13.37	14.86	11.73	13.62	15.12
Natural Gas	6.60	6.39	6.57	6.70	6.27	6.43	6.52	6.21	6.36	6.43
Electricity	23.58	21.43	21.67	21.98	21.38	21.50	21.65	21.24	21.33	21.48
Commercial	**13.13**	**11.77**	**12.14**	**12.51**	**11.75**	**12.04**	**12.30**	**11.76**	**12.00**	**12.19**
Primary Energy[1]	5.06	5.22	5.54	5.78	5.19	5.51	5.73	5.22	5.53	5.73
Petroleum Products[2]	4.55	5.06	6.27	7.25	5.09	6.36	7.57	5.16	6.49	7.65
Distillate Fuel	3.93	4.44	5.56	6.47	4.50	5.63	6.77	4.59	5.73	6.80
Residual Fuel	2.49	2.90	3.74	4.52	2.90	3.79	4.75	2.91	3.87	4.78
Natural Gas[3]	5.26	5.35	5.53	5.66	5.31	5.48	5.57	5.34	5.50	5.57
Electricity	21.76	18.30	18.65	19.13	18.17	18.37	18.61	18.08	18.17	18.32
Industrial[4]	**4.88**	**4.88**	**5.48**	**5.98**	**4.91**	**5.55**	**6.08**	**5.01**	**5.65**	**6.17**
Primary Energy	3.41	3.65	4.32	4.86	3.68	4.42	5.02	3.79	4.55	5.14
Petroleum Products[2]	4.58	4.63	5.88	6.94	4.57	5.97	7.20	4.65	6.11	7.33
Distillate Fuel	4.02	4.55	5.66	6.56	4.61	5.71	6.85	4.69	5.89	6.91
Liquefied Petroleum Gas	7.11	6.31	7.87	9.11	6.15	8.00	9.50	6.33	8.25	9.78
Residual Fuel	2.49	2.37	3.23	4.01	2.36	3.30	4.27	2.36	3.38	4.28
Natural Gas[5]	2.66	3.10	3.28	3.41	3.22	3.38	3.45	3.36	3.50	3.56
Metallurgical Coal	1.72	1.59	1.60	1.61	1.54	1.56	1.56	1.48	1.50	1.51
Steam Coal	1.45	1.26	1.26	1.27	1.20	1.21	1.22	1.15	1.16	1.17
Electricity	13.09	11.45	11.66	11.93	11.32	11.43	11.57	11.25	11.27	11.38
Transportation	**7.53**	**7.69**	**9.13**	**10.10**	**7.60**	**9.11**	**10.32**	**7.45**	**9.04**	**10.29**
Primary Energy	7.51	7.66	9.11	10.09	7.57	9.09	10.30	7.42	9.02	10.27
Petroleum Products[2]	7.51	7.65	9.11	10.09	7.56	9.08	10.31	7.41	9.01	10.28
Distillate Fuel[6]	7.51	7.91	9.01	9.85	7.88	9.02	10.15	7.75	8.97	10.11
Jet Fuel[7]	4.06	4.59	5.74	6.59	4.60	5.89	7.09	4.56	5.91	7.76
Motor Gasoline[8]	8.54	8.67	10.35	11.43	8.59	10.35	11.63	8.46	10.30	11.48
Residual Fuel	2.22	2.29	3.21	4.04	2.31	3.30	4.30	2.32	3.39	4.33
Liquid Petroleum Gas[9]	11.01	12.07	13.48	14.67	11.82	13.47	14.87	11.79	13.50	14.92
Natural Gas[10]	6.10	6.90	7.22	7.38	7.06	7.45	7.56	7.08	7.49	7.58
Ethanol (E85)[11]	14.35	15.15	17.66	19.61	15.38	17.74	20.07	15.47	17.79	19.66
Methanol (M85)[12]	8.99	12.20	14.32	16.06	12.10	14.38	16.45	11.97	14.42	16.37
Electricity	16.46	14.18	14.15	14.24	13.84	13.68	13.76	13.60	13.38	13.40
Average End-Use Energy	**8.08**	**7.94**	**8.81**	**9.46**	**7.91**	**8.81**	**9.54**	**7.88**	**8.81**	**9.55**
Primary Energy	7.59	7.53	8.49	9.18	7.49	8.49	9.30	7.45	8.49	9.32
Electricity	19.56	17.23	17.50	17.84	17.11	17.24	17.42	16.99	17.06	17.19
Electric Generators[13]										
Fossil Fuel Average	1.48	1.49	1.55	1.60	1.60	1.64	1.67	1.65	1.67	1.68
Petroleum Products	2.24	2.32	3.28	4.53	2.41	3.40	5.09	2.50	3.54	5.25
Distillate Fuel	3.19	4.01	5.12	6.02	4.01	5.10	6.23	4.01	5.23	6.28
Residual Fuel	2.17	2.22	3.13	4.20	2.22	3.19	4.69	2.24	3.30	4.80
Natural Gas	2.34	2.86	3.08	3.22	3.01	3.21	3.30	3.16	3.33	3.40
Steam Coal	1.25	1.05	1.07	1.09	1.02	1.03	1.04	0.98	0.98	0.99

Table C3. Energy Prices by Sector and Source (Continued)

(1998 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1998	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]	6.64	6.83	8.32	9.36	6.75	8.35	9.60	6.66	8.35	9.63
Distillate Fuel	6.60	7.04	8.19	9.07	7.01	8.22	9.37	6.91	8.22	9.36
Jet Fuel	4.06	4.59	5.74	6.59	4.60	5.89	7.09	4.56	5.91	7.76
Liquefied Petroleum Gas	7.76	7.43	8.93	10.13	7.26	9.02	10.47	7.40	9.22	10.69
Motor Gasoline[8]	8.54	8.67	10.35	11.43	8.59	10.35	11.63	8.46	10.30	11.48
Residual Fuel	2.24	2.29	3.23	4.09	2.29	3.31	4.35	2.30	3.40	4.38
Natural Gas	3.92	4.12	4.29	4.41	4.09	4.26	4.34	4.16	4.31	4.37
Coal	1.29	1.07	1.09	1.11	1.04	1.04	1.06	0.99	0.99	1.01
Ethanol (E85)[11]	14.35	15.15	17.66	19.61	15.38	17.74	20.07	15.47	17.79	19.66
Methanol (M85)[12]	8.99	12.20	14.32	16.06	12.10	14.38	16.45	11.97	14.42	16.37
Electricity	19.56	17.23	17.50	17.84	17.11	17.24	17.42	16.99	17.06	17.19
Non-Renewable Energy Expenditures by Sector (billion 1998 dollars)										
Residential	131.06	147.55	150.04	152.41	153.61	155.58	157.30	160.11	161.86	163.39
Commercial	96.86	102.86	105.14	107.51	106.86	108.63	110.17	108.27	109.62	110.80
Industrial	101.24	114.35	126.14	136.08	121.15	134.52	145.45	128.83	142.83	153.87
Transportation	188.11	245.84	287.60	314.45	262.14	308.82	343.28	274.22	325.96	362.97
Total Non-Renewable Expenditures	517.28	610.60	668.93	710.45	643.77	707.54	756.20	671.43	740.27	791.03
Transportation Renewable Expenditures	0.04	0.97	1.01	1.03	1.29	1.31	1.32	1.40	1.41	1.36
Total Expenditures	**517.32**	**611.57**	**669.94**	**711.48**	**645.06**	**708.85**	**757.52**	**672.84**	**741.68**	**792.39**

[1]Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Excludes independent power producers.
[4]Includes cogenerators.
[5]Excludes uses for lease and plant fuel.
[6] Low sulfur diesel fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[8]Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[9]Includes Federal and State taxes while excluding county and local taxes.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]M85 is 85 percent methanol and 15 percent motor gasoline.
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[14]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380 (98/03-99/04) (Washington, DC, 1998-99). 1998 prices for all other petroleum products are derived from the EIA,*State Energy Price and Expenditure Report 1995*, DOE/EIA-0376(95) (Washington, DC, August 1998). 1998 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1994*. 1998 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(99/06) (Washington, DC, June 1999). 1998 coal prices based on EIA, *Quarterly Coal Report* , DOE/EIA-0121(99/1Q) (Washington, DC, August 1999), and EIA, AEO 2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A. 1998 electricity prices for commercial, industrial, and transportation: EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A. **Projections:** EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C4. Residential Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1998	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	74.69	84.42	84.38	84.34	87.68	87.61	87.56	90.62	90.55	90.50
Multifamily	21.68	24.97	24.94	24.91	26.66	26.60	26.57	28.29	28.23	28.20
Mobile Homes	6.47	7.80	7.81	7.82	8.30	8.31	8.32	8.75	8.77	8.78
Total	**102.84**	**117.19**	**117.13**	**117.07**	**122.63**	**122.52**	**122.45**	**127.66**	**127.54**	**127.49**
Average House Square Footage	**1667**	**1699**	**1698**	**1698**	**1704**	**1704**	**1704**	**1707**	**1707**	**1707**
Energy Intensity (million Btu consumed per household)										
Delivered Energy Consumption	99.54	102.63	101.65	100.89	101.62	100.69	100.00	101.34	100.44	99.81
Electricity Related Losses	82.95	85.04	83.31	82.98	83.19	81.33	81.26	82.26	79.78	79.77
Total Energy Consumption	182.49	187.67	184.95	183.87	184.81	182.02	181.26	183.60	180.22	179.57
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.38	0.46	0.46	0.46	0.48	0.48	0.48	0.49	0.50	0.50
Space Cooling	0.56	0.59	0.58	0.58	0.63	0.62	0.62	0.67	0.67	0.66
Water Heating	0.40	0.43	0.43	0.43	0.44	0.44	0.44	0.44	0.44	0.44
Refrigeration	0.45	0.34	0.34	0.34	0.32	0.32	0.32	0.32	0.32	0.32
Cooking	0.10	0.12	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.13
Clothes Dryers	0.22	0.26	0.26	0.26	0.27	0.27	0.27	0.29	0.29	0.28
Freezers	0.12	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.08
Lighting	0.33	0.41	0.40	0.40	0.42	0.42	0.42	0.44	0.44	0.43
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	0.05	0.05	0.05	0.06	0.06	0.06
Color Televisions	0.12	0.16	0.16	0.16	0.16	0.16	0.16	0.17	0.17	0.17
Personal Computers	0.05	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10
Other Uses[2]	0.96	1.60	1.60	1.59	1.80	1.80	1.79	1.98	1.97	1.97
Delivered Energy	**3.83**	**4.72**	**4.70**	**4.69**	**5.00**	**5.00**	**4.99**	**5.30**	**5.30**	**5.29**
Natural Gas										
Space Heating	3.01	3.67	3.67	3.65	3.79	3.79	3.78	3.93	3.93	3.94
Space Cooling	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02
Water Heating	1.23	1.35	1.34	1.34	1.39	1.38	1.38	1.42	1.42	1.42
Cooking	0.18	0.22	0.22	0.22	0.23	0.23	0.23	0.24	0.24	0.24
Clothes Dryers	0.06	0.09	0.09	0.09	0.10	0.09	0.09	0.10	0.10	0.10
Other Uses[3]	0.11	0.13	0.13	0.13	0.14	0.14	0.14	0.15	0.14	0.14
Delivered Energy	**4.61**	**5.47**	**5.46**	**5.44**	**5.65**	**5.65**	**5.64**	**5.86**	**5.86**	**5.86**
Distillate										
Space Heating	0.71	0.66	0.62	0.59	0.63	0.58	0.55	0.60	0.55	0.51
Water Heating	0.13	0.12	0.11	0.11	0.11	0.10	0.10	0.10	0.10	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	**0.84**	**0.78**	**0.73**	**0.70**	**0.74**	**0.69**	**0.64**	**0.70**	**0.65**	**0.61**
Liquefied Petroleum Gas										
Space Heating	0.27	0.32	0.29	0.27	0.32	0.28	0.26	0.32	0.28	0.25
Water Heating	0.10	0.11	0.10	0.09	0.11	0.10	0.09	0.11	0.09	0.08
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Other Uses[3]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Delivered Energy	**0.41**	**0.48**	**0.43**	**0.41**	**0.48**	**0.42**	**0.39**	**0.48**	**0.41**	**0.37**
Marketed Renewables (wood)[5]	0.38	0.44	0.44	0.44	0.45	0.45	0.44	0.46	0.45	0.45
Other Fuels[6]	0.16	0.15	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.13

Table C4. Residential Sector Key Indicators and End-Use Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1998	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Delivered Energy Consumption by End-Use										
Space Heating	4.91	5.71	5.62	5.56	5.81	5.72	5.65	5.94	5.85	5.79
Space Cooling	0.56	0.59	0.59	0.59	0.64	0.64	0.63	0.68	0.68	0.68
Water Heating	1.87	2.01	1.98	1.97	2.04	2.02	2.01	2.07	2.05	2.03
Refrigeration	0.45	0.34	0.34	0.34	0.32	0.32	0.32	0.32	0.32	0.32
Cooking	0.32	0.37	0.37	0.37	0.39	0.39	0.39	0.41	0.40	0.40
Clothes Dryers	0.28	0.34	0.34	0.34	0.37	0.37	0.36	0.39	0.39	0.39
Freezers	0.12	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.08
Lighting	0.33	0.41	0.40	0.40	0.42	0.42	0.42	0.44	0.44	0.43
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	0.05	0.05	0.05	0.06	0.06	0.06
Color Televisions	0.12	0.16	0.16	0.16	0.16	0.16	0.16	0.17	0.17	0.17
Personal Computers	0.05	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10
Other Uses[7]	1.08	1.75	1.74	1.74	1.95	1.95	1.94	2.13	2.13	2.13
Delivered Energy	**10.24**	**12.03**	**11.91**	**11.81**	**12.46**	**12.34**	**12.24**	**12.94**	**12.81**	**12.72**
Electricity Related Losses	**8.53**	**9.97**	**9.76**	**9.71**	**10.20**	**9.96**	**9.95**	**10.50**	**10.18**	**10.17**
Total Energy Consumption by End-Use										
Space Heating	5.75	6.68	6.58	6.52	6.78	6.67	6.61	6.91	6.80	6.75
Space Cooling	1.81	1.84	1.80	1.79	1.91	1.88	1.87	2.01	1.96	1.95
Water Heating	2.76	2.92	2.88	2.86	2.93	2.89	2.88	2.94	2.89	2.88
Refrigeration	1.45	1.07	1.06	1.05	0.98	0.96	0.96	0.95	0.93	0.93
Cooking	0.55	0.62	0.62	0.62	0.64	0.64	0.64	0.66	0.65	0.65
Clothes Dryers	0.77	0.89	0.88	0.87	0.92	0.91	0.90	0.96	0.94	0.93
Freezers	0.40	0.27	0.27	0.27	0.26	0.25	0.25	0.25	0.25	0.25
Lighting	1.06	1.26	1.24	1.23	1.28	1.26	1.26	1.30	1.27	1.27
Clothes Washers	0.10	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Dishwashers	0.15	0.16	0.15	0.15	0.16	0.16	0.16	0.17	0.16	0.16
Color Televisions	0.38	0.49	0.49	0.48	0.49	0.48	0.48	0.51	0.50	0.50
Personal Computers	0.18	0.29	0.28	0.28	0.29	0.29	0.29	0.32	0.32	0.32
Furnace Fans	0.21	0.26	0.26	0.25	0.27	0.27	0.27	0.29	0.28	0.28
Other Uses[7]	3.21	5.14	5.05	5.03	5.63	5.53	5.52	6.05	5.92	5.91
Total	**18.77**	**21.99**	**21.66**	**21.53**	**22.66**	**22.30**	**22.19**	**23.44**	**22.99**	**22.89**
Non-Marketed Renewables										
Geothermal[8]	0.01	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05
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**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**

[1]Does not include electric water heating portion of load.
[2]Includes small electric devices, heating elements, and motors.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as swimming pool and hot tub heaters.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1997*.
[6]Includes kerosene and coal.
[7]Includes all other uses listed above.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Source: 1998: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1999*. Online. http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C5. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1998	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	59.6	69.3	69.3	69.3	72.1	72.1	72.1	72.9	72.9	72.9
New Additions	1.7	1.6	1.6	1.6	1.2	1.2	1.2	0.9	0.9	0.9
Total	**61.2**	**70.9**	**70.9**	**70.9**	**73.3**	**73.3**	**73.3**	**73.8**	**73.8**	**73.8**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	121.7	124.4	123.3	122.4	125.1	124.1	123.3	125.8	124.8	124.2
Electricity Related Losses	129.4	130.4	127.5	126.6	127.9	124.7	124.3	125.7	121.7	121.4
Total Energy Consumption	251.2	254.9	250.8	249.0	252.9	248.8	247.6	251.5	246.5	245.6
Delivered Energy Consumption by Fuel										
Purchased Electricity										
Space Heating	0.10	0.11	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.10
Space Cooling	0.45	0.43	0.43	0.43	0.43	0.43	0.43	0.42	0.42	0.42
Water Heating	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.11	0.11	0.11
Ventilation	0.17	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02
Lighting	1.17	1.24	1.24	1.23	1.26	1.26	1.25	1.23	1.23	1.23
Refrigeration	0.18	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Office Equipment (PC)	0.08	0.13	0.13	0.13	0.15	0.15	0.15	0.16	0.16	0.16
Office Equipment (non-PC)	0.26	0.38	0.37	0.37	0.42	0.42	0.42	0.46	0.46	0.45
Other Uses[1]	1.00	1.55	1.54	1.53	1.69	1.69	1.69	1.78	1.78	1.78
Delivered Energy	**3.56**	**4.38**	**4.36**	**4.33**	**4.60**	**4.58**	**4.57**	**4.68**	**4.68**	**4.66**
Natural Gas[2]										
Space Heating	1.10	1.31	1.31	1.32	1.32	1.34	1.34	1.29	1.33	1.33
Space Cooling	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Water Heating	0.49	0.56	0.56	0.55	0.58	0.58	0.58	0.58	0.59	0.58
Cooking	0.20	0.24	0.24	0.24	0.26	0.25	0.25	0.26	0.26	0.26
Other Uses[3]	1.30	1.46	1.45	1.44	1.53	1.52	1.52	1.57	1.56	1.56
Delivered Energy	**3.11**	**3.59**	**3.58**	**3.57**	**3.70**	**3.71**	**3.71**	**3.73**	**3.75**	**3.75**
Distillate										
Space Heating	0.16	0.20	0.17	0.15	0.21	0.16	0.14	0.21	0.15	0.13
Water Heating	0.06	0.06	0.05	0.05	0.06	0.05	0.05	0.06	0.05	0.04
Other Uses[4]	0.15	0.16	0.15	0.15	0.17	0.16	0.15	0.17	0.16	0.15
Delivered Energy	**0.38**	**0.43**	**0.38**	**0.35**	**0.44**	**0.37**	**0.33**	**0.44**	**0.36**	**0.32**
Other Fuels[5]	**0.32**	**0.35**	**0.35**	**0.34**	**0.36**	**0.35**	**0.35**	**0.35**	**0.35**	**0.35**
Marketed Renewable Fuels										
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Delivered Energy	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Delivered Energy Consumption by End-Use										
Space Heating	1.37	1.62	1.59	1.57	1.63	1.60	1.58	1.60	1.57	1.56
Space Cooling	0.46	0.45	0.45	0.44	0.45	0.45	0.45	0.44	0.44	0.44
Water Heating	0.67	0.74	0.73	0.72	0.76	0.75	0.74	0.76	0.75	0.74
Ventilation	0.17	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Cooking	0.23	0.27	0.27	0.27	0.28	0.28	0.28	0.28	0.28	0.28
Lighting	1.17	1.24	1.24	1.23	1.26	1.26	1.25	1.23	1.23	1.23
Refrigeration	0.18	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Office Equipment (PC)	0.08	0.13	0.13	0.13	0.15	0.15	0.15	0.16	0.16	0.16
Office Equipment (non-PC)	0.26	0.38	0.37	0.37	0.42	0.42	0.42	0.46	0.46	0.45
Other Uses[6]	2.86	3.60	3.57	3.55	3.83	3.80	3.78	3.96	3.93	3.91
Delivered Energy	**7.46**	**8.82**	**8.74**	**8.67**	**9.17**	**9.10**	**9.04**	**9.28**	**9.22**	**9.16**

Table C5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1998	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Electricity Related Losses	**7.93**	**9.25**	**9.04**	**8.97**	**9.38**	**9.14**	**9.11**	**9.28**	**8.98**	**8.96**
Total Energy Consumption by End-Use										
Space Heating	1.60	1.85	1.82	1.80	1.85	1.81	1.79	1.80	1.76	1.75
Space Cooling	1.46	1.36	1.33	1.33	1.33	1.31	1.30	1.28	1.25	1.25
Water Heating	0.94	1.00	0.98	0.97	1.00	0.99	0.98	0.98	0.96	0.96
Ventilation	0.54	0.59	0.58	0.57	0.58	0.57	0.57	0.56	0.55	0.54
Cooking	0.30	0.33	0.33	0.32	0.34	0.33	0.33	0.33	0.33	0.33
Lighting	3.76	3.87	3.80	3.77	3.83	3.76	3.74	3.68	3.60	3.58
Refrigeration	0.57	0.62	0.61	0.61	0.62	0.61	0.61	0.61	0.60	0.60
Office Equipment (PC)	0.27	0.41	0.41	0.40	0.44	0.44	0.43	0.47	0.46	0.46
Office Equipment (non-PC)	0.84	1.17	1.15	1.14	1.28	1.26	1.25	1.36	1.33	1.33
Other Uses[6]	5.09	6.86	6.77	6.72	7.28	7.17	7.14	7.49	7.35	7.33
Total	**15.38**	**18.07**	**17.78**	**17.64**	**18.55**	**18.24**	**18.15**	**18.57**	**18.20**	**18.12**
Non-Marketed Renewable Fuels										
Solar[7]	0.02	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Total	**0.02**	**0.03**	**0.04**	**0.04**	**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, cogeneration in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, district services, emergency electric generators, and cogeneration in commercial buildings.
[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, cogeneration in commercial buildings, 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, and electricity generation by solar photovoltaic systems.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Source: 1998 Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1999.* Online. http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1998	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Key Indicators										
Value of Gross Output (billion 1987 dollars)										
Manufacturing	3,291	4,242	4,227	4,222	4,677	4,663	4,658	5,052	5,040	5,034
Nonmanufacturing	835	990	989	989	1,066	1,067	1,069	1,130	1,131	1,133
Total	**4,126**	**5,233**	**5,216**	**5,212**	**5,744**	**5,730**	**5,727**	**6,182**	**6,171**	**6,167**
Energy Prices (1998 dollars per million Btu)										
Electricity	13.09	11.45	11.66	11.93	11.32	11.43	11.57	11.25	11.27	11.38
Natural Gas	2.66	3.10	3.28	3.41	3.22	3.38	3.45	3.36	3.50	3.56
Steam Coal	1.45	1.26	1.26	1.27	1.20	1.21	1.22	1.15	1.16	1.17
Residual Oil	2.49	2.37	3.23	4.01	2.36	3.30	4.27	2.36	3.38	4.28
Distillate Oil	4.02	4.55	5.66	6.56	4.61	5.71	6.85	4.69	5.89	6.91
Liquefied Petroleum Gas	7.11	6.31	7.87	9.11	6.15	8.00	9.50	6.33	8.25	9.78
Motor Gasoline	8.54	8.63	10.32	11.41	8.55	10.32	11.62	8.41	10.28	11.48
Metallurgical Coal	1.72	1.59	1.60	1.61	1.54	1.56	1.56	1.48	1.50	1.51
Energy Consumption										
Consumption[1]										
Purchased Electricity	3.57	4.16	4.15	4.15	4.45	4.45	4.44	4.71	4.70	4.70
Natural Gas[2]	9.75	10.97	10.96	11.00	11.52	11.53	11.63	11.92	11.99	12.07
Steam Coal	1.54	1.61	1.59	1.58	1.64	1.61	1.60	1.66	1.63	1.62
Metallurgical Coal and Coke[3]	0.82	0.84	0.83	0.83	0.82	0.82	0.81	0.80	0.80	0.80
Residual Fuel	0.27	0.32	0.29	0.23	0.33	0.30	0.26	0.36	0.31	0.25
Distillate	1.08	1.32	1.29	1.27	1.41	1.38	1.35	1.49	1.46	1.42
Liquefied Petroleum Gas	2.06	2.41	2.40	2.38	2.55	2.53	2.51	2.67	2.64	2.62
Petrochemical Feedstocks	1.39	1.58	1.58	1.58	1.67	1.66	1.66	1.74	1.73	1.73
Other Petroleum[4]	4.32	4.91	4.97	4.91	5.09	5.17	5.08	5.25	5.31	5.23
Renewables[5]	2.08	2.37	2.40	2.43	2.48	2.53	2.57	2.57	2.63	2.69
Delivered Energy	**26.89**	**30.49**	**30.46**	**30.37**	**31.96**	**31.96**	**31.92**	**33.17**	**33.20**	**33.13**
Electricity Related Losses	7.95	8.80	8.61	8.60	9.09	8.87	8.86	9.34	9.03	9.02
Total	**34.84**	**39.29**	**39.08**	**38.97**	**41.05**	**40.83**	**40.78**	**42.51**	**42.23**	**42.16**
Consumption per Unit of Output[1] **(thousand Btu per 1987 dollars)**										
Purchased Electricity	0.87	0.80	0.80	0.80	0.78	0.78	0.78	0.76	0.76	0.76
Natural Gas[2]	2.36	2.10	2.10	2.11	2.01	2.01	2.03	1.93	1.94	1.96
Steam Coal	0.37	0.31	0.30	0.30	0.28	0.28	0.28	0.27	0.26	0.26
Metallurgical Coal and Coke[3]	0.20	0.16	0.16	0.16	0.14	0.14	0.14	0.13	0.13	0.13
Residual Fuel	0.06	0.06	0.05	0.04	0.06	0.05	0.05	0.06	0.05	0.04
Distillate	0.26	0.25	0.25	0.24	0.25	0.24	0.24	0.24	0.24	0.23
Liquefied Petroleum Gas	0.50	0.46	0.46	0.46	0.44	0.44	0.44	0.43	0.43	0.42
Petrochemical Feedstocks	0.34	0.30	0.30	0.30	0.29	0.29	0.29	0.28	0.28	0.28
Other Petroleum[4]	1.05	0.94	0.95	0.94	0.89	0.90	0.89	0.85	0.86	0.85
Renewables[5]	0.51	0.45	0.46	0.47	0.43	0.44	0.45	0.42	0.43	0.44
Delivered Energy	**6.52**	**5.83**	**5.84**	**5.83**	**5.56**	**5.58**	**5.57**	**5.36**	**5.38**	**5.37**
Electricity Related Losses	1.93	1.68	1.65	1.65	1.58	1.55	1.55	1.51	1.46	1.46
Total	**8.44**	**7.51**	**7.49**	**7.48**	**7.15**	**7.13**	**7.12**	**6.88**	**6.84**	**6.84**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net coke coal imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.

