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Annual Energy Outlook 1997

With Projections to 2015

December 1996

Energy Information Administration
Office of Integrated Analysis and Forecasting
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Preface

The *Annual Energy Outlook 1997 (AEO97)* presents midterm forecasts of energy supply, demand, and prices through 2015 prepared by the Energy Information Administration (EIA). These projections are based on results of EIA's National Energy Modeling System (NEMS).

This report begins with a summary of the reference case, followed by a discussion of the legislative assumptions and evolving legislative and regulatory issues. "Issues in Focus" discusses emerging energy issues and other topics of particular interest. It is followed by the analysis of energy market trends.

The analysis in *AEO97* 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 summaries of the reference case forecasts in units of oil equivalence and household energy expenditures. Twenty-three other cases explore the impacts of varying key assumptions in NEMS—generally, technology penetration, with the major results shown in Appendix F.

Appendix G briefly describes NEMS and the major *AEO97* assumptions, with a summary table. Appendix H provides tables of energy conversion and metric conversion factors. Appendix I presents instructions for obtaining tables through the EIA Fax-On-Demand system. *AEO97* and the detailed assumptions will also be available on the EIA Home Page and on CD-ROM.

The *AEO97* projections are based on Federal, State, and local laws and regulations in effect on October 1, 1996. Pending legislation and sections of existing legislation for which funds have not been appropriated are not reflected in the forecasts. The *AEO97* projections were prepared by using the most current data available as of July 31, 1996, when most 1995 data but only partial 1996 data were available. Historical data are presented for comparative purposes. Data documents referenced in the source notes should be consulted for official values. The *AEO97* projections for 1996 and 1997 incorporate the short-term projections from EIA's *Short-Term Energy Outlook (STEO)*, Fourth Quarter 1996, published in October 1996.

The *AEO97* 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 *AEO97* 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 and demographic trends and current laws and regulations, thus providing 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. The forecasts 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 events which shape energy markets are random and cannot be anticipated, including severe weather, political disruptions, strikes, and technological breakthroughs. In addition, assumptions concerning future technology, demographics, and resources cannot be known with any degree of certainty. Many key uncertainties in the *AEO97* projections are addressed through alternative cases.

EIA has endeavored to make these forecasts as objective, reliable, and useful as possible, but these projections should serve as an adjunct to, not a substitute for, the analytical process that should be used to examine policy initiatives.

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Once again, in the *Annual Energy Outlook 1997* (*AEO97*), the Energy Information Administration (EIA) presents baseline projections of energy markets for the use of our customers. These projections extend to the year 2015 and, in addition to the reference case, include a number of side analyses that address some of the key uncertainties that influence energy supply, demand, and prices.

Use of the Projections

The projections in *AEO97* are generated from EIA's National Energy Modeling System (NEMS), which examines the total energy system, including all energy-producing and consuming sectors and the most significant macroeconomic indicators that affect or are affected by the energy system. This allows us to look at the complex interactions within energy markets—as examples, the impact of increasing energy demand on domestic and international supplies and prices, or the economic tradeoffs between conventional fossil fuels and renewable energy sources.

As important as the projections in *AEO97* are to the many users of the report as forecasts of energy, even more important is its use as a baseline for policy analysis. Here again, the total look at energy markets is valuable, as NEMS is used to anticipate the impacts of new or proposed policies. The direct impacts of policies are often obvious, but the magnitude of those impacts and the indirect impacts are frequently less obvious without the total view of the energy system. For example, an initiative to stimulate production of domestic oil and natural gas would have the positive impact of lowering consumer prices for the fuels and reducing oil imports. However, secondary effects would include reducing the incentive for more efficient energy-using equipment and slowing the penetration of renewable sources of energy—ultimately increasing consumption and potentially harmful emissions. This total look enables us to identify and quantify the most significant outcomes of policy initiatives.

The *AEO97* projections extend to 2015. This 20-year period is a time interval during which EIA believes that the most important characteristics of energy consumption and production are sufficiently well understood for credible projections to be developed in considerable detail. The longer view is significant for several reasons. First, the impacts of energy policies or new technologies often take a number of years to develop fully because of the gradual turnover of the vast stock of energy-using and producing equipment and the gradual adaption to changing energy prices. Second, the longer term projections, examined in conjunction with long historical trends, help us put short-term phenomena in perspective. Severe weather conditions, international political events, and disruptions in domestic supplies all have had significant, but short-term, impacts on the price and availability of energy in the past several years. But such short-term events typically have little impact on the longer term trends presented in *AEO97*. Finally, by projecting energy markets for two decades, the report can alert readers to future issues, such as the likely retirement of a significant number of the Nation's nuclear generating plants and the need to replace them with new plants using natural gas, coal, or renewable fuels.

Limitations of the Projections

Recognizing the value of the *AEO97* projections, we must also be aware of and alert our readers to the limitations of the projections. First, although we use the term "forecast" interchangeably with "projections," we fully recognize that we cannot predict the future. There are too many underlying forces of energy markets that cannot be known with certainty. Also, in its role as a policy-neutral data and analysis organization, EIA does not speculate on changes in energy policy. For this analysis, we assume that all current policies and regulations will be stable over the projection period. However, policy will be modified over a 20-year period, and that alone is a significant reason for energy markets to develop differently than the forecasts indicate. The assumption of stable regulation leads to assumptions as sweeping as assuming that the current regulatory environment for the electricity industry will continue and as simple, but still important, as assuming that Federal gasoline taxes will remain unchanged.

In addition, the projections do not reflect short-term volatility. Prices on the futures markets can shift dramatically over several weeks or even days as a result of short-term conditions. Although monthly and annual averages serve to dampen the extent of price movements or other short-term events, extreme conditions can cause actual markets to differ from projections. To consider these possibilities, we present ranges for key energy variables, such as world oil prices. While prices can move outside these ranges, it would most likely be for a short period of time.

Users of this report also must be alerted to the fact that the projections employ many of the perspectives and conventions of economics. The prices projected in *AEO97* are controlled for general levels of inflation. Thus, a level track of prices does not indicate that prices would be unchanged but that they would increase at the general level of inflation. For example, the average crude oil price is projected to rise from about $17 a barrel in 1995 to $21 a barrel in 2015 in inflation-adjusted dollars, or 1995 real dollars. Accounting for likely inflation, the price in 2015 would be about $39 per barrel.

Technology is another key dynamic in energy markets. Over recent years, major improvements in energy technologies have dramatically improved the efficiency of energy consumption and production. At the same time, new end uses of energy have developed, and other uses, such as air-conditioning, have continued to penetrate. Because of the time it takes new technologies to penetrate markets, it is far easier to assess such penetration in the early years of the forecast period than in the more distant years. We project substantial improvements in technology through the forecast horizon, but the magnitude of such improvements is particularly difficult to assess in the later years. Also, we do not project any breakthrough or substantially new technologies. Because of these uncertainties and because technology is so important in the use and production of energy, *AEO97* presents a number of alternative cases that explore the impacts of slower or more rapid rates of improvement in technology or productivity than those assumed in the reference case.

As difficult as it is to project developments in energy in the United States, where the economy is relatively stable and valid data are readily available, it is even more difficult to assess international trends, which increasingly have impacts on the United States. It has long been recognized that events in the energy-exporting nations have profound effects on international energy supply and prices. But increasingly, attention is being focused on economic growth and related energy use in countries without the developed infrastructure of the nations in the Organization for Economic Cooperation and Development. In addition, although we assume some technological improvements in the international production of oil, our ability to assess technological developments worldwide and their impacts on domestic technology development is limited. For further discussions of international energy developments, readers are referred to the *International Energy Outlook 1997*, scheduled for publication in April 1997.

Early Availability of *AEO97*

Early availability of the *AEO* results is a frequent request to EIA, and we are making an effort to accelerate the release of all our data and analysis publications. As a result, *AEO97* is being published a month earlier, in December 1996, still using the same dates for historical data inputs and assumptions about legislation and regulations. In addition, with continued growth in the use of EIA's Internet site, we have made the reference case results and a summary discussion available on our Home Page in November, at the time this report was released for printing. We intend to continue this service to our customers in the future.

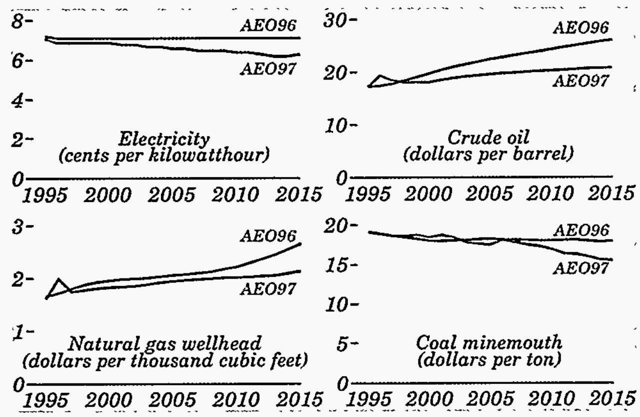
Jay E. Hakes
Administrator
Energy Information Administration

Overview

Prices

The *Annual Energy Outlook 1997* (*AEO97*) projects lower prices for all energy fuels than were projected in *AEO96* (Figure 1). Average world crude oil prices in *AEO97* are projected to be about $21 a barrel (in 1995 dollars) in 2015, $5 lower than the *AEO96* price of $26 a barrel. The lower prices reflect expectations that oil production from the Organization of Petroleum Exporting Countries (OPEC) will expand and that technology advances will sustain non-OPEC production. It is assumed that Iraqi oil production will not resume until 1998 and then will increase gradually to full capacity in 2000.

Figure 1. Fuel price projections, 1995-2015: AEO96 and AEO97 compared (1995 dollars)



The *AEO97* average wellhead price of natural gas in 2015 is $2.13 per thousand cubic feet, compared with $2.63 in *AEO96*, primarily as the result of a reevaluation of the impacts of technological progress on oil and natural gas discovery. In *AEO96*, technological progress was assumed to slow the decline in finding rates—reserves discovered per new well. In *AEO97*, technological progress arrests and even reverses declining finding rates in some regions. As a result, natural gas production is increased, with less drilling activity and at lower cost, particularly in offshore regions, where technological progress has a greater impact on the development of relatively immature fields. In addition, competition within the industry and projections of lower interest rates reduce the costs of transmission and distribution, offsetting the projected increase in wellhead prices, so that the average delivered price of natural gas declines between 1995 and 2015 at an average annual rate of 0.2 percent.

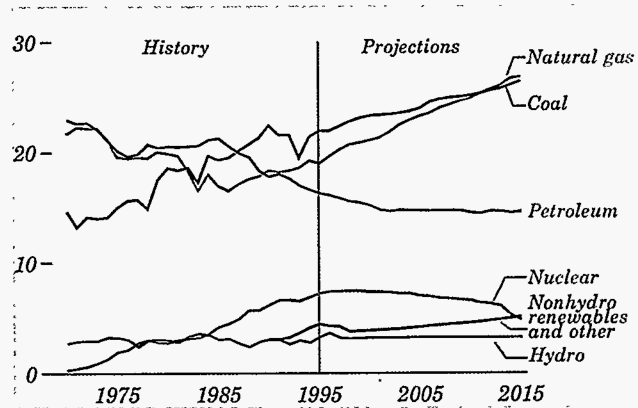
Coal minemouth prices are projected to decline in the forecast as a result of increasing productivity, a shift to western production, and competitive pressures on labor costs. In *AEO97*, the average minemouth price of coal is projected to be $15.46 per ton in 2015, compared with $17.75 in *AEO96*. Lower coal transportation rates—leading to higher production from western mines, where production costs are lower than in the East—are the primary reason for the lower minemouth prices.

Average electricity prices also decline through 2015 and are lower than in *AEO96*. The average price in 2015 is projected to be 6.3 cents per kilowatthour, compared with 7.1 cents in *AEO96*, as a result of lower projected fossil fuel prices and anticipated industry restructuring. Increased competition in the electricity industry is assumed to lead to lower operating and maintenance costs, lower general and administrative costs, early retirement of inefficient units, and other cost reductions. *AEO97* reflects the evolving trend of competition within electricity markets but does not include the full impacts of restructuring and deregulation. Although the projections include the recent actions taken by the Federal Energy Regulatory Commission on open access, specific actions to be taken by State public utility commissions and their timing are not yet known and have not been incorporated. Electricity industry restructuring is discussed further on pages 16-19.

Production and Imports

As a result of lower projected oil prices, crude oil production in the United States is lower in the *AEO97* forecast, declining to 5.2 million barrels a day in 2015 (Figure 2), compared with 5.8 million barrels a day in *AEO96*. On average, U.S. oil production declines by 1.1 percent a year between 1995 and 2015, consistent with long-term historical

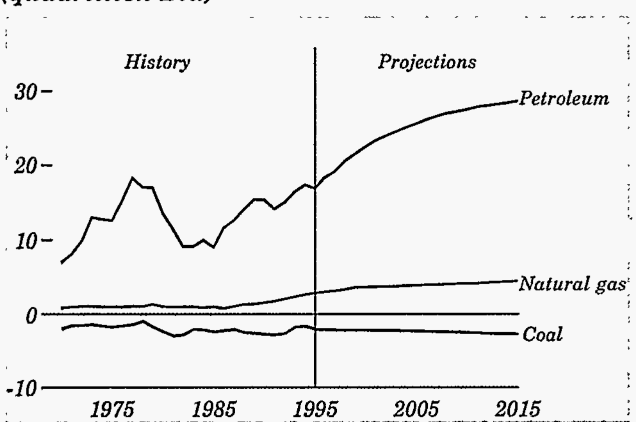
Figure 2. Energy production by fuel, 1970-2015 (quadrillion Btu)



trends. Advances in oil discovery technologies are expected to be insufficient to offset declining resources.

Declining production and rising consumption lead to growing reliance on petroleum imports through 2015 (Figure 3). The share of petroleum consumption met by net imports rises from 44 percent in 1995 (measured in barrels per day) to 61 percent in 2015.

Figure 3. Net energy imports by fuel, 1970-2015 (quadrillion Btu)



Natural gas production is projected to increase at an average annual rate of 1.7 percent between 1995 and 2015 to meet most of the growing demand for gas. In 2015, production is estimated to reach 26.1 trillion cubic feet, compared to 18.5 trillion cubic feet in 1995. Net imports of natural gas, primarily from Canada, also increase by 1.6 trillion cubic feet by 2015 due to assumed growth and higher utilization of pipeline capacity coupled with abundant supplies of Canadian gas available at competitive prices.

Coal production increases by 1.0 percent a year through 2015, from 1,033 million tons in 1995 to 1,268 million in 2015. Most of the increase results from increasing domestic consumption. In addition, export demand is projected to rise through 2015. Exports of steam coal will primarily serve expanding markets for electricity generation in Europe and Asia, and some growth in metallurgical coal exports to Asia is also projected in response to increasing demand for steel.

With lower prices projected for all fuels, renewable energy production, including hydropower, is 0.8 quadrillion British thermal units (Btu) lower in the *AEO97* forecast in 2015 than it was in *AEO96*. Lower prices, particularly for natural gas, delay the penetration of some renewable technologies. Renewable energy production, including hydropower, is projected to reach 7.7 quadrillion Btu in 2015, up from 6.3 quadrillion Btu in 1995. More than half the increase, 0.8 quadrillion Btu, is biomass used by industry and electricity generators, and most of the rest is geothermal, municipal solid waste, and wind.

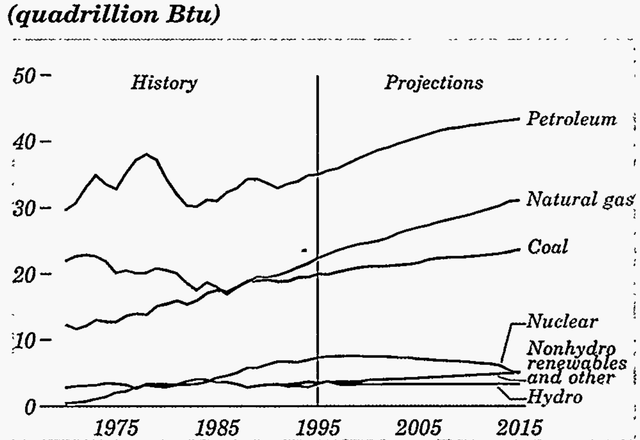
Consumption

The lower energy prices in *AEO97* than in *AEO96* result in higher total consumption in 2015—111 quadrillion Btu, compared with 108 quadrillion Btu in *AEO96*. Both industrial and transportation demand are higher, with stronger economic growth and higher projected travel.

Residential demand is the same in *AEO97* as in *AEO96*. The lower prices are offset by more mobile and multifamily homes, improvements in shell and equipment efficiencies, and more conversions from oil and conventional resistance heating to higher efficiency heating. Commercial demand is only slightly higher than in *AEO96*, because the lower prices are mostly offset by improvements in lighting and in building shells for new construction, and by a 4 percent lower estimate of floorspace in 2015.

Natural gas consumption increases by an average of 1.7 percent a year (Figure 4), mainly because of growth in gas-fired electricity generation. Gas consumption by electric generators, excluding cogenerators, is projected to increase from 3.5 trillion cubic feet in 1995 to 8.5 trillion cubic feet in 2015. Gas consumption in the industrial sector, which includes cogenerators, increases by 1.3 trillion cubic feet. Combined, by 2015 the residential and commercial sectors contribute 1.2 trillion cubic feet to the increased use of gas.

Figure 4. Energy consumption by fuel, 1970-2015 (quadrillion Btu)



Coal remains the primary fuel for electricity generation. Although the share of coal-fired generation declines, 50 percent of generation (excluding cogenerators) is expected to be coal-fired in 2015. Total coal consumption grows by 0.9 percent a year, with 90 percent of the coal used for electricity generation.

Petroleum consumption is projected to grow at an average rate of 1.1 percent a year. More than two-thirds of the petroleum is used for transportation. Increases in light-duty vehicle miles traveled more than offset the increases in vehicle efficiency throughout the projection period. Trends in vehicle efficiency and alternative-fuel vehicle sales are discussed on pages 21-25. Sustained economic growth also leads to continued increases in the use of petroleum for freight travel and shipping.

Renewable fuel use, including hydropower, increases at an average annual rate of 1.0 percent. About 60 percent of renewable fuels are used for electricity generation and the remainder for dispersed heating and cooling, industrial uses, and blending into vehicle fuels. Hydropower, the main renewable source used for generation, declines slightly, because regulatory actions limit capacity at existing sites and no large new sites are available for development.

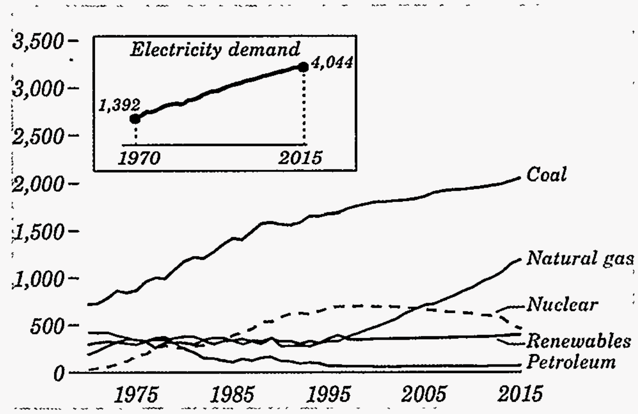
Electricity consumption is projected to grow by 1.5 percent a year through 2015. Efficiency gains in the use of electricity partially offset the continued trend of electrification and the penetration of new electricity-using equipment, resulting in a growth rate that is slower than the average 1.9-percent annual growth in gross domestic product (GDP).

Electricity Generation

Electricity generation from both natural gas and coal is projected to increase significantly through 2015 to meet increased demand for electricity and offset the decline in generation from nuclear power (Figure 5). Many nuclear plants will near the end of their 40-year operating licenses by the end of the forecast horizon. Of the approximately 100 gigawatts of nuclear capacity available in 1996, 38 gigawatts are assumed to be retired by 2015—primarily during the last 10 years of the forecast.

Because of the low cost of natural gas and because capital requirements for gas-fired capacity are lower than those for coal-fired capacity, natural gas nearly triples its share of electricity generation over the forecast period, from 10 percent to 29 percent. Coal-

Figure 5. Electricity generation by fuel, 1970-2015 (billion kilowatthours)



fired generation increases in the *AEO97* forecast but is slightly lower in 2015 than was projected in *AEO96*. Competitive pressures are assumed to lead to earlier retirements of some less efficient coal-fired plants, which are replaced mainly by gas-fired plants. Despite lower oil prices, total generating costs do not favor petroleum for generation.

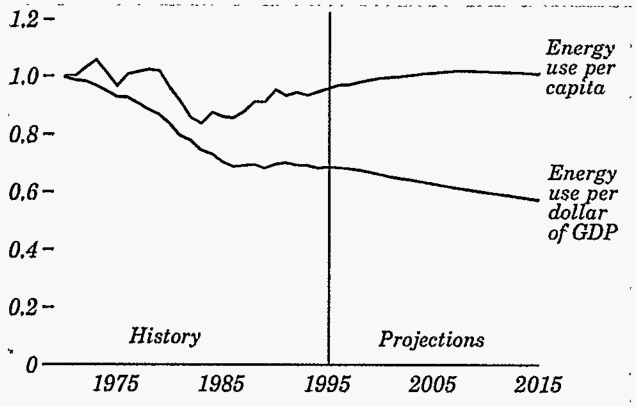
With fossil fuel prices lower in the *AEO97* projections, most renewable energy sources penetrate more slowly in the generation market than they did in the *AEO96* forecast. Except for hydropower, which declines slightly, the use of all other renewable sources increases between 1995 and 2015.

One new nuclear unit, Watts Bar 1, was completed in 1996, but no others are projected over the forecast horizon, and 38 percent of the total 1996 nuclear capacity is assumed to be retired by 2015. Nuclear generation rises slightly through 1999 with improved performance of existing plants, then declines to only two-thirds of the 1995 level in 2015 as older plants are retired.

Energy Efficiency

Energy intensity, measured as energy use per dollar of GDP, has generally declined since 1970, particularly during periods of rapid increases in energy prices (Figure 6). In the 1970s and early 1980s, energy intensity declined at an average rate of nearly 2 percent a year as the economy shifted to less energy-intensive industries and increasingly efficient technologies. In the late 1980s and into the projection period, moderate price increases and the growth of more energy-intensive industries lead to a slower projected decline—a yearly average of 0.9 percent—from 1995 to 2015.

Figure 6. Energy use per capita and per dollar of gross domestic product, 1970-2015 (index, 1970 = 1)



Energy use per person, which also declined from 1970 through the mid-1980s, rose in the mid-1980s as energy prices dropped. Per capita energy use is expected to remain nearly stable through 2015 and below the high in the early 1970s, as efficiency gains offset higher demand for energy services.

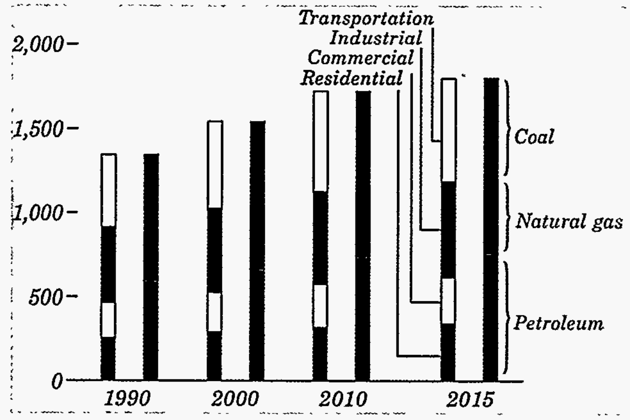
AEO97 incorporates the efficiency standards for new energy-using equipment in buildings and for motors mandated through 1994 by the National Appliance Energy Conservation Act of 1987 and the Energy Policy Act of 1992. Additional improvements in the efficiency of energy-using technologies beyond the standards are likely. Several alternative cases in *AEO97* examine the impact of the penetration of more energy-efficient technologies in the end-use sectors beyond that projected in the reference case.

Carbon Emissions

Carbon emissions from energy use are projected to increase by 1.2 percent a year through 2015, reaching 1,799 million metric tons (Figure 7), compared with the *AEO96* projection of 1,735 million metric tons. The higher emissions projections are the result of higher total energy consumption and lower penetration of renewable energy sources.

Higher projected economic growth in *AEO97* and lower use of renewables contribute to higher carbon emissions in the industrial sector. Emissions are also higher in the transportation sector, as stronger economic growth and lower fuel prices boost personal and freight travel and fuel consumption. Emissions in the residential and commercial sectors are only slightly higher.

Figure 7. U.S. carbon emissions by sector and fuel, 1990-2015 (million metric tons)



Over the forecast horizon, 40 percent of the increase in emissions results from the transportation sector, where increases in travel are projected for all modes. The industrial sector accounts for 28 percent of the increase. The sectoral values in Figure 7 include emissions from the generation of electricity used in each sector. Although part of the growth in emissions from electricity generation results from the replacement of nuclear power by fossil-fired generation, the increased use of natural gas relative to coal moderates the growth in emissions.

The Climate Change Action Plan (CCAP) was developed to stabilize greenhouse gas emissions in 2000 at 1990 levels. In 1990, carbon emissions from energy use were estimated to be about 1,340 million metric tons. *AEO97* analyzes the impacts of CCAP provisions, including Climate Challenge and Climate Wise, which foster voluntary reductions in emissions by electric utilities and industry. The first report on voluntary programs, *Voluntary Reporting of Greenhouse Gases 1995*, was released in July 1996 [*1*]. That report documents the Climate Wise and Climate Challenge commitments.

Emissions grew more rapidly than expected in the early 1990s, partly due to lower than expected growth in energy prices, which is projected to continue through 2015. That trend, combined with funding reductions for some CCAP programs, leads to higher projected emissions than were estimated at the time CCAP was formulated. The impacts of additional efforts that may be undertaken to curtail emissions are not analyzed in these projections. Further discussion of carbon emissions, as well as other emissions, begins on page 72.

Table 1. Summary of results for five cases

Sensitivity Factors	1994	1995	2015 Reference	2015 Low Economic Growth	2015 High Economic Growth	2015 Low World Oil Price	2015 High World Oil Price
Primary Production (quadrillion Btu)							
Petroleum	16.57	16.26	14.55	14.02	15.06	11.74	18.16
Natural Gas	19.27	19.01	26.83	24.97	28.68	25.92	27.68
Coal	22.07	21.98	26.46	25.07	29.06	26.18	26.60
Nuclear Power	6.84	7.19	4.79	4.79	4.79	4.79	4.79
Renewable Energy	5.82	6.29	7.71	7.22	8.18	7.56	7.78
Other	0.98	1.34	0.42	0.40	0.45	0.43	0.48
Total Primary Production	**71.55**	**72.08**	**80.75**	**76.47**	**86.21**	**76.62**	**85.49**
Net Imports (quadrillion Btu)							
Petroleum (including SPR)	17.28	16.87	28.60	26.21	30.92	34.16	23.33
Natural Gas	2.51	2.74	4.33	4.33	4.33	4.33	4.33
Coal/Other (- indicates export)	-1.21	-1.67	-2.40	-2.46	-2.35	-2.40	-2.40
Total Net Imports	**18.59**	**17.93**	**30.54**	**28.08**	**32.90**	**36.09**	**25.25**
Discrepancy	-1.40	0.91	-0.40	-0.31	-0.42	-0.77	-0.40
Consumption (quadrillion Btu)							
Petroleum Products	34.77	34.92	43.26	40.33	46.11	45.66	41.65
Natural Gas	21.35	22.18	30.97	29.12	32.81	30.04	31.84
Coal	19.50	19.95	23.76	22.41	26.41	23.51	23.92
Nuclear Power	6.84	7.19	4.79	4.79	4.79	4.79	4.79
Renewable Energy	5.82	6.30	7.71	7.23	8.18	7.56	7.78
Other	0.46	0.39	0.37	0.36	0.38	0.37	0.37
Total Consumption	**88.74**	**90.93**	**110.87**	**104.23**	**118.67**	**111.93**	**110.35**
Prices (1995 dollars)							
World Oil Price (dollars per barrel)	15.94	17.26	20.98	19.78	22.21	13.99	28.23
Domestic Natural Gas at Wellhead (dollars per thousand cubic feet)	1.97	1.61	2.13	1.83	2.49	2.12	2.16
Domestic Coal at Minemouth (dollars per short ton)	19.89	18.83	15.46	15.32	15.90	14.82	16.24
Average Electricity Price (cents per kilowatthour)	7.2	7.1	6.3	6.0	6.5	6.2	6.3
Economic Indicators							
Real Gross Domestic Product (billion 1992 dollars)	6,604	6,739	9,880	8,982	10,766	9,919	9,836
(annual change, 1995-2015)	--	--	1.9%	1.4%	2.4%	2.0%	1.9%
GDP Implicit Price Deflator (index, 1992=1.00)	1.049	1.076	1.986	2.779	1.675	1.983	1.991
(annual change, 1995-2015)	--	--	3.1%	4.9%	2.2%	3.1%	3.1%
Real Disposable Personal Income (billion 1987 dollars)	3,894	4,047	6,109	5,614	6,585	6,137	6,075
(annual change, 1995-2015)	--	--	2.1%	1.7%	2.5%	2.1%	2.1%
Index of Manufacturing Gross Output (index, 1987=1.00)	1.211	1.246	1.904	1.709	2.102	1.913	1.893
(annual change, 1995-2015)	--	--	2.1%	1.6%	2.7%	2.2%	2.1%
Energy Intensity (thousand Btu per 1992 dollar of GDP)	13.44	13.50	11.23	11.62	11.03	11.30	11.23
(annual change, 1995-2015)	--	--	-0.9%	-0.7%	-1.0%	-0.9%	-0.9%
Carbon Emissions (million metric tons)	1,397	1,424	1,799	1,689	1,941	1,821	1,790

Notes: Assumptions underlying the alternative cases are defined in the Economic Activity and International Oil Markets sections, beginning on page 32. 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.

Source: Tables A1, A8, A19, A20, B1, B8, B19, B20, C1, C8, C19, and C20.

Legislation and Regulations

Because EIA analyses are required to remain policy-neutral, the *AEO97* projections assume that Federal, State, and local laws and regulations in effect on October 1, 1996, remain unchanged through 2015. The impacts of pending or proposed legislation and sections of existing legislation for which funds have not been appropriated are not reflected in the projections.