Sources: 1998 prices for gasoline and distillate are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380 (98/03-99/04) (Washington, DC, 1998-99). 1998 coal prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(99/08) (Washington, DC, August 1999). 1998 electricity prices: EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A. Other 1998 prices derived from EIA, *State Energy Data Report 1996* , DOE/EIA-0214(96) (Washington, DC, February 1999). Other 1998 values: EIA, *Short-Term Energy Outlook, September 1999.* Online. http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	1998	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										
Level of Travel (billions)										
Light-Duty Vehicles <8,500 pounds (VMT)	2403	3075	3048	3015	3308	3282	3234	3523	3498	3448
Commercial Light Trucks (VMT)[1]	72	91	90	90	99	98	97	105	105	104
Freight Trucks >10,000 pounds (VMT)	184	229	228	228	244	243	243	257	256	256
Air (seat miles available)	1061	1787	1765	1751	2139	2118	2092	2517	2495	2437
Rail (ton miles traveled)	1246	1486	1489	1487	1581	1581	1580	1668	1672	1673
Marine (ton miles traveled)	692	777	781	786	820	827	838	854	861	874
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[2]	24.2	25.2	25.6	26.0	25.6	26.2	26.7	25.8	26.5	27.0
New Car (miles per gallon)[2]	28.2	30.5	31.4	32.0	30.7	31.7	32.4	30.6	31.6	32.3
New Light Truck (miles per gallon)[2]	20.6	21.4	21.6	21.9	21.9	22.3	22.7	22.3	22.8	23.2
Light-Duty Fleet (miles per gallon)[3]	20.7	20.2	20.4	20.6	20.1	20.5	20.7	20.2	20.6	20.9
New Commercial Light Truck (MPG)[1]	20.4	20.7	21.0	21.2	21.2	21.6	22.0	21.6	22.1	22.5
Stock Commercial Light Truck (MPG)[1]	14.7	15.7	15.8	15.9	16.1	16.2	16.3	16.3	16.5	16.7
Aircraft Efficiency (seat miles per gallon)	51.4	56.4	56.4	56.5	58.5	58.4	58.7	60.5	60.5	60.7
Freight Truck Efficiency (miles per gallon)	5.6	6.0	6.0	6.0	6.2	6.2	6.2	6.4	6.4	6.5
Rail Efficiency (ton miles per thousand Btu)	2.7	3.1	3.1	3.1	3.2	3.2	3.2	3.4	3.4	3.4
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.4	2.8	2.8	2.8	3.0	3.0	3.0	3.2	3.2	3.2
Energy Use by Mode (quadrillion Btu)										
Light-Duty Vehicles	14.64	18.91	18.54	18.21	20.36	19.87	19.34	21.64	21.03	20.41
Commercial Light Trucks[1]	0.61	0.72	0.71	0.71	0.77	0.76	0.75	0.81	0.79	0.78
Freight Trucks[4]	4.35	5.05	5.01	4.99	5.21	5.16	5.14	5.31	5.24	5.22
Air	3.40	4.96	4.91	4.87	5.66	5.61	5.53	6.37	6.32	6.16
Rail[5]	0.56	0.61	0.61	0.61	0.62	0.62	0.62	0.64	0.64	0.64
Marine[6]	1.17	1.50	1.50	1.50	1.66	1.65	1.65	1.81	1.81	1.80
Pipeline Fuel	0.75	0.85	0.87	0.87	0.93	0.95	0.95	0.97	0.99	0.99
Other[7]	0.26	0.30	0.30	0.29	0.32	0.31	0.31	0.33	0.33	0.32
Total	**25.74**	**32.95**	**32.48**	**32.10**	**35.59**	**34.99**	**34.34**	**37.94**	**37.20**	**36.39**
Energy Use by Mode[8] (million barrels per day)										
Light-Duty Vehicles	7.63	9.99	9.79	9.61	10.77	10.50	10.21	11.46	11.12	10.78
Commercial Light Trucks[1]	0.32	0.38	0.37	0.37	0.40	0.40	0.39	0.42	0.42	0.41
Freight Trucks[4]	1.97	2.29	2.27	2.26	2.37	2.34	2.33	2.41	2.38	2.37
Railroad	0.21	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Domestic Shipping	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.13
International Shipping	0.28	0.42	0.41	0.41	0.48	0.48	0.48	0.54	0.54	0.54
Air Transportation	1.42	2.17	2.15	2.13	2.50	2.48	2.44	2.84	2.82	2.74
Military Use	0.25	0.26	0.26	0.26	0.26	0.26	0.26	0.27	0.27	0.27
Bus Transportation	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Rail Transportation[5]	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07
Recreational Boats	0.13	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.15
Lubricants	0.12	0.14	0.14	0.14	0.15	0.15	0.15	0.16	0.15	0.15
Pipeline Fuel	0.38	0.43	0.44	0.44	0.47	0.48	0.48	0.49	0.50	0.50
Total	**12.97**	**16.71**	**16.46**	**16.25**	**18.06**	**17.73**	**17.39**	**19.25**	**18.85**	**18.42**

[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.
[8]Nonpetroleum fuels converted to crude oil equivalent.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998: U.S. Department of Transportation, Bureau of Transportation Statistics, *Air Carrier Statistics Monthly, December 1998/1997*, (Washington, DC, 1998); Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1999.* Online. http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999); 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, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C8. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1998	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	1817	2112	2121	2114	2165	2200	2203	2229	2296	2312
Petroleum	114	148	48	20	174	41	14	204	37	14
Natural Gas	325	723	796	820	1003	1085	1100	1173	1256	1247
Nuclear Power	674	627	627	627	506	511	510	422	427	433
Pumped Storage	-2	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[2]	360	379	381	381	386	386	387	391	393	394
Total	**3288**	**3989**	**3973**	**3961**	**4234**	**4222**	**4213**	**4418**	**4409**	**4400**
Non-Utility Generation for Own Use	10	16	16	16	16	16	16	16	16	16
Cogenerators[3]										
Coal	52	51	51	51	51	51	51	51	51	51
Petroleum	8	7	6	6	8	6	6	9	7	6
Natural Gas	195	201	205	206	207	212	214	216	220	222
Other Gaseous Fuels[4]	3	6	6	6	7	7	7	7	7	7
Renewable Sources[2]	40	46	48	49	48	51	52	51	54	55
Other[5]	8	8	8	8	8	8	8	8	8	8
Total	**306**	**320**	**325**	**327**	**330**	**336**	**339**	**342**	**348**	**351**
Sales to Utilities	148	154	156	157	159	162	164	165	169	170
Generation for Own Use	165	171	174	175	176	179	180	181	184	185
Other Generators[6]	**7**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
Net Imports[7]	**30**	**26**	**26**	**26**	**19**	**19**	**19**	**20**	**20**	**20**
Electricity Sales by Sector										
Residential	1124	1382	1379	1375	1465	1464	1462	1552	1553	1551
Commercial	1045	1283	1277	1270	1347	1344	1339	1372	1371	1367
Industrial	1047	1220	1217	1217	1305	1303	1303	1381	1378	1376
Transportation	20	37	36	36	44	44	43	50	49	49
Total	**3236**	**3922**	**3909**	**3898**	**4162**	**4155**	**4147**	**4355**	**4350**	**4343**
End-Use Prices (1998 cents per kwh)[8]										
Residential	8.0	7.3	7.4	7.5	7.3	7.3	7.4	7.2	7.3	7.3
Commercial	7.4	6.2	6.4	6.5	6.2	6.3	6.3	6.2	6.2	6.3
Industrial	4.5	3.9	4.0	4.1	3.9	3.9	3.9	3.8	3.8	3.9
Transportation	5.6	4.8	4.8	4.9	4.7	4.7	4.7	4.6	4.6	4.6
All Sectors Average	**6.7**	**5.9**	**6.0**	**6.1**	**5.8**	**5.9**	**5.9**	**5.8**	**5.8**	**5.9**
Emissions (million short tons)										
Sulfur Dioxide	13.04	9.83	9.15	8.95	9.07	8.95	8.95	8.95	8.95	8.95
Nitrogen Oxide	5.98	5.79	5.66	5.62	6.01	5.87	5.83	6.14	5.93	5.89

[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]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[7]In 1998 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[8]Prices represent average revenue per kilowatthour.
Kwh = Kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 commercial and transportation sales derived from: Energy Information Administration (EIA), *State Energy Data Report 1996*, DOE/EIA-0214(96) (Washington, DC, February 1999), 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. 1998 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: EIA, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). 1998 residential electricity prices derived from EIA, *Short-Term Energy Outlook, September 1999.* Online. http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999). **1998 electricity prices for commercial, industrial, and transportation; emissions; and projections**: EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C9. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1998	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[2]										
Capability										
Coal Steam	305.2	298.4	301.7	301.5	301.4	306.8	307.5	306.4	317.0	319.5
Other Fossil Steam[3]	138.2	126.3	119.5	111.6	125.3	117.1	108.3	123.8	109.9	100.7
Combined Cycle	19.5	74.1	93.1	98.7	104.6	124.7	128.7	128.9	154.6	156.8
Combustion Turbine/Diesel	73.2	169.2	153.5	151.0	198.6	180.4	181.3	225.1	202.3	202.1
Nuclear Power	97.1	84.1	84.1	84.1	66.8	67.4	67.4	56.4	57.0	57.8
Pumped Storage	19.9	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Fuel Cells	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Renewable Sources[4]	87.2	93.7	93.8	93.8	95.2	95.3	95.4	96.4	96.7	96.8
Total	**740.2**	**865.9**	**865.7**	**860.8**	**912.0**	**911.8**	**908.6**	**957.1**	**957.5**	**953.9**
Cumulative Planned Additions[5]										
Coal Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Combustion Turbine/Diesel	0.0	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
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	0.1	0.1	0.1
Renewable Sources[4]	0.0	4.8	4.8	4.8	5.7	5.7	5.7	5.9	5.9	5.9
Total	**0.0**	**11.1**	**11.1**	**11.1**	**12.0**	**12.0**	**12.0**	**12.2**	**12.2**	**12.2**
Cumulative Unplanned Additions[5]										
Coal Steam	0.0	2.0	3.8	3.3	5.6	9.5	9.9	11.9	21.0	23.3
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	49.9	68.9	74.6	80.5	100.6	104.6	104.8	130.5	132.7
Combustion Turbine/Diesel	0.0	97.6	81.9	78.7	127.5	109.4	109.4	154.0	132.3	130.4
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.0	1.6	1.8	1.7	2.4	2.6	2.6	3.5	3.8	3.9
Total	**0.0**	**151.2**	**156.4**	**158.4**	**216.1**	**222.1**	**226.6**	**274.2**	**287.6**	**290.2**
Cumulative Total Additions	**0.0**	**162.2**	**167.4**	**169.5**	**228.1**	**234.1**	**238.6**	**286.4**	**299.8**	**302.5**
Cumulative Retirements[6]	**0.0**	**43.5**	**48.4**	**56.1**	**63.3**	**69.0**	**77.6**	**76.5**	**89.0**	**96.1**
Cogenerators[7]										
Capability										
Coal	8.8	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Petroleum	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Natural Gas	31.8	36.1	36.4	36.6	37.0	37.3	37.6	38.1	38.4	38.6
Other Gaseous Fuels	0.4	0.8	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.0
Renewable Sources[4]	6.6	7.6	7.9	8.0	8.0	8.5	8.7	8.5	9.0	9.3
Other	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Total	**50.3**	**56.2**	**56.8**	**57.2**	**57.6**	**58.4**	**59.0**	**59.3**	**60.2**	**60.6**
Cumulative Additions[5]	**0.0**	**5.9**	**6.6**	**6.9**	**7.3**	**8.1**	**8.7**	**9.0**	**9.9**	**10.3**

Table C9. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1998	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
Other Generators[8]										
Capability	1.1	1.4	1.4	1.4	1.5	1.5	1.5	1.8	1.8	1.8
Cumulative Additions	0.0	0.3	0.3	0.3	0.4	0.4	0.4	0.7	0.7	0.7

[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, 1998.
[6]Cumulative total retirements after December 31, 1998.
[7]Nameplate capacity is reported for nonutilities on Form EIA-867, “Annual Nonutility Power Producer Report, 1997.” Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.
[8]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
Notes: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators for AEO2000. Net summer capacity is used to be consistent with electric utility capacity estimates.
Sources: 1998 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 1998 and planned additions based on EIA, Form EIA-867, “Annual Nonutility Power Producer Report, 1997.” **Projections:** EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C10. Electricity Trade

(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1998	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
Interregional Electricity Trade										
Gross Domestic Firm Power Trade	202.4	102.4	102.4	102.4	48.5	48.5	48.5	0.0	0.0	0.0
Gross Domestic Economy Trade	144.1	208.6	199.7	208.1	201.1	182.4	188.1	210.4	186.1	187.0
Gross Domestic Trade	**346.4**	**311.0**	**302.1**	**310.6**	**249.6**	**230.9**	**236.6**	**210.4**	**186.1**	**187.0**
Gross Domestic Firm Power Sales (million 1998 dollars)	9,607.3	4,862.3	4,862.3	4,862.3	2,303.2	2,303.2	2,303.2	0.0	0.0	0.0
Gross Domestic Economy Sales (million 1998 dollars)	4,260.3	6,295.2	6,218.7	6,902.3	6,179.2	5,728.2	6,118.4	6,517.6	5,832.9	5,977.0
Gross Domestic Sales (million 1998 dollars)	**13,867.6**	**11,157.5**	**11,081.0**	**11,764.6**	**8,482.4**	**8,031.4**	**8,421.6**	**6,517.6**	**5,832.9**	**5,977.0**
International Electricity Trade										
Firm Power Imports From Canada & Mexico[1]	19.0	4.6	4.6	4.6	2.2	2.2	2.2	0.0	0.0	0.0
Economy Imports From Canada and Mexico[1]	26.5	39.3	39.3	39.3	29.4	29.4	29.4	27.9	27.9	27.9
Gross Imports From Canada and Mexico[1]	**45.4**	**43.8**	**43.8**	**43.8**	**31.6**	**31.6**	**31.6**	**27.9**	**27.9**	**27.9**
Firm Power Exports To Canada and Mexico	0.3	10.4	10.4	10.4	4.9	4.9	4.9	0.0	0.0	0.0
Economy Exports To Canada and Mexico	15.0	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**15.4**	**18.1**	**18.1**	**18.1**	**12.6**	**12.6**	**12.6**	**7.7**	**7.7**	**7.7**

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

Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 1998 interregional firm electricity trade data: North American Electricity Reliability Council (NERC), Electricity Sales and Demand Database 1998. 1998 international electricity trade data: DOE Form FE-718R, “Annual Report of International Electrical Export/Import Data.” 1998 firm/economy share: National Energy Board, *Annual Report 1998*. **Projections:** Energy Information Administration, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1998	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
Crude Oil										
Domestic Crude Production[1]	6.25	4.84	5.18	5.50	4.69	5.20	5.80	4.65	5.26	6.02
Alaska	1.18	0.79	0.81	0.83	0.59	0.63	0.65	0.47	0.51	0.53
Lower 48 States	5.08	4.06	4.36	4.67	4.10	4.57	5.15	4.18	4.75	5.49
Net Imports	8.60	12.06	11.45	11.10	12.35	11.48	10.94	12.47	11.59	10.88
Gross Imports	8.70	12.07	11.47	11.14	12.36	11.50	10.99	12.48	11.62	10.94
Exports	0.11	0.01	0.03	0.04	0.01	0.03	0.05	0.01	0.03	0.06
Other Crude Supply[2]	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**14.89**	**16.90**	**16.62**	**16.60**	**17.04**	**16.68**	**16.74**	**17.12**	**16.84**	**16.90**
Natural Gas Plant Liquids	**1.76**	**2.04**	**2.05**	**2.06**	**2.24**	**2.26**	**2.28**	**2.35**	**2.37**	**2.38**
Other Inputs[3]	**0.25**	**0.25**	**0.29**	**0.35**	**0.27**	**0.30**	**0.35**	**0.28**	**0.32**	**0.36**
Refinery Processing Gain[4]	**0.89**	**0.99**	**1.11**	**1.17**	**1.01**	**1.12**	**1.19**	**1.00**	**1.12**	**1.19**
Net Product Imports[5]	**1.17**	**3.11**	**2.40**	**1.85**	**4.32**	**3.48**	**2.69**	**5.61**	**4.45**	**3.59**
Gross Refined Product Imports[6]	1.63	3.43	2.65	2.11	4.43	3.68	2.98	5.67	4.60	3.91
Unfinished Oil Imports	0.30	0.57	0.67	0.67	0.73	0.72	0.69	0.74	0.74	0.73
Ether Imports	0.07	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00
Exports	0.83	0.90	0.92	0.93	0.86	0.91	0.98	0.81	0.90	1.05
Total Primary Supply[7]	**18.95**	**23.28**	**22.47**	**22.03**	**24.89**	**23.85**	**23.25**	**26.37**	**25.09**	**24.41**
Refined Petroleum Products Supplied										
Motor Gasoline[8]	8.25	10.38	10.18	10.01	11.07	10.81	10.53	11.71	11.37	11.06
Jet Fuel[9]	1.62	2.37	2.35	2.33	2.70	2.68	2.64	3.04	3.02	2.94
Distillate Fuel[10]	3.45	3.95	3.85	3.81	4.16	4.00	3.94	4.33	4.11	4.04
Residual Fuel	0.95	1.23	0.77	0.61	1.34	0.79	0.66	1.48	0.83	0.70
Other[11]	4.67	5.39	5.37	5.31	5.63	5.60	5.51	5.83	5.77	5.68
Total	**18.94**	**23.31**	**22.51**	**22.06**	**24.91**	**23.87**	**23.28**	**26.38**	**25.10**	**24.42**
Refined Petroleum Products Supplied										
Residential and Commercial	1.06	1.11	1.03	0.98	1.10	1.00	0.93	1.09	0.96	0.90
Industrial[12]	4.80	5.55	5.54	5.46	5.82	5.81	5.72	6.07	6.03	5.93
Transportation	12.54	15.98	15.73	15.54	17.20	16.89	16.56	18.33	17.94	17.53
Electric Generators[13]	0.54	0.68	0.21	0.08	0.78	0.18	0.06	0.90	0.16	0.06
Total	**18.94**	**23.31**	**22.51**	**22.06**	**24.91**	**23.87**	**23.28**	**26.38**	**25.10**	**24.42**
Discrepancy[14]	**0.01**	**-0.03**	**-0.04**	**-0.03**	**-0.02**	**-0.03**	**-0.03**	**-0.01**	**-0.01**	**-0.01**
World Oil Price (1998 dollars per barrel)[15]	**12.10**	**14.90**	**21.00**	**26.31**	**14.90**	**21.53**	**27.86**	**14.90**	**22.04**	**28.04**
Import Share of Product Supplied	**0.52**	**0.65**	**0.62**	**0.59**	**0.67**	**0.63**	**0.59**	**0.69**	**0.64**	**0.59**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 1998 dollars)	**46.55**	**86.75**	**109.73**	**127.17**	**97.73**	**124.19**	**143.25**	**108.28**	**138.16**	**155.29**
Domestic Refinery Distillation Capacity[16]	**16.3**	**17.9**	**17.6**	**17.6**	**17.9**	**17.6**	**17.7**	**18.0**	**17.8**	**17.8**
Capacity Utilization Rate (percent)	**96.0**	**94.5**	**94.8**	**94.7**	**95.3**	**95.1**	**94.7**	**95.3**	**95.2**	**95.3**

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.
[3]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, and other hydrocarbons.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[6]Includes blending components.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net petroleum imports.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes naphtha and kerosene types.
[10]Includes distillate and kerosene.
[11]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[12]Includes consumption by cogenerators.
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses and gains.
[15]Average refiner acquisition cost for imported crude oil.
[16] End-of-year capacity.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 product supplied data from Table C2. Other 1998 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1998,* DOE/EIA-0340(98/1) (Washington, DC, June 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C12. Petroleum Product Prices
(1998 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	1998	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 (1998 dollars per barrel)	**12.10**	**14.90**	**21.00**	**26.31**	**14.90**	**21.53**	**27.86**	**14.90**	**22.04**	**28.04**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	84.9	92.0	107.3	119.9	93.2	108.5	124.4	94.7	109.3	124.8
Liquefied Petroleum Gas	90.0	100.6	114.0	124.8	99.7	115.4	128.3	101.2	117.6	130.5
Commercial										
Distillate Fuel	54.4	61.5	77.1	89.7	62.5	78.0	93.8	63.6	79.5	94.3
Residual Fuel	37.3	43.3	56.0	67.7	43.4	56.8	71.2	43.5	57.9	71.6
Residual Fuel (1998 dollars per barrel)	15.65	18.20	23.51	28.44	18.22	23.85	29.89	18.28	24.33	30.06
Industrial[1]										
Distillate Fuel	55.7	63.1	78.5	91.0	63.9	79.1	95.0	65.0	81.6	95.8
Liquefied Petroleum Gas	61.4	54.4	68.0	78.6	53.1	69.0	82.0	54.7	71.2	84.4
Residual Fuel	37.2	35.4	48.4	60.1	35.3	49.4	63.9	35.4	50.6	64.1
Residual Fuel (1998 dollars per barrel)	15.64	14.88	20.32	25.24	14.84	20.76	26.86	14.86	21.24	26.91
Transportation										
Diesel Fuel (distillate)[2]	104.1	109.7	125.0	136.7	109.3	125.1	140.8	107.6	124.3	140.2
Jet Fuel[3]	54.7	62.0	77.5	89.0	62.1	79.5	95.7	61.5	79.8	104.8
Motor Gasoline[4]	106.9	107.9	128.8	142.3	106.9	128.7	144.8	105.2	128.2	142.8
Liquid Petroleum Gas	95.0	104.2	116.3	126.7	102.0	116.3	128.4	101.8	116.6	128.8
Residual Fuel	33.3	34.3	48.1	60.5	34.5	49.4	64.4	34.7	50.7	64.8
Residual Fuel (1998 dollars per barrel)	13.98	14.43	20.20	25.39	14.51	20.75	27.03	14.56	21.29	27.21
Ethanol (E85)	128.6	135.6	158.1	175.5	137.6	158.8	179.6	138.4	159.2	175.9
Methanol (M85)	66.0	89.4	105.0	117.7	88.7	105.4	120.6	87.8	105.7	120.0
Electric Generators[5]										
Distillate Fuel	44.2	55.6	70.9	83.4	55.6	70.7	86.4	55.6	72.5	87.1
Residual Fuel	32.5	33.2	46.9	62.9	33.2	47.7	70.2	33.5	49.4	71.8
Residual Fuel (1998 dollars per barrel)	13.67	13.95	19.69	26.40	13.95	20.05	29.48	14.07	20.76	30.16
Refined Petroleum Product Prices[6]										
Distillate Fuel	91.6	97.7	113.6	125.8	97.2	114.0	130.0	95.9	114.0	129.8
Jet Fuel[3]	54.7	62.0	77.5	89.0	62.1	79.5	95.7	61.5	79.8	104.8
Liquefied Petroleum Gas	67.0	64.1	77.0	87.4	62.6	77.8	90.4	63.9	79.6	92.3
Motor Gasoline[4]	106.9	107.9	128.8	142.3	106.9	128.7	144.8	105.2	128.2	142.8
Residual Fuel	33.6	34.2	48.3	61.2	34.2	49.5	65.1	34.4	50.8	65.5
Residual Fuel (1998 dollars per barrel)	14.10	14.37	20.28	25.70	14.38	20.79	27.36	14.45	21.35	27.51
Average	**87.4**	**89.8**	**108.9**	**121.9**	**88.8**	**109.2**	**125.1**	**87.5**	**109.1**	**125.3**