Federal legislation incorporated in the projections includes the Omnibus Budget Reconciliation Act of 1993, which adds 4.3 cents per gallon [2] to the Federal tax on highway fuels; the Clean Air Act Amendments of 1990 (CAAA90); and the Energy Policy Act of 1992 (EPACT). The provisions of EPACT are focused primarily on reducing energy demand, requiring minimum building efficiency standards for Federal buildings and other new buildings that receive federally backed mortgages. Efficiency standards for electric motors, lights, and other equipment are required, and owners of fleets of automobiles and trucks are required to phase in vehicles that do not rely on petroleum products.

CAAA90 requires a phased reduction in vehicle emissions of regulated pollutants, to be met primarily through the use of reformulated gasoline. In addition, under CAAA90, annual emissions of sulfur dioxide by electricity generators are, in general, capped at 8.9 million short tons a year in 2000 and thereafter, although banking of allowances from earlier years is permitted. CAAA90 also calls for the U.S. Environmental Protection Agency (EPA) to issue standards for the reduction of nitrogen oxide (NO_x) emissions, leading to regulations that impose limits on electricity generators for NO_x emissions. The impacts of CAAA90 on electricity generators are discussed on page 74. NO_x emissions regulations are discussed below.

Climate Change Action Plan

The *AEO97* projections include analysis of provisions of the Climate Change Action Plan (CCAP), 44 actions developed by the Clinton Administration to achieve the stabilization of greenhouse gas emissions (carbon dioxide, methane, nitrous oxide, and others) in the United States at 1990 levels by 2000. Energy combustion is the primary source of anthropogenic (human-caused) carbon emissions. *AEO97* 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 to energy fuels and are not incorporated in the analysis. The projections do not include additional steps that might be taken in response to the recent call by Timothy Wirth, Under Secretary of State for Global Affairs, for binding international agreements.

Climate Wise and Climate Challenge are two programs cosponsored by EPA and the U.S. Department of Energy to foster voluntary reductions in emissions on the part of industry and electricity generators. These programs are new and are only beginning to have effects, as reported in the EIA publication *Voluntary Reporting of Greenhouse Gases 1995* [*3*]. *AEO97* includes analysis of the impacts of both programs (see Appendix G).

Recent Actions

Legislation lifting a ban on exports of Alaskan crude oil was signed on November 28, 1995. With the exception of limited trade agreements, export of North Slope crude oil had been banned since 1973. Although this legislation passed late in 1995, the impacts were included in *AEO96*. With the export ban removed, it is expected that Alaskan crude oil will be exported to the Pacific Rim—primarily to Japan. It is projected that 100,000 barrels per day will be shipped in 1997, declining to 70,000 barrels in 1999. Exports of less than 50,000 barrels per day are expected to continue through the remainder of the forecast.

The Outer Continental Shelf Deep Water Royalty Relief Act was also enacted on November 28, 1995. This legislation gives the Secretary of the Interior authority to suspend royalty requirements on new oil and gas production from qualifying existing leases—generally, production in most deep areas of the Gulf of Mexico that would not be economical without royalty relief. It also requires that royalty payments be waived on new leases sold in the next 5 years for production in most of the deep Gulf. Although a representation of this legislation is included for the first time in the analytical framework underlying *AEO97*, the projected impacts on crude oil and natural gas production are small.

Within the past year, Congressional action was initiated to allow leasing of the 1.5-million-acre coastal plain of the Arctic National Wildlife Refuge for oil and gas drilling and to suspend the 4.3-cents-per-gallon tax on highway fuels added in 1993. Neither effort has resulted in signed legislation. Therefore, these changes are not included in the projections.

Recent actions by the Federal Energy Regulatory Commission (FERC) foster alternative ratemaking by the natural gas industry and efficient capacity release, leading to a more efficient market. FERC also issued Orders 888 and 889, providing open access to interstate transmission lines in electricity markets, a major step toward restructuring of the electricity industry. The impacts of these actions on the natural gas and electricity industries are discussed below.

Natural Gas Regulatory Actions

The natural gas industry has witnessed major regulatory and legislative changes during the past several years [*4*]. Some of the regulatory changes have allowed market forces to govern rate and service levels in areas of the industry where traditional regulatory oversight was previously in effect. Recent regulatory actions have continued to expose more aspects of the industry to market forces and have increased the options for interstate pipeline companies and shippers.

An alternative rate policy paper issued by FERC on January 31, 1996, provided interstate pipeline companies with the criteria for approval of applications for rates other than the traditional cost-of-service rates for transportation service. Options for alternative rates include market-based rates (customer-driven, based on rates for competing services), negotiated rates (negotiated individually with each customer), and incentive rates (determined by the achievement of target goals, such as improved efficiency or improved customer satisfaction relative to some specific index).

Issuance of the policy statement indicates FERC's recognition that additional rate design flexibility may be needed in the restructured environment. For instance, pipeline companies may need rate design flexibility to market, and recover the costs associated with, excess capacity (capacity over and above that which is subscribed to by customers). FERC will evaluate requests for alternative rates on a case-by-case basis.

In addition to its policy statement on alternative ratemaking methods, FERC has established a formal regulatory proceeding in which it will consider a proposal to allow pipeline companies to negotiate service terms and conditions. Negotiating terms and conditions may allow pipeline companies to tailor services to meet their customers' specific needs.

FERC is also providing pipeline companies with flexibility in their access to markets. In an Order issued on January 31, 1996 [*5*], FERC clarified that Order 636 does not prohibit interstate pipeline companies from obtaining capacity on other pipelines [*6*]. FERC cites at least two benefits of pipeline companies holding capacity on other pipelines. First, it would allow the pipeline companies to provide shippers access to new supply and market areas. Second, it would reduce the administrative burden of shippers having to deal with several pipeline companies to secure the flow paths they desire.

On July 31, 1996, FERC issued a Notice of Proposed Rulemaking (NOPR) that eliminates the requirement for competitive bidding and price constraints on released capacity (unused firm capacity that is made available for resale on the secondary, or capacity release, market) in some instances. The notice also requires pipeline companies to have comparable procedures for procuring released capacity, interruptible, and short-term service (service not held under long-term contract and generally for less than 30 days). In the notice, FERC proposes to discontinue the current bidding requirements in an effort to end the uncertainty and delay that some shippers have experienced before they may use the released capacity. FERC is also proposing to remove the price cap for released, interruptible, and short-term firm capacity when releasing shippers and pipeline companies can demonstrate that they are unable to exercise market power.

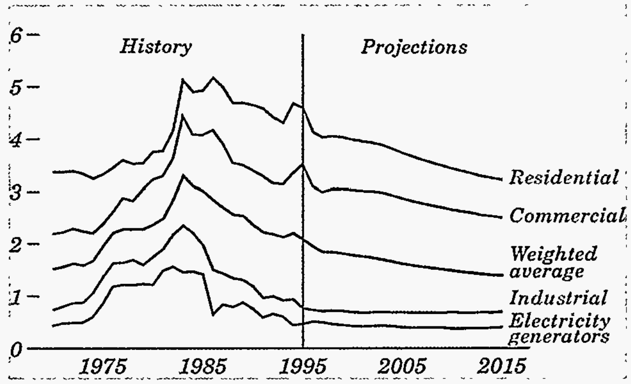
In addition to making these services more comparable, the removal of the price cap will enable releasing shippers and pipeline companies to sell the capacity at market prices. Shippers releasing capacity may also be able to recover more of their firm capacity costs, making this secondary (resale) market more attractive.

At the State level, unbundling is also making considerable inroads. Unbundled sales and delivery services for large industrial and electricity generator customers are now commonplace, and State regulators are experimenting with various methods to extend choice to small customers. Some regulators are making provisions to allow third-party marketers to aggregate the gas needs of smaller residential and commercial customers so that these customers can exercise choice in gas markets. A number of States have announced pilot projects in which participating residential customers may choose their gas suppliers. All of these changes are driven by the desire of regulators to give customers access to gas services that meet individual needs in the best way and at the least cost.

An unintended impact on consumer prices sometimes occurs as the result of taxes during the restructuring of public utility industries. When final consumers purchase gas and transportation services from parties other than the locally franchised provider, they may avoid paying some or all of the State and local taxes that would have been collected on a sale had it been made by the traditional provider. This sometimes makes it less expensive to purchase services from third-party, out-of-State vendors, even when the vendor's prices before taxes are higher than the traditional provider's. Many jurisdictions are now trying to remedy both the competitive and the revenue impacts of these taxes by replacing franchise and public utility sales taxes with energy importation or consumption taxes.

All of these changes tend to reduce the price of gas to end-use consumers, and projected transmission and distribution margins (costs the customers pay for transmission and distribution services) decline at an even greater rate than was projected in *AEO96* (Figure 8). Other factors that have contributed to the decline in the projected average margin are changes in the mix of end uses and changes in capital costs. While changes in the mix of end uses are similar in both *AEO96* and *AEO97*, a significant reduction in the cost of capital as a result of projected lower interest rates is reflected in *AEO97*. This reduction contributes to a decline in transmission and distribution margins over the forecast period, with projected margins in 2015 almost 20 percent lower than those projected in *AEO96*.

Figure 8. Comparison of average natural gas transmission and distribution margins, 1970-2015 (1995 dollars)



The greatest decline in margins is seen in the residential and commercial sectors, which consist predominantly of core customers who depend on firm transportation service. Declines in margins in both of these sectors are about 30 percent between 1995 and 2015. Margins in these two sectors include significant distribution costs, which are heavily influenced by interest rates, inasmuch as approximately 40 percent of the distribution costs is assumed to be related to the cost of capital. Industrial customers and electricity generators generally incur small distribution costs because they place a low burden on the system relative to the large volumes they purchase, or because they obtain their natural gas directly from the pipelines, bypassing the distribution segment of the market. Thus, they do not see the declines that are seen in the other sectors.

Nitrogen Oxide Emissions Regulations

Title IV of CAAA90 requires that EPA establish NO_x emission standards for certain coal-fired power plants. NO_x emissions from these power plants contribute to acid deposition in lakes and streams, concentrations of ground level ozone, and smog. The goal of the program is to reduce NO_x emissions by approximately 2 million tons from what they would have been without the program.

As specified in CAAA90, the EPA has developed a two-phase program, with the first set of standards taking force in 1996 and the second set to be implemented in 2000 [7] (Table 2). Dry-bottom wall-fired and tangential-fired boilers, the most common boiler types, referred to as Group 1 boilers, are required to make significant reductions beginning in 1996 and further reductions in 2000. Relative to their uncontrolled emission rates, which range roughly between 0.6 and 1.0 pounds per million Btu, they are required to make reductions of between 25 and 50 percent to meet the Phase I limits.

Table 2. NO_x emissions standards under the Clean Air Act Amendments of 1990 (pounds per million Btu)

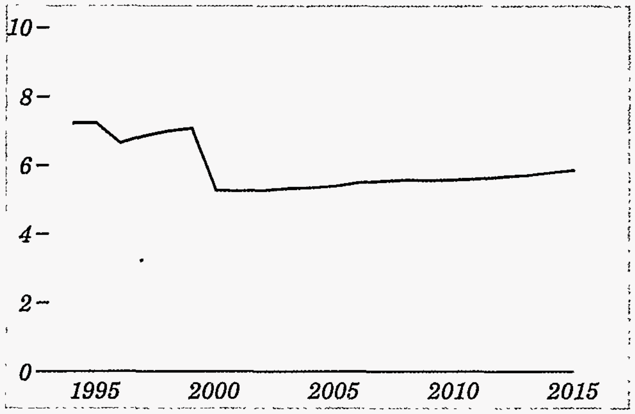
Boiler type	Number of boilers	Phase I limit	Phase II limit
Group 1 boilers			
Dry-bottom wall-fired	284	0.50	0.45
Tangential-fired	296	0.45	0.38
Group 2 boilers			
Cell burners	35	NA	0.68
Cyclones	88	NA	0.94
Wet-bottom wall-fired	38	NA	0.86
Vertically fired	29	NA	0.80
Fluidized-bed	5	NA	0.29

NA = not applicable.

The remaining boilers, Group 2 boilers, are not required to make reductions until 2000. With the exception of fluidized-bed boilers, these boiler types are not as amenable to control as Group 1 boilers, and as a result their standards are higher. However, the required reductions are still significant, ranging between 40 and 50 percent below their uncontrolled levels.

With these standards, NO_x emissions from electricity generators will fall significantly (Figure 9). From 1995 to 1996, NO_x emissions decline by about 0.5 million tons, from 7.2 to 6.7 million tons. With the Phase II standards, the reductions in 2000 are even larger, more than triple the reduction in 1996. NO_x emissions continue to grow between 2000 and 2015 as generators increase their use of fossil fuels to meet the growing demand for electricity. The retirement of older nuclear plants also contributes to emissions growth. Emissions increase to 5.9 million tons in 2015 but remain below the 1995 level. EPA and FERC, with various States, are monitoring NO_x emissions and reviewing the need for additional mitigation programs to bring areas currently unable to meet air quality standards into compliance. An emissions trading program under consideration might further lower NO_x emissions, but the impacts of the program are not addressed in *AEO97*, because it is under negotiation. The Ozone Transport Assessment Group (OTAG), a committee of 37 eastern States, is currently analyzing interstate air quality issues.

Figure 9. Nitrogen oxide emissions, 1994-2015 (million tons)



Open Access and Emissions Impacts

On April 24, 1996, FERC issued Orders 888 and 889, which are designed to increase competition in interstate electricity trade. The orders were titled "Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities" and "Open Access Same-Time Information System and Standards of Conduct," respectively.

Order 888 requires that utilities operating interstate transmission facilities provide purchasers and sellers of wholesale power (other utilities, nonutility power producers, and power marketers and brokers) open access to the facilities under the same terms and conditions that they provide to themselves. As a result, transmitting utilities must operate their facilities as if they were separate companies, independent of other operational units (i.e., generation and distribution). Also, the rule permits affected utilities to seek recovery of "legitimate, prudent and verifiable stranded costs" caused by the implementation of the rule.

Order 889 facilitates open access to interstate transmission facilities by requiring utilities owning or operating such facilities to provide current and potential customers with real-time information about available capacity, prices, and any other terms needed to make purchase decisions. Again, they must provide the same information to potential customers as they provide to their other operational units.

As stated by FERC, "The Commission's goal is to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers." In the short term, these rules are expected to provide owners of economical, currently underutilized power plants with a larger market for their output. In the long term, these rules should provide power project developers with better information on the economics of their projects by detailing the costs and operational constraints of delivering power to potential customers.

As these rules were being developed, concerns were raised that the rules might have harmful environmental impacts, particularly with respect to NO_x emissions, because open access might allow older, dirtier power plants to increase their generation by selling power to neighboring regions. In response to those concerns, FERC prepared an environmental impact statement (EIS) [*8*], which found that the implementation of the rules would have only small impacts on NO_x emissions, generally changes of less than 2 percent. The key result was that NO_x emissions were much more sensitive to relative coal and natural gas prices than to the open access rule. In fact, they found that, if the ratio of natural gas prices to coal prices remains at its current level, NO_x emissions might be slightly lower with open access.

EIA found similar results in an independent analysis of the rule requested by Senator James M. Jeffords, Vice Chairman of the Senate Subcommittee on Energy Production and Regulation [*9*]. EIA found that the impact of the open access rule on emissions is small relative to the change in emissions resulting from growth in the demand for electricity. Absent the new boiler standards, NO_x emissions would grow substantially. The effects of open access depend to a large extent on the availability of excess generation and transmission capacity, which determine how much surplus power exists and how much and where the electricity can be delivered. However, changes in excess generating capacity have more impact on the results than does transmission capacity. Thus, as demand grows, the amount of excess economical capacity available for trade declines, and the impact of open access on emissions becomes very small (less than 3 percent).

The key result was that NO_x and carbon emissions are expected to increase through 2015, with or without open access, as a result of growth in electricity demand and retirements of nuclear plants. In most cases, with Group 1 boiler standards only, NO_x emissions will stay below current levels through 2010 but exceed 1994 levels by 2015. Group 2 boiler standards have been issued for comment by EPA and are expected to be implemented in late 1996. If the standards are implemented, NO_x emissions are likely to stay below 1994 levels through 2015.

Gasoline Regulations

AEO97 gasoline projections reflect current legislation, although ongoing environmental debates add uncertainty to the long-term outlook. In 1995, the reformulated gasoline program set forth in CAAA90 was finally initiated. As a result, cleaner burning reformulated gasoline (RFG) was sold in many areas of the United States failing to meet the EPA's ozone attainment standards, representing around 28 percent of total gasoline sales in 1995 [*10*]. The RFG share of gasoline sales for 1996 will be higher due to the enactment of California's State-wide requirement for its own version of RFG. The *AEO97* market share for RFG assumes current levels of participation and remains around 36 percent from 1996 through the end of the forecast. Currently debated proposals to change ozone attainment standards, to allow attainment areas to require RFG, and to develop a national RFG requirement could substantially change the reformulated gasoline picture.

As set forth in CAAA90, the requirement to use RFG would apply to the nine areas with the worst ozone pollution record, classified by EPA as "severe ozone nonattainment areas." Other, less severe nonattainment areas are also allowed to "opt-in" to the program at the discretion of their governors. Some areas that initially opted-in requested to opt-out of the program before its onset. While it is possible for some areas to opt-out in the future, proposed changes make it even more likely that other areas will join the program.

EPA has proposed a new national air standard that would result in the classification of new ozone nonattainment areas. A trade group has estimated that the proposed standards would result in 119 ozone nonattainment areas, compared with 75 areas under current standards [*11*]. The proposed standard would clearly increase the number of areas able to participate in the RFG programs. The impact on RFG demand would depend on which areas were required to use RFG (severe nonattainment areas) and which areas opted in.

EPA has also been considering a new provision that would allow areas that are in attainment but wish to curb ozone problems to participate in the RFG program. The provision would provide more opportunity for renewable fuels to be used in RFG. While States currently can only require nonattainment areas to use RFG, larger areas—or even entire States—could potentially join the RFG program under the new provision. Refiners and marketers are also concerned about logistical problems created by areas joining and dropping out of the program on short notice.

The magnitude of the uncertainty surrounding RFG is illustrated by recent discussions of national and regional RFG programs. The idea of a national RFG program has been promoted by Senate Minority Leader Thomas Daschle (South Dakota) as a means to reduce pollution and petroleum imports [*12*]. The requirement for 2.0 percent oxygen in Federal RFG results in oxygenate blending, which displaces a portion of the petroleum content of gasoline, thereby reducing petroleum imports. During 1996 the Ozone Transport Assessment Group (OTAG) conducted studies on initiating a regional RFG program across the 37 member States.

Federal RFG (phase 2) is only one of the formulations of gasoline being looked at by OTAG. Others include California-style RFG and a formulation that is lower in sulfur and olefins than conventional gasoline [*13*]. Unlike Federal RFG, the other formulations under study do not have a minimum oxygen content and, therefore, would not require blending with oxygenates. If a program requiring a new formulation were pursued, it is unclear what would happen to areas currently using Federal RFG. OTAG plans to provide a proposal for controlling ozone pollution to the EPA in 1997. A recommendation for an OTAG gasoline program could set the stage for dramatic changes in the U.S. gasoline supply around the year 2000.

The impact of additional RFG demand on the gasoline market would depend on the magnitude and the location of the new demand. RFG currently represents about 16 percent of U.S. petroleum consumption but could reach more than 40 percent if a national RFG program were enacted. Such a dramatic change would require long-term planning and investment on the part of refiners, pipelines, and marketers. Consumers would also pay a little extra for the cleaner gasoline.

Issues in Focus

Electricity Deregulation

The Route to Competition

The electricity industry in the United States is in the midst of a dramatic restructuring. Like the telecommunications, trucking, airlines, and natural gas industries, the electricity infrastructure is being driven to a more competitive framework by pressures from consumers and legislators. In only two decades, electricity consumers have seen a transformation from an industry structure that offered no real choices in power purchases to the birth of a competitive era where debates about the merits of competition are being replaced by debates about how to effect the transition quickly and efficiently.

In hindsight, the route to competition can be seen as the result of the passage of two pieces of legislation: the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Energy Policy Act of 1992 (EPACT). Under PURPA, utilities are expected to increase energy efficiency and conservation by examining the impacts of conservation policies—such as demand-side management programs—on their resource planning. PURPA also requires utilities to purchase electricity from certain "qualifying facilities" (QFs) at a price equal to the utility's avoided cost (the utility's estimated cost of new plant construction plus forecast fuel consumption, or power purchases from other utilities, for example). The Act defines QFs as renewable generators and cogenerators—facilities that meet certain ownership, operating, and efficiency criteria and that produce electricity and another form of useful energy (such as steam or heat) as inputs to an industrial or commercial process.

As a result of the QF provision, PURPA initiated a massive increase in the number of nonutility power producers. By 1995, QFs were annually generating 340 billion kilowatthours of electricity—equivalent to 2 years' power requirement for the State of New York. PURPA demonstrated the practicality of extending the Nation's power resources beyond the established private and public utility paradigm.

Passage of EPACT further extended the scope of nonutility producers. EPACT establishes a class of suppliers called "exempt wholesale generators" (EWGs), which can sell electricity in wholesale markets. Unlike QFs, EWGs are not constrained by efficiency or fuel requirements. Furthermore, unlike PURPA, which barred utilities from controlling ownership of QFs, EPACT allows full utility participation in the operation and ownership of EWGs.

More importantly, EPACT mandates that the owners of transmission facilities (primarily utilities) provide EWGs access to the grid by "wheeling" power to wholesale customers at cost-based rates. The FERC is required to establish regulations that will provide EWGs with open and nondiscriminatory transmission services from public utilities. After a series of individual utility wheeling orders under EPACT, FERC determined that uniform open access to foster competition was needed. This determination resulted in two closely related rules—Orders No. 888 and 889—detailing the mechanisms to be used to assure nondiscriminatory open access by wholesale power generators and recovery of the utilities' prudently incurred costs.

Utilities have owned and operated the electricity transmission system for more than 100 years. They have maintained reliability, resolved pricing issues among neighboring utilities, and served their native customers through experimentation and voluntary cooperation with other utilities. More importantly, they currently operate in a vertically integrated environment, in which transmission, generation, and distribution costs are "bundled" into a single price.

To ensure open access, Order No. 889 requires functional independence between wholesale transmission operations and marketing services. Extending open access to retail competition could require the complete divestiture of transmission assets by the owners of generation and distribution assets, to assure unbiased service. In addition, "stranded costs" as a result of retail wheeling could be significantly higher than those arising from similar changes in wholesale power markets.

Competition in electricity markets also raises environmental issues. Open access to the national transmission grid, giving suppliers the means to ship power over vast distances, could affect local emissions from generating plants. Lower electricity prices could lead to more consumption and less concern for conservation. Unless specific provisions are made, the high capital costs and intermittent availability of some renewable technologies could preclude them from meaningful competition in new capacity decisions.

On the consumer side, although competition generally leads to lower prices, there are some specific areas of concern for retail customers. For example, if the value of utility properties is diminished, the loss of tax revenues may be felt by local customers. The capability for customers to make price-based purchasing decisions might also require new metering technologies to record sales from more than one supplier, and the customers themselves could bear the conversion costs.

Even in a deregulated market, it is likely that consumers will have varying degrees of freedom to choose among energy service providers. Large industrial and commercial consumers may well have greater flexibility than residential consumers. Some competitors may be tempted to charge captive customers (those who have no alternative supplier of energy services) higher prices than they charge their more elastic customers (those who have greater freedom to switch to another energy service provider). If they do, the transition costs of restructuring and the fixed costs of electricity production could be borne primarily by residential and small commercial consumers. In their effort to manage the transition to competition, some legislators and regulators, such as those in California, are attempting to protect the interests of small consumers.

State Initiatives

Currently, most States are attempting to address such concerns. The diversity of proposed solutions across the States attests to the complexity of the transformation. Nevertheless, scrutiny of the proposals reveals areas of consensus. First, most States agree that utilities should be required to provide service to their regional customers until the customers choose service from another provider. Second, most legislators and public utility commissions are moving toward the creation of independent system operators (ISOs) to operate, coordinate, and assure reliability of the local grid. The ISOs are expected to dispatch generation on the basis of market prices, dispatching low-cost generators first and basing subsequent dispatching on a "merit order" of bid prices. Third, most commissions agree that competition should sustain past commitments in the areas of public and environmental policy, such as use of renewable fuels, assistance to low-income households, and conservation. On the other hand, a number of proposals are vague about how those commitments are to be funded in the future. Lastly, while most States agree that some recovery of stranded costs is desirable, the amounts to be recovered and the methods proposed for recovery vary widely.

Recovery of stranded costs is the thorniest issue facing competition-minded public service commissions. Estimates of stranded costs are in the range of zero to $130 billion and higher. Some sense of the many possible approaches can be acquired by examining the propositions advanced in three States: California, New York, and Maine.

Among the States, California is at the forefront of restructuring legislation. The State's legislature has supported the California Public Utility Commission's order to permit competition and customer choice by passing legislation to create a new industry structure and provide for recovery of stranded costs. As a result, California has taken the position that, while all electricity customers are responsible for past obligations, the interests of residential and small commercial customers must be protected. Regarding stranded costs (called "transition costs" in the California legislation), accelerated recovery of past obligations is accomplished through a "competitive transition charge" (CTC).

The CTC is to be charged to all customers, based on their electricity consumption as a "non-bypassable" severance fee. ("Non-bypassable" means that the charge is not transferable.) A rate cap guarantees that no customer's rate will be higher than it was on June 10, 1996. Small customers (with a maximum peak demand less than 20 kilowatts) are to receive a rate reduction of at least 10 percent by January 1, 1998, with a cumulative 20-percent reduction anticipated by April 1, 2002. Investor-owned utilities (IOUs) have until December 31, 2001, to complete recovery of most of their stranded costs. Control, but not ownership, of the transmission assets will be turned over to the ISO.

The New York Public Service Commission (NYPSC) is also proposing to distribute stranded costs across all consumers by mandating a non-bypassable "wires charge" at the distribution level. The NYPSC does not presume full recovery of uneconomical contracts and investments under competition, but instead requires utilities under its jurisdiction to submit proposals that apply "creative means . . . to reduce the amount of strandable costs before they are considered for recovery."

The Commission estimates that about 38 percent of New York's strandable costs are the result of contracts by utilities for purchases from independent power producers (IPPs) at above-market prices. Apparently, the "creative means" directive hints that New York's utilities and IPPs should begin investigating the possibility of buying out or renegotiating those agreements. The resolution of each proposal will be accomplished through individual rate case or utility specific proceedings starting in 1996. While New York is stopping short of legislative statutes, the NYPSC is moving to resolve stranded cost issues as quickly as possible. The Commission has indicated that divestiture of generation assets is strongly encouraged to alleviate vertical market power and provide a basis for recovery of stranded costs.

In contrast, the Public Utility Commission of the State of Maine (MPUC) is taking a more moderate approach to the problem of stranded assets, by deferring estimates of each utility's stranded costs until the year 2000 and readjusting the estimates in 2003 and 2006. Similarly, divestiture of transmission and distribution assets by Maine's utilities (municipal utilities and rural cooperatives are exempt) is to begin in 2000 and to be completed by 2006. The MPUC views stranded costs as a problem whose magnitude shrinks with the passage of time. Nevertheless, the MPUC recognizes that some amount of stranded costs may persist after 2000. In those cases, cost recovery will be accomplished through a surcharge that will be administered through the divested transmission and distribution companies and will be comparable with similar charges that existed before deregulation [*14*].

Consumer and Supplier Responses

Many other State legislatures and public utility commissions are also developing proposals for competition, but the final form of a restructured electric power industry is still far from apparent. Consequently, the *AEO97* reference case does not address the major components of a restructured industry, such as stranded costs and open retail access. Ongoing EIA research, to be published in the spring of 1997 [*15*] provides clues as to the potential price impacts of institutional changes and changes in consumer behavior. The value that consumers place on adequate generating resources, and their willingness to pay for reliability of service, will have important implications for the willingness of market participants to build generating plants.

Utilities attempt to design systems and select reserve margins to balance the marginal costs and marginal benefits of reserve capacity. The standard measure on which systems have been designed is to provide enough generating capacity so that only one day of capacity shortage results every 10 years. The implementation of this standard means that the cheapest capacity in service—typically, a combustion turbine plant that requires an annual carrying cost (not including the costs of operation) of about $36 per kilowatt—is used 8 to 10 hours a year. Accordingly, the resulting reduction of 10 hours of unmet demand (also called "unserved energy") is worth $3.60 per kilowatthour ($36/10) in mitigated opportunity costs for consumers.

In reality, the value of unserved energy is difficult to compute, because the opportunity costs for consumers vary widely. Estimates range from $2 to $25 per kilowatthour and are affected by the nature of consumption, the timing of service curtailment, the length of the interruption, and the amount of warning before curtailment begins. For example, a blackout without warning during the dinner hour is much more expensive for a restaurant owner than it is for most residential consumers. Hence, a restaurant owner (and commercial consumers in general) would be willing to pay more for reliable electric power than would most residential consumers. Further, a disruption is more costly if it lasts for a longer period of time and creates costs associated with food spoilage, prolonged loss of residential heating and cooling, and the like.

In a competitive electric power industry, energy service companies may have the means to determine the value of unserved energy. If the real opportunity cost to consumers during a blackout is actually lower than the assumed value that system planners have traditionally used, and if consumer prices do not support the level of capacity that has been built under regulation, then reserve margins will fall. Lower reserve margins could have important implications for system operating costs and electricity prices.

Under cost-of-service regulation, prices can be expected to increase when new capacity enters into service, because new capacity additions generally qualify for regulated cost recovery. As a result, annual depreciation expense (representing investors' return of capital) and a return on investment (equal to the cost of capital, representing fair compensation to investors) are added into the price calculation. In the past, there have been occasions when additions to prices have been so high (as with expensive nuclear plants) that they could have created rate shock, making it necessary to develop and use special regulatory and financial conventions—such as rate phase-in plans and sales-leaseback transactions—to mitigate the shock.

The price impact of capacity additions under a competitive environment may be the opposite of that under cost-of-service regulation. That is, prices could fall when new capacity comes into service in a competitive market if the price of electricity is dictated by supply and demand. A new generating plant, representing an increase in supply, could put downward pressure on electricity prices.

Another important aspect of consumer response to a competitive electricity market is the degree to which demand patterns may change. Several actions may be taken by market participants to stimulate changes in demand patterns. Some end-use consumers may pay time-of-use prices for electricity, which would be higher during peak consumption periods and lower during off-peak periods, providing an incentive for consumers to reduce peak period consumption and increase off-peak consumption.