[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.
Note: Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380 (98/03-99/04) (Washington, DC, 1998-99). 1998 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditure Report 1995*, DOE/EIA-0376(95) (Washington, DC, August 1998). **Projections**: EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1998	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Production										
Dry Gas Production[1]	18.88	22.32	22.46	22.60	24.81	25.03	25.27	26.24	26.40	26.52
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	**3.13**	**4.37**	**4.52**	**4.57**	**4.78**	**4.85**	**4.84**	**5.04**	**5.14**	**5.07**
Canada	3.15	4.18	4.32	4.37	4.64	4.72	4.70	4.91	5.01	4.94
Mexico	-0.04	-0.13	-0.13	-0.13	-0.19	-0.19	-0.19	-0.20	-0.20	-0.20
Liquefied Natural Gas	0.02	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Total Supply	**22.13**	**26.75**	**27.03**	**27.23**	**29.64**	**29.94**	**30.17**	**31.33**	**31.59**	**31.65**
Consumption by Sector										
Residential	4.48	5.32	5.30	5.28	5.49	5.49	5.48	5.69	5.69	5.70
Commercial	3.03	3.49	3.48	3.47	3.60	3.61	3.60	3.62	3.65	3.65
Industrial[3]	8.23	9.24	9.22	9.26	9.64	9.64	9.73	9.92	9.99	10.06
Electric Generators[4]	3.67	6.16	6.45	6.64	8.09	8.37	8.51	9.11	9.26	9.24
Lease and Plant Fuel[5]	1.24	1.42	1.43	1.43	1.56	1.57	1.58	1.67	1.67	1.67
Pipeline Fuel	0.73	0.83	0.84	0.85	0.91	0.92	0.92	0.94	0.96	0.96
Transportation[6]	0.02	0.23	0.22	0.22	0.29	0.28	0.28	0.32	0.32	0.32
Total	**21.39**	**26.67**	**26.95**	**27.15**	**29.57**	**29.88**	**30.10**	**31.27**	**31.53**	**31.59**
Discrepancy[7]	**0.73**	**0.08**	**0.08**	**0.08**	**0.07**	**0.06**	**0.06**	**0.06**	**0.05**	**0.05**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 1998 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(99/06) (Washington, DC, June 1999). 1998 transportation sector consumption: EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A. Other 1998 consumption: EIA, *Short-Term Energy Outlook, September 1999. Online.*http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep99.pdf (October 12, 1999) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A. **Projections:** EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C14. Natural Gas Prices, Margins, and Revenue
(1998 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1998	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
Source Price										
Average Lower 48 Wellhead Price[1]	1.96	2.44	2.60	2.72	2.56	2.71	2.78	2.68	2.81	2.87
Average Import Price	1.96	2.43	2.64	2.79	2.49	2.67	2.80	2.77	2.92	2.98
Average[2]	**1.96**	**2.44**	**2.61**	**2.74**	**2.55**	**2.70**	**2.78**	**2.70**	**2.83**	**2.89**
Delivered Prices										
Residential	6.79	6.58	6.76	6.90	6.45	6.62	6.71	6.39	6.55	6.62
Commercial	5.42	5.51	5.69	5.83	5.47	5.64	5.73	5.50	5.66	5.73
Industrial[3]	2.73	3.19	3.38	3.50	3.31	3.48	3.55	3.46	3.60	3.66
Electric Generators[4]	2.40	2.92	3.14	3.29	3.08	3.28	3.38	3.23	3.41	3.48
Transportation[5]	6.27	7.10	7.43	7.59	7.27	7.66	7.78	7.28	7.70	7.80
Average[6]	**4.03**	**4.23**	**4.41**	**4.53**	**4.21**	**4.38**	**4.46**	**4.27**	**4.43**	**4.50**
Transmission and Distribution Margins[7]										
Residential	4.83	4.14	4.15	4.16	3.90	3.91	3.93	3.70	3.72	3.73
Commercial	3.46	3.07	3.08	3.09	2.92	2.93	2.95	2.80	2.83	2.84
Industrial[3]	0.77	0.75	0.77	0.77	0.76	0.77	0.77	0.76	0.77	0.78
Electric Generators[4]	0.44	0.48	0.54	0.56	0.53	0.57	0.59	0.53	0.58	0.59
Transportation[5]	4.31	4.66	4.82	4.86	4.72	4.96	5.00	4.59	4.87	4.91
Average[6]	**2.07**	**1.79**	**1.80**	**1.80**	**1.66**	**1.67**	**1.67**	**1.58**	**1.60**	**1.61**
Transmission and Distribution Revenue (billion 1998 dollars)										
Residential	21.62	22.01	22.01	21.99	21.41	21.48	21.53	21.04	21.18	21.26
Commercial	10.46	10.71	10.73	10.72	10.50	10.59	10.62	10.16	10.31	10.35
Industrial[3]	6.37	6.97	7.09	7.12	7.31	7.46	7.50	7.57	7.73	7.81
Electric Generators[4]	1.60	2.98	3.45	3.71	4.27	4.80	5.04	4.85	5.34	5.42
Transportation[5]	0.09	1.06	1.08	1.07	1.35	1.40	1.39	1.47	1.55	1.56
Total	**40.15**	**43.72**	**44.36**	**44.62**	**44.85**	**45.72**	**46.08**	**45.09**	**46.12**	**46.41**

[1]Represents lower 48 onshore and offshore supplies.
[2]Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, “transmission and distribution” margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term “transmission and distribution” margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.

Sources: 1998 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1994*. 1998 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(99/06) (Washington, DC, June 1999). **Other 1998 values, and projections:** EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C15. Oil and Gas Supply

Production and Supply	1998	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]										
(1998 dollars per barrel)	**11.60**	**14.36**	**20.62**	**25.85**	**14.21**	**20.86**	**27.40**	**14.03**	**21.27**	**27.53**
Production (million barrels per day)[2]										
U.S. Total	**6.25**	**4.84**	**5.18**	**5.50**	**4.69**	**5.20**	**5.80**	**4.65**	**5.26**	**6.02**
Lower 48 Onshore	3.60	2.69	3.00	3.30	2.70	3.17	3.65	2.75	3.28	3.81
Conventional	2.87	2.32	2.39	2.49	2.37	2.49	2.66	2.45	2.57	2.74
Enhanced Oil Recovery	0.73	0.38	0.61	0.80	0.33	0.68	0.99	0.30	0.71	1.07
Lower 48 Offshore	1.47	1.36	1.36	1.37	1.40	1.40	1.50	1.43	1.47	1.68
Alaska	1.18	0.79	0.81	0.83	0.59	0.63	0.65	0.47	0.51	0.53
Lower 48 End of Year Reserves										
(billion barrels)[2]	**18.05**	**12.27**	**13.38**	**14.55**	**11.62**	**13.32**	**15.45**	**11.16**	**13.21**	**15.78**
Natural Gas										
Lower 48 Average Wellhead Price[1]										
(1998 dollars per thousand cubic feet)	**1.96**	**2.44**	**2.60**	**2.72**	**2.56**	**2.71**	**2.78**	**2.68**	**2.81**	**2.87**
Production (trillion cubic feet)[3]										
U.S. Total	**18.72**	**22.32**	**22.46**	**22.60**	**24.81**	**25.03**	**25.27**	**26.24**	**26.40**	**26.52**
Lower 48 Onshore	12.75	16.33	16.37	16.59	17.79	17.83	17.94	19.49	19.47	19.32
Associated-Dissolved[4]	1.56	1.25	1.25	1.27	1.24	1.25	1.30	1.24	1.25	1.30
Non-Associated	11.19	15.09	15.12	15.32	16.55	16.58	16.64	18.25	18.22	18.02
Conventional	6.68	10.14	9.81	9.43	10.54	10.09	9.66	11.27	10.75	10.36
Unconventional	4.51	4.95	5.30	5.89	6.02	6.49	6.98	6.98	7.47	7.66
Lower 48 Offshore	5.53	5.50	5.60	5.53	6.51	6.68	6.81	6.22	6.39	6.66
Associated-Dissolved[4]	0.88	0.88	0.88	0.89	0.89	0.89	0.91	0.90	0.91	0.95
Non-Associated	4.65	4.62	4.72	4.65	5.61	5.79	5.90	5.31	5.48	5.71
Alaska	0.44	0.49	0.49	0.49	0.51	0.51	0.51	0.54	0.54	0.54
Lower 48 End of Year Reserves										
(trillion cubic feet)	**155.00**	**172.03**	**173.45**	**176.35**	**188.35**	**191.59**	**194.20**	**187.72**	**191.37**	**193.03**
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)	**23.96**	**27.86**	**32.86**	**38.56**	**29.67**	**35.69**	**42.51**	**33.21**	**38.66**	**44.76**

[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.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 1998,* DOE/EIA-0340(98/1) (Washington, DC. June 1999). 1998 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(99/06) (Washington, DC, June 1999). Other 1998 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C16. Coal Supply, Disposition, and Prices

(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1998	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	470	435	427	423	403	412	412	376	385	384
Interior	168	154	146	139	139	147	142	140	155	151
West	489	649	669	674	713	710	714	781	776	786
East of the Mississippi	580	573	559	550	531	547	543	504	528	523
West of the Mississippi	548	664	682	687	724	721	725	793	788	798
Total	**1128**	**1237**	**1242**	**1237**	**1255**	**1269**	**1268**	**1297**	**1316**	**1320**
Net Imports										
Imports	9	17	17	17	18	18	18	20	20	20
Exports	78	63	64	64	57	57	57	58	58	58
Total	**-69**	**-46**	**-47**	**-47**	**-38**	**-38**	**-38**	**-38**	**-38**	**-38**
Total Supply[2]	**1058**	**1192**	**1195**	**1190**	**1216**	**1230**	**1230**	**1259**	**1278**	**1282**
Consumption by Sector										
Residential and Commercial	6	7	7	7	7	7	7	7	7	7
Industrial[3]	69	74	73	73	75	74	74	76	75	75
Coke Plants	28	24	23	23	22	21	21	20	20	19
Electric Generators[4]	939	1088	1092	1088	1114	1129	1130	1157	1177	1183
Total	**1043**	**1193**	**1195**	**1191**	**1218**	**1232**	**1231**	**1260**	**1279**	**1284**
Discrepancy and Stock Change[5]	**16**	**-1**	**-1**	**-1**	**-2**	**-1**	**-2**	**-2**	**-1**	**-1**
Average Minemouth Price										
(1998 dollars per short ton)	17.51	13.82	13.84	13.99	13.31	13.34	13.39	12.38	12.54	12.53
(1998 dollars per million Btu)	0.83	0.66	0.66	0.66	0.63	0.64	0.64	0.60	0.60	0.60
Delivered Prices (1998 dollars per short ton)[6]										
Industrial	32.26	27.32	27.44	27.58	26.08	26.27	26.44	24.97	25.24	25.38
Coke Plants	46.06	42.60	42.93	43.11	41.23	41.72	41.80	39.72	40.19	40.44
Electric Generators										
(1998 dollars per short ton)	25.64	21.77	22.13	22.52	21.10	21.19	21.47	19.93	20.01	20.22
(1998 dollars per million Btu)	1.25	1.05	1.07	1.09	1.02	1.03	1.04	0.98	0.98	0.99
Average	**26.65**	**22.53**	**22.86**	**23.24**	**21.77**	**21.86**	**22.12**	**20.56**	**20.63**	**20.82**
Exports[7]	38.89	35.81	36.05	36.22	34.73	35.08	35.27	33.53	33.91	34.10

[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, 8.8 million tons in 1996, 8.1 million tons in 1997, and are projected to reach 9.5 million tons in 1998, and 11.6 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. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 data based on Energy Information Administration (EIA), *Quarterly Coal Report* , DOE/EIA-0121(99/1Q) (Washington, DC, August 1999), and EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A. **Projections:** EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C17. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1998	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	77.71	78.33	78.33	78.33	78.33	78.33	78.33	78.33	78.33	78.33
Geothermal[2]	2.89	2.86	2.98	2.96	2.96	3.11	3.13	3.60	3.75	3.86
Municipal Solid Waste[3]	2.49	4.48	4.47	4.47	5.00	5.00	5.00	5.17	5.17	5.16
Wood and Other Biomass[4]	1.76	2.41	2.41	2.41	2.70	2.71	2.72	2.79	2.93	2.94
Solar Thermal	0.33	0.40	0.40	0.40	0.44	0.44	0.44	0.48	0.48	0.48
Solar Photovoltaic	0.01	0.19	0.19	0.19	0.35	0.35	0.35	0.52	0.52	0.52
Wind	1.99	5.07	5.07	5.07	5.40	5.40	5.40	5.49	5.49	5.49
Total	**87.19**	**93.72**	**93.84**	**93.82**	**95.17**	**95.33**	**95.36**	**96.38**	**96.67**	**96.78**
Generation (billion kilowatthours)										
Conventional Hydropower	316.79	300.49	300.50	300.48	299.90	299.90	299.91	299.35	299.35	299.35
Geothermal[2]	14.29	16.38	17.35	17.20	18.48	19.62	19.82	23.56	24.70	25.54
Municipal Solid Waste[3]	17.78	30.65	30.63	30.60	34.56	34.55	34.51	35.73	35.71	35.67
Wood and Other Biomass[4]	6.86	19.13	20.35	20.29	19.22	18.23	19.02	17.91	18.80	19.12
Dedicated Plants	6.86	11.00	11.00	11.00	12.94	13.03	13.06	13.59	14.55	14.70
Cofiring	0.00	8.13	9.34	9.28	6.28	5.20	5.96	4.32	4.25	4.42
Solar Thermal	0.89	1.09	1.09	1.09	1.22	1.22	1.22	1.35	1.35	1.35
Solar Photovoltaic	0.00	0.46	0.46	0.46	0.86	0.86	0.86	1.30	1.30	1.30
Wind	3.39	10.95	10.95	10.95	11.87	11.87	11.87	12.09	12.09	12.09
Total	**360.00**	**379.16**	**381.33**	**381.07**	**386.13**	**386.26**	**387.21**	**391.30**	**393.32**	**394.44**
Cogenerators[5]										
Net Summer Capability										
Municipal Solid Waste	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Biomass	6.04	7.06	7.37	7.51	7.51	7.94	8.16	7.93	8.46	8.73
Total	**6.56**	**7.58**	**7.89**	**8.03**	**8.03**	**8.46**	**8.68**	**8.45**	**8.98**	**9.25**
Generation (billion kilowatthours)										
Municipal Solid Waste	3.00	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13
Biomass	37.34	42.99	45.06	45.73	45.34	48.28	49.29	47.42	51.02	52.34
Total	**40.34**	**46.13**	**48.19**	**48.86**	**48.47**	**51.41**	**52.42**	**50.55**	**54.15**	**55.47**
Other Generators[6]										
Net Summer Capability										
Conventional Hydropower[7]	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.01	0.35	0.35	0.35	0.42	0.42	0.42	0.75	0.74	0.74
Total	**1.10**	**1.44**	**1.44**	**1.44**	**1.52**	**1.52**	**1.51**	**1.84**	**1.84**	**1.83**
Generation (billion kilowatthours)										
Conventional Hydropower[7]	7.25	4.85	4.85	4.85	4.84	4.84	4.84	4.83	4.83	4.83
Geothermal	0.00	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Solar Photovoltaic	0.01	0.46	0.46	0.46	0.47	0.47	0.47	0.50	0.50	0.50
Total	**7.26**	**5.38**	**5.38**	**5.38**	**5.38**	**5.37**	**5.38**	**5.40**	**5.40**	**5.40**

[1]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.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Cogenerators produce electricity and other useful thermal energy.
[6] Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[7]Represents own-use industrial hydroelectric power.

Notes: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators for AEO2000. Net summer capability is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.

Sources: 1998 electric utility capability: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report." 1998 nonutility and cogenerator capability: EIA, Form EIA-867, "Annual Nonutility Power Producer Report, 1997." 1998 generation: EIA, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C18. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1998	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	**0.38**	**0.44**	**0.44**	**0.44**	**0.45**	**0.45**	**0.44**	**0.46**	**0.45**	**0.45**
Wood	0.38	0.44	0.44	0.44	0.45	0.45	0.44	0.46	0.45	0.45
Commercial	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Industrial[3]	**2.08**	**2.37**	**2.40**	**2.43**	**2.48**	**2.53**	**2.57**	**2.57**	**2.63**	**2.69**
Conventional Hydroelectric	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	1.91	2.20	2.23	2.26	2.31	2.35	2.40	2.40	2.46	2.52
Transportation	**0.12**	**0.17**	**0.18**	**0.19**	**0.20**	**0.21**	**0.22**	**0.21**	**0.23**	**0.25**
Ethanol used in E85[4]	0.00	0.05	0.05	0.04	0.07	0.06	0.05	0.07	0.06	0.05
Ethanol used in Gasoline Blending	0.12	0.12	0.14	0.15	0.13	0.15	0.17	0.14	0.17	0.19
Electric Generators[5]	**4.12**	**4.39**	**4.43**	**4.45**	**4.55**	**4.59**	**4.63**	**4.72**	**4.75**	**4.78**
Conventional Hydroelectric	3.33	3.09	3.09	3.09	3.09	3.09	3.09	3.08	3.08	3.08
Geothermal	0.40	0.49	0.52	0.55	0.59	0.64	0.67	0.75	0.77	0.80
Municipal Solid Waste	0.27	0.49	0.49	0.49	0.55	0.55	0.55	0.57	0.57	0.57
Biomass	0.06	0.18	0.19	0.19	0.18	0.17	0.18	0.17	0.17	0.18
Dedicated Plants	0.06	0.10	0.10	0.10	0.12	0.12	0.12	0.13	0.13	0.14
Cofiring	0.00	0.08	0.09	0.09	0.06	0.05	0.06	0.04	0.04	0.04
Solar Thermal	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.04	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.12
Total Marketed Renewable Energy	**6.79**	**7.45**	**7.53**	**7.60**	**7.75**	**7.85**	**7.95**	**8.03**	**8.14**	**8.25**
Non-Marketed Renewable Energy[6]										
Selected Consumption										
Residential	**0.02**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**
Solar Hot Water Heating	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal Heat Pumps	0.01	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.03**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**
Solar Thermal	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Ethanol										
From Corn	0.12	0.15	0.16	0.17	0.16	0.16	0.17	0.15	0.16	0.17
From Cellulose	0.00	0.02	0.02	0.02	0.04	0.05	0.05	0.06	0.07	0.08
Total	**0.12**	**0.17**	**0.18**	**0.19**	**0.20**	**0.21**	**0.22**	**0.21**	**0.23**	**0.25**

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table C8.
[3]Includes all electricity production by industrial and other cogenerators for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes renewable energy delivered to the grid from electric utilities and nonutilities other than cogenerators. Renewable energy used in generating electricity for own use is included in the individual sectoral electricity energy consumption values.
[6]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. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 ethanol: Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). 1998 electric generators: EIA, Form EIA-860, "Annual Electric Generator Report," and EIA, Form EIA-867, "Annual Nonutility Power Producer Report, 1997." Other 1998: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C19. Carbon Emissions by Sector and Source
(Million Metric Tons per Year)

Sector and Source	1998	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Residential										
Petroleum	24.8	25.3	23.5	22.4	24.5	22.4	21.0	23.9	21.5	20.0
Natural Gas	66.3	78.8	78.6	78.3	81.4	81.3	81.2	84.3	84.4	84.4
Coal	1.5	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3
Electricity	191.0	245.8	240.2	238.2	261.8	255.8	254.7	277.6	270.5	269.7
Total	**283.5**	**351.2**	**343.7**	**340.3**	**369.1**	**361.0**	**358.3**	**387.2**	**377.7**	**375.4**
Commercial										
Petroleum	12.9	13.3	12.2	11.5	13.6	12.1	11.4	13.6	11.8	11.1
Natural Gas	44.9	51.7	51.6	51.4	53.3	53.5	53.4	53.7	54.1	54.0
Coal	2.2	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.7
Electricity	177.5	228.1	222.5	220.0	240.6	234.8	233.2	245.4	238.8	237.6
Total	**237.5**	**295.6**	**288.8**	**285.5**	**310.2**	**303.0**	**300.6**	**315.3**	**307.3**	**305.4**
Industrial[1]										
Petroleum	100.8	105.6	105.6	103.1	109.4	109.2	106.9	113.5	112.4	109.5
Natural Gas[2]	140.0	155.5	155.4	156.0	163.4	163.5	165.0	168.9	170.1	171.2
Coal	58.0	62.0	61.4	61.1	62.2	61.4	61.1	62.4	61.6	61.3
Electricity	178.0	217.0	212.0	210.9	233.2	227.6	226.9	247.0	240.0	239.3
Total	**476.8**	**540.1**	**534.4**	**531.1**	**568.3**	**561.8**	**559.9**	**591.8**	**584.1**	**581.4**
Transportation										
Petroleum[3]	473.4	605.1	595.8	588.4	651.5	639.7	627.5	694.4	679.9	664.2
Natural Gas[4]	10.8	15.6	15.8	15.8	17.7	17.8	17.8	18.7	18.9	19.0
Other[5]	0.0	1.8	1.8	1.6	2.5	2.3	2.1	2.9	2.7	2.4
Electricity	3.4	6.5	6.3	6.2	7.9	7.7	7.5	8.9	8.6	8.5
Total[3]	**487.5**	**629.0**	**619.7**	**612.1**	**679.5**	**667.5**	**654.9**	**724.9**	**710.0**	**694.0**
Total Carbon Emissions by Delivered Fuel										
Petroleum[3]	611.9	749.2	737.1	725.5	799.1	783.5	766.7	845.3	825.6	804.8
Natural Gas	262.0	301.6	301.3	301.4	315.8	316.1	317.4	325.7	327.4	328.6
Coal	61.7	66.0	65.4	65.1	66.3	65.5	65.1	66.4	65.6	65.3
Other[5]	0.0	1.8	1.8	1.6	2.5	2.3	2.1	2.9	2.7	2.4
Electricity	549.8	697.4	681.0	675.3	743.6	725.9	722.4	778.8	757.8	755.1
Total[3]	**1485.4**	**1816.0**	**1786.6**	**1768.9**	**1927.1**	**1893.4**	**1873.7**	**2019.1**	**1979.2**	**1956.3**
Electric Generators[6]										
Petroleum	24.8	32.8	10.2	3.9	37.6	8.6	2.8	43.1	7.7	2.8
Natural Gas	47.8	90.6	95.0	97.7	119.1	123.1	125.2	134.1	136.2	135.9
Coal	477.3	574.0	575.8	573.6	586.8	594.2	594.4	601.6	613.9	616.4
Total	**549.8**	**697.4**	**681.0**	**675.3**	**743.6**	**725.9**	**722.4**	**778.8**	**757.8**	**755.1**
Total Carbon Emissions by Primary Fuel[7]										
Petroleum[3]	636.7	782.0	747.3	729.4	836.7	792.1	769.5	888.4	833.3	807.6
Natural Gas	309.8	392.2	396.3	399.2	434.8	439.3	442.6	459.8	463.7	464.6
Coal	538.9	640.0	641.2	638.7	653.1	659.7	659.5	668.1	679.5	681.7
Other[5]	0.0	1.8	1.8	1.6	2.5	2.3	2.1	2.9	2.7	2.4
Total[3]	**1485.4**	**1816.0**	**1786.6**	**1768.9**	**1927.1**	**1893.4**	**1873.7**	**2019.1**	**1979.2**	**1956.3**
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**

[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.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 1998,* DOE/EIA-0573(98), (Washington, DC, October 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C20. Macroeconomic Indicators
(Billion 1992 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	1998	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
GDP Chain-Type Price Index (1992=1.000)	**1.127**	**1.416**	**1.423**	**1.428**	**1.587**	**1.591**	**1.594**	**1.855**	**1.857**	**1.858**
Real Gross Domestic Product	**7,552**	**10,097**	**10,054**	**10,031**	**11,179**	**11,147**	**11,124**	**12,205**	**12,179**	**12,151**
Real Consumption	5,153	6,946	6,906	6,882	7,772	7,743	7,720	8,610	8,585	8,557
Real Investment	1,330	1,953	1,937	1,928	2,249	2,239	2,231	2,497	2,489	2,483
Real Government Spending	1,297	1,579	1,575	1,573	1,669	1,666	1,663	1,782	1,779	1,775
Real Exports	985	2,245	2,233	2,225	2,944	2,931	2,921	3,682	3,669	3,651
Real Imports	1,223	2,668	2,623	2,591	3,564	3,522	3,486	4,655	4,610	4,543
Real Disposable Personal Income	**5,348**	**7,245**	**7,204**	**7,178**	**8,115**	**8,083**	**8,058**	**9,037**	**9,008**	**8,974**
Index of Manufacturing Gross Output (index 1987=1.000)	**1.411**	**1.818**	**1.812**	**1.810**	**2.005**	**1.999**	**1.996**	**2.166**	**2.160**	**2.158**
AA Utility Bond Rate (percent)	6.91	7.52	7.72	7.84	8.03	8.14	8.22	8.76	8.81	8.86
Real Yield on Government 10 Year Bonds (percent)	4.29	4.51	4.59	4.64	4.85	4.91	4.98	4.65	4.69	4.76
Real Utility Bond Rate (percent)	5.33	5.37	5.55	5.65	5.59	5.79	5.90	5.35	5.43	5.53
Energy Intensity (thousand Btu per 1992 dollar of GDP)										
Delivered Energy	9.32	8.35	8.32	8.28	7.99	7.94	7.88	7.65	7.60	7.53
Total Energy	12.57	11.16	11.07	11.02	10.58	10.47	10.41	10.07	9.94	9.87
Consumer Price Index (1982-84=1.00)	1.63	2.18	2.20	2.21	2.46	2.48	2.49	2.89	2.90	2.92
Unemployment Rate (percent)	4.48	5.62	5.72	5.76	5.25	5.30	5.32	5.07	5.10	5.08
Unit Sales of Light-Duty Vehicles (millions)	**15.64**	**16.57**	**16.02**	**15.70**	**17.46**	**17.06**	**16.79**	**17.41**	**17.09**	**16.81**
Millions of People										
Population with Armed Forces Overseas	270.6	298.3	298.3	298.3	310.8	310.8	310.8	323.4	323.4	323.4
Population (aged 16 and over)	208.6	235.2	235.2	235.2	245.6	245.6	245.6	255.3	255.3	255.3
Employment, Non-Agriculture	126.2	140.8	140.1	139.7	145.2	144.6	144.3	148.2	147.8	147.4
Employment, Manufacturing	19.0	17.3	17.2	17.2	16.6	16.6	16.5	15.9	15.9	15.8
Labor Force	137.7	157.4	157.3	157.2	162.7	162.6	162.5	167.1	167.0	167.0

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 1998: Standard & Poor's DRI, Simulation T250899. **Projections:** Energy Information Administration, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Table C21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1998	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 (1998 dollars per barrel)[1]	**12.10**	**14.90**	**21.00**	**26.31**	**14.90**	**21.53**	**27.86**	**14.90**	**22.04**	**28.04**
Production[2]										
OECD										
U.S. (50 states)	9.14	8.11	8.62	9.08	8.22	8.89	9.62	8.28	9.06	9.95
Canada	2.70	3.16	3.22	3.25	3.32	3.39	3.44	3.35	3.43	3.48
Mexico	3.52	3.88	3.99	4.06	3.77	3.90	3.99	3.66	3.80	3.89
OECD Europe[3]	6.95	7.61	7.72	7.79	6.91	7.03	7.11	6.40	6.52	6.60
Other OECD	0.77	0.89	0.92	0.94	0.84	0.88	0.91	0.78	0.82	0.85
Total OECD	**23.09**	**23.65**	**24.48**	**25.13**	**23.06**	**24.09**	**25.06**	**22.48**	**23.63**	**24.77**
Developing Countries										
Other South & Central America	3.64	4.30	4.43	4.51	4.63	4.79	4.90	4.81	4.99	5.12
Pacific Rim	2.19	2.92	3.00	3.06	3.06	3.17	3.24	3.15	3.27	3.35
OPEC	31.70	48.45	42.02	38.08	55.98	47.56	41.98	65.74	55.47	48.93
Other Developing Countries	4.69	5.34	5.50	5.60	6.39	6.61	6.76	7.30	7.57	7.76
Total Developing Countries	**42.23**	**61.01**	**54.96**	**51.25**	**70.07**	**62.13**	**56.88**	**81.00**	**71.30**	**65.15**
Eurasia										
Former Soviet Union	7.24	9.86	10.14	10.33	11.68	12.08	12.36	12.58	13.05	13.37
Eastern Europe	0.25	0.38	0.39	0.39	0.40	0.42	0.43	0.44	0.45	0.46
China	3.20	3.42	3.52	3.58	3.50	3.62	3.70	3.49	3.63	3.71
Total Eurasia	**10.69**	**13.65**	**14.05**	**14.30**	**15.58**	**16.12**	**16.49**	**16.51**	**17.13**	**17.55**
Total Production	**76.01**	**98.31**	**93.48**	**90.67**	**108.71**	**102.33**	**98.43**	**119.99**	**112.06**	**107.47**
Consumption										
OECD										
U.S. (50 states)	18.94	23.31	22.51	22.06	24.91	23.87	23.28	26.38	25.10	24.42
U.S. Territories	0.28	0.39	0.34	0.32	0.42	0.36	0.33	0.44	0.38	0.35
Canada	1.88	2.39	2.14	2.00	2.52	2.22	2.04	2.63	2.29	2.09
Mexico	1.78	2.68	2.47	2.35	3.18	2.87	2.69	3.73	3.33	3.09
Japan	5.51	6.93	6.04	5.55	7.57	6.30	5.59	8.19	6.59	5.71
Australia and New Zealand	0.94	1.18	1.13	1.10	1.27	1.21	1.17	1.36	1.29	1.24
OECD Europe[3]	14.74	17.24	16.37	15.85	17.90	16.90	16.24	18.58	17.46	16.77
Total OECD	**44.07**	**54.13**	**51.01**	**49.23**	**57.77**	**53.74**	**51.33**	**61.32**	**56.43**	**53.67**
Developing Countries										
Other South and Central America	4.67	6.99	6.78	6.65	8.22	7.95	7.77	9.64	9.30	9.09
Pacific Rim	7.47	11.27	10.88	10.65	13.03	12.52	12.19	15.00	14.37	13.97
OPEC	5.47	7.19	7.19	7.19	8.06	8.06	8.06	9.07	9.07	9.07
Other Developing Countries	3.71	5.47	5.06	4.82	6.45	5.79	5.40	7.58	6.65	6.10
Total Developing Countries	**21.32**	**30.93**	**29.92**	**29.32**	**35.76**	**34.33**	**33.43**	**41.29**	**39.39**	**38.24**
Eurasia										
Former Soviet Union	4.23	5.12	4.91	4.79	5.64	5.39	5.23	6.23	5.93	5.75
Eastern Europe	1.47	1.75	1.70	1.67	1.80	1.75	1.71	1.85	1.79	1.76
China	3.91	6.69	6.23	5.96	8.04	7.43	7.04	9.60	8.82	8.35
Total Eurasia	**9.62**	**13.56**	**12.85**	**12.43**	**15.48**	**14.57**	**13.98**	**17.68**	**16.55**	**15.86**

Table C21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1998	Projections								
		2010			2015			2020		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Total Consumption	**74.99**	**98.61**	**93.78**	**90.97**	**109.01**	**102.63**	**98.73**	**120.29**	**112.36**	**107.77**
Non-OPEC Production	44.31	49.87	51.46	52.59	52.73	54.77	56.45	54.25	56.60	58.54
Net Eurasia Exports	1.08	0.09	1.20	1.87	0.10	1.55	2.51	-1.17	0.58	1.69
OPEC Market Share	0.42	0.49	0.45	0.42	0.51	0.46	0.43	0.55	0.49	0.46

[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. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: 1998 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook, September 1999.* Online. http://www.eia.doe.gov/ pub/forecasting/steo/ oldsteos/sep99.pdf (October 12, 1999). **Projections:** EIA, AEO2000 National Energy Modeling System runs LWOP2K.D100199A, AEO2K.D100199A, and HWOP2K.D100199A.

Crude Oil Equivalency Summary

Table D1. Total Energy Supply and Disposition Summary
(Million Barrels per Day Oil Equivalent, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Production							
Crude Oil and Lease Condensate	6.45	6.25	5.36	5.18	5.20	5.26	-0.8%
Natural Gas Plant Liquids	1.22	1.18	1.21	1.37	1.51	1.59	1.4%
Dry Natural Gas	9.18	9.17	9.56	10.91	12.15	12.78	1.5%
Coal	10.99	11.29	12.18	12.37	12.58	12.89	0.6%
Nuclear Power	3.17	3.40	3.40	3.16	2.58	2.15	-2.1%
Renewable Energy[1]	3.31	3.15	3.34	3.49	3.64	3.76	0.8%
Other[2]	0.31	0.27	0.29	0.28	0.30	0.31	0.7%
Total	**34.62**	**34.70**	**35.36**	**36.75**	**37.95**	**38.73**	**0.5%**
Imports							
Crude Oil [3]	8.23	8.70	10.82	11.47	11.50	11.62	1.3%
Petroleum Products[4]	1.84	1.89	2.54	3.21	4.24	5.13	4.7%
Natural Gas	1.45	1.59	2.14	2.32	2.51	2.64	2.3%
Other Imports[5]	0.25	0.28	0.47	0.42	0.42	0.46	2.3%
Total	**11.76**	**12.46**	**15.96**	**17.42**	**18.68**	**19.85**	**2.1%**
Exports							
Petroleum[6]	0.99	0.92	0.92	0.93	0.92	0.91	-0.0%
Natural Gas	0.08	0.08	0.11	0.14	0.17	0.17	3.5%
Coal	1.04	0.97	0.75	0.77	0.68	0.69	-1.5%
Total	**2.10**	**1.96**	**1.78**	**1.84**	**1.77**	**1.77**	**-0.5%**
Discrepancy[7]	**0.30**	**-0.41**	**0.11**	**0.12**	**0.13**	**0.04**	**N/A**
Consumption							
Petroleum Products[8]	17.21	17.57	19.47	20.78	22.03	23.11	1.3%
Natural Gas	10.68	10.39	11.61	13.08	14.49	15.25	1.8%
Coal	10.07	10.13	11.60	11.77	12.09	12.40	1.0%
Nuclear Power	3.17	3.40	3.40	3.16	2.58	2.15	-2.1%
Renewable Energy[1]	3.31	3.15	3.34	3.50	3.64	3.77	0.8%
Other[9]	0.16	0.15	0.24	0.17	0.15	0.17	0.6%
Total	**44.59**	**44.79**	**49.65**	**52.46**	**54.99**	**56.85**	**1.1%**
Net Imports - Petroleum	**9.28**	**9.89**	**12.72**	**14.05**	**15.12**	**16.09**	**2.2%**
Prices (1998 dollars per unit)							
World Oil Price (dollars per barrel)[10]	18.71	12.10	20.49	21.00	21.53	22.04	2.8%
Gas Wellhead Price (dollars per Mcf)[11]	2.39	1.96	2.34	2.60	2.71	2.81	1.7%
Coal Minemouth Price (dollars per ton)	18.32	17.51	14.71	13.84	13.34	12.54	-1.5%
Average Electric Price (cents per kilowatthour)	6.9	6.7	6.1	6.0	5.9	5.8	-0.6%

[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 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.
Mcf = Thousand cubic feet.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1997 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1997*, DOE/EIA-0131(97) (Washington, DC, October 1998). 1997 coal minemouth prices: EIA, *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998). Other 1997 values: EIA, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). 1998 natural gas values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(99/06) (Washington, DC, June 1999). 1998 petroleum values: EIA, *Petroleum Supply Annual 1998,* DOE/EIA-0340(98/1) (Washington, DC, June 1999). Other 1998 values: EIA, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(99/1Q) (Washington, DC, August 1999). **Projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Table D2. Total Energy Supply and Disposition Summary
(Mtoes per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case						Annual Growth 1998-2020 (percent)
	1997	1998	2005	2010	2015	2020	
Production							
Crude Oil and Lease Condensate	344.14	333.49	286.02	276.10	277.39	280.47	-0.8%
Natural Gas Plant Liquids	64.88	62.84	64.78	73.20	80.77	84.64	1.4%
Dry Natural Gas	489.55	488.97	510.26	581.86	648.40	683.80	1.5%
Coal	586.56	602.10	649.92	659.69	671.02	689.55	0.6%
Nuclear Power	169.16	181.28	181.46	168.81	137.40	114.92	-2.1%
Renewable Energy[1]	176.32	168.10	178.18	186.35	193.97	201.01	0.8%
Other[2]	16.57	14.29	15.63	14.79	15.79	16.56	0.7%
Total	**1847.17**	**1851.08**	**1886.25**	**1960.80**	**2024.74**	**2070.95**	**0.5%**
Imports							
Crude Oil[3]	450.04	476.25	591.99	627.61	629.35	635.46	1.3%
Petroleum Products[4]	97.95	100.57	135.37	171.25	226.30	273.93	4.7%
Natural Gas	77.11	84.94	113.96	123.69	133.88	141.35	2.3%
Other Imports[5]	13.49	14.93	24.96	22.50	22.46	24.43	2.3%
Total	**638.60**	**676.69**	**866.28**	**945.06**	**1011.99**	**1075.17**	**2.1%**
Exports							
Petroleum[6]	52.78	48.95	48.91	49.55	49.26	48.70	-0.0%
Natural Gas	4.04	4.25	5.99	7.41	8.90	9.08	3.5%
Coal	55.26	51.63	39.98	41.13	36.26	36.91	-1.5%
Total	**112.09**	**104.83**	**94.88**	**98.09**	**94.42**	**94.69**	**-0.5%**
Discrepancy[7]	**-5.50**	**32.01**	**4.63**	**4.08**	**2.54**	**3.56**	**N/A**
Consumption							
Petroleum Products[8]	918.05	937.59	1038.61	1108.35	1175.50	1236.16	1.3%
Natural Gas	569.54	554.09	619.13	697.74	773.16	816.02	1.8%
Coal	537.75	541.85	622.85	632.97	651.14	670.30	1.0%
Nuclear Power	169.16	181.28	181.46	168.81	137.40	114.92	-2.1%
Renewable Energy[1]	176.34	168.17	178.34	186.64	194.35	201.41	0.8%
Other[9]	8.36	7.95	12.63	9.18	8.22	9.06	0.6%
Total	**2379.19**	**2390.93**	**2653.02**	**2803.68**	**2939.77**	**3047.86**	**1.1%**
Net Imports - Petroleum	**495.22**	**527.87**	**678.45**	**749.31**	**806.39**	**860.68**	**2.2%**
Prices (1998 dollars per unit)							
World Oil Price (dollars per barrel)[10]	18.71	12.10	20.49	21.00	21.53	22.04	2.8%
Gas Wellhead Price (dollars per Mcf)[11]	2.39	1.96	2.34	2.60	2.71	2.81	1.7%
Coal Minemouth Price (dollars per ton)	18.32	17.51	14.71	13.84	13.34	12.54	-1.5%
Average Electric Price (cents per kilowatthour)	6.9	6.7	6.1	6.0	5.9	5.8	-0.6%

[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 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.
Mtoes = Million tons of oil equivalent.
Mcf = Thousand cubic feet.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1997 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1997*, DOE/EIA-0131(97) (Washington, DC, October 1998). 1997 coal minemouth prices: EIA, *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998). Other 1997 values: EIA, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). 1998 natural gas values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(99/06) (Washington, DC, June 1999). 1998 petroleum values: EIA, *Petroleum Supply Annual 1998,* DOE/EIA-0340(98/1) (Washington, DC, June 1999). Other 1998 values: EIA, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(99/1Q) (Washington, DC, August 1999). **Projections:** EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Household Expenditures

Table E1. 1998 Average Household Expenditures for Energy by Household Characteristic
(1998 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2060.87**	**1145.43**	**765.35**	**319.89**	**60.18**	**915.44**
Households by Income Quintile						
1st	1302.78	870.43	553.12	275.41	41.90	432.35
2nd	1703.53	1004.64	651.33	303.47	49.84	698.89
3rd	2173.33	1140.03	790.95	285.95	63.14	1033.30
4th	2322.63	1241.79	849.39	324.29	68.11	1080.84
5th	2830.92	1474.22	990.03	405.39	78.79	1356.70
Households by Census Division						
New England	2288.57	1372.96	747.21	308.99	316.76	915.61
Middle Atlantic	2066.09	1384.30	716.10	474.31	193.89	681.79
South Atlantic	2128.11	1136.34	628.83	484.97	22.54	991.77
East North Central	1993.98	1061.02	671.79	350.78	38.45	932.96
East South Central	1974.45	1137.95	938.40	167.00	32.55	836.51
West North Central	2345.37	1255.15	1038.32	211.78	5.05	1090.22
West South Central	2206.76	1250.42	962.33	288.10	0.00	956.33
Mountain	2029.78	937.95	633.76	298.69	5.49	1091.84
Pacific	1827.80	848.40	606.24	230.89	11.27	979.41

Source: Energy Information Administration, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Table E2. 2005 Average Household Expenditures for Energy by Household Characteristic
(1998 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2304.56**	**1144.90**	**744.05**	**336.20**	**64.65**	**1159.67**
Households by Income Quintile						
1st	1425.91	875.86	544.12	286.26	45.47	550.05
2nd	1894.93	1013.07	639.53	319.40	54.14	881.85
3rd	2444.03	1136.61	766.97	302.21	67.42	1307.42
4th	2609.95	1238.28	823.94	341.33	73.01	1371.67
5th	3190.74	1467.10	955.27	427.54	84.28	1723.64
Households by Census Division						
New England	2611.26	1436.26	735.60	323.38	377.28	1175.00
Middle Atlantic	2272.33	1383.91	675.17	493.34	215.39	888.43
South Atlantic	2369.41	1125.51	592.29	509.89	23.34	1243.90
East North Central	2228.83	1059.69	636.53	381.79	41.38	1169.14
East South Central	2155.33	1117.93	912.56	173.26	32.11	1037.41
West North Central	2588.19	1219.72	981.06	233.26	5.40	1368.46
West South Central	2459.92	1246.69	940.18	306.51	0.00	1213.23
Mountain	2322.52	973.21	648.59	318.87	5.75	1349.32
Pacific	2147.48	884.50	613.00	258.32	13.18	1262.98

Source: Energy Information Administration, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Table E3. 2010 Average Household Expenditures for Energy by Household Characteristic
(1998 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2334.22**	**1141.74**	**752.25**	**330.73**	**58.75**	**1192.48**
Households by Income Quintile						
1st	1438.14	872.09	551.22	279.26	41.61	566.05
2nd	1917.25	1011.47	648.68	313.18	49.61	905.78
3rd	2478.12	1133.88	775.13	297.82	60.94	1344.24
4th	2648.37	1235.77	833.10	336.34	66.34	1412.60
5th	3242.22	1465.07	965.01	423.66	76.40	1777.15
Households by Census Division						
New England	2651.99	1427.10	742.54	318.95	365.61	1224.90
Middle Atlantic	2278.11	1364.35	682.08	482.27	200.00	913.75
South Atlantic	2385.21	1108.47	595.11	492.46	20.90	1276.73
East North Central	2254.87	1056.61	646.75	373.69	36.18	1198.26
East South Central	2192.91	1127.65	923.29	176.50	27.86	1065.25
West North Central	2625.41	1219.71	977.59	237.14	4.98	1405.70
West South Central	2462.31	1221.13	930.79	290.34	0.00	1241.18
Mountain	2407.19	993.36	659.28	329.04	5.04	1413.83
Pacific	2202.28	914.80	630.92	271.69	12.19	1287.48

Source: Energy Information Administration, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Table E4. 2015 Average Household Expenditures for Energy by Household Characteristic
(1998 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2338.54**	**1130.81**	**756.64**	**320.56**	**53.61**	**1207.73**
Households by Income Quintile						
1st	1435.03	862.48	554.80	269.52	38.16	572.56
2nd	1917.54	1001.80	653.09	303.03	45.67	915.74
3rd	2485.39	1123.84	779.00	289.59	55.25	1361.55
4th	2660.04	1226.39	839.08	326.69	60.63	1433.65
5th	3261.09	1453.41	972.09	411.74	69.58	1807.68
Households by Census Division						
New England	2670.71	1416.36	748.92	313.61	353.82	1254.36
Middle Atlantic	2273.09	1352.64	699.27	467.89	185.48	920.46
South Atlantic	2390.30	1104.19	607.04	478.00	19.15	1286.10
East North Central	2244.40	1038.57	640.94	364.84	32.80	1205.82
East South Central	2211.06	1126.76	928.03	174.07	24.66	1084.30
West North Central	2631.52	1212.02	969.02	238.29	4.72	1419.49
West South Central	2462.04	1210.36	926.79	283.56	0.00	1251.68
Mountain	2435.56	974.91	652.60	317.90	4.41	1460.66
Pacific	2196.19	899.70	626.86	262.31	10.53	1296.49

Source: Energy Information Administration, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Table E5. 2020 Average Household Expenditures for Energy by Household Characteristic
(1998 Dollars)

Household Characteristics	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
	Fuels					
Average U.S. Household	**2340.45**	**1127.01**	**762.45**	**315.32**	**49.25**	**1213.43**
Households by Income Quintile						
1st	1433.39	858.30	559.22	263.89	35.19	575.08
2nd	1917.32	998.07	657.91	297.75	42.41	919.25
3rd	2489.32	1120.75	784.50	285.68	50.57	1368.57
4th	2667.46	1224.91	847.20	321.92	55.79	1442.55
5th	3273.93	1451.13	981.32	406.18	63.64	1822.79
Households by Census Division						
New England	2684.74	1420.18	766.60	313.60	339.98	1264.56
Middle Atlantic	2260.87	1346.73	713.83	460.98	171.92	914.14
South Atlantic	2379.95	1097.88	607.59	472.06	18.23	1282.07
East North Central	2230.51	1032.63	638.77	363.21	30.65	1197.88
East South Central	2220.20	1124.90	929.22	173.22	22.46	1095.30
West North Central	2632.36	1211.65	966.91	240.15	4.59	1420.70
West South Central	2485.71	1236.29	957.33	278.96	0.00	1249.42
Mountain	2487.93	960.62	642.91	313.76	3.95	1527.31
Pacific	2183.72	887.02	621.11	256.45	9.45	1296.70

Source: Energy Information Administration, AEO2000 National Energy Modeling System run AEO2K.D100199A.

Appendix F

Results from Side Cases

Table F1. Key Results for Residential Sector Technology Cases

Energy Consumption	1998	2005				2010			
		2000 Tech.	Reference Case	High Technology	Best Available Tech.	2000 Tech.	Reference Case	High Technology	Best Available Tech.
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.84	0.80	0.79	0.75	0.72	0.76	0.73	0.68	0.63
Kerosene	0.10	0.09	0.09	0.09	0.08	0.09	0.09	0.08	0.07
Liquefied Petroleum Gas	0.41	0.45	0.44	0.43	0.39	0.45	0.43	0.42	0.39
Petroleum Subtotal	1.36	1.34	1.31	1.27	1.20	1.30	1.25	1.18	1.09
Natural Gas	4.61	5.31	5.22	5.03	4.86	5.62	5.46	5.06	4.81
Coal	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05
Renewable Energy	0.38	0.44	0.44	0.43	0.44	0.45	0.44	0.43	0.43
Electricity	3.83	4.43	4.37	4.30	4.07	4.83	4.70	4.57	4.12
Delivered Energy	**10.24**	**11.58**	**11.40**	**11.08**	**10.62**	**12.26**	**11.91**	**11.29**	**10.52**
Electricity Related Losses	8.53	9.55	9.42	9.27	8.78	10.02	9.76	9.47	8.55
Total	**18.77**	**21.12**	**20.82**	**20.35**	**19.40**	**22.27**	**21.66**	**20.76**	**19.06**
Delivered Energy Consumption per Household (million Btu per year)	**99.54**	**104.03**	**102.43**	**99.58**	**95.44**	**104.66**	**101.65**	**96.40**	**89.78**

Table F2. Key Results for Commercial Sector Technology Cases

Energy Consumption	1998	2005				2010			
		2000 Tech.	Reference Case	High Technology	Best Available Tech.	2000 Tech.	Reference Case	High Technology	Best Available Tech.
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.38	0.38	0.38	0.38	0.37	0.38	0.38	0.37	0.36
Residual Fuel	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Kerosene	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquid Petroleum Gas	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Motor Gasoline	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.61	0.62	0.62	0.62	0.61	0.62	0.62	0.62	0.61
Natural Gas	3.11	3.44	3.43	3.42	3.34	3.60	3.58	3.55	3.43
Coal	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Electricity	3.56	4.07	4.06	4.02	3.79	4.40	4.36	4.27	3.91
Delivered Energy	**7.46**	**8.31**	**8.28**	**8.23**	**7.91**	**8.80**	**8.74**	**8.62**	**8.13**
Electricity Related Losses	7.93	8.78	8.75	8.66	8.17	9.12	9.04	8.87	8.11
Total	**15.38**	**17.09**	**17.03**	**16.89**	**16.08**	**17.92**	**17.78**	**17.49**	**16.24**
Delivered Energy Consumption per Square Foot (thousand Btu per year)	**121.74**	**123.79**	**123.40**	**122.66**	**117.83**	**124.17**	**123.33**	**121.68**	**114.73**

Table F1. Key Results for Residential Sector Technology Cases (Continued)

2015				2020				Annual Growth 1998-2020			
2000 Tech.	Reference Case	High Technology	Best Available Tech.	2000 Tech.	Reference Case	High Technology	Best Available Tech.	2000 Tech.	Reference Case	High Technology	Best Available Tech.
0.73	0.69	0.62	0.56	0.71	0.65	0.57	0.50	-0.8%	-1.2%	-1.8%	-2.3%
0.09	0.09	0.08	0.07	0.09	0.09	0.08	0.07	-0.7%	-0.9%	-1.2%	-1.9%
0.45	0.42	0.40	0.37	0.45	0.41	0.39	0.36	0.4%	0.0%	-0.2%	-0.6%
1.27	1.19	1.10	1.00	1.24	1.15	1.04	0.93	-0.4%	-0.8%	-1.2%	-1.7%
5.90	5.65	5.05	4.69	6.22	5.86	5.04	4.39	1.4%	1.1%	0.4%	-0.2%
0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	-0.4%	-0.4%	-0.4%	-0.4%
0.46	0.45	0.43	0.43	0.47	0.45	0.43	0.44	0.9%	0.8%	0.5%	0.6%
5.20	5.00	4.78	4.18	5.58	5.30	4.99	4.33	1.7%	1.5%	1.2%	0.5%
12.88	**12.34**	**11.42**	**10.36**	**13.56**	**12.81**	**11.56**	**10.15**	**1.3%**	**1.0%**	**0.6%**	**-0.0%**
10.36	9.96	9.54	8.34	10.71	10.18	9.59	8.31	1.0%	0.8%	0.5%	-0.1%
23.24	**22.30**	**20.96**	**18.70**	**24.27**	**22.99**	**21.16**	**18.45**	**1.2%**	**0.9%**	**0.5%**	**-0.1%**
105.12	**100.69**	**93.18**	**84.57**	**106.28**	**100.44**	**90.61**	**79.51**	**0.3%**	**0.0%**	**-0.4%**	**-1.0%**

Tech. = Technology.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all feedbacks are captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2000 National Energy Modeling System, runs RSFRZN.D100499A, AEO2K.D100199A, RSHIGH.D100499B, and RSBEST.D100499A.