It is possible that most end-use consumers will not see time-of-use prices but, instead, will purchase service contracts that specify a fixed fee per kilowatthour of consumption, regardless of when the electricity is used. Still, the incentives that time-of-use prices provide for cutting consumption during peak periods may actually be incorporated into attractively priced service packages offered by aggregators and distributors to consumers who are willing to have service curtailed briefly during peak usage periods. In effect, this would translate the incentives of time-of-use market prices to the end-use consumer.

If time-of-use rates are used and consumers do respond to them, there could be two significant effects: aggregate consumption could rise in response to lower overall electricity prices; and flatter demands (lower peak period consumption or higher off-peak period consumption) could produce higher plant utilization and, as a result, lower capacity requirements. Reduced demand for electricity during peak periods (or increased demand during off-peak periods) could increase the efficiency of the electric power industry and lower the cost of electricity in the long run. However, there are no compelling research results indicating the degree to which consumption patterns will actually change. Like the market value of reserve capacity, the way in which consumers respond to price signals and incentives must be market tested so that builders of generating capacity and providers of energy services can make sound decisions.

Electricity Futures

At 10:30 A.M. on March 29, 1996, the New York Mercantile Exchange (NYMEX) launched the first-ever electricity futures contracts. By the end of the day, 1,216 wholesale power contracts had been traded, comparable to the first-day volumes of the crude oil and natural gas futures markets (1,884 and 918 contracts, respectively). This event signaled the recognition that, in a competitive market, electricity prices could be influenced by highly variable changes in supply and demand. With prices likely to become volatile, a futures market could hedge some of the price risk. Thus, electricity is joining copper, pork bellies, corn, and other products in the intensely competitive and highly visible open auctions that are the hallmarks of today's commodity markets.

The possibility of an electricity futures market was anticipated by NYMEX and the Bonneville Power Administration (BPA) in 1993. They were quickly joined by Pacific Gas and Electric (PG&E), Portland General, and PacificCorp in committees to supply information about the characteristics of the western supply region and to research possible delivery locations.

NYMEX is the exchange that specializes in energy futures contracts, historically launching trading in specific energy products with the development of spot or cash markets. NYMEX has developed futures markets in natural gas, crude oil, gasoline, and other energy products on the basis of expectations of continued price volatility in oil products and deregulation of natural gas markets. Until recently, however, price stability in the regulated electricity industry has not provided enough volatility for viable futures trading. Although the industry is still tightly regulated, a move toward competition and the ability of consumers to choose their electricity suppliers—driven by the spirit of open transmission access—is expected not only to lower average prices but also to make them volatile. Volatility, coupled with the fungibility of electricity and the existing large pool of diverse buyers and sellers, is recognized by commodity traders as the minimum criterion for an active futures market.

About three-fourths of the energy-related contracts introduced since 1978 have failed. While it is difficult—if not impossible—to determine the reasons for specific failures, in general, lack of liquidity, insufficient volatility, low correlation between futures and cash prices, a nonviable spot market, and limited effectiveness as a hedging instrument have been recognized as contributing factors in the downfall of new futures markets. A viable electricity futures market is far from certain; however, the elements needed to maintain active participation may be discernible in the example of a recent energy futures market, namely, natural gas.

During the 1980s, natural gas markets were characterized by excess supply, low prices, and a legacy of prior long-term contracts for high-priced gas. Natural gas futures were introduced in 1990 to furnish buyers and sellers the tools to hedge price risk and to provide an index for determining the price of delivered gas. Since then, the number of contracts traded daily has been regularly surpassing contracts in many other futures markets, with daily volumes frequently in excess of 40,000 contracts.

More importantly, the natural gas futures contract price is being used as an index of the physical price of gas in spot market negotiations. In addition, a significantly higher proportion of participants are hedging or "commercial" traders, as opposed to speculators. Hedging is the substitution of futures for the later purchase or sale of the physical commodity. Hedgers expect to maintain a position in the physical market. In contrast, speculators do not attempt to maintain a position in the physical market but "take profits" based on price changes between contracts. By significantly adding to the volumes traded, speculators play an important and necessary role. Without their participation, liquidity would be severely diminished. Yet it is the combination of the price discovery mechanisms of gas futures and high-volume participation by marketers and producers that has resulted in an active market.

The electricity industry currently shows similarities to the natural gas industry of the 1980s: surplus supply (in the form of excess baseload capacity) and high-priced, long-term contracts (brought about by the qualifying facility provision of the Public Utility Regulatory Policies Act of 1978). And, although electricity prices in many regions of the country cannot be characterized as low, the use of cost-of-service or rate-of-return pricing by utilities and regulators has kept them stable.

Competition in the electricity industry is expected to result in lower but more volatile prices. Price volatility could accelerate the development of short-term or cash markets for consumers seeking progressively lower prices. Conversely, suppliers could need a mechanism to assure future revenue targets. Electricity futures may provide a mechanism for suppliers to control price risk and stabilize revenue streams.

In addition, the interaction of paper and physical electricity could accelerate movement toward the full potential for interregional trade. Open trade could make apparent the current high ratio of capacity to demand, putting downward pressure on prices. The imbalance of supply and demand could expose economic inefficiencies, such as excess reserve margins; however, suppliers and public utility commissions will need to monitor minimal reserve margin levels accurately to ensure reliability. The difference between electricity prices and the cost of generation (the "crack") could decrease as inefficiencies are eliminated. As in the natural gas market, the price and terms of electricity futures could be used as a standard for prices and contract terms in the physical market.

Electricity futures prices are based on an index of electricity prices for delivery at two locations—the Palo Verde nuclear switchyard in Arizona and the California-Oregon Border (COB) intertie in the Pacific Northwest. The index for each location is volume-weighted and calculated on the basis of transactions reported by 15 industry participants. Dow Jones began publishing the COB electricity index in June 1995. Currently, both indexes are published daily as advertising in the *Wall Street Journal.*

The COB connects utilities in the Northwest to California. The intertie consists of three 500-kilovolt lines on the south and three on the north side of the California border. Transmission capacity is rated at 4,800 megawatts north-to-south and 3,675 megawatts south-to-north. BPA operates the system north of the intertie, and PG&E manages flows to the south. Palo Verde is the intertie that connects utilities in the Southwest to California—with capacity to move 6,100 megawatts east and 2,500 megawatts west. A single contract for both locations consists of 736 megawatts of peak power in increments of 2 megawatts an hour over 23 business days in each month. Delivery is scheduled beginning at 7:00 am and ending at 10:00 pm, with delivery into Saturday and Sunday allowed for months with fewer than 23 business days.

As this publication goes to press it appears that the current Palo Verde and COB contracts are struggling to achieve the degree of liquidity needed to maintain interest by traders. The first few weeks of trading found an average of 50 traders daily in the pits. Currently, trading volumes are about half the initial volumes, with no more than 5 to 7 "warrant" traders (local traders who pay a fee to work new trading rings) in the pits daily. While a handful of brokerage firms are still active, trading is being dominated by only one or two, with none achieving the volumes anticipated when the contract began. It appears that these "noncommercial" or speculative traders are concentrating on the more profitable natural gas and crude oil markets and abandoning electricity futures.

A lack of interest by commercial traders is also apparent. A limited number of power marketers are active, but they are participating at volumes lower than when trading began. And although a few utilities such as BPA, Portland General Electric, and one or two others are maintaining limited positions in the COB market, utility interest in Palo Verde contracts is nonexistent. It appears that utilities are managing risk by using such traditional tools as over-the-counter sales and block purchases of electricity—transactions that are more liquid than the futures market and have the added benefit of generally not requiring administrative approval from a utility's board of directors or new accounting procedures to document losses.

It is possible for competitive electricity markets to exist without a futures market. Forward contracts, energy swaps, or hedging with natural gas or oil futures may be all that is required for risk management. The transmission and delivery of electricity also presents technical challenges, requiring a far greater measure of system control than is required for the distribution of natural gas. In addition, electricity transmission systems are highly fragmented, with local control tightly concentrated. Transmission networks in the East, West, and Texas are functionally independent. With no mechanism for delivery to the East, traders there have little interest in West Coast indexes.

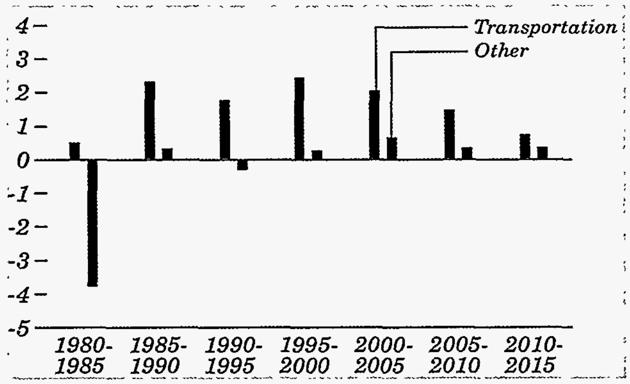
While experiments in and plans for competition are underway in many States, deregulation is still in its infancy. Most States see 1998 as the earliest possible date for retail wheeling and full consumer choice. Perhaps, as deregulation progresses, utilities will incur higher levels of price and supply risk than can be covered by traditional tools. If so, they may turn to the futures market for coverage. Without strong utility support, the prognosis for a viable electricity futures market is uncertain.

Transportation Issues

The transportation sector's almost exclusive reliance on oil and its increasing responsibility for higher U.S. carbon emissions has made it a focal point of recent policy debates. While consumers generally appreciate low fuel prices and high rates of economic growth, these factors exacerbate problems associated with the Nation's dependence on imported oil. In recent years, improvement in vehicle efficiency has slowed while reliance on mass transit has diminished. Consequently, transportation sector oil consumption has increasingly contributed to higher demand for oil products and rising emissions of greenhouse gases.

Between 1980 and 1985, oil consumption for non-transportation uses declined by 25 percent, or almost 4 quadrillion Btu (Figure 10), as consumers substituted other fuels to escape the high prices of oil products and concerns about availability. But with no economically competitive alternatives available for vehicle fuels, transportation oil consumption increased by 0.5 quadrillion Btu over the same period, despite substantial improvements in the fuel efficiency of light-duty vehicles (cars, vans, pickup trucks, and utility vehicles).

Figure 10. Changes in oil consumption for transportation and other uses, 1980-2015 (quadrillion Btu)

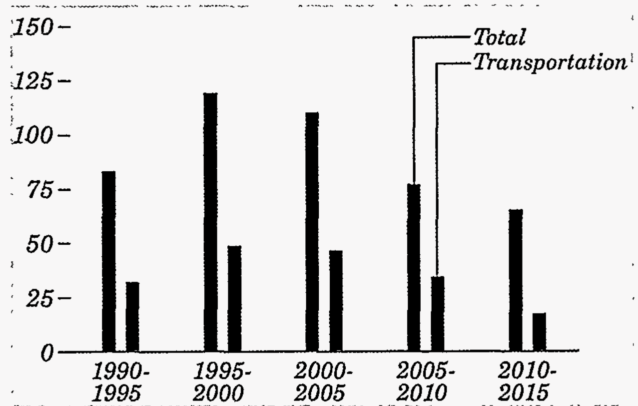


In the *AEO97* forecast, transportation uses of oil continue to dominate growth in domestic oil use. About 80 percent of the increase in annual oil consumption between 1995 and 2015 is directly attributable to transportation vehicles. In fact, beyond 2000, transportation oil use alone roughly equals total U.S. oil imports.

Compared with last year's forecast, *AEO97* features lower energy prices and higher economic growth. Both tend to increase energy consumption, and the transportation sector is particularly sensitive to these changes. Of the increase in projected energy consumption in 2015—2.9 quadrillion Btu higher than last year's forecast—transportation uses account for more than two-thirds.

Growth in transportation oil use has been a major factor impeding the Nation's progress toward the policy objective of rolling back carbon emissions to 1990 levels. Cumulatively, carbon emissions in 2015 are expected to be 64 million metric tons higher than last year's estimate, with transportation energy use contributing two-thirds of that increase. Annual carbon emissions are expected to reach 1,799 million metric tons or 34 percent above the 1990 target stabilization level, and transportation-related emissions account for 39 percent of the overage (Figure 11).

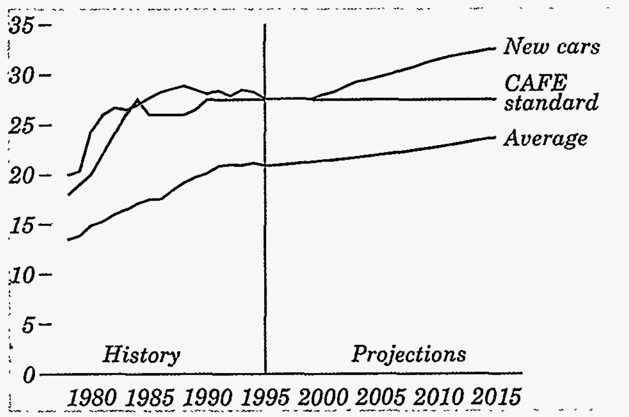
Figure 11. Changes in carbon emissions, 1990-2015 (million metric tons)



Oil consumed in light-duty vehicles is expected to continue to account for more than half of total transportation oil consumption throughout the forecast, even though population growth slows and an increasing proportion of the driving population is beyond retirement age [*16*]. Light-duty vehicles are expected to consume 23 percent more energy in 2015 than in 1995, with gasoline accounting for 80 percent.

Although highway travel growth slows over the forecast, the growth exceeds the minimal gains expected in stock average "on-the-road" fuel efficiency (Figure 12). New car and light truck fuel efficiencies in the

Figure 12. Trends in automobile fuel efficiency in the reference case, 1978-2015 (miles per gallon)



reference case do not exceed the corporate average fuel economy (CAFE) standards currently being met [*17*] until the turn of the century. Average light-duty vehicle fuel economy is thus expected to be only about 8 percent higher in 2015 than it was in 1995, whereas vehicle miles traveled are projected to be almost one-third higher. As a consequence, gasoline demand in 2015 is expected to be more than 1 million barrels per day above 1995 levels.

The projected growth in vehicle miles traveled—about 1.4 percent annually for the period 1995 to 2015—is lower than actual rates of growth over the past decade. Between 1985 and 1995, vehicle miles traveled in the United States increased by more than 3 percent a year. Slower growth is anticipated in the future, principally because of slowing economic and population growth. If recent historical rates of growth in vehicle miles traveled were sustained over the projection period, gasoline requirements in 2015 would be 3 million barrels per day higher than the *AEO97* reference case projection of about 9 million barrels per day.

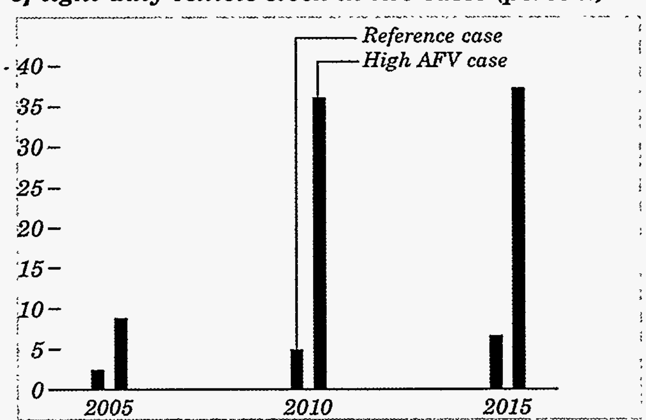
The current and projected slow growth in fuel efficiency is a direct byproduct of oil price behavior and rising per capita income. At today's prices (adjusted for inflation), annual expenditures for gasoline and oil account for only about 15 percent of annual vehicle ownership costs, roughly half their share in 1975 [*18*], and interest in fuel economy on the part of the car-buying population is limited. Oil price increases over the next 15 years are expected to be relatively modest. Thus, the projections indicate a similar relationship between fuel and overall car operating costs and relatively slow market penetration by more fuel-efficient vehicles.