Table F2. Key Results for Commercial Sector Technology Cases (Continued)

2015				2020				Annual Growth 1998-2020			
2000 Tech.	Reference Case	High Technology	Best Available Tech.	2000 Tech.	Reference Case	High Technology	Best Available Tech.	2000 Tech.	Reference Case	High Technology	Best Available Tech.
0.37	0.37	0.36	0.35	0.36	0.36	0.35	0.34	-0.2%	-0.2%	-0.3%	-0.5%
0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	-0.2%	-0.2%	-0.2%	-0.2%
0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.1%	-0.1%	-0.1%	-0.1%
0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.9%	0.9%	0.9%	0.9%
0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.3%	-0.3%	-0.3%	-0.3%
0.62	0.62	0.61	0.60	0.61	0.60	0.60	0.59	-0.0%	-0.1%	-0.1%	-0.2%
3.73	3.71	3.68	3.54	3.77	3.75	3.72	3.57	0.9%	0.9%	0.8%	0.6%
0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.9%	0.9%	0.9%	0.9%
0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	N/A	0.0%	0.0%	0.0%
4.66	4.58	4.45	4.01	4.79	4.68	4.51	4.04	1.4%	1.2%	1.1%	0.6%
9.19	**9.10**	**8.93**	**8.33**	**9.35**	**9.22**	**9.01**	**8.38**	**1.0%**	**1.0%**	**0.9%**	**0.5%**
9.28	9.14	8.88	8.01	9.20	8.98	8.66	7.76	0.7%	0.6%	0.4%	-0.1%
18.47	**18.24**	**17.81**	**16.34**	**18.55**	**18.20**	**17.67**	**16.14**	**0.9%**	**0.8%**	**0.6%**	**0.2%**
125.35	**124.09**	**121.74**	**113.67**	**126.62**	**124.85**	**122.04**	**113.52**	**0.2%**	**0.1%**	**0.0%**	**-0.3%**

Tech. = Technology.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all feedbacks are captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2000 National Energy Modeling System, runs COMFZN.D100499B, AEO2K.D100199A, COMHTEK.D100499A, and COMBTEK.D100499A.

Table F3. Key Results for Industrial Technology Cases

Consumption	1998	2010			2015			2020		
		2000 Technology	Reference Case	High Technology	2000 Technology	Reference Case	High Technology	2000 Technology	Reference Case	High Technology
Energy Consumption (quadrillion Btu)										
Distillate Fuel	1.08	1.30	1.29	1.28	1.39	1.38	1.36	1.47	1.46	1.42
Liquefied Petroleum Gas	2.06	2.41	2.40	2.36	2.54	2.53	2.46	2.65	2.64	2.54
Petrochemical Feedstocks	1.39	1.58	1.58	1.55	1.67	1.66	1.62	1.74	1.73	1.67
Residual Fuel	0.27	0.31	0.29	0.28	0.32	0.30	0.27	0.34	0.31	0.27
Motor Gasoline	0.21	0.25	0.25	0.24	0.27	0.26	0.26	0.28	0.28	0.28
Other Petroleum	4.11	4.76	4.72	4.69	4.95	4.91	4.85	5.08	5.03	4.95
Petroleum Subtotal	9.12	10.60	10.53	10.40	11.14	11.04	10.82	11.57	11.45	11.12
Natural Gas	9.75	11.26	10.96	10.85	11.94	11.53	11.29	12.46	11.99	11.64
Metallurgical Coal[1]	0.82	0.88	0.83	0.77	0.88	0.82	0.72	0.88	0.80	0.67
Steam Coal	1.54	1.66	1.59	1.39	1.70	1.61	1.39	1.74	1.63	1.39
Coal Subtotal	2.36	2.54	2.42	2.17	2.58	2.42	2.11	2.62	2.43	2.06
Renewable Energy	2.08	2.36	2.40	2.46	2.46	2.53	2.62	2.55	2.63	2.75
Electricity	3.57	4.29	4.15	4.00	4.60	4.45	4.22	4.87	4.70	4.40
Delivered Energy	**26.89**	**31.05**	**30.46**	**29.88**	**32.72**	**31.96**	**31.05**	**34.07**	**33.20**	**31.97**
Electricity Related Losses	7.95	8.90	8.61	8.29	9.18	8.87	8.42	9.36	9.03	8.46
Total	**34.84**	**39.94**	**39.08**	**38.17**	**41.91**	**40.83**	**39.47**	**43.43**	**42.23**	**40.43**
Delivered Energy Use per Dollar of Output (thousand Btu per 1987 dollar)	**6.52**	**5.95**	**5.84**	**5.73**	**5.71**	**5.58**	**5.42**	**5.52**	**5.38**	**5.18**

[1]Includes net coal coke imports.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2000 National Energy Modeling System runs INDFRZN2K.D100599A, AEO2K.D100199A, and INDHIGH2K.D100599A.

Table F4. Key Results for Transportation Technology Cases

Consumption and Indicators	1998	2010			2015			2020		
		2000 Tech.	Reference Case	High Tech.	2000 Tech.	Reference Case	High Tech.	2000 Tech.	Reference Case	High Tech.
Energy Consumption (quadrillion Btu)										
Distillate Fuel	4.95	5.96	5.76	5.57	6.45	6.02	5.64	6.91	6.22	5.69
Jet Fuel	3.36	4.93	4.85	4.83	5.72	5.55	5.40	6.55	6.24	5.88
Motor Gasoline	15.59	19.52	19.12	17.58	21.08	20.30	17.81	22.52	21.35	18.03
Residual Fuel	0.65	0.94	0.92	0.92	1.07	1.05	1.05	1.20	1.18	1.17
Liquid Petroleum Gas	0.05	0.11	0.11	0.13	0.12	0.12	0.18	0.13	0.13	0.21
Other Petroleum	0.30	0.34	0.34	0.34	0.36	0.36	0.36	0.37	0.37	0.37
Petroleum Subtotal	24.89	31.79	31.10	29.37	34.80	33.39	30.44	37.69	35.49	31.36
Pipeline Fuel Natural Gas	0.75	0.87	0.87	0.87	0.95	0.95	0.95	0.99	0.99	0.99
Compressed Natural Gas	0.02	0.22	0.23	0.24	0.27	0.29	0.31	0.30	0.33	0.36
Renewables (E85)	0.00	0.06	0.06	0.08	0.08	0.07	0.10	0.09	0.08	0.12
Methanol (M85)	0.01	0.11	0.10	0.13	0.15	0.13	0.16	0.17	0.15	0.18
Liquid Hydrogen	0.00	0.00	0.00	0.01	0.00	0.00	0.02	0.00	0.00	0.03
Electricity	0.07	0.13	0.12	0.10	0.17	0.15	0.11	0.19	0.17	0.12
Delivered Energy	**25.74**	**33.18**	**32.48**	**30.79**	**36.41**	**34.99**	**32.08**	**39.43**	**37.20**	**33.15**
Electricity Related Losses	0.15	0.28	0.26	0.20	0.33	0.30	0.22	0.36	0.32	0.22
Total	**25.89**	**33.45**	**32.74**	**30.99**	**36.75**	**35.28**	**32.30**	**39.80**	**37.53**	**33.38**
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[1]	24.2	24.2	25.6	30.5	24.2	26.2	32.3	24.2	26.5	33.3
New Car (miles per gallon)[1]	28.2	29.1	31.4	36.3	29.2	31.7	38.1	29.2	31.6	39.0
New Light Truck (miles per gallon)[1]	20.6	20.7	21.6	26.4	20.7	22.3	28.1	20.7	22.8	29.1
Light-Duty Fleet (miles per gallon)[2]	20.7	20.0	20.4	22.2	19.7	20.5	23.3	19.4	20.6	24.3
New Commercial Light Truck (MPG)[3]	20.4	20.2	21.0	25.4	20.1	21.6	27.0	20.1	22.1	28.0
Stock Commercial Light Truck (MPG)[3]	14.7	15.6	15.8	17.1	15.8	16.2	18.2	15.8	16.5	19.2
Aircraft Efficiency (seat miles per gallon)	51.4	55.4	56.4	56.7	56.5	58.4	60.2	57.4	60.5	64.5
Freight Truck Efficiency (miles per gallon)	5.6	5.9	6.0	6.2	5.9	6.2	6.6	6.0	6.4	7.0
Rail Efficiency (ton miles per thousand Btu)	2.7	2.8	3.1	3.3	2.8	3.2	3.5	2.8	3.4	3.8
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.4	2.5	2.8	2.9	2.5	3.0	3.2	2.5	3.2	3.4
Light-Duty Vehicles Less Than 8500 Pounds (vehicle miles traveled)	**2403**	**3046**	**3048**	**3057**	**3278**	**3282**	**3296**	**3491**	**3498**	**3516**

[1]Environmental Protection Agency rated miles per gallon.
[2]Combined car and light truck "on-the-road" estimate.
[3]Commercial trucks 8,500 to 10,000 pounds.
Tech = Technology.
Btu = British thermal unit.
MPG = Miles per gallon.

Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.

Source: Energy Information Administration, AEO2000 National Energy Modeling System runs FROZEN.D100499A, AEO2K.D100199A, and HTECH.D100599F.

Table F5. Key Results for Integrated Technology Cases

Consumption and Emissions	1998	2010			2015			2020		
		2000 Technology	Reference Case	High Technology	2000 Technology	Reference Case	High Technology	2000 Technology	Reference Case	High Technology
Consumption by Sector (quadrillion Btu)										
Residential	18.8	22.3	21.7	20.8	23.2	22.3	21.1	24.3	23.0	21.1
Commercial	15.4	17.9	17.8	17.6	18.4	18.2	18.0	18.5	18.2	17.7
Industrial	34.8	40.1	39.1	37.9	42.1	40.8	39.3	43.7	42.2	40.1
Transportation	25.9	33.5	32.7	31.1	36.8	35.3	32.5	39.8	37.5	33.8
Total	**94.9**	**113.8**	**111.3**	**107.4**	**120.6**	**116.7**	**111.0**	**126.3**	**120.9**	**112.6**
Consumption by Fuel (quadrillion Btu)										
Petroleum Products	37.2	45.0	44.0	41.9	48.5	46.6	43.3	51.7	49.1	44.7
Natural Gas	22.0	28.9	27.7	26.5	32.1	30.7	28.8	33.6	32.4	30.0
Coal	21.5	25.4	25.1	24.3	26.4	25.8	25.0	27.8	26.6	24.9
Nuclear Power	7.2	6.7	6.7	6.7	5.4	5.5	5.0	4.7	4.6	3.8
Renewable Energy	6.7	7.4	7.4	7.6	7.8	7.7	8.4	8.2	8.0	8.8
Other	0.3	0.4	0.4	0.4	0.3	0.3	0.4	0.4	0.4	0.4
Total	**94.9**	**113.8**	**111.3**	**107.4**	**120.6**	**116.7**	**111.0**	**126.3**	**120.9**	**112.6**
Energy Intensity (thousand Btu per 1992 dollar of GDP)	**12.6**	**11.3**	**11.1**	**10.7**	**10.8**	**10.5**	**10.0**	**10.4**	**9.9**	**9.2**
Carbon Emissions by Sector (million metric tons)										
Residential	283.5	353.6	343.7	328.4	376.7	361.0	340.7	400.8	377.7	344.1
Commercial	237.5	290.7	288.8	283.4	306.4	303.0	297.6	313.7	307.3	295.9
Industrial	476.8	552.6	534.4	511.7	585.6	561.8	532.5	611.8	584.1	542.6
Transportation	487.5	634.7	619.7	587.9	696.8	667.5	613.7	753.4	710.0	637.5
Total	**1,485.4**	**1,831.6**	**1,786.6**	**1,711.4**	**1,965.5**	**1,893.4**	**1,784.4**	**2,079.7**	**1,979.2**	**1,820.2**
Carbon Emissions by End-Use Fuel (million metric tons)										
Petroleum	611.9	753.5	737.1	702.6	814.4	783.5	726.6	870.8	825.6	749.5
Natural Gas	262.0	307.9	301.3	295.0	324.7	316.1	305.7	337.1	327.4	313.4
Coal	61.7	68.4	65.4	58.9	69.7	65.5	57.4	70.7	65.6	56.1
Other	0.0	1.9	1.8	2.1	2.6	2.3	2.6	3.1	2.7	3.0
Electricity	549.8	699.9	681.0	652.9	754.1	725.9	692.1	798.1	757.8	698.2
Total	**1,485.4**	**1,831.6**	**1,786.6**	**1,711.4**	**1,965.5**	**1,893.4**	**1,784.4**	**2,079.7**	**1,979.2**	**1,820.2**
Carbon Emissions by Electric Generators (million metric tons)										
Petroleum	24.8	13.7	10.2	6.1	14.3	8.6	3.8	14.1	7.7	3.0
Natural Gas	47.8	105.7	95.0	84.5	134.6	123.1	105.9	144.7	136.2	115.7
Coal	477.3	580.6	575.8	562.3	605.3	594.2	582.4	639.3	613.9	579.5
Total	**549.8**	**699.9**	**681.0**	**652.9**	**754.1**	**725.9**	**692.1**	**798.1**	**757.8**	**698.2**
Carbon Emissions by Primary Fuel (million metric tons)										
Petroleum	636.7	767.2	747.3	708.7	828.6	792.1	730.4	884.8	833.3	752.5
Natural Gas	309.8	413.6	396.3	379.4	459.2	439.3	411.6	481.8	463.7	429.1
Coal	538.9	648.9	641.2	621.2	675.0	659.7	639.7	710.0	679.5	635.5
Other	0.0	1.9	1.8	2.1	2.6	2.3	2.6	3.1	2.7	3.0
Total	**1,485.4**	**1,831.6**	**1,786.6**	**1,711.4**	**1,965.5**	**1,893.4**	**1,784.4**	**2,079.7**	**1,979.2**	**1,820.2**

Btu = British thermal unit.
GDP = Gross domestic product.
Note: Includes end-use, fossil electricity, and renewable technology assumptions. Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2000 National Energy Modeling System runs LTRKITEN.D100799A, AEO2K.D100199A, and HTRKITEN.D100799A.

Table F6. Key Results for Buildings Efficiency Standards Cases

Energy Consumption	1998	2010 Reference Case	2010 10% Standards Case	2010 20% Standards Case	2015 Reference Case	2015 10% Standards Case	2015 20% Standards Case	2020 Reference Case	2020 10% Standards Case	2020 20% Standards Case
Energy Consumption (quadrillion Btu)										
Distillate Fuel	1.22	1.10	1.10	1.10	1.05	1.05	1.05	1.01	1.00	1.00
Kerosene	0.14	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Liquefied Petroleum Gas	0.48	0.52	0.52	0.52	0.51	0.50	0.50	0.50	0.49	0.48
Petroleum Subtotal[1]	1.97	1.87	1.87	1.87	1.81	1.80	1.80	1.75	1.73	1.73
Natural Gas	7.72	9.04	8.98	8.97	9.36	9.21	9.15	9.61	9.36	9.26
Coal	0.14	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Renewable Energy	0.46	0.52	0.52	0.52	0.52	0.52	0.52	0.53	0.53	0.53
Electricity	7.40	9.06	8.92	8.92	9.58	9.33	9.33	9.97	9.65	9.63
Delivered Energy[1]	**17.69**	**20.65**	**20.44**	**20.44**	**21.44**	**21.03**	**20.96**	**22.03**	**21.43**	**21.31**
Electricity Related Losses	16.46	18.80	18.50	18.51	19.11	18.61	18.60	19.16	18.54	18.50
Total[1]	**34.15**	**39.44**	**38.95**	**38.94**	**40.54**	**39.64**	**39.56**	**41.19**	**39.97**	**39.81**
Buildings Carbon Emissions (million metric tons)	**521.00**	**632.49**	**624.35**	**624.30**	**664.00**	**648.86**	**647.74**	**685.06**	**664.63**	**661.97**

[1]Includes small amounts of residual fuel and motor gasoline consumption in the commercial sector.
Btu = British thermal unit.
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 efficiency standards cases. Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2000 National Energy Modeling System, runs AEO2K.D100199A, RSSTD10.D100599A, COMSTND.D100599C, RSSTD20.D100599A, and COMSTND.D100599E.

Table F7. Key Results for Nuclear Generation Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capability, Generation, Emissions, and Fuel Prices	1998	Projections								
		2010			2015			2020		
		Low Nuclear	Reference Case	High Nuclear	Low Nuclear	Reference Case	High Nuclear	Low Nuclear	Reference Case	High Nuclear
Electric Generators										
Capability										
Coal Steam	305.2	303.6	301.7	301.1	310.3	306.8	305.3	322.2	317.0	313.6
Other Fossil Steam	138.2	119.8	119.5	119.8	114.1	117.1	115.4	106.6	109.9	113.0
Combined Cycle	19.5	100.5	93.1	92.5	135.9	124.7	120.3	166.7	154.6	145.6
Combustion Turbine/Diesel	73.2	154.7	153.5	151.2	180.5	180.4	176.6	200.6	202.3	199.4
Nuclear Power	97.1	72.5	84.1	90.2	53.5	67.4	79.7	43.7	57.0	71.1
Pumped Storage	19.9	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Fuel Cells	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Renewable Sources	87.2	93.8	93.8	93.8	95.3	95.3	95.3	96.7	96.7	96.6
Total	**740.2**	**865.0**	**865.7**	**868.8**	**909.8**	**911.8**	**912.8**	**956.6**	**957.5**	**959.5**
Cumulative Planned Additions	**0.0**	**11.1**	**11.1**	**11.1**	**12.0**	**12.0**	**12.0**	**12.2**	**12.2**	**12.2**
Cumulative Unplanned Additions										
Coal Steam	0.0	4.3	3.8	3.4	11.7	9.5	8.2	25.0	21.0	17.8
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	76.4	68.9	68.4	111.8	100.6	96.2	142.6	130.5	121.5
Combustion Turbine/Diesel	0.0	82.4	81.9	79.4	109.3	109.4	105.3	129.5	132.3	128.1
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	1.8	1.8	1.8	2.6	2.6	2.6	3.8	3.8	3.7
Total	**0.0**	**164.8**	**156.4**	**153.0**	**235.3**	**222.1**	**212.4**	**300.9**	**287.6**	**271.1**
Cumulative Total Additions	**0.0**	**175.9**	**167.4**	**164.0**	**247.4**	**234.1**	**224.4**	**313.1**	**299.8**	**283.3**
Cumulative Retirements	**0.0**	**58.6**	**48.4**	**42.9**	**85.3**	**69.0**	**59.2**	**104.2**	**89.0**	**71.5**
Generation by Fuel Type (billion kilowatthours)										
Coal	1817	2138	2121	2115	2233	2200	2176	2337	2296	2260
Petroleum	114	53	48	43	51	41	38	43	37	35
Natural Gas	325	847	796	780	1147	1085	1034	1309	1256	1198
Nuclear Power	674	555	627	655	405	511	589	326	427	524
Pumped Power	-2	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources	360	380	381	380	387	386	387	394	393	393
Total	**3288**	**3973**	**3973**	**3973**	**4222**	**4222**	**4222**	**4408**	**4409**	**4409**
Carbon Emissions by Electric Generators (million metric tons)										
Petroleum	24.8	11.4	10.2	9.2	10.7	8.6	7.9	8.9	7.7	7.2
Natural Gas	47.8	100.4	95.0	92.9	128.9	123.1	117.6	140.6	136.2	131.0
Coal	477.3	580.7	575.8	573.9	603.0	594.2	587.9	623.7	613.9	605.7
Total	**549.8**	**692.5**	**681.0**	**676.0**	**742.7**	**725.9**	**713.3**	**773.2**	**757.8**	**744.0**
Natural Gas Prices to Electric Generators (1998 dollars per mcf)	**2.40**	**3.23**	**3.14**	**3.10**	**3.41**	**3.28**	**3.18**	**3.54**	**3.41**	**3.27**
Coal Prices to Electric Generators (1998 dollars per short ton)	**25.64**	**22.35**	**22.13**	**22.12**	**21.42**	**21.19**	**21.26**	**20.14**	**20.01**	**20.05**

Mcf = Thousand cubic feet.

Notes: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators for AEO2000. Net summer capability is used to be consistent with electric utility capability estimates. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured.

Source: Energy Information Administration, AEO2000 National Energy Modeling System runs LNUC00.D100599A, AEO2K.D100199A, and HNUC00.D100599A.

Table F8. Key Results for Electricity Demand Cases

Key Indicators	1998	2005		2010		2020		Annual Growth 1998-2020	
		Reference Case	High Demand	Reference Case	High Demand	Reference Case	High Demand	Reference Case	High Demand
Electricity Sales (billion kilowatthours)	**3,236**	**3,647**	**3,784**	**3,909**	**4,203**	**4,350**	**5,002**	**1.4%**	**2.0%**
Net Imports (billion kilowatthours)	**30**	**43**	**43**	**26**	**26**	**20**	**20**	**-1.8%**	**-1.8%**
Electricity Prices									
(1998 cents per kilowatthour)	**6.7**	**6.1**	**6.3**	**6.0**	**6.5**	**5.8**	**6.5**	**-0.6%**	**-0.1%**
Generation by Fuel (billion kilowatthours)									
Coal	1,869	2,128	2,160	2,173	2,250	2,347	2,746	1.0%	1.8%
Natural Gas	520	717	804	1,001	1,187	1,477	1,685	4.9%	5.5%
Renewables	408	416	416	435	434	453	456	0.5%	0.5%
Nuclear	674	674	674	627	627	427	439	-2.1%	-1.9%
Petroleum/Other	130	81	106	68	115	58	121	-3.6%	-0.2%
Total	**3,601**	**4,016**	**4,161**	**4,303**	**4,613**	**4,762**	**5,447**	**1.3%**	**1.9%**
Generating Capability (gigawatts)									
Coal	305.2	301.6	301.5	301.7	305.8	317.0	366.8	0.2%	0.8%
Combined-Cycle/CombustionTurbine	92.6	170.8	172.4	246.5	265.4	356.9	410.1	6.3%	7.0%
Renewables	87.2	91.1	91.1	93.8	93.9	96.7	97.0	0.5%	0.5%
Nuclear Power	97.1	93.4	93.4	84.1	84.1	57.0	58.7	-2.4%	-2.3%
Cogenerators	50.3	55.6	55.6	56.8	56.8	60.2	60.1	0.8%	0.8%
Petroleum/Other	158.0	145.3	145.2	139.6	138.8	130.0	123.6	-0.9%	-1.1%
Total	**790.4**	**857.8**	**859.2**	**922.6**	**944.8**	**1,017.6**	**1,116.4**	**1.2%**	**1.6%**
Cumulative Electric Generator Capability Additions (gigawatts)									
Coal Steam	0.0	0.8	0.8	3.9	7.1	21.1	70.2	N/A	N/A
Combined Cycle/Turbines	0.0	80.0	81.4	157.0	175.2	269.0	320.7	N/A	N/A
Renewable Sources	0.0	3.7	3.7	6.6	6.6	9.7	10.0	N/A	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A	N/A
Other	0.0	0.0	0.0	0.0	0.0	0.1	0.1	N/A	N/A
Total	**0.0**	**84.5**	**86.0**	**167.5**	**188.9**	**299.8**	**401.0**	**N/A**	**N/A**
Energy Production									
Coal (million short tons)	1,128	1,221	1,240	1,242	1,277	1,316	1,473	0.7%	1.2%
Natural Gas (trillion cubic feet)	18.88	19.70	20.46	22.46	23.95	26.40	27.39	1.5%	1.7%
Carbon Emissions by Electric Generators (million metric tons)									
Petroleum	24.8	13.6	19.1	10.2	20.9	7.7	20.8	-5.2%	-0.8%
Natural Gas	47.8	66.6	79.5	95.0	119.5	136.2	157.7	4.9%	5.6%
Coal	477.3	565.3	574.6	575.8	596.2	613.9	692.8	1.2%	1.7%
Total	**549.8**	**645.5**	**673.3**	**681.0**	**736.7**	**757.8**	**871.3**	**1.5%**	**2.1%**
Electric Generator Fossil Fuel Consumption (quadrillion Btu)									
Petroleum	1.23	0.64	0.90	0.48	0.99	0.37	0.99	-5.3%	-1.0%
Coal	19.00	22.13	22.50	22.54	23.36	24.01	27.08	1.1%	1.6%
Natural Gas	3.75	4.62	5.52	6.60	8.30	9.46	10.95	4.3%	5.0%
Prices to Electric Generators (1998 dollars per million Btu)									
Petroleum	2.24	3.23	3.20	3.28	3.25	3.54	3.54	2.1%	2.1%
Coal	1.25	1.11	1.12	1.07	1.11	0.98	1.00	-1.1%	-1.0%
Natural Gas	2.34	2.79	2.97	3.08	3.52	3.33	3.98	1.6%	2.4%

Btu = British thermal unit.
N/A = Not applicable.
Notes: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports. Other includes non-coal fossil steam, pumped storage, methane, propane and blast furnace gas. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured.
Source: Energy Information Administration, AEO2000 National Energy Modeling System runs AEO2K.D100199A, and HIEL2K.D100599A.

Table F9. Key Results for Electricity Sector Fossil Technology Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capability, and Emissions	1998	2005			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	304.7	300.5	300.6	301.3	299.4	298.6	303.1	309.8	300.5	313.5
Coal Gasification Combined-Cycle	0.5	0.5	1.0	3.1	0.5	3.0	9.5	0.5	16.5	17.9
Conventional Natural Gas Combined-Cycle	19.5	47.9	40.8	44.4	80.8	55.3	48.3	157.2	68.4	48.7
Advanced Natural Gas Combined-Cycle	0.0	8.1	15.0	11.3	11.2	37.8	43.4	11.9	86.3	142.7
Conventional Combustion Turbine	73.2	116.6	111.7	108.0	155.9	140.4	135.5	192.2	163.5	148.0
Advanced Combustion Turbine	0.0	2.3	3.3	5.4	2.9	13.1	14.9	3.0	38.8	37.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
Nuclear	97.1	93.4	93.4	93.4	84.1	84.1	83.0	57.0	57.0	49.5
Oil and Gas Steam	138.2	123.1	125.3	123.5	118.9	119.5	117.1	110.3	109.9	87.2
Renewable Sources	107.0	111.1	111.1	111.1	113.8	113.9	113.7	117.3	116.7	116.4
Total	**740.2**	**803.7**	**802.2**	**801.5**	**867.4**	**865.7**	**868.6**	**959.2**	**957.5**	**961.0**
Cumulative Planned Additions										
Pulverized Coal	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
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	0.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
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 Combustion Turbine	0.0	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
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	0.1	0.1	0.1
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	0.0	2.7	2.7	2.7	4.8	4.8	4.8	5.9	5.9	5.9
Total	**0.0**	**8.9**	**8.9**	**8.9**	**11.1**	**11.1**	**11.1**	**12.2**	**12.2**	**12.2**
Cumulative Unplanned Additions										
Pulverized Coal	0.0	0.3	0.3	1.0	1.5	1.3	5.4	13.9	5.0	19.2
Coal Gasification Combined-Cycle	0.0	0.0	0.5	2.5	0.0	2.5	9.0	0.0	16.0	17.4
Conventional Natural Gas Combined-Cycle	0.0	23.7	16.6	20.3	56.7	31.2	24.2	133.1	44.2	24.6
Advanced Natural Gas Combined-Cycle	0.0	8.1	15.0	11.3	11.2	37.8	43.4	11.9	86.3	142.7
Conventional Combustion Turbine	0.0	43.3	38.8	35.0	84.1	68.8	63.8	121.0	93.6	80.0
Advanced Combustion Turbine	0.0	2.3	3.3	5.4	2.9	13.1	14.9	3.0	38.8	37.0
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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	1.1	1.1	1.1	1.7	1.8	1.7	4.3	3.8	3.5
Total	**0.0**	**78.8**	**75.6**	**76.6**	**158.1**	**156.4**	**162.3**	**287.2**	**287.6**	**324.4**
Cumulative Total Additions	**0.0**	**87.8**	**84.5**	**85.5**	**169.2**	**167.4**	**173.4**	**299.4**	**299.8**	**336.6**
Cumulative Retirements	**0.0**	**31.0**	**28.9**	**30.9**	**48.7**	**48.4**	**51.7**	**87.2**	**89.0**	**122.6**
Carbon Emissions by Electric Generators (million metric tons)										
Petroleum	24.8	13.0	13.6	12.4	10.9	10.2	7.7	12.1	7.7	3.5
Natural Gas	47.8	69.0	66.6	65.7	101.1	95.0	88.0	145.3	136.2	120.5
Coal	477.3	562.1	565.3	566.6	571.4	575.8	583.6	612.7	613.9	608.0
Total	**549.8**	**644.1**	**645.5**	**644.7**	**683.4**	**681.0**	**679.3**	**770.1**	**757.8**	**732.0**
Cogenerators										
Capability										
Coal	8.8	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Petroleum	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Natural Gas	31.8	35.8	35.7	35.8	36.4	36.4	36.4	38.4	38.4	38.4
Other Gaseous Fuels	0.4	0.8	0.8	0.8	0.8	0.8	0.8	1.0	1.0	1.0
Renewables	6.6	7.4	7.4	7.4	7.9	7.9	7.9	9.0	9.0	9.0
Other	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Total	**50.3**	**55.6**	**55.6**	**55.6**	**56.8**	**56.8**	**56.9**	**60.2**	**60.2**	**60.2**
Cumulative Additions	**0.0**	**5.3**	**5.3**	**5.3**	**6.6**	**6.6**	**6.6**	**9.9**	**9.9**	**9.9**
Other Generators[1]										
Capability	1.1	1.2	1.2	1.2	1.4	1.4	1.4	1.8	1.8	1.8
Cumulative Additions	0.0	0.1	0.1	0.1	0.3	0.3	0.3	0.7	0.7	0.7

[1] Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

Notes: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators for AEO2000. Net summer capacity is used to be consistent with electric utility capacity estimates.

Source: Energy Information Administration, AEO2000 National Energy Modeling System runs LOTECEL.D100799A, AEO2K.D100199A, and HITECEL.D100799A.

Table F10. Key Results for Electricity Competitive Pricing Cases

Key Indicators	1998	2005			2010			2020		
		Low Gas Price	Mid Gas Price	High Gas Price	Low Gas Price	Mid Gas Price	High Gas Price	Low Gas Price	Mid Gas Price	High Gas Price
Electricity Sales										
(billion kilowatthours)	**3,236**	**3,665**	**3,663**	**3,660**	**3,935**	**3,919**	**3,900**	**4,380**	**4,321**	**4,247**
Electricity Prices										
(1998 cents per kilowatthour)	**6.7**	**5.9**	**5.9**	**6.0**	**5.7**	**5.9**	**6.1**	**5.5**	**6.0**	**6.8**
Generation by Fuel										
(billion kilowatthours)										
Coal	1,869	2,129	2,136	2,138	2,155	2,176	2,191	2,227	2,315	2,385
Natural Gas	520	740	725	714	1,056	1,007	954	1,644	1,470	1,209
Oil	121	63	69	74	44	56	73	29	53	160
Nuclear	674	674	674	674	627	627	627	428	427	433
Conventional Hydropower	324	305	305	305	305	305	305	304	304	304
Geothermal	14	16	16	16	17	17	17	23	24	24
Municipal Solid Waste	21	29	29	29	34	34	34	39	39	39
Wood and Other Biomass	44	57	57	57	66	64	66	69	70	72
Solar Thermal	1	1	1	1	1	1	1	1	1	1
Solar Photovoltaic	0	0	0	0	1	1	1	2	2	2
Wind	3	8	8	8	11	11	11	12	12	12
Other[1]	9	13	13	13	13	13	13	15	15	14
Total	**3,601**	**4,036**	**4,033**	**4,030**	**4,331**	**4,313**	**4,294**	**4,794**	**4,731**	**4,655**
Generating Capability										
(gigawatts)										
Coal	314	310	310	310	310	310	311	316	321	327
Natural Gas and Oil	264	332	332	332	393	390	387	492	476	457
Nuclear	97	93	93	93	84	84	84	57	57	58
Conventional Hydropower	79	79	79	79	79	79	79	79	79	79
Geothermal	3	3	3	3	3	3	3	4	4	4
Municipal Solid Waste	3	4	4	4	5	5	5	6	6	6
Wood and Other Biomass	8	9	9	9	10	10	10	11	11	12
Solar Thermal	0	0	0	0	0	0	0	0	0	0
Solar Photovoltaic	0	0	0	0	1	1	1	1	1	2
Wind	2	4	4	4	5	5	5	5	5	6
Other[1]	22	22	22	22	22	22	22	22	22	22
Total	**792**	**857**	**857**	**857**	**913**	**910**	**908**	**994**	**984**	**972**
Energy Production										
Coal (million short tons)	1,128	1,223	1,226	1,228	1,234	1,244	1,250	1,259	1,304	1,346
Natural Gas (trillion cubic feet)	18.9	20.0	19.8	19.5	23.2	22.6	21.8	28.3	26.5	24.7
Carbon Emissions by Electric Generators										
(million metric tons)										
Petroleum	24.8	12.3	13.6	14.8	8.0	10.6	14.4	4.6	9.7	29.2
Natural Gas	47.8	69.8	67.6	66.0	102.8	96.4	89.4	159.5	138.1	107.7
Coal	477.3	565.6	567.6	568.1	571.3	577.0	581.1	586.6	608.5	625.4
Total	**549.8**	**647.7**	**648.8**	**648.9**	**682.1**	**684.1**	**685.0**	**750.8**	**756.3**	**762.2**
Fuel Prices to Electric Generators										
(1998 dollars per million Btu)										
Coal	1.25	1.11	1.11	1.11	1.07	1.08	1.08	0.97	0.99	1.02
Natural Gas	2.34	2.69	2.79	2.90	2.80	3.06	3.33	2.72	3.34	4.27

[1]Includes pumped storage and for cogenerators, refiners and still gas, and hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquer.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2000 National Energy Modeling System runs LMRG.D100899B, COMP.D100299A, and HMRG.D100899A.

Table F11. Key Results for Renewable Portfolio Standard Cases

Key Indicators	1998	2010				2020			
		Reference	RPS Cap and Sunset	RPS Cap No Sunset	RPS No Cap No Sunset	Reference	RPS Cap and Sunset	RPS Cap No Sunset	RPS No Cap No Sunset
Electricity Sales (billion kilowatthours)	**3,236**	**3,909**	**3,907**	**3,905**	**3,883**	**4,350**	**4,348**	**4,341**	**4,327**
Electricity Prices									
(1998 cents per kilowatthour)	**6.67**	**5.97**	**5.99**	**6.00**	**6.16**	**5.82**	**5.83**	**5.86**	**5.90**
National Electricity Bill									
(billion 1998 dollars)	**215.9**	**233.4**	**233.9**	**234.3**	**239.2**	**253.2**	**253.4**	**254.4**	**255.3**
Change in Bill from Reference									
(billion 1998 dollars)	**N/A**	**N/A**	**0.5**	**0.9**	**5.8**	**N/A**	**0.2**	**1.3**	**2.1**
Generation by Fuel[1]									
(billion kilowatthours)									
Coal	1,869	2,173	2,110	2,124	2,101	2,347	2,329	2,294	2,238
Natural Gas	520	1,001	984	967	890	1,477	1,474	1,454	1,389
Oil	121	54	51	53	39	44	46	44	33
Nuclear	674	627	627	627	627	427	427	427	428
Conventional Hydropower	317	300	300	300	300	299	299	299	299
Geothermal	14	17	24	28	35	25	41	53	65
Municipal Solid Waste	21	34	34	34	34	39	39	39	39
Wood and Other Biomass	44	65	95	92	151	70	69	91	131
Solar Thermal	1	1	1	1	1	1	1	1	1
Solar Photovoltaic	0	0	0	0	0	1	1	1	1
Wind	3	11	11	11	80	12	12	12	96
Other[2]	9	13	13	13	13	15	15	15	15
Total	**3,594**	**4,298**	**4,251**	**4,252**	**4,271**	**4,757**	**4,754**	**4,731**	**4,735**
RPS Qualifying Renewable Generation	**75**	**116**	**152**	**154**	**287**	**133**	**149**	**183**	**318**
Generating Capacity (gigawatts)[1]									
Coal	314	311	311	311	308	326	324	323	312
Natural Gas and Oil	264	404	404	402	384	507	507	505	495
Nuclear	97	84	84	84	84	57	57	57	57
Conventional Hydropower	78	78	78	78	78	78	78	78	78
Geothermal	3	3	4	4	5	4	6	7	9
Municipal Solid Waste	3	5	5	5	5	6	6	6	6
Wood and Other Biomass	8	10	10	10	15	11	11	11	21
Solar Thermal	0	0	0	0	0	0	0	0	0
Solar Photovoltaic	0	0	0	0	0	1	1	1	1
Wind	2	5	5	5	31	5	5	6	36
Other[2]	22	22	22	22	22	22	22	22	22
Total	**790**	**923**	**924**	**923**	**933**	**1,018**	**1,018**	**1,017**	**1,037**
Energy Production									
Coal (million short tons)	1,128	1,242	1,214	1,222	1,212	1,316	1,308	1,291	1,273
Natural Gas (trillion cubic feet)	18.9	22.5	22.3	22.2	21.9	26.4	26.5	26.4	26.3
Total Carbon Emissions									
(million metric tons)	**1,485**	**1,787**	**1,768**	**1,770**	**1,753**	**1,979**	**1,978**	**1,966**	**1,947**
Carbon Change from Reference									
(million metric tons)	**N/A**	**N/A**	**-19**	**-17**	**-34**	**N/A**	**-1**	**-13**	**-32**
Fuel Prices to Electric Generators									
(1998 dollars per million Btu)									
Coal	1.25	1.07	1.07	1.05	1.06	0.98	0.98	0.98	0.99
Natural Gas	2.34	3.08	3.04	3.02	2.85	3.33	3.30	3.28	3.11

[1]Includes grid-connected utilities and nonutilities and cogenerators, but does not include small on-site generating systems in the residential, commercial, and industrial sectors.
[2]Includes pumped storage and for cogenerators, refiners and still gas, and hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquer.
Btu = British thermal unit.
N/A = Not applicable.
RPS = Renewable portfolio standard.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2000 National Energy Modeling System runs AEO2K.D100199A, RPS2KSUN.D100699A, RPS2KCAP.D100699A, and RPS2KFUL.D100699B.

Table F12. Key Results for High Renewable Energy Case

Capacity, Generation, and Emissions	1998	2010		2020	
		Reference	High Renewables	Reference	High Renewables
Renewable Capability (Gigawatts)					
Net Summer Capability					
Electric Generators					
Conventional Hydropower	77.71	78.33	78.33	78.33	78.33
Geothermal	2.89	2.98	4.01	3.75	5.67
Municipal Solid Waste	2.49	4.47	4.98	5.17	5.88
Wood and Other Biomass	1.76	2.41	2.41	2.93	3.54
Solar Thermal	0.33	0.40	0.40	0.48	0.48
Solar Photovoltaic	0.01	0.19	0.19	0.52	0.52
Wind	1.99	5.07	5.57	5.49	17.99
Total	**87.19**	**93.84**	**95.88**	**96.67**	**112.40**
Cogenerators					
Municipal Solid Waste	0.52	0.52	0.52	0.52	0.52
Wood and Other Biomass	6.04	7.37	7.37	8.46	8.46
Total	**6.56**	**7.89**	**7.89**	**8.98**	**8.98**
Other Generators[1]					
Conventional Hydropower	1.10	1.10	1.10	1.10	1.10
Geothermal	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.01	0.35	0.35	0.74	0.74
Total	**1.10**	**1.44**	**1.44**	**1.84**	**1.84**
Generation (billion kilowatthours)					
Electric Generators					
Coal	1817	2121	2103	2296	2273
Petroleum	114	48	43	37	32
Natural Gas	325	796	805	1256	1214
Total Fossil[2]	**2256**	**2966**	**2952**	**3589**	**3518**
Conventional Hydropower	316.79	300.50	300.50	299.35	299.35
Geothermal	14.29	17.35	25.47	24.70	39.84
Municipal Solid Waste	17.78	30.63	34.11	35.71	40.54
Wood and Other Biomass	6.86	20.35	20.43	18.80	20.50
Solar Thermal	0.89	1.09	1.09	1.35	1.35
Solar Photovoltaic	0.00	0.46	0.46	1.30	1.30
Wind	3.39	10.95	12.83	12.09	61.70
Total Renewable	**360.00**	**381.33**	**394.88**	**393.32**	**464.58**
Cogenerators					
Coal	52	51	51	51	51
Petroleum	8	6	6	7	7
Natural Gas	195	205	205	220	220
Total Fossil[2]	**255**	**262**	**262**	**278**	**278**
Municipal Solid Waste	3.00	3.13	3.13	3.13	3.13
Wood and Other Biomass	37.34	45.06	45.06	51.02	51.02
Total Renewables	**40.34**	**48.19**	**48.19**	**54.15**	**54.15**
Other Generators[1]					
Conventional Hydropower	7.25	4.85	4.85	4.83	4.83
Geothermal	0.00	0.07	0.07	0.07	0.07
Solar Photovoltaic	0.01	0.46	0.46	0.50	0.50
Total	**7.26**	**5.38**	**5.38**	**5.40**	**5.40**
Carbon Emissions (million metric tons)					
Electric Generators					
Petroleum	24.8	10.2	9.1	7.7	6.6
Natural Gas	47.8	95.0	96.2	136.2	130.9
Coal	477.3	575.8	570.6	613.9	608.6
Total	**549.8**	**681.0**	**675.9**	**757.8**	**746.1**

[1]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[2]Total of items presented.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2000 National Energy Modeling System runs AEO2K.D100199A and HIRENEW.D100799A.

Table F13. Key Results for Oil and Gas Technological Progress Cases
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1998	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	13.23	11.00	11.35	11.70	10.28	10.96	11.76	9.86	11.13	12.53
Natural Gas Plant Liquids	2.49	2.54	2.57	2.59	2.83	2.90	2.99	3.14	3.36	3.58
Dry Natural Gas	19.40	20.02	20.25	20.41	22.47	23.09	23.79	25.29	27.13	28.92
Coal	23.89	25.84	25.79	25.76	26.28	26.18	25.93	28.14	27.36	26.28
Nuclear Power	7.19	7.20	7.20	7.20	6.70	6.70	6.70	4.62	4.56	4.57
Renewable Energy	6.67	7.07	7.07	7.07	7.40	7.39	7.39	7.99	7.98	7.95
Other	0.57	0.62	0.62	0.62	0.59	0.59	0.61	0.62	0.66	0.66
Total	**73.46**	**74.29**	**74.85**	**75.34**	**76.54**	**77.81**	**79.16**	**79.67**	**82.18**	**84.49**
Imports										
Crude Oil[1]	18.90	23.83	23.49	23.15	25.53	24.91	24.12	26.52	25.22	23.90
Petroleum Products	3.99	5.43	5.37	5.30	7.01	6.80	6.63	11.96	10.87	10.45
Natural Gas	3.37	4.55	4.52	4.55	4.93	4.91	4.95	4.41	5.61	5.92
Other Imports	0.59	0.99	0.99	0.99	0.89	0.89	0.89	0.97	0.97	0.97
Total	**26.85**	**34.81**	**34.38**	**33.99**	**38.36**	**37.50**	**36.60**	**43.87**	**42.67**	**41.23**
Exports										
Petroleum	1.94	1.92	1.94	1.96	1.90	1.97	2.01	1.84	1.93	2.05
Natural Gas	0.17	0.24	0.24	0.24	0.29	0.29	0.29	0.36	0.36	0.36
Coal	2.05	1.59	1.59	1.59	1.63	1.63	1.60	1.46	1.46	1.46
Total	**4.16**	**3.75**	**3.76**	**3.80**	**3.83**	**3.89**	**3.90**	**3.67**	**3.76**	**3.87**
Discrepancy	**1.27**	**0.20**	**0.18**	**0.18**	**0.17**	**0.16**	**0.15**	**0.18**	**0.14**	**0.06**
Consumption										
Petroleum Products	37.21	41.25	41.21	41.15	44.10	43.98	43.90	49.98	49.05	48.88
Natural Gas	21.99	24.37	24.57	24.76	27.09	27.69	28.43	29.34	32.38	34.47
Coal	21.50	24.75	24.72	24.67	25.23	25.12	24.91	27.39	26.60	25.54
Nuclear Power	7.19	7.20	7.20	7.20	6.70	6.70	6.70	4.62	4.56	4.57
Renewable Energy	6.67	7.07	7.08	7.07	7.41	7.41	7.40	8.01	7.99	7.97
Other	0.32	0.50	0.50	0.50	0.36	0.36	0.36	0.36	0.36	0.36
Total	**94.88**	**105.15**	**105.28**	**105.35**	**110.90**	**111.26**	**111.70**	**119.69**	**120.95**	**121.78**
Net Imports - Petroleum	**20.95**	**27.35**	**26.92**	**26.49**	**30.63**	**29.73**	**28.74**	**36.64**	**34.15**	**32.29**
Carbon Emissions by Primary Fuel (million metric tons)										
Petroleum	636.7	700.8	699.9	698.2	750.1	747.3	745.4	853.2	833.3	829.3
Natural Gas	309.8	348.6	351.5	354.2	387.7	396.3	407.0	419.8	463.7	493.7
Coal	538.9	631.8	630.9	629.6	644.1	641.2	635.8	699.9	679.5	652.3
Other	0.0	1.1	1.1	1.1	1.7	1.8	1.7	2.6	2.7	2.6
Total	**1,485.4**	**1,682.4**	**1,683.4**	**1,683.2**	**1,783.6**	**1,786.6**	**1,789.9**	**1,975.6**	**1,979.2**	**1,978.0**
Prices (1998 dollars per unit)										
World Oil Price (dollars per barrel)	12.10	20.49	20.49	20.49	21.00	21.00	21.00	22.04	22.04	22.04
Gas Wellhead Price (dollars per Mcf)	1.96	2.44	2.34	2.25	2.86	2.60	2.33	3.74	2.81	2.23
Coal Minemouth Price (dollars per ton)	17.51	14.69	14.71	14.79	13.98	13.84	13.78	12.57	12.54	12.55
Average Electricity Price (cents per Kwh)	6.7	6.1	6.1	6.1	6.1	6.0	5.9	6.3	5.8	5.5
Natural Gas Supply and Disposition										
Production (trillion cubic feet)										
Dry Gas Production	18.88	19.47	19.70	19.86	21.86	22.46	23.14	24.60	26.40	28.13
Supplemental Natural Gas	0.12	0.11	0.11	0.11	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports (trillion cubic feet)	**3.13**	**4.22**	**4.19**	**4.22**	**4.53**	**4.52**	**4.56**	**3.96**	**5.14**	**5.44**
Total Supply (trillion cubic feet)	**22.13**	**23.81**	**24.00**	**24.19**	**26.45**	**27.03**	**27.75**	**28.63**	**31.59**	**33.63**

Table F13. Key Results for Oil and Gas Technological Progress Cases (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1998	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
Consumption by Sector (trillion cubic feet)										
Residential	4.48	5.05	5.07	5.10	5.24	5.30	5.37	5.44	5.69	5.87
Commercial	3.03	3.32	3.34	3.35	3.43	3.48	3.54	3.44	3.65	3.77
Industrial	8.23	8.77	8.81	8.84	9.11	9.22	9.34	9.57	9.99	10.22
Electric Generators	3.67	4.42	4.53	4.62	6.15	6.45	6.88	7.33	9.26	10.61
Lease and Plant Fuel	1.24	1.25	1.26	1.27	1.40	1.43	1.46	1.58	1.67	1.75
Pipeline Fuel	0.73	0.74	0.75	0.75	0.82	0.84	0.87	0.88	0.96	1.02
Transportation	0.02	0.15	0.15	0.15	0.22	0.22	0.23	0.31	0.32	0.33
Total	**21.39**	**23.71**	**23.91**	**24.09**	**26.37**	**26.95**	**27.68**	**28.56**	**31.53**	**33.57**
Discrepancy (trillion cubic feet)	**0.73**	**0.09**	**0.09**	**0.09**	**0.08**	**0.08**	**0.08**	**0.06**	**0.05**	**0.05**
Crude Oil Supply										
Lower 48 Average Wellhead Price (1998 dollars per barrel)	**11.60**	**20.09**	**20.08**	**19.99**	**20.67**	**20.62**	**20.54**	**21.33**	**21.27**	**21.08**
Production (million barrels per day)										
U.S. Total	**6.25**	**5.20**	**5.36**	**5.53**	**4.85**	**5.18**	**5.55**	**4.66**	**5.26**	**5.92**
Lower 48 Onshore	3.60	2.96	3.01	3.07	2.89	3.00	3.14	2.96	3.28	3.58
Conventional	2.87	2.39	2.42	2.45	2.33	2.39	2.46	2.38	2.57	2.79
Enhanced Oil Recovery	0.73	0.57	0.59	0.61	0.56	0.61	0.68	0.58	0.71	0.79
Lower 48 Offshore	1.47	1.31	1.38	1.47	1.22	1.36	1.54	1.28	1.47	1.72
Alaska	1.18	0.93	0.96	1.00	0.75	0.81	0.88	0.42	0.51	0.62
Lower 48 End of Year Reserves (billion barrels)	**18.05**	**13.73**	**14.15**	**14.57**	**12.65**	**13.38**	**14.34**	**11.85**	**13.21**	**14.65**
Natural Gas Supply										
Lower 48 Average Wellhead Price (1998 dollars per Mcf)	**1.96**	**2.44**	**2.34**	**2.25**	**2.86**	**2.60**	**2.33**	**3.74**	**2.81**	**2.23**
Production (trillion cubic feet)										
U.S. Total	**18.72**	**19.47**	**19.70**	**19.86**	**21.86**	**22.46**	**23.14**	**24.61**	**26.40**	**28.13**
Lower 48 Onshore	12.75	13.23	13.22	13.20	16.16	16.37	16.59	18.02	19.47	19.99
Associated-Dissolved	1.56	1.32	1.34	1.35	1.24	1.25	1.27	1.20	1.25	1.31
Non-Associated	11.19	11.90	11.88	11.85	14.92	15.12	15.33	16.82	18.22	18.69
Conventional	6.68	7.13	6.91	6.75	9.79	9.81	9.83	10.41	10.75	11.02
Unconventional	4.51	4.77	4.98	5.09	5.14	5.30	5.50	6.41	7.47	7.66
Lower 48 Offshore	5.53	5.79	6.02	6.20	5.21	5.60	6.06	6.04	6.39	7.60
Associated-Dissolved	0.88	0.88	0.89	0.91	0.85	0.88	0.92	0.86	0.91	0.97
Non-Associated	4.65	4.91	5.12	5.29	4.36	4.72	5.14	5.18	5.48	6.63
Alaska	0.44	0.46	0.46	0.46	0.49	0.49	0.49	0.54	0.54	0.54

Table F13. Key Results for Oil and Gas Technological Progress Cases (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1998	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
U.S. End of Year Reserves (trillion cubic feet)	**155.00**	**149.23**	**155.85**	**162.06**	**161.92**	**173.45**	**186.66**	**159.61**	**191.37**	**218.56**
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)	**23.96**	**25.75**	**24.92**	**24.85**	**34.54**	**32.86**	**31.35**	**42.26**	**38.66**	**36.57**
Electric Generator Capability (gigawatts)	**740.15**	**802.20**	**802.24**	**802.08**	**865.06**	**865.75**	**866.46**	**949.42**	**957.47**	**966.56**

Kwh = Kilowatthour.
Btu = British thermal unit.
Mcf = Thousand cubic feet.
Note: Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Sources: Energy Information Administration, AEO2000 National Energy Modeling System runs OGLTEC.D100799A, AEO2K.D100199A, and OGHTEC.D100799C.