Just as low oil prices have suppressed the Nation's appetite for more fuel-efficient vehicles, they have also reduced market demand for vehicles that burn alternative fuels. From a technological standpoint, alternative-fuel vehicles (AFVs) have been available for many years. The conventional internal combustion engine, with relatively minor and inexpensive modifications, can burn ethanol derived from "fuel crops," methanol derived from natural gas, or compressed natural gas stored in canisters on the vehicle.

Vehicles currently utilizing these fuels can be seen outside some government buildings and in use by many energy-related companies; however, most current demand is driven by government policy, not economics. The Energy Policy Act of 1992 mandated the introduction of such vehicles. Not many are being bought by the general public. While AFVs may not cost much more than conventional vehicles, they do not offer much in the way of improved fuel economy. Often, technology that improves the fuel economy of AFVs is also applicable to the engines that drive conventional gasoline-powered vehicles. Thus, the disadvantages of AFVs—range and fuel availability—are likely to continue to impede their competitive success.

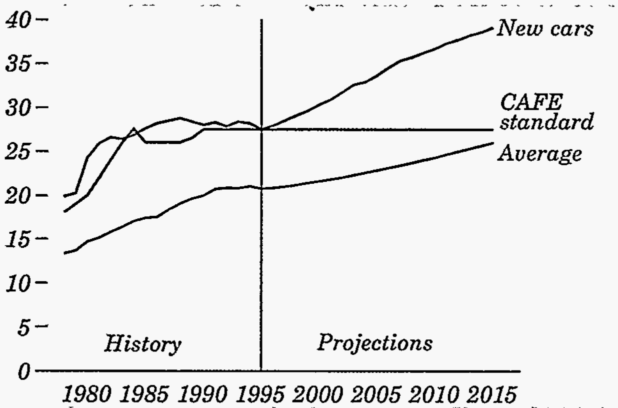
More advanced AFVs (battery-powered vehicles, fuel cell electric vehicles) may offer significant operating cost savings in the future, but estimates of purchase price, performance characteristics, and consumer acceptance remain uncertain. In the reference case even in 2015, AFVs account for less than 10 percent of annual vehicle sales and 6 percent of the total light-duty stock. More aggressive introduction, however, has the potential to be a major influence on gasoline consumption (Figure 13). If the same mix of AFVs chosen in the reference case reached roughly an equal sales share with conventional vehicles by 2005 and maintained that share thereafter, almost 40 percent of all light-duty vehicles in 2015 could burn fuels other than gasoline, potentially resulting in a 20-percent reduction in gasoline consumption.

Figure 13. Alternative-fuel vehicle shares of light-duty vehicle stock in two cases (percent)



The reference case outlook projects continued reliance on conventional vehicles with increasing horsepower. This forecast is based on analysis of recent auto industry sales trends. It is not a statement based on technical absolutes, and it does not consider alternative domestic and foreign political developments that could profoundly alter the picture. For example, if new car fuel economy improvements over the forecast were to match the improvements achieved between 1975 and 1995 (roughly 11 miles per gallon), new cars would average 39 miles per gallon by 2015. The average automobile stock efficiency would reach 26 miles per gallon by 2015—10 percent higher than in the reference case (Figure 14). Such efficiency gains could, annually, save more than 2 quadrillion Btu (about 1 million barrels of gasoline a day) and reduce carbon emissions by 50 million metric tons. In that context, almost no increase in gasoline demand would occur over the next two decades.

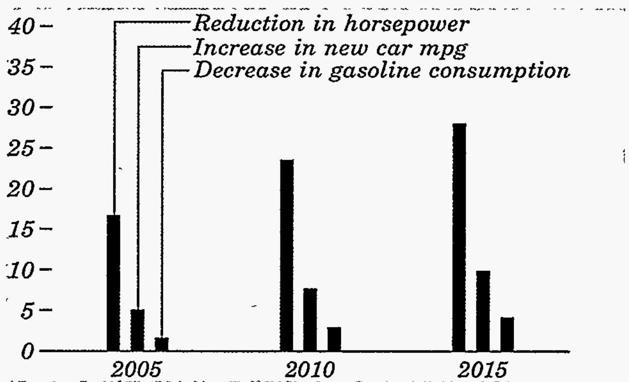
Figure 14. Trends in automobile fuel efficiency in the high efficiency case, 1978-2015 (miles per gallon)



If new car efficiency rose to 45 miles per gallon and fleet average efficiency increased to 34 miles per gallon by 2015, gasoline consumption would fall below current levels by more than 1 million barrels per day. For those gains to be achieved, however, the costs of fuel-saving technologies would have to fall by 50 percent or more over the projection period relative to the reference case. Vehicles that achieve this efficiency level are available for sale today in the subcompact size class. Also, jointly funded research efforts by the auto industry and the Federal Government are underway to greatly extend the availability of high-efficiency vehicles comparable in size and performance characteristics to today's midsize cars [*19*]. The target for achieving the advances is 2006.

Within a vehicle size class, fuel economy and horsepower compete directly for market share. In recent years, horsepower has been the winner. Between 1990 and 1995, new car fuel efficiency remained practically fixed at 28 miles per gallon. Over the same period, average new car horsepower increased by 19 percent. Vehicle horsepower is expected to continue to increase in the reference case, although at a decreasing rate. By 2015, average new car horsepower is expected to be more than one-third higher than in 1995. If vehicle horsepower remained constant at 1995 levels, however, new car fuel economy could reach nearly 36 miles per gallon by 2015, 10 percent higher than in the reference case (Figure 15). Such an improvement would cut gasoline demand by 4 percent, or 2 percent of total transportation oil consumption.

Figure 15. Changes from the reference case, assuming no increase in new car horsepower (percent)



Vehicle miles traveled for personal transportation are projected to increase by nearly 25 percent between 1995 and 2015. One-third of the increase relates to more drivers being on the road. The balance relates to increased travel intensity for all drivers. Policy initiatives designed to slow growth in travel intensity include actions to encourage more car pooling or use of mass transit or, alternatively, the substitution of telecommuting for actual commuting. Were travel per driver to stabilize at current levels over the forecast horizon, three-fourths of all projected increases in gasoline demand could be avoided, all else being equal.

As noted, projected gasoline demand does respond to alternative price paths. The low and high world oil price cases included in this report result in upward and downward shifts in gasoline prices in the range of 12 to 15 percent. In response to higher or lower prices, consumers shift new car purchases. In the high price case, the market penetration of relatively more fuel-efficient automobiles increases somewhat as consumers favor smaller cars with less horsepower. In the low price case the converse occurs. Although high prices moderate the growth in demand for gasoline, a price rise of 15 percent diminishes demand by only about 2 percent over the projection period. New car fuel economy in the high world oil price case in 2015 is 3 percent higher than in the reference case (33.5 miles per gallon). In the reference case, gasoline demand in 2015 is projected to be about 1.3 million barrels per day higher than it was in 1995. The projected increase in the high price case, although lower, still reaches 1 million barrels per day.

Buildings Sector Issues

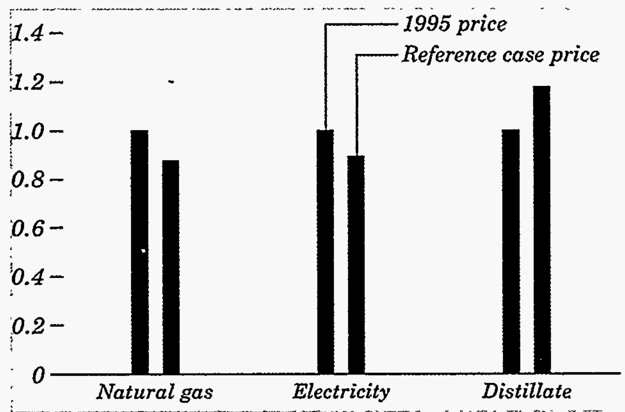
The buildings sector encompasses all the energy consumed in residential and commercial buildings, as well as non-building energy use in the commercial sector, such as street lights and other municipal uses. In 1995, the buildings sector, which is heavily dependent on electricity, accounted for 36 percent of the total energy consumed—and 35 percent of total carbon emissions—in the United States, when electric generation losses are included. For these reasons, numerous policies have been initiated over the past decade to increase energy efficiency, thereby reducing energy consumption and carbon emissions, in the buildings sector.

The *AEO97* reference case includes existing policies that have had the effect of reducing the potential growth of energy consumption in the buildings sector. Examples include the minimum efficiency standards set forth in the National Appliance Energy Conservation Act of 1987 (NAECA) and the Energy Policy Act of 1992 (EPACT), both of which targeted certain energy-using equipment in the sector by requiring that equipment be manufactured to meet or exceed minimum efficiency levels.

Traditionally, efficiency standards and energy price shocks have had large impacts on energy use in the United States. For the buildings sector, the level of efficiency for each energy-using appliance purchased in any given year is in part a function of mandated efficiency standards and energy prices. All else being equal, the higher the energy price and the more stringent the efficiency standard, the higher will be the purchased efficiency level and the lower the energy consumption and carbon emissions.

In 2015, energy consumption in the buildings sector in the *AEO97* reference case is projected to be 16 percent (5.3 quadrillion Btu) higher than in 1995. Given the forecast for a decline in real energy prices (for natural gas and electricity) delivered to residential and commercial customers in the reference case (Figure 16), projected energy consumption in 2015 would likely be lower if it were assumed that prices remained constant. Figure 16 relates the energy prices for major fuels in the buildings sector in 1995 to the prices in 2015 in the reference case and in a constant price case, in which prices are assumed to remain at 1995 levels.

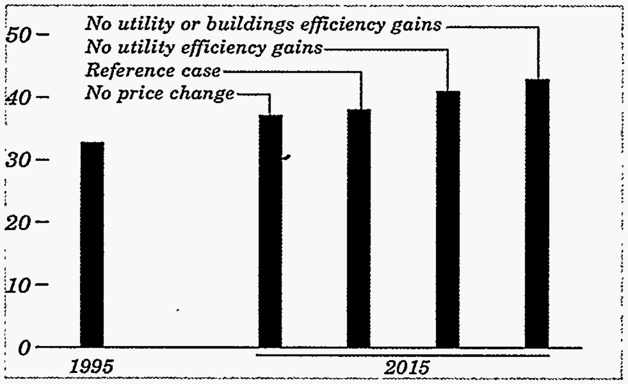
Figure 16. Buildings sector energy prices, 1995 and 2015 (index, 1995 = 1)



For both natural gas and electricity, real prices to consumers in the buildings sector are projected to be more than 10 percent lower in 2015 in the reference case than their respective 1995 levels, while distillate prices are projected to be more than 18 percent higher. In the constant price case, therefore, projected distillate consumption in 2015 is higher than in the reference case, and natural gas and electricity consumption are lower. In the constant price case, buildings sector consumers are less likely to switch from distillate use for heating applications to natural gas or electricity. Lower real energy prices discourage investment in energy-saving equipment and more efficient building shells, increasing the demand for energy. If buildings sector energy prices were to remain at 1995 levels, almost 19 percent (1 quadrillion Btu) of the projected increase in energy demand in the reference case would be averted (Figure 17).

In the constant efficiency case, assuming no efficiency gains beyond 1995 levels, projected energy

Figure 17. Buildings sector energy consumption in alternative price and efficiency cases (quadrillion Btu)



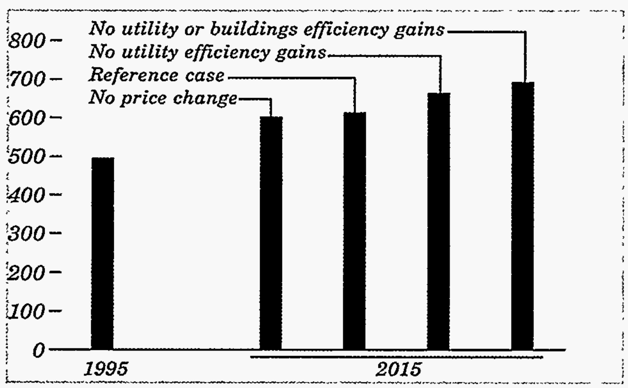
consumption in 2015 is higher than in the reference case, which incorporates numerous efficiency gains in the buildings sector as well as other sectors. In analyzing the effect of efficiency gains on total energy consumption in the reference case, it is important to distinguish efficiency changes within the sector from those associated with electricity generation. Since direct use of electricity and the losses associated with its generation and transmission account for more than two-thirds of all buildings sector energy consumption, efficiency gains in those areas should be considered in the evaluation of overall energy savings.

By fixing end-use efficiency and the ratio of electricity-related losses to delivered electricity at their respective 1995 levels, the constant efficiency case provides an estimate of the total amount of energy projected to be saved by efficiency gains in the buildings sector in the reference case. Figure 17 shows the relative importance of these efficiency changes in terms of energy consumption avoided in 2015. With no change in the efficiency of electricity generation and distribution, an additional 2.9 quadrillion Btu of energy would be used to provide the buildings sector the same amount of electricity needed in the reference case in 2015. Within the buildings sector, efficiency gains in the reference case save an additional 1.9 quadrillion Btu in 2015.

Carbon emissions associated with energy use in the buildings sector—mostly attributable to electricity generation from coal—are also a significant issue. The Climate Change Action Plan (CCAP) contains numerous programs aimed at increasing energy efficiency and, thereby, reducing carbon emissions. Examples of CCAP measures affecting the buildings sector are the Rebuild America program, sponsored by the Department of Energy, and the Green Lights program, sponsored by the Environmental Protection Agency (EPA). The goal of these programs is to promote energy efficiency and awareness through nonregulatory means. Another example of a nonregulatory program is EPA's Energy Star Financing program, which allows prospective home buyers to finance larger mortgages on homes built to certain energy-saving specifications.

Figure 18 relates 1995 buildings sector carbon emissions to those projected for 2015 in the constant price and constant efficiency cases. The *AEO97* reference case projects an additional 25 percent (122 million metric tons) of carbon emissions from the buildings sector (including generation losses) in 2015, relative to emissions in 1995 (494 million metric tons). When efficiency is held constant in both the buildings and electricity generation sectors, emissions increase by 40 percent (198 million metric tons) over 1995 levels. Conversely, when energy prices are held constant, the increase in carbon emissions between 1995 and 2015 is 13 percent (65 million metric tons) lower than in the reference case.

Figure 18. Buildings sector carbon emissions in alternative price and efficiency cases (million metric tons of carbon)



Effects of Oil and Gas Supply Technology on Natural Gas and Renewables Markets

In order to explore the impacts of slower and more rapid technological progress than that assumed in the reference case, *AEO97* contains technology cases for each of the energy-consuming and producing sectors. The following discussion focuses on the oil and gas technology cases for two reasons. First, there is considerable uncertainty about the future price and supply of natural gas, which are heavily influenced by the rate of technological advances in the industry and by the uncertainty of the Nation's oil and gas resources. Second, the price of natural gas is likely to have a significant impact on the consumption of gas in both the end-use and electricity generation sectors, with resulting impacts on competing fuels.

Cases with slower or more rapid technological progress in the oil and gas production sector analyze the impacts on natural gas prices without feedback from the consuming sectors, thus presenting the outer range of the potential impacts. In addition, because of the market impacts of natural gas technology, fully integrated cases with demand feedback are also presented.

Within oil and natural gas supply markets, technological progress has historically expanded the economically recoverable resource base and reduced effective exploration and development costs. Over the past decade, the domestic oil and natural gas marketplace has seen the introduction and deployment of major new technological advances. Examples include the increased use of advanced computer-imaging technologies to provide new perspectives on resources beneath the ground, the advancement of offshore drilling in the deeper waters of the Gulf of Mexico, and recovery of additional natural gas from reserves below prior depth frontiers or from shallower geologic structures using unconventional recovery techniques. The future pace and extent of such technological progress, however, and its potential effects on natural gas and other energy markets are uncertain.

The *AEO97* forecasts reflect key assumptions about the progress of oil and gas supply technologies, including assumed annual improvement rates for onshore and offshore drilling, lease equipment, and operating costs; inferred reserves and undiscovered resources; and finding and success rates. The reference case, high and low world oil price cases, and high and low economic growth cases use a single set of assumptions about these rates, derived from an analysis of historical trends, which are generally assumed to continue throughout the forecast. However, the historical rates can be estimated only with considerable uncertainty, and changes to these assumptions—reflective of their uncertainty—may have a major impact on the forecasts.

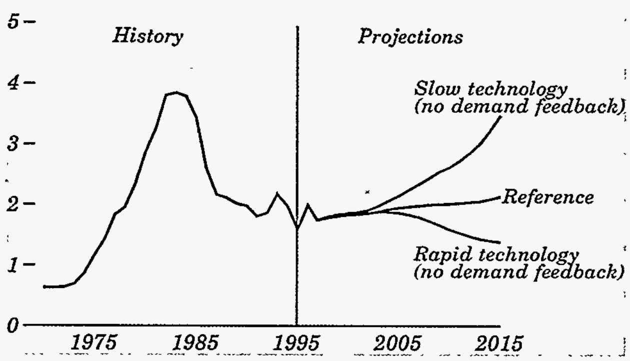
In order to test and quantify the sensitivity of the *AEO97* projections to changes in assumptions about future progress in oil and gas supply technologies, two alternative cases were analyzed, based on assumptions of more rapid and slower technological progress. Whereas the reference case assumes that the *most likely* estimate of this historical influence will continue throughout the forecast period, the rapid technology case assumes a *higher* estimate, and the slow technology case assumes a *lower* estimate. In addition, both of the alternative cases were run in two modes: with natural gas demand held at reference case levels (no demand feedback), and with market-driven demand-side adjustments in the oil and gas supply sector that cause consumption and production to deviate from reference case levels (with demand feedback).

The alternative cases do not address the possible impacts of making changes to national levels of investment in technological research, development, or deployment from their historical patterns. For this reason, the macroeconomic assumptions used for the reference case are also used for the two alternative oil and gas technology cases. Additional analysis and description of the alternative assumptions can be found in the "Market Trends" section of this report (pages 62-63) and in Appendix G.

Impacts on Natural Gas Markets

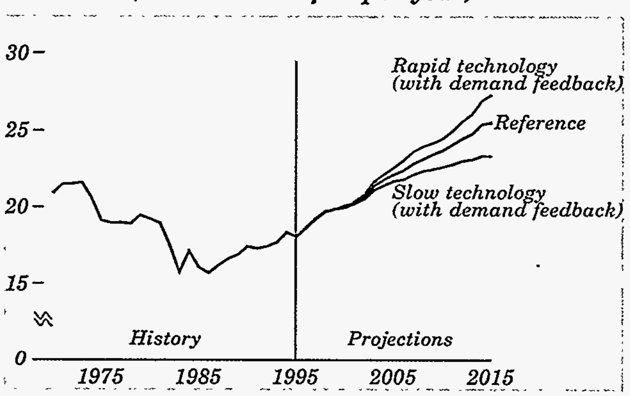
The impact of changes in technological progress assumptions on projected natural gas prices when production is assumed to remain at reference case levels is shown in Figure 19. Shortly after the year 2000, natural gas prices begin to diverge markedly from their reference case values. By 2015, the average wellhead price is $1.37 per thousand cubic feet in the rapid technology case and $3.48 per thousand cubic feet in the slow technology case—35 percent below and 63 percent above the reference case price of $2.13 per thousand cubic feet, respectively. Compared with historical levels, the 2015 wellhead price in the slow technology case is below the peak wellhead price in 1983. In the rapid technology case, the 2015 wellhead price falls within the range of prices over the past two decades.

Figure 19. Lower 48 natural gas wellhead prices in two alternative oil and gas technology cases, 1970-2015 (1995 dollars per thousand cubic feet)



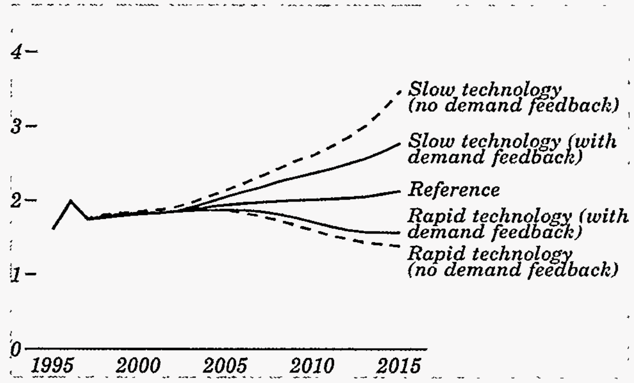
When market feedbacks are introduced, the projected levels of natural gas production change as shown in Figure 20. Production in 2015 is 6.6 percent higher in the rapid technology case than in the reference case and 8.5 percent lower in the slow technology case. The response is greater in the slow technology case because reference case natural gas prices are already very competitive. Consequently, the effect of lower prices on consumption, and therefore on production, in the rapid technology case is not as great as the effect of higher prices in the slow technology case.

Figure 20. Lower 48 natural gas production in two alternative oil and gas technology cases, 1970-2015 (trillion cubic feet per year)



When market feedbacks are introduced, the effects of the alternative technology assumptions on natural gas prices are moderated (Figure 21). In the rapid technology case, the lower prices made possible by more rapid technological progress tend to stimulate additional natural gas consumption. As a result, higher levels of domestic production are projected, imposing upward pressure on natural gas prices, which partially offsets the price reductions that result from improved technology. In the rapid technology case, the demand response eliminates 24 percent of the change in the wellhead price in 2015 relative to the reference case price. In the slow technology case, the demand response eliminates 52 percent of the change in the wellhead price in 2015.

Figure 21. Lower 48 natural gas wellhead prices in alternative oil and gas technology cases, 1995-2015 (1995 dollars per thousand cubic feet)



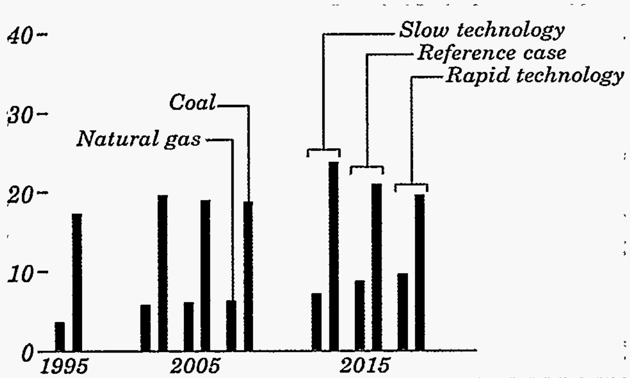
In the alternative technology cases with demand feedback, changes in projected natural gas prices for consumers in the industrial sector are accompanied primarily by changes in the consumption of steam coal and electricity. In the slow technology case, industrial coal use and electricity use are slightly higher than in the reference case in 2015. Similarly, industrial coal demand and electricity demand are slightly lower in the rapid technology case. The changes in projected industrial demand for electricity also affect demand for natural gas in the electricity generation sector, where 80 percent of the increase in generation requirements from 1995 to 2015 in the reference case is projected to be supplied by gas-fired capacity.

In 2015, projected natural gas consumption for electric power generation varies from 7.0 trillion cubic feet per year in the slow technology case to 9.4 trillion in the rapid technology case. Most of this consumption is utilized by capacity built during the forecast period. Cumulative unplanned additions of combined-cycle generating capacity (essentially all natural gas) vary from 96.5 to 143.0 gigawatts across the cases in 2015.

Within the electricity generation sector, changes in natural gas consumption complement changes in consumption of residual fuel oil, coal, and renewable fuels. Although small in total quantity, the projected use of residual fuel oil for electricity generation in 2015 increases by 35 percent in the slow technology case relative to the reference case and decreases by 25 percent in the rapid technology case. For the most part, these movements reflect changes in fuel use for dual-fired boilers.

Changes in coal consumption are much larger, because natural gas competes directly with coal for much of the new electricity generation capacity built during the forecast period. Steam coal consumption in 2015, which is projected to total 21.0 quadrillion Btu in the reference case, drops to 19.6 quadrillion Btu in the rapid technology case and rises to 23.8 quadrillion Btu in the slow technology case (Figure 22). Reflecting these changes in consumption, cumulative unplanned additions of coal-fired generation capacity vary from 20 to 74 gigawatts across the cases.

Figure 22. Natural gas and coal use for electricity generation in two alternative oil and gas technology cases, 1995, 2005, and 2015 (quadrillion Btu)

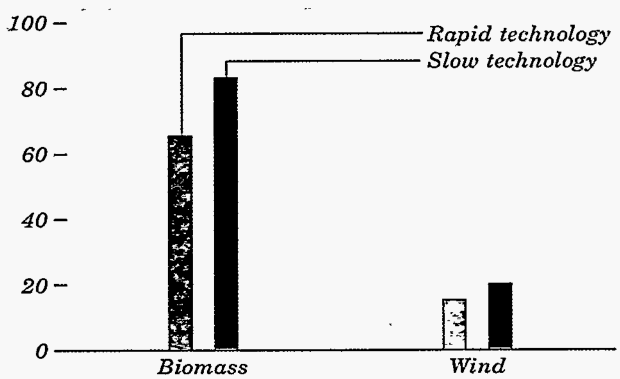


Impacts on Renewable Energy Markets

Natural gas prices also have important implications for the construction of new generating capacity powered by renewable fuels. Over the forecast horizon, projected unplanned additions of generating capacity using renewable resources (excluding conventional hydroelectric) vary from 7.6 gigawatts in the rapid oil and gas technology case to 11.6 gigawatts in the slow technology case. Although the increases are much smaller than those for coal or natural gas capacity, they are large in relation to the current total of 15.7 gigawatts of nonhydroelectric renewable generating capacity, including cogenerators.

Some renewables are responsive to the changes in projected natural gas prices, while others are not (Figure 23). Electricity generation from biomass, including energy crops, in 2015 is almost 27 percent (18 billion kilowatthours) higher in the slow oil and gas technology case, with higher natural gas prices, than in the rapid technology case, with lower gas prices. When gas prices are higher, energy crops become more cost-competitive, and biomass gasification—like coal gasification—also becomes more competitive. Similarly, generation from wind power, used primarily as a fuel saver, is 31 percent (5 billion kilowatthours) higher in 2015 in the slow oil and gas technology cases than in the rapid technology case.

Figure 23. Electricity generation from renewables in two alternative oil and gas technology cases, 2015 (billion kilowatthours)



Other renewables are relatively unresponsive to changes in natural gas prices. Conventional hydropower is assumed to be constant across the cases. Generation from municipal solid waste (MSW), which is based on the rate at which waste is produced, is driven primarily by overall economic growth. Geothermal capacity expansion will remain concentrated in the western States. And, although solar thermal and photovoltaic technologies are expected to enjoy expansion in selected small markets, they are projected to remain significantly more costly than fossil fuel alternatives for central station generation through 2015.

Market Trends

The projections in *AEO97* 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 and demographic trends and current laws and regulations, thus providing 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.

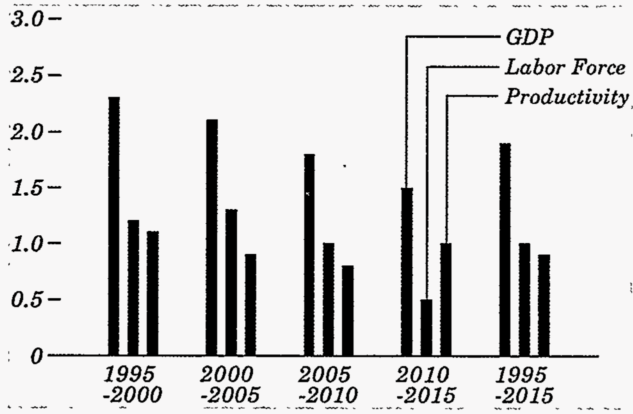
Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. The forecasts are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics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

Energy market projections are subject to much uncertainty. Many events which shape energy markets are random and cannot be anticipated, including severe weather, political disruptions, strikes, and technological breakthroughs. Also, assumptions concerning future technology, demographics, and resources cannot be known with any degree of certainty. Many key uncertainties in the *AEO97* projections are addressed through alternative cases.

EIA has endeavored to make these forecasts as objective, reliable, and useful as possible, but these projections should serve as an adjunct to, not a substitute for, the analytical process that should be used to examine policy initiatives.

Productivity and Investment Lead Projected Gains in Economic Growth

Figure 24. Average annual real growth rates of economic factors, 1995-2015 (percent)



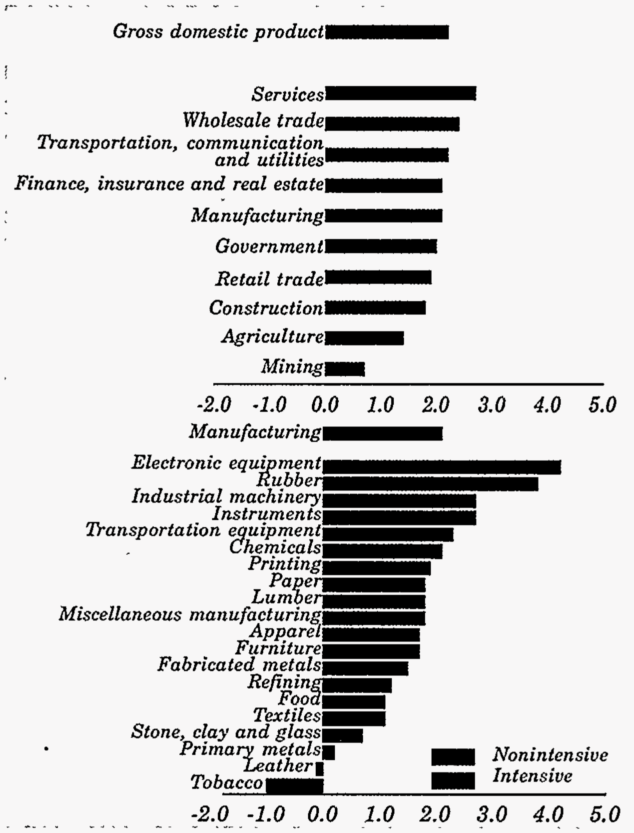
The output of the Nation's economy, measured by gross domestic product (GDP), is projected to increase by 1.9 percent a year between 1995 and 2015 (with GDP based on 1992 chain-weighted dollars [*20*], the revised measure of economic growth by the Bureau of Economic Analysis) (Figure 24). In fixed-weight 1987 dollars, GDP grows by 2.2 percent a year, compared with 2.0 percent in *AEO96*. The projected rate of growth in GDP slows in the latter half of the forecast period as the expansion of the labor force slows, but increases in labor productivity moderate the effects of lower labor force growth.