Table F14. Key Results for Reduced Sulfur Gasoline Case

Changes in Gasoline Sulfur and Prices	2004	2007	2010
Changes in Gasoline Volumes by Sulfur Content (thousand barrels per day)			
340 ppm Average	-6,176	-6,506	-6,820
150 ppm	-3,084	-3,233	-3,359
80 ppm	6,176		
30 ppm	3,084	9,739	10,179
Changes in Cumulative Investment (billion 1998 dollars)	**2.19**	**5.65**	**7.74**
Changes in National Average Gasoline Prices (1998 cents per gallon)	**2.3**	**3.9**	**3.5**

PPM = Parts per million.
Note: Side cases were run without the fully integrated modeling system, so not all potential feedbacks are captured.
Source: Energy Information Administration, AEO2000 National Energy Modeling System runs 30PPMX.D100799B and RFDFT10.D100699B.

Table F15. Key Results for MTBE Reduction Case

Changes in Gasoline Blending, Imports, and Prices	2003	2004	2005
Changes in MTBE Blended with Gasoline (thousand barrels per day)	**-136**	**-140**	**-138**
Changes in Ethanol Blended with Gasoline (thousand barrels per day)	**27**	**20**	**21**
Changes in Imports of Gasoline and Blending Components (thousand barrels per day)	**135**	**123**	**141**
Changes in Cumulative Investment (billion 1998 dollars)	**2.43**	**2.11**	**1.71**
Changes in Gasoline Prices (1998 cents per gallon)			
National Average Gasoline Price	1.3	1.4	1.4
National Average Reformulated Gasoline Price	2.8	2.8	1.8

MTBE = Methyl tertiary butyl ether.
Note: Side cases were run without the fully integrated modeling system, so not all potential feedbacks are captured.
Source: Energy Information Administration, AEO2000 National Energy Modeling System runs TRG30.D100799D and RFDFT10.D100699B.

Table F16. Key Results for Coal Mining Cost Cases

Prices, Productivity, Wages, and Emissions	1998	2005			2010			2020		
		Low Cost	Reference Case	High Cost	Low Cost	Reference Case	High Cost	Low Cost	Reference Case	High Cost
Minemouth Price (1998 dollars per short ton)	17.51	13.96	14.71	15.90	12.60	13.84	15.81	10.56	12.54	15.05
Delivered Price to Electric Generators (1998 dollars per million Btu)	1.25	1.06	1.11	1.16	1.00	1.07	1.15	0.85	0.98	1.13
Labor Productivity (short tons per miner per hour)	6.47	8.85	8.19	7.31	10.77	9.17	7.55	14.01	10.61	7.86
Labor Productivity (average annual growth from 1998)	N/A	4.6	3.4	1.8	4.3	2.9	1.3	3.6	2.3	0.9
Average Coal Miner Wage (1998 dollars per hour)	19.15	18.49	19.15	19.83	18.03	19.15	20.33	17.15	19.15	21.37
Average Coal Miner Wage (average annual growth from 1998)	N/A	-0.5	0.0	0.5	-0.5	0.0	0.5	-0.5	0.0	0.5
Carbon Emissions by Electric Generators (million metric tons)										
Petroleum	24.8	13.1	13.6	13.5	9.8	10.2	9.9	6.9	7.7	9.0
Natural Gas	47.8	66.3	66.6	67.4	94.5	95.0	96.5	134.0	136.2	138.8
Coal	477.3	566.8	565.3	564.0	577.7	575.8	572.7	618.8	613.9	608.0
Total	**549.8**	**646.2**	**645.5**	**644.9**	**681.9**	**681.0**	**679.1**	**759.7**	**757.8**	**755.8**
Electric Generator Capability (gigawatts)	**740.2**	**802.1**	**802.2**	**802.0**	**866.0**	**865.7**	**866.5**	**958.4**	**957.5**	**960.4**

Btu = British thermal unit.
N/A = Not applicable.
Note: Side cases were run without the fully integrated modeling system, so not all potential feedbacks are captured. Totals may not equal sum of components due to independent rounding. Data for 1998 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2000 National Energy Modeling System runs LLCST2K.D100599C, AEO2K.D100199A, and HLCST2K.D100599A.

Appendix G

Major Assumptions for the Forecasts

The National Energy Modeling System

The projections in the *Annual Energy Outlook 2000* (*AEO2000*) are generated from the National Energy Modeling System (NEMS), developed and maintained by the Office of Integrated Analysis and Forecasting of the Energy Information Administration (EIA). In addition to its use in the development of the *AEO* projections, NEMS is also used in analytical studies for the U.S. Congress and other offices within the Department of Energy. The *AEO* forecasts are also used by analysts and planners in other government agencies and outside organizations.

The projections in NEMS are developed with the use of a market-based approach to energy analysis. For each fuel and consuming sector, NEMS balances 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 nine Census divisions for the end-use demand models; production regions specific to oil, gas, and coal supply and distribution; the North American Electric Reliability Council regions and subregions for electricity; and aggregations of the Petroleum Administration for Defense Districts for refineries.

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

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

Each NEMS component also represents the 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, 1999, such as the Clean Air Act Amendments of 1990 (CAAA90) and the costs of compliance with other regulations.

In general, the *AEO2000* projections were prepared by using the most current data available as of July 31, 1999. At that time, most 1998 data were available, but only partial 1999 data were available. Carbon emissions were calculated by using carbon coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 1998*, published in October 1999 [*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 *AEO2000* 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 *AEO2000* includes cogeneration in the industrial or commercial sector and other nonutility generators in the electricity sector. Footnotes in the appendix tables of this report indicate the definitions and sources of all historical data.

The *AEO2000* projections for 1999 and 2000 incorporate short-term projections from EIA's September 1999 *Short-Term Energy Outlook* (*STEO*). For short-term energy projections, readers are referred to the monthly updates of the *STEO* [*2*].

Component modules

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

Macroeconomic Activity Module

The Macroeconomic Activity Module provides a set of essential macroeconomic drivers to the energy modules and a macroeconomic feedback mechanism within NEMS. Key macroeconomic variables include gross domestic product (GDP), interest rates, disposable income, and employment. Industrial drivers are calculated for 35 industrial sectors. This module is a kernel regression representation of the Standard and Poor's DRI Macroeconomic Model of the U.S. Economy.

International Module

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

Household Expenditures Module

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

Residential and Commercial Demand Modules

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

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 alternative-fuel vehicles.

Electricity Market Module

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

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules that provide the representation of the supply response for biomass (including wood and energy crops), conventional hydroelectric, geothermal, municipal solid waste (including landfill gas), solar thermal, solar photovoltaics, and wind energy. The RFM contains natural resource supply estimates representing the regional opportunities for renewable energy development.

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships between the various sources of supply: onshore, offshore, and Alaska by both conventional and nonconventional techniques, including enhanced oil recovery and unconventional gas recovery from 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. *AEO2000* reflects the California ban on the gasoline blending component methyl tertiary butyl ether (MTBE) in 2003. Because the *AEO2000* reference case assumes current laws and regulations, it assumes that the Federal oxygen requirement for reformulated gasoline in Federal nonattainment areas will remain intact. Costs include capacity expansion for refinery processing units based on a 15-percent hurdle rate and a 15-percent return on investment. End-use prices are based on the marginal costs of production, plus markups representing product distribution costs, State and Federal taxes, and environmental costs.

Coal Market Module

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

Major assumptions for the *Annual Energy Outlook 2000*

Table G1 provides a summary of the cases used to derive the *AEO2000* forecasts. For each case, the table gives the name used in this report, a brief description of the major assumptions underlying the projections, a designation of the mode in which the case was run in the NEMS model (either fully integrated, partially integrated, or standalone), and a reference to the pages in the body of the report and in this appendix where the case is discussed.

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

World oil market assumptions

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

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

World oil supply. Supply outside the United States is assumed to be total liquids and includes production of crude oils (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, refinery gains, alcohol, and liquids produced from coal and other sources. The forecast of oil supply is a function of the world oil price, estimates of proved oil reserves, estimates of ultimately recoverable oil resources, and technological improvements that affect exploration, recovery, and cost. Estimates of proved oil reserves are provided by the *Oil & Gas Journal* and represent country-level assessments as of January 1, 1999. Estimates of ultimately recoverable oil resources are provided by the United States Geological Survey (USGS) and are part of its periodic "World Petroleum Assessment and Analysis." Technology factors are derived from the DESTINY forecast software and are a part of the International Energy Services of Petroconsultants, Incorporated.

Buildings sector assumptions

The buildings sector includes both residential and commercial structures. 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 that affect future buildings sector energy use. The most significant are minimum equipment efficiency standards, which require that new heating, cooling,

Table G1. Summary of the *AEO2000* 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 1.7 percent, compared to the reference case growth of 2.2 percent.	Fully integrated	p. 49	—
High Economic Growth	Gross domestic product grows at an average annual rate of 2.6 percent, compared to the reference case growth of 2.2 percent.	Fully integrated	p. 49	—
Low World Oil Price	World oil prices are $14.90 per barrel in 2020, compared to $22.04 per barrel in the reference case.	Fully integrated	p. 50	—
High World Oil Price	World oil prices are $28.04 per barrel in 2020, compared to $22.04 per barrel in the reference case.	Fully integrated	p. 50	—
Residential: 2000 Technology	Future equipment purchases based on equipment available in 2000. Building shell efficiencies fixed at 2000 levels.	Standalone	p. 61	p. 229
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone	p. 61	p. 229
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available. Existing building shell efficiencies increase by 25 percent from 1997 values by 2020.	Standalone	p. 61	p. 229
Commercial: 2000 Technology	Future equipment purchases based on equipment available in 2000. Building shell efficiencies fixed at 2000 levels.	Standalone	p. 62	p. 230
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone	p. 62	p. 230
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. 62	p. 230
Buildings: 10-Percent Standards	Assumes that near-term standards will be promulgated on time, and that future revisions will increase efficiency by 10 percent if technically feasible.	Standalone	p. 35	p. 231
Buildings: 20-Percent Standards	Assumes that near-term standards will be promulgated on time, and that future revisions will increase efficiency by 20 percent if technically feasible.	Standalone	p. 35	p. 231
Industrial: 2000 Technology	Efficiency of plant and equipment fixed at 2000 levels.	Standalone	p. 63	p. 231
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone	p. 63	p. 231
Transportation: 2000 Technology	Efficiencies for new equipment in all modes of travel are fixed at 2000 levels.	Standalone	p. 63	p. 233
Transportation: High Technology	Reduced costs and improved efficiencies are assumed for advanced technologies.	Standalone	p. 63	p. 233

Table G1. Summary of the *AEO2000* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix G
Consumption: 2000 Technology	Combination of the residential, commercial, industrial, and transportation 2000 technology cases and electricity low fossil technology case.	Fully integrated	p. 38	—
Consumption: High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases, electricity high fossil technology case, and high renewables case.	Fully integrated	p. 38	—
Electricity: Low Nuclear	Relative to the reference case, higher capital investments and operating costs are assumed to be required when plants are evaluated for retirement.	Partially integrated	p. 69	p. 235
Electricity: High Nuclear	No capital investments are assumed to be required through the initial 40-year plant lifetime, and investment and operating costs are lower than in the reference case.	Partially integrated	p. 69	p. 235
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. 69	p. 235
Electricity: Low Fossil Technology	New fossil generating technologies are assumed not to improve over time from 1999.	Fully integrated	p. 70	p. 235
Electricity: High Fossil Technology	Costs and efficiencies for advanced fossil-fired generating technologies are assumed to improve from reference case values.	Fully integrated	p. 70	p. 235
Electricity: Competitive Pricing With Reference Gas Prices	Competitive pricing is phased in over 10 years in all regions of the country.	Fully integrated	p. 21	p. 236
Electricity: Competitive Pricing With Higher Gas Prices	Competitive pricing is phased in over 10 years in all regions of the country. Cost, finding rate, and success rate parameters for natural gas adjusted for slower improvement.	Fully integrated	p. 22	p. 236
Electricity: Competitive Pricing With Lower Gas Prices	Competitive pricing is phased in over 10 years in all regions of the country. Cost, finding rate, and success rate parameters for natural gas adjusted for more rapid improvement.	Fully integrated	p. 22	p. 236
Electricity: RPS With Cap and Sunset	Nonhydroelectric renewable generation is required to increase to 7.5 percent of total electricity sales for the period 2010-2015, subject to a 1.5 cent per kilowatthour limit on the price of renewable credits. The RPS requirement sunsets in 2015.	Fully integrated	p. 18	p. 237
Electricity: RPS With Cap, No Sunset	Nonhydroelectric renewable generation is required to increase to 7.5 percent of total electricity sales in 2010 and all years thereafter, subject to a 1.5 cent per kilowatthour limit on the price of renewable credits.	Fully integrated	p. 18	p. 237
Electricity: RPS No Cap, No Sunset	Nonhydroelectric renewable generation is required to increase to 7.5 percent of total electricity sales in 2010 and all years thereafter.	Fully integrated	p. 18	p. 237
Renewables: High Renewables	Lower costs and higher efficiencies are assumed for new renewable generating technologies	Fully integrated	p. 72	p. 237

Table G1. Summary of the *AEO2000* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix G
Oil and Gas: Slow Technology	Cost, finding rate, and success rate parameters adjusted for slower improvement.	Fully integrated	p. 78	p. 237
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate parameters adjusted for more rapid improvement.	Fully integrated	p. 78	p. 237
Oil and Gas: Gasoline Sulfur Reduction	The sulfur content of all gasoline in the United States is reduced to a 30 ppm annual average standard starting in 2004. Reformulated gasoline meets the 30 ppm requirement in 2004. Conventional gasoline meets an 80 ppm specification in 2004 but meets the 30 ppm limit by 2007.	Standalone	p. 31	p. 239
Oil and Gas: BRP/MTBE Reduction	MTBE blended with gasoline is reduced to 3 percent of all gasoline by 2003. The Federal requirement for 2.0 percent oxygen in reformulated gasoline is waived.	Standalone	p. 34	p. 240
Coal: Low Mining Cost	Productivity increases at an annual rate of 3.6 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. 85	p. 241
Coal: High Mining Cost	Productivity increases at an annual rate of 0.9 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. 85	p. 241

and other specified energy-using equipment meet minimum energy efficiency levels, which change over time. The manufacture of equipment that does not meet the standards is prohibited. Executive Order 13123, “Greening the Government Through Efficient Energy Management,” signed in June 1999, is expected to affect future energy use in Federal buildings.

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

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

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 9 percent and 17 percent, respectively, by 2020 relative to the 1997 stock average. For space cooling, the corresponding increases are 7 percent and 16 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 that 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 5.6 million metric tons, primarily because of differences in the estimated penetration of energy-saving technologies.

The *AEO2000* version of the NEMS residential module is based on EIA's Residential Energy Consumption Survey (RECS) [*4*]. This survey, last conducted in 1997, provides most of the housing, appliance, and energy characteristics for the residential sector and NEMS residential module. The most significant changes from the 1993 RECS survey include energy use estimates for color televisions and personal computers. The estimates, derived from outside sources, have changed the *AEO2000* forecast for the amount of energy needed to power these devices. The new estimates have decreased the energy use attributable to color televisions while increasing the energy use attributable to personal computers in *AEO2000*, relative to *AEO99*.

In addition to the *AEO2000* 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 *2000 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2000. Building shell efficiencies are assumed to be fixed at 2000 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 25 percent over 1997 levels by 2020.

- The *high technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [*5*].

Commercial assumptions. Minimum equipment efficiency standards for the commercial sector are mandated in the EPACT legislation [*6*]. 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 *AEO2000* 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 through discount parameters for controlling cost-based equipment retrofit decisions in various market segments. To model programs such as Green Lights, which target particular end uses, the *AEO2000* 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 2010. For the reference case, carbon reductions are estimated to be 11.5 million metric tons in 2010, primarily because of differences in the estimated penetration of energy-saving technologies. Federal buildings are assumed to participate in CCAP programs and to use the 10-year Treasury Bond rate as a discount rate in making equipment purchase decisions, pursuant to the directives in Executive Order 13123.

The definition of the commercial sector for *AEO2000* is based on data from the 1995 Commercial Buildings Energy Consumption Survey (CBECS) [*7*]. Parking garages and commercial buildings on multibuilding manufacturing sites, included in the previous CBECS, were eliminated from the target building population for the 1995 CBECS. In addition, the CBECS data are estimates based on reported data from representatives of a randomly chosen subset of the entire population of commercial buildings. As a result, the estimates always differ from the true population values and vary from survey to survey. Differences between the estimated values and the actual population values result from both nonsampling errors that would be expected to occur in all possible samples and sampling errors that occur because the survey estimate is calculated from a randomly chosen subset of the entire population [*8*].

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 previous CBECS estimates. 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 *AEO2000* projections is seen in commercial energy intensity. Commercial energy use per square foot reported in *AEO2000* is significantly higher than in *AEO*s before *AEO99*, not because energy consumption is higher but because the 1995 floorspace estimates are lower. The variability between CBECS surveys also results in different estimates of the amount of each major fuel used to provide end-use services such as space heating, lighting, etc., affecting the *AEO2000* 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 *AEO2000* 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 *2000 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2000. Building shell efficiencies are assumed to be fixed at 2000 levels.

- The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than the reference case [*9*]. Building shell efficiencies are assumed to improve at a rate that is 50 percent faster than the rate of improvement in the reference case.

- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year in the high technology case, regardless of cost. Building shell efficiencies are assumed to improve at a 50 percent faster rate than in the reference case.

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

Distributed generation includes both photovoltaics and fuel cells. The forecast of distributed generation is developed on the basis of economic returns projected for investments in photovoltaics and fuel cells. The model uses a detailed cash-flow approach for each technology to estimate the number of years required to achieve a cumulative positive cash flow (although some technologies may never achieve a cumulative positive cash flow). Penetration assumptions for the distributed generation technologies are a function of the estimated number of years required to achieve a positive cash flow. Solar photovoltaic technology specifications for the residential and commercial sectors are based on a joint U.S. Department of Energy and Electric Power Research Institute report published in December 1997. Program-driven installations of photovoltaic systems are based on information from DOE's Photovoltaic and Million Solar Roofs programs, as well as DOE news releases and the Utility PhotoVoltaic Group web site. Commercial sector solar thermal consumption for water heating is represented by displaced primary energy relative to an electric water heater.

Buildings standards cases. The buildings sector also includes two cases to examine the potential effects of future appliance efficiency standards on energy consumption. For these cases, near-term efficiency standards and the effective dates of the standards are based on the American Council for an Energy-Efficient Economy's *Approaching the Kyoto Targets: Five Key Strategies for the United States*. Future updates to these standards are assumed to occur every 8 years, increasing the efficiency level by 10 percent and 20 percent—if technically feasible—in the *10-percent standards case* and *20-percent standards case*, respectively.

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* [*10*]. Compared to the building sector, there are relatively few regulations that target industrial sector energy use. The electric motor standards in EPACT require a 10-percent increase in efficiency above 1992 efficiency levels for motors sold after 1999 [*11*]. It has been estimated that electric motors account for about 60 percent of industrial process electricity use. Thus, these standards, incorporated into the Industrial Demand Module through the analysis of efficiencies for new industrial processes, are expected to lead to significant improvements in efficiency.

Climate Change Action Plan. Several programs included in the CCAP target the industrial sector, and 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. In their most recent update, the DOE program offices estimated that full implementation of these programs would reduce industrial electricity consumption by 20 billion kilowatthours and non-electric consumption by 193 trillion Btu in 2000. However, because the energy savings associated with the CCAP voluntary programs are, to a large extent, already contained in the *AEO2000* 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 in 2000. 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 DOE program offices estimated electricity savings of 79 billion kilowatthours and fossil fuel savings of 359 trillion Btu. For the reason cited above, the estimates for *AEO2000* were revised to 25 billion kilowatthours for electricity and 65 trillion Btu for fossil fuels. In this situation, carbon emissions would be reduced by about 5 million metric tons (1 percent) in 2010.

High technology and 2000 technology cases. The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*12*]. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changing composition of industrial output. Because the composition of industrial output remains the same as in the reference case, aggregate intensity falls by 1.2 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 1998 and 2020. The *2000 technology case* holds the energy efficiency of plant and equipment constant at the 2000 level over the forecast. Both cases were run with only the Industrial Demand Module rather than as fully integrated NEMS runs. Consequently, no potential feedback effects from energy market interactions were captured.

Transportation sector assumptions

The transportation sector accounts for two-thirds of the Nation's oil use and has been subject to regulations for many years. The Corporate Average Fuel Economy (CAFE) standards, which mandate average miles-per-gallon standards for manufacturers, continue to be widely debated. The *AEO2000* projections assume that there will be no further increase in the CAFE standards from the current 27.5 miles per gallon standard for automobiles and 20.7 miles per gallon for light trucks and sport utility vehicles. This assumption is consistent with the overall policy that only current legislation is assumed.

EPACT requires that centrally fueled light-duty fleet operators—Federal and State governments and fuel providers (e.g., gas and electric utilities)—purchase a minimum fraction of alternative-fuel vehicles [*13*]. Federal fleet purchases of alternative-fuel vehicles must reach 50 percent of their total vehicle purchases by 1998 and 75 percent by 1999. Purchases of alternative-fuel vehicles by State governments must reach 25 percent of total purchases by

1999 and 75 percent by 2001. Private fuel-provider companies are required to purchase 50 percent alternative-fuel vehicles in 1998, increasing to 90 percent by 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. The municipal and private business fleet mandates, which are proposed to begin in 2002 at 20 percent and scale up to 70 percent by 2005, are not included in *AEO2000*.

In addition to these requirements, the State of California has delayed its Low Emission Vehicle Program, which now requires that 10 percent of all new vehicles sold by 2003 meet the requirements for zero-emission vehicles (ZEVs). California recently passed legislation to allow 60 percent of the ZEV mandate to be met by ZEV credits from advanced technology vehicles, depending on their degree of similarity to electric vehicles. The remaining 40 percent of the ZEV mandate must be achieved with “true ZEVs,” which include only electric vehicles and hydrogen fuel cell vehicles [*14*]. Originally, Massachusetts and New York also adopted the California 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.

Technology choice. Conventional light-duty vehicle technologies are chosen by consumers and penetrate the market based on the assumption of cost-effectiveness, which compares the capital cost to the discounted stream of fuel savings from the technology. There are approximately 52 fuel-saving technologies, which vary by capital cost, date of availability, marginal fuel efficiency improvement, and marginal horsepower effect [*15*]. The projections assume that the regulations for alternative-fuel and advanced technology vehicles represent minimum requirements for alternative-fuel vehicle sales; consumers are allowed to purchase more of the vehicles if their cost, fuel efficiency, range, and performance characteristics make them desirable.

For freight trucks, technology choice is based on several technology characteristics, including capital cost, marginal fuel improvement, payback period, and discount rate, which are used to calculate a fuel price at which the technologies become cost-effective [*16*]. When the fuel price exceeds this price, the technology will begin to penetrate the market. When technologies are mutually exclusive, the more cost-effective technology will gain market share relative to the less cost-effective technology. Efficiency improvements for both rail and ship are based on recent historical trends [*17*].

Similar to freight trucks, fuel efficiency improvements for new aircraft are also determined by a trigger fuel price, the time the technology becomes commercially available, and the projected marginal fuel efficiency improvement. The advanced technologies are ultra-high bypass, propfan, thermodynamics, hybrid laminar flow, advanced aerodynamics, and weight-reducing materials [*18*].

Travel. Projections for both personal travel [*19*] and freight travel [*20*] are based on the assumption that modal shares (for example, personal automobile travel versus mass transit) remain stable over the forecast and follow recent historical patterns. Important factors affecting the forecast of vehicle-miles traveled for light-duty vehicles are personal disposable income per capita; the ratio of miles driven by females to males in the total driving population, which increases from 56 percent in 1990 to 80 percent by 2010; and the aging of the population, which will slow the growth in vehicle-miles traveled. The projections incorporate recent data indicating that retirees are driving far more than retirees of a decade ago.

Travel by freight truck, rail, and ship is based on the growth in industrial output by sector and the historical relationship between freight travel and industrial output [*21*]. Both rail and ship travel are also based on projected coal production and distribution. Air travel is estimated for domestic travel (both personal and business), international travel, and dedicated air freight by U.S. carriers. Depending on the market segment, the demand in air travel is based on projected disposable personal income, GDP, merchandise exports, and ticket price as a function of jet fuel prices. Load factors, which represent the percentage of seats occupied per plane and are used to convert air travel expressed in revenue-passenger miles and revenue-ton miles to seat-miles demand, remain relatively constant over the forecast period [*22*].

Climate Change Action Plan. Four CCAP programs focus on transportation energy use: (1) reform Federal subsidy for employer-provided parking; (2) adopt a transportation system efficiency strategy;

(3) promote telecommuting; and (4) develop fuel economy labels for tires. The assumed combined effect of the Federal subsidy, system efficiency, and telecommuting policies in the *AEO2000* reference case is a 1.6-percent reduction in vehicle-miles traveled (140 trillion Btu) by 2010, with a net carbon emissions reduction of 2.8 million metric tons. The fuel economy tire labeling program improved new fuel efficiency by 4 percent among pre-1999 vehicles that switched to low rolling resistance tires; therefore, there are no new fuel or carbon savings from this program.

2000 technology case. The *2000 technology case* assumes that new fuel efficiency levels are held constant at 2000 levels through the forecast horizon for all modes of travel.

High technology case. For the *high technology case*, light-duty alternative-fuel vehicle characteristics originate from the DOE Office of Energy Efficiency and Renewable Energy, and conventional light-duty vehicle fuel-saving technology characteristics are from the American Council for an Energy-Efficient Economy [*23*]. New technologies in this case include a high-efficiency advanced light-duty direct injection diesel vehicle with attributes similar to gasoline engines; electric and electric hybrid (gasoline and diesel) vehicles with higher efficiencies, lower costs, and earlier introduction dates than in the reference case; and fuel cell gasoline, methanol, and hydrogen light-duty vehicles. In the air travel sector, the high technology case assumes 40-percent efficiency improvement from new aircraft technologies by 2020, as concluded by the Aeronautics and Space Engineering Board of the National Research Council. Based on the analysis of the Federal Aviation Administration, the case also assumes an additional 5-percent fleet efficiency improvement from the Air Traffic Management program.

In the freight truck sector, the high technology case assumes more optimistic costs and incremental fuel efficiency improvements for technologies including advanced tires (existing and advanced), drag reduction (existing and advanced), advanced transmissions, lightweight materials, synthetic gear lube, electronic engine control, advanced engines, turbocompounding, hybrid power trains, and port injection [*24*]. More optimistic assumptions for fuel efficiency improvements are also made for the rail and shipping sectors.

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

Electricity assumptions

Characteristics of generating technologies. The costs and performance of new generating technologies are important factors in determining the future mix of capacity. There are 26 fossil, renewable, and nuclear generating technologies included in the *AEO2000* projections. Technologies represented include those currently available as well as those that are expected to be commercially available within the horizon of the forecast. Capital cost estimates and operational characteristics, such as efficiency of electricity production, are used for decisionmaking. It is assumed that the selection of new plants to be built is based on least cost, subject to environmental constraints. The incremental costs associated with each option are evaluated and used as the basis for selecting plants to be built. Details about each of the generating plant options are described in the detailed assumptions, which are available on the Internet at web site www.eia.doe.gov/oiaf/aeo/ assumption/index.html.

Regulation of electricity markets. It is assumed that electricity producers comply with CAAA90, which mandates a limit of 8.95 million short tons of sulfur dioxide emissions per year by 2010. Utilities are assumed to comply with the limits on sulfur 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 1998 dollars, although they 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.

The reference case assumes a transition to full competitive pricing in California, New York, New England, the Mid-Atlantic Area Council, and Texas. In addition, electricity prices in the East Central Area Reliability Council, the Mid-America Interconnected Network, and the Rocky Mountain Power Area/ Arizona (Arizona, New Mexico, Colorado, and eastern Wyoming) regions are assumed to be partially competitive. Some of the States in each of these regions have not taken action to deregulate their pricing of electricity, and in those States prices are assumed to continue to be based on traditional cost-of-service pricing. The reference case assumes that, in California, electricity prices will remain constant at nominal 1996 levels between 2000 and 2001 for commercial and industrial customers, whereas residential customers will see a 10-percent reduction from 1996 prices in 2000. A transition from regulated to competitive prices between 2002 and 2008 is assumed. Similarly, in the other regions for which competitive pricing is assumed, the transition period is assumed to be from 1999 through 2008, so that fully competitive pricing of electricity begins in 2009. The transition period reflects the time needed for the establishment of competitive market institutions and recovery of stranded costs as permitted by regulators. The reference case assumes that the competitive price in these regions will be the marginal cost of generation.

Competitive cost of capital. To better represent the risks facing developers of new generating plants in the restructured environment, the cost of capital has been reevaluated. The yield on debt represents that of an AA corporate bond rather than that of utilities, and the cost of equity is calculated to be more representative of unregulated industries similar to the electricity generation sector. Furthermore, it is assumed that the capital invested in a new plant must be recovered over a 20-year plant life rather than the traditional 30-year life. Because the transmission and distribution sectors are assumed to remain regulated, their cost of capital is reduced by 100 basis points from the level used for the generation sector.

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 reduce their greenhouse gas emissions voluntarily 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 emissions offsets from international sources.

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

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

It is assumed that older nuclear power plants will incur aging-related expenditures in the form of increased capital costs, decreases in performance, and/or increased maintenance expenditures to maintain a given level of performance. The decision to either incur the aging-related costs for a unit or retire it is based on the relative economics of the alternatives. In *AEO2000*, the retirement decision for each nuclear unit is evaluated every 10 years, starting after 30 years of operation. An assumption is made about the capital investment required to operate for an additional 10 years beyond the point of evaluation. In the reference case, the required capital investment is assumed to be $150 million at 30 years of operation, $175 million at 40 years, and $250 million at 50 years, where dollar amounts are based on an average plant size of 1,000 megawatts. The investment cost is assumed to be recovered over 10 years, and an annual payment is calculated. If the combined operating costs and annual capital payment costs are lower than the cost of building new capacity, then the nuclear unit continues to operate for another 10 years, until the next evaluation.

Plants that have recently incurred a major expenditure (such as a steam generator replacement) are assumed not to need an additional investment at 30 years and only one-third of the investment at 40 years. Additionally, the investment cost assumptions are adjusted downward for the newest vintage of nuclear reactors, to reflect improvements in construction and design.

Two alternative cases were developed with different assumptions about the capital investments required for nuclear plant life extension. In the *low nuclear case* the capital investment was increased by $50 million at each decision point, and the adjustments for new plants were removed, making them require higher capital investments. In the *high nuclear case* it was assumed that no additional investment would be needed during the first 40 years of operation, and the capital expenditures required to continue operation at 40 and 50 years were reduced by $100 million and $125 million, respectively.

The average nuclear capacity factor in 1998 was 78 percent, the highest annual average ever in the United States. The average annual capacity factor generally increases throughout the forecast, to a maximum of about 85 percent. Capacity factor assumptions are developed at the unit level, and improvements or decrements are based on the age of the reactor.

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

International learning. For *AEO2000*, capital costs for all new fossil-fueled electricity generating technologies decrease in response to foreign as well as domestic experience, to the extent that the new plants reflect technologies and firms also competing in the United States. *AEO2000* includes 2,524 megawatts of advanced coal gasification combined-cycle capacity and 5,244 megawatts of advanced combined-cycle natural gas capacity to be built outside the United States from 2000 through 2003.

High electricity demand case. The *high electricity demand case* assumes that the demand for electricity grows by 2.0 percent annually between 1998 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 standalone, partially integrated run. The Macroeconomic Activity, Petroleum Marketing, International Energy, and end-use demand modules use the reference case values and are not affected by the higher electricity demand growth. Conversely, the Oil and Gas, Natural Gas Transmission and Distribution, Coal Market, and Renewable Fuels Modules interact with the Electricity Market Module in the high electricity demand case. Rapid growth in electricity demand also leads to higher prices. The price of electricity in 2020 is 6.5 cents per kilowatthour in the high demand case, as compared with 5.8 cents in the reference case. Higher fuel prices, especially for natural gas, are the key factor leading to higher electricity prices.

High and low fossil technology cases. The high and low fossil technology cases are standalone, partially integrated cases. In the *high fossil technology case*, capital costs and heat rates for coal gasification combined-cycle units, pulverized coal units, molten carbonate fuel cell units, and advanced combustion turbine and combined-cycle units are assumed to be lower and decline faster than in the reference case. The capital costs and heat rates for renewable, nuclear, and other fossil technologies are assumed to be the same as in the reference case. The values used in the high fossil case for capital costs and heat rates were developed in consultation with DOE's Office of Fossil Energy. In the *low fossil technology case*, capital costs for coal gasification combined-cycle units, molten carbonate fuel cell units, and advanced combustion turbine and combined-cycle units do not decline during the forecast period and remain fixed at the 1999 capital costs assumed in the reference case. Details about annual capital costs, operating and maintenance costs, plant efficiencies, and other factors used in these assumptions are described in the detailed assumptions, which are available on the Internet at web site www.eia.doe.gov/oiaf/aeo/assumption/index.html.

Competitive pricing cases. The *competitive pricing cases* assume 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. Prices in two other regions, NWP and STV, are weighted to reflect the assumption that public power will still be priced at average costs. Reserve margins are set endogenously to balance the value consumers place on reliability against the cost of adding new capacity.

In the competitive pricing cases, 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, low-usage periods. All other assumptions, including improvements in operations and maintenance efficiency, are identical to those in the reference case.

In addition to the above assumptions, the *competitive pricing case with low gas prices* incorporates the oil and natural gas supply technology assumptions from the oil and gas rapid technology case. Similarly, the *competitive pricing case with high gas prices* incorporates the oil and natural gas supply technology assumptions from the oil and gas slow technology case.

Renewable fuels assumptions

Energy Policy Act of 1992. The EPACT 10-year renewable electricity production credit of 1.5 cents per kilowatthour for new wind plants expired on June 30, 1999, and was not extended. *AEO2000* applies the credit to all wind plants built through 1999 [*25*]. The 10-percent investment tax credit for solar and geothermal technologies that generate electric power is continued.

Supplemental additions. AEO2000 includes 5,249 megawatts of new central station generating capacity using renewable resources, as reported by utilities and independent power producers or identified by EIA to be built from 2000 through 2020, including 2,848 megawatts of wind capacity, 1,210 megawatts of municipal solid waste capacity (primarily landfill gas), 982 megawatts of biomass capacity (excluding co-firing capacity, which is included with coal), 163 megawatts of geothermal steam capacity, and 46 megawatts of central station solar capacity (thermal and photovoltaic). It includes the 5,168 megawatts expected to be added after 1999 as a result of State renewable portfolio standard (RPS) and other mandates and an additional 81 megawatts expected to result from voluntary initiatives by utilities and other generators. In instances where a State RPS defines the percentage of State electricity supply to be reached by renewables before 2020, the additional renewables capacity needed to maintain the percentage through 2020 is estimated.

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

Solar energy (direct normal insolation) for thermal applications is considered economical only in drier regions west of the Mississippi River. Photovoltaics can be economical in all regions, although conditions are also superior in the West. Wind energy resource potential, while large, is constrained by wind quality differences, distance from markets, power transmission costs, alternative land uses, and environmental objections. The geographic distribution of available wind resources is based on work by the Pacific Northwest Laboratory [*26*], enumerating winds among average annual wind-power classes. Geothermal energy is limited geographically to regions in the western United States with hydrothermal resources of hot water and steam. Although the potential for biomass is large, transportation costs limit the amount of the resource that is economically productive, because biomass fuels have a low thermal conversion factor (Btu content per weight of fuel). 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.

The *AEO2000* reference case incorporates capital cost adjustment factors (proxies for supply elasticities) for biomass and wind technologies, in recognition of the higher costs of consuming increasing proportions of a region's resources. Capital costs are assumed to increase in response to (1) declining natural resource quality, such as rough or steep terrain or turbulent winds, (2) increasing costs of upgrading the existing transmission and distribution network, and (3) market conditions that increase wind costs in competition with other land uses, such as for crops, recreation, or environmental or cultural preferences. These factors have no effect on the *AEO2000* reference case but can affect results in cases assuming rapid growth in demand for renewable energy technologies.

High renewables case. For the *high renewables case*, greater improvements are assumed for central station generating technologies using renewable resources than in the reference case, including capital costs falling either 15 percent below reference case estimates by 2020 or to match DOE's Office of Energy Efficiency and Renewable Energy December 1997 *Renewable Energy Technology Characterizations* [*27*], whichever is lower. This case also incorporates reduced operations and maintenance costs, improvements in capacity factors for wind technologies, and increased biomass supplies. Other generating technologies and forecast assumptions remain unchanged from the reference case.

Renewable portfolio standard (RPS) cases. The RPS cases show possible outcomes from the RPS in the Administration's proposed Comprehensive Electricity Competition Act (CECA). The CECA RPS requires retail electricity suppliers annually to obtain renewable energy credits equal to an increasing percentage of retail electricity sales, reaching 7.5 percent by 2010 through expiration (sunset) in 2015. Credits are obtained by (1) generating with specified renewables, one credit for every kilowatthour; (2) purchasing credits from others; or (3) purchasing credits unsupported by generation from DOE at 1.5 cents per credit. The 1.5-cent offering effectively sets a credit price maximum, or "cap."

Three cases examine the CECA RPS. The *RPS with cap and sunset case* has both the 1.5-cent credit price cap and the 2015 sunset provision. The *RPS with cap, no sunset case* has no sunset, remaining in force indefinitely and thereby requiring some additional renewables capacity after 2015 in order to maintain the 7.5-percent share. The "no sunset" provision effectively extends the credit subsidy for the full operating life of all qualified renewables capacity built before 2015, increasing its economic value and encouraging the construction of additional renewable energy capacity. The *RPS no cap, no sunset case* features neither a cap nor a sunset, illustrating the importance of the 1.5-cent credit cap. Removing 1.5-cent cap has the effect of forcing construction of renewable energy capacity even at costs above 1.5 cents per kilowatthour.

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 [*28*].

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 roughly from 0.3 percent to 2.0 percent. These technological impacts work against increases in costs associated with drilling to greater depths, higher drilling activity levels, and rig availability. 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 by plus or minus 33 percent. For unconventional gas, a number of key exploration and production technologies were assumed to penetrate at alternative rates with varying degrees of effectiveness in the *rapid and slow technology cases*. For consistency, Canadian consumption and key supply parameters were adjusted to simulate the assumed impacts of rapid and slow oil and gas technology penetration on Canadian markets.

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

All other parameters in the model were kept at the reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of liquefied natural gas and natural gas trade between the United States and Mexico. Specific detail by region and fuel category is presented in the *Assumptions to the Annual Energy Outlook 2000*, which will be available on the Internet at web site at www.eia.doe.gov/oiaf/aeo/assumption/index.html.

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 *AEO2000* assumption is that it reaches production levels of 29 billion cubic feet in 2010 and 35 billion cubic feet in 2020.

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

Gas supply from Alaska and LNG imports. The Alaska Natural Gas Transportation System is assumed to come on line no earlier than 2005 and only after the U.S.-Canada border price reaches $3.93, in 1998 dollars per thousand cubic feet. The liquefied natural gas (LNG) facilities at Everett, Massachusetts, and Lake Charles, Louisiana (the only ones currently in operation) have a combined operating capacity of 359 billion cubic feet per year, including a 1999 expansion of 48 billion cubic feet in the Massachusetts facility. The facility at Elba Island, Georgia, is assumed to reopen in 2002, bringing total operating capacity to 477 billion cubic feet. The facility at Cove Point, Maryland, is assumed to reopen when economically justified, but not before 2000. Should this facility reopen, total LNG operating capacity would increase to 842 billion cubic feet per year.

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

In determining interstate pipeline tariffs, capital expenditures for refurbishment over and above 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.) Distribution markups to core customers (not including electricity generators) change over the forecast in response to changes in consumption levels and in the costs of capital and labor.

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

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 from 2000 through the end of the forecast period that otherwise might be lost to fugitive emissions.

Petroleum market assumptions

The petroleum refining and marketing industry is assumed to incur environmental costs to comply with CAAA90 and other regulations. Investments related to reducing emissions at refineries are represented as an average annualized expenditure. Costs identified by the National Petroleum Council [*29*] are allocated among the prices of liquefied petroleum gases, gasoline, distillate, and jet fuel, assuming that they are recovered in the prices of light products. The lighter products, such as gasoline and distillate, are assumed to bear a greater amount of the costs because demand for light products is less price-responsive than that for the heavier products.

Petroleum product prices also include additional costs resulting from requirements for cleaner burning fuels, including oxygenated and reformulated gasolines and low-sulfur diesel. The additional costs are determined in the representation of refinery operations by incorporating specifications and demands for the fuels. Demands for traditional, reformulated, and oxygenated gasolines are disaggregated from composite gasoline consumption on the basis of their 1998 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 that voluntarily opted into the program [*30*]. An additional 70 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 State-wide requirement in California and reformulated gasoline in Phoenix, Arizona, required by State law. RFG is assumed to account for about 34 percent of annual gasoline sales throughout the *AEO2000* forecast, which reflects the 1998 market share with adjustments for the opt-in of St. Louis in June 1999.

RFG reflects the “Complex Model” definition as required by the EPA and the tighter Phase 2 requirements beginning in 2000. Throughout the forecast, traditional gasoline is blended according to 1990 baseline specifications, to reflect CAAA90 “antidumping” requirements aimed at preventing traditional gasoline from becoming more polluting. The *AEO2000* projections also reflect California’s Statewide requirement for severely reformulated gasoline first required in 1996 and incorporate the California phaseout of MTBE by 2003 in areas not covered by Federal RFG regulations. In keeping with an overall assumption of current laws and regulations, it is assumed that the Federal oxygen requirement will remain intact in Federal nonattainment areas, including Los Angeles, San Diego, and Sacramento.

State taxes on gasoline, diesel, jet fuel, M85, and E85 are assumed to increase with inflation, as they have tended to in the past. Federal taxes, which have increased sporadically in the past, are assumed to stay at 1998 nominal levels (a decline in real terms). The extension of the tax credit for blending corn-based ethanol with gasoline, included in the Federal Highway Bill of 1998, is incorporated in the projections. 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. It is assumed 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).

AEO2000 assumes that refining capacity expansion may occur on the east and west coasts, as well as the Gulf Coast.

Gasoline sulfur reduction case. The regulations for Tier 2 emissions standards and related sulfur reductions for gasoline and diesel fuel have not been finalized and are therefore not included in the *AEO2000* reference case. The potential impacts of the proposed regulations are explored in an alternative *gasoline sulfur reduction case*, which assumes a reduction in gasoline sulfur content to 30 ppm. The 30-ppm limit is met by all RFG by 2004. The sulfur content of conventional gasoline is substantially reduced, to 80 ppm in 2004, and meets the 30-ppm restriction by 2007. The more gradual reduction for conventional gasoline reflects extensions granted to small refiners.

In order to reduce gasoline sulfur to the level of 30 ppm, refiners will need to invest in conventional hydrotreating processes or in newly developed desulfurization processes, which are potentially less costly but commercially unproven. *AEO99* included a national low-sulfur gasoline case that did not include new desulfurization technologies. Unlike the low-sulfur scenario in *AEO99*, the *AEO2000* fuel sulfur reduction case incorporates new desulfurization technologies.

In the gasoline sulfur reduction case, gasoline consumption and crude oil price projections remain the same as in the *AEO2000* reference case. For consistency with other recent cost analyses, the sulfur reduction case uses a 15-percent hurdle rate and a 10-percent return on investment, and the results are compared with those of a modified reference case using the same financial assumptions.

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

Although the BRP did not specify a target level of MTBE, but only stated that its use should be reduced substantially, the level of MTBE and other ethers in gasoline is limited to 3 percent by volume in the BRP/MTBE reduction case. This was the level of refinery inputs of MTBE in gasoline in 1993, the first year in which EIA published the MTBE inputs separately. The use of MTBE began to increase as a result of the introduction of oxygenated gasoline in the fall of 1993.

The elimination of the oxygen specification in RFG requires that other specifications be adjusted in order to maintain air quality. In order to maintain current emissions levels of air toxics, as recommended by the BRP, the BRP/MTBE reduction case assumes tighter limits on benzene and sulfur in RFG than does the *AEO2000* reference case. Gasoline consumption and crude oil price projections remain the same as in the *AEO2000* reference case. The only changes relative to the reference case are gasoline specifications and the cap on ether use. For consistency with other recent cost analyses, the MTBE reduction case uses a 15-percent hurdle rate and a 10-percent return on investment, and the results are compared with those of a modified reference case using the same financial assumptions.

Coal market assumptions

Productivity. Technological advances in the coal industry, such as improvements in coal haulage systems at underground mines, contribute to increases in productivity, as measured in average tons of coal per miner per hour. Productivity improvements are assumed to continue but to decline in magnitude over the forecast horizon. Different rates of improvement are assumed by region and by mine type (surface and underground). On a national basis, labor productivity is assumed to improve on average at a rate of 2.3 percent per year, declining from an estimated annual improvement rate of 6.1 percent achieved in 1997 to approximately 1.5 percent over the 2010 to 2020 period.

Coal transportation costs. Transportation rates are escalated or de-escalated over the forecast period to reflect projected changes in input factor costs. The escalators used to adjust the rates year by year are generated endogenously from a regression model.

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

Mining cost cases. 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 *AEO2000* 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 in 2020 (in short tons per hour) were 14.01 in the *low mining cost case* and 7.86 in the *high mining cost case*, compared with 10.61 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, because mine-mouth prices vary with the levels of production required to meet demand.

Notes

[*1*] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1998*, DOE/EIA-0573(98) (Washington, DC, October 1999).

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

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

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

[*5*] 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).

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

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

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

[*9*] 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).

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

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

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

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

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

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

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

[*17*] S. Davis, *Transportation Energy Databook No. 17*, prepared for the Office of Transportation Technologies, U.S. Department of Energy (Oak Ridge, TN: Oak Ridge National Laboratory, August 1997).

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

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

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

[*21*] U.S. Department of Transportation, Census of Transportation, *Truck Inventory and Use Survey*, 1992; Federal Highway Administration, *Highway Statistics*

1997; and S. Davis, *Transportation Energy Databook No. 17*, prepared for the Office of Transportation Technologies, U.S. Department of Energy (Oak Ridge, TN: Oak Ridge National Laboratory, August 1997).

[*22*] Federal Aviation Administration, *FAA Aviation Forecasts, Fiscal Years 1997-2008*.

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

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

[*25*] National Energy Policy Act of 1992, P.L. 102-486, Title XIX, Section 1916.

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

[*27*] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, and Electric Power Research Institute, *Renewable Energy Technology Characterizations*, EPRI-TR-109496 (Washington, DC, December 1997).

[*28*] D.L. Goutier et al., *1995 National Assessment of the United States Oil and Gas Resources* (Washington, DC: U.S. Department of the Interior, U.S. Geological Survey, 1995); U.S. Department of the Interior, Minerals Management Service, *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf*, OCS Report MMS 96-0034 (Washington, DC, June 1997); L.W. Cooke, *Estimates of Undiscovered, Economically Recoverable Oil and Gas Resources for the Outer Continental Shelf, Revised as of January 1990*, OCS Report MMS 91-0051 (Washington, DC: U.S. Department of the Interior, Minerals Management Service, July 1991).

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

[*30*] Required areas: Baltimore, Chicago, Hartford, Houston, Los Angeles, Milwaukee, New York City, Philadelphia, San Diego, and Sacramento. Opt-in areas are in the following States: Connecticut, Delaware, Kentucky, Massachusetts, Maryland, 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	21.296
Consumption	million Btu per short ton	20.835
Coke Plants	million Btu per short ton	26.800
Industrial	million Btu per short ton	22.172
Residential and Commercial	million Btu per short ton	22.494
Electric Utilities	million Btu per short ton	20.548
Imports	million Btu per short ton	25.000
Exports	million Btu per short ton	26.251
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	5.358
Motor Gasoline[2]	million Btu per barrel	5.213
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	5.437
Exports[2]	million Btu per barrel	5.734
Natural Gas Plant Liquids		
Production[2]	million Btu per barrel	3.879
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

Btu = British thermal unit.
[1]Conversion factors vary from year to year. 1997 values are reported.
[2]Conversion factors vary from year to year. 2000 values are reported.
Sources: Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999), and EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

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Table H2. Metric Conversion Factors

United States Unit	multiplied by	Conversion Factor	equals	Metric Unit
Mass				
Pounds (lb)	X	0.453 592 37	=	kilograms (kg)
Short Tons (2000 lb)	X	0.907 184 7	=	metric tons (t)
Length	X	1.609 344	=	kilometers (km)
Miles				
Energy				
British Thermal Unit (Btu)	X	1055.056[a]	=	joules(J)
Quadrillion Btu	X	25.2	=	million tons of oil equivalent (Mtoe)
Kilowatthours (kWh)	X	3.6	=	megajoules(MJ)
Volume				
Barrels of Oil (bbl)	X	0.158 987 3	=	cubic meters (m^3)
Cubic Feet (ft^3)	X	0.028 316 85	=	cubic meters (m^3)
U.S. Gallons (gal)	X	3.785 412	=	liters (L)
Area				
Square feet (ft^2)	X	0.092 903 04	=	square meters (m^2)

Note: Spaces have been inserted after every third digit to the right of the decimal for ease of reading.
[a]The Btu used in this table is the International Table Btu adopted by the Fifth International Conference on Properties of Steam, London, 1956.
Source: Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98)(Washington, DC, July 1999), Table B1 and EIA, *International Energy Outlook 1999,* DOE/EIA-0484 (99) (Washington, DC, April 1999).

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 1998*, DOE/EIA-0384(98)(Washington, DC, July 1999), Table B2, and EIA, Statistics and Methods Group.