The slowing growth in the size of the labor force is a result of slowing population growth after 2000 and a decline after 2005 in the labor force participation rate [*21*]. Over the forecast period, the labor force participation rate is expected to peak in 2005 and then decline as "baby boom" cohorts begin to retire.

A key to achieving the 1.9-percent growth rate is maintaining productivity growth at about 1 percent a year, which results from an increase in the investment share of GDP for the first 12 years of the forecast. The robust growth in investment results from a projected decline in the Federal budget deficit, expected to average $76 billion per year between 1995 and 2015 (compared with the projected $256 billion average in *AEO96*). Interest rates, both real and nominal, are projected to decline over most of the next 20 years, with real long-term interest rates (10-year bond rates) averaging 2.5 percent (compared with 3.5 percent in *AEO96*).

Trade and Service Sectors Grow More Rapidly Than Manufacturing

Figure 25. Sectoral composition of GDP growth, 1995-2015 (percent per year)

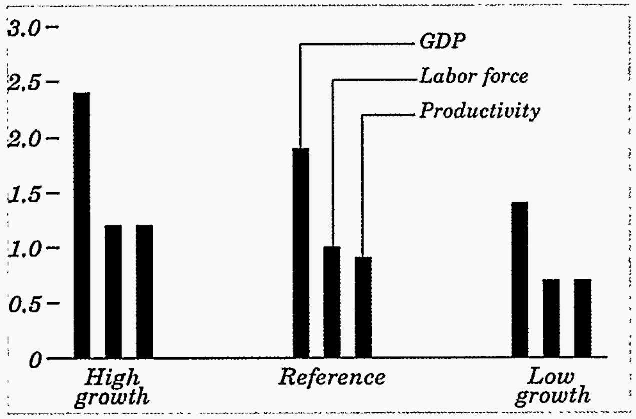


The projected growth rate for manufacturing production is 2.1 percent a year, with energy-intensive industries growing more slowly than non-energy-intensive industries (1.3 percent and 2.6 percent annual growth, respectively) [*22*]. The industrial machinery, electronic equipment, and transportation equipment industries lead the expected growth in manufacturing (Figure 25). The electronic equipment industry is expected to grow twice as fast as manufacturing industries altogether. Higher growth is projected for the trade and services sectors than for the manufacturing sector, as in last year's forecast.

This year's industrial forecast uses updated 1987 technology estimates and Standard Industrial Code (SIC) definitions. Differences from last year's industrial forecast result from the combination of different underlying macroeconomic conditions and different configurations of industry data.

High and Low Economic Growth Cases Show Effects of Different Assumptions

Figure 26. Average annual real growth rates of economic factors in three cases, 1995-2015 (percent)



To reflect the uncertainty in forecasts of economic growth, *AEO97* includes high and low economic growth cases in addition to the reference case (Figure 26). The high and low growth cases show the effects of alternative growth assumptions on energy markets. All three economic growth cases are based on macroeconomic forecasts prepared by DRI/ McGraw-Hill (DRI) [*23*]. The DRI forecasts used in *AEO97* are the February 1996 trend growth scenario and the optimistic and pessimistic growth projections. EIA has adjusted DRI's forecasts to incorporate the world oil price assumptions used in the *AEO97* reference case. With this change incorporated, the DRI projections are used as the starting point for the macroeconomic forecasts within the National Energy Modeling System (NEMS) simulations for *AEO97*. The macroeconomic activity module within NEMS incorporates energy price feedback impacts on the aggregate economy.

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 is projected to increase by 2.4 percent a year. 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 1.4 percent a year from 1995 through 2015.

Higher Investment Share Would Yield More Rapid Economic Growth

Figure 27. Change in annual GDP growth rate for the preceding 20 years, 1966-2015 (percent)

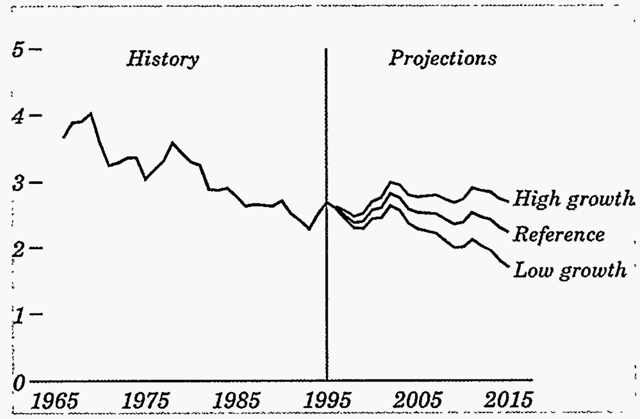
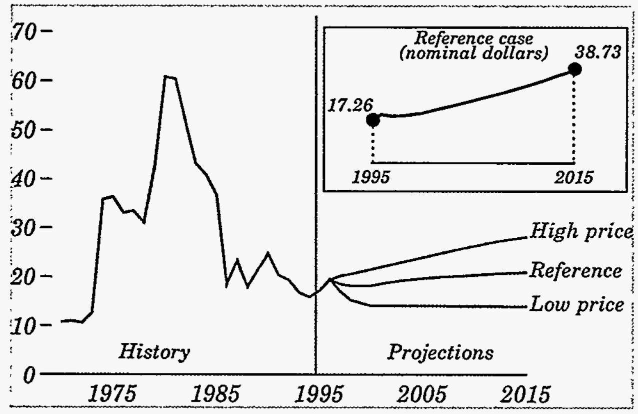


Figure 27 shows the trend in the moving 20-year annual growth rate for GDP, including projections for three *AEO97* cases. The value for each year is calculated as the annual growth rate over the preceding 20 years. The pattern for the 20-year average shows the major long-term trends in GDP growth rates by smoothing the more volatile year-to-year changes. The figure highlights two features that are important for assessing the uncertainties in future growth. First, the trend is downward. Second, annual growth has fluctuated considerably around the trend. The high and low growth cases are presented to capture the potential for different paths of long-term output growth in the forecast.

One reason for the variability of the forecasts is the composition of the output of the economy, as reflected by the share of GDP devoted to consumption and investment. In the reference case, consumption as a share of GDP remains fairly stable at approximately 68 percent, while the share of output devoted to investment is steady at 16 percent. In the high growth case, a larger share of the output is devoted to investment—rising from 16 percent to 17 percent—while the consumption share falls from 68 to 67 percent. This shift is small, but it is significant for overall economic growth. Higher investment rates lead to faster capital accumulation and higher labor productivity gains, which, coupled with higher population and labor force growth, yield faster growth in the aggregate economy than in the reference case. The opposite profile is seen in the low growth case.

Slow Growth Projected for World Oil Prices in the *AEO97* Reference Case

Figure 28. World oil prices in three cases, 1970-2015 (1995 dollars per barrel)



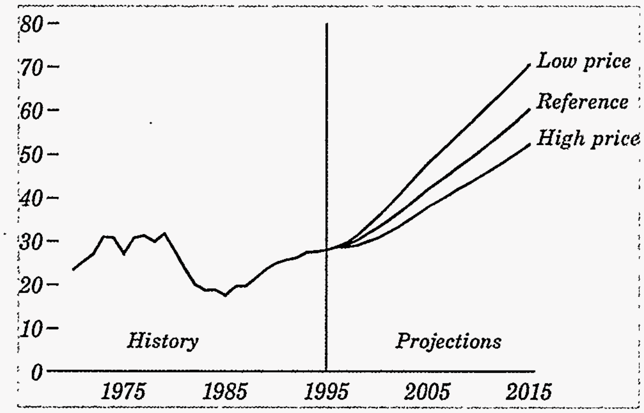
Just as the historical record shows substantial variability in world oil prices, there is considerable uncertainty about future prices. Three *AEO97* cases with different price paths allow an assessment of alternative views on the course of future oil prices (Figure 28). For the reference case, prices rise by about 1.4 percent a year, reaching $21 in constant 1995 dollars in 2015. In nominal dollars, the reference case price reaches $39 in 2015. In the high and low price cases, the 2015 price is about $7.00 higher and lower, respectively, than in the reference case (in 1995 dollars).

The reference case price in 2015 is about $5.00 lower than the corresponding price projection in *AEO96*, reflecting increased 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 continue to increase slowly, reaching 44.5 million barrels per day shortly after the turn of the century and declining gradually thereafter, but remaining above the 1995 level of 41.6 million barrels per day throughout the forecast.

Total worldwide demand for oil is expected to reach 103 million barrels per day by 2015. Developing countries in Asia show the largest growth in demand, averaging 5 percent a year. They could account for one-fourth of total oil consumption in 2015, putting their consumption on par with North America's and 10 million barrels per day higher than Western Europe's.

Projected OPEC Oil Production Is the Key Determinant of World Oil Prices

Figure 29. OPEC oil production in three cases, 1970-2015 (million barrels per day)



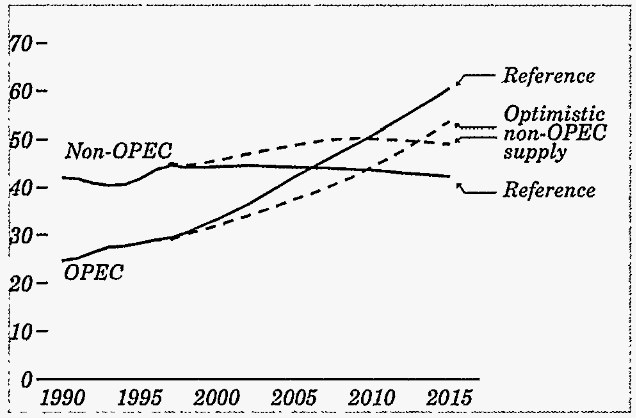
The three price cases are based on alternative assumptions about oil production levels in OPEC nations: higher production in the low price case and lower production in the high price case. With its vast store of readily accessible oil reserves, OPEC—primarily the Persian Gulf nations—is expected to be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

By 2000, OPEC supply in the reference case is 33 million barrels per day, consistent with announced plans for OPEC capacity expansion [*24*]. By 2015, OPEC production is 60 million barrels per day (more than twice its production in 1995) in the reference case, 53 million in the high case, and 71 million in the low case (Figure 29). Worldwide demand for oil varies across the price cases in response to the different price paths. Total world demand for oil ranges from 110.7 million barrels per day in the low case to 97.7 in the high case.

This variation reflects uncertainty about the prospects for future production from the Persian Gulf region. The expansion of productive capacity will require major capital investments, which could depend on the availability and acceptability of foreign investments. Political instability could also limit expansion of production in the region. Iraq is assumed to resume selling some oil to the world market in 1998 and to increase production gradually, reaching 3.4 million barrels per day in 2000. Thereafter, Iraq's production expands to 7.2 million barrels per day in 2015.

Continued Competition in Oil Markets Expected from Non-OPEC Producers

Figure 30. OPEC and non-OPEC oil production in two cases, 1990-2015 (million barrels per day)

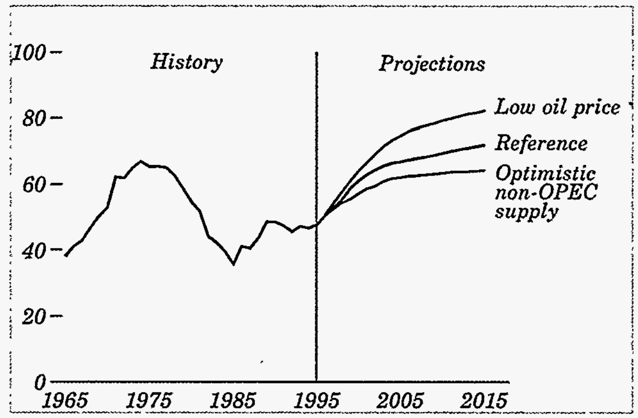


The growth and diversity in non-OPEC oil supply has played a significant role in the erosion of OPEC's market share over the past two decades. Although OPEC producers will certainly benefit from the projected growth in oil demand, significant competition is expected from non-OPEC suppliers, who have demonstrated surprising resilience even in the low price environment of this decade. In the reference case, the OPEC market share of worldwide production begins to exceed that of non-OPEC suppliers by the year 2007 (Figure 30). Non-OPEC production peaks in 1997 and 2002 (44.5 million barrels per day) and declines only slightly by the end of the forecast period.

While the oil price cases make alternative assumptions about OPEC supply, it is also possible that non-OPEC supply could expand beyond the levels assumed for the reference case. In an optimistic non-OPEC supply case—in which one-third of the world's undiscovered oil is assumed to be economical to develop over the forecast period at reference case prices—OPEC would not regain the majority market share until 2013 [*25*]. In this case, non-OPEC production would increase steadily until 2009, to more than 50.1 million barrels a day. While significant production increases are anticipated from the world's developing countries (especially those of Latin America and Asia), much of the increase in non-OPEC supply over the next decade is expected to come from the former Soviet Union, as the outlook for recovery from the economic problems of the post-Communist era remains optimistic.

Continued Increase Projected for Persian Gulf Share of Oil Exports

Figure 31. Persian Gulf share of worldwide oil exports, 1965-2015 (percent)

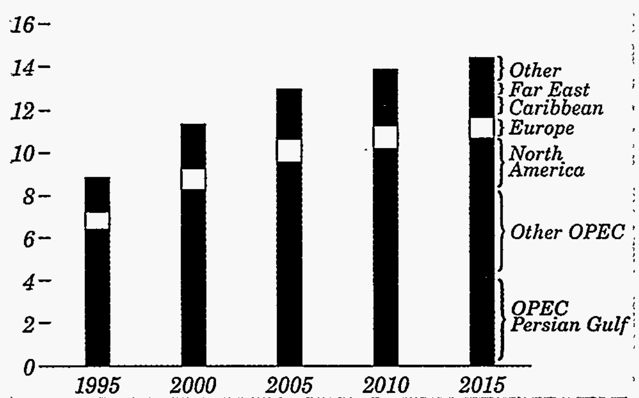


Considering the world market in oil exports, the historical peak for Persian Gulf exports (as a percent of world oil exports) occurred in 1974, when they made up more than two-thirds of the oil traded in world markets (Figure 31). The most recent historical low for Persian Gulf oil exports came in 1985 as a result of more than a decade of high oil prices, which led to significant reductions in worldwide petroleum consumption. Less than 40 percent of the oil traded in 1985 came from Persian Gulf suppliers. Following the 1985 oil price collapse, the Persian Gulf export percentage has been steadily increasing. For the first time in over a decade, Persian Gulf producers are expected to account for more than 50 percent of worldwide trade in 1996.

In the reference case, the Persian Gulf share of total exports is expected to exceed 60 percent shortly after the turn of the century and gradually increase to over 72 percent by the year 2015. In the *AEO97* low oil price case, the Persian Gulf share of worldwide petroleum exports is expected to exceed 65 percent shortly after the turn of the century and steadily increase to over 82 percent by 2015. In the optimistic non-OPEC supply case, the Persian Gulf share of oil exports is not expected to return to its historical peak during the forecast period. While all Persian Gulf producers are expected to increase their oil production capacity significantly over the forecast period, both Saudi Arabia and Iraq are expected to more than double their current production capacity levels.

OPEC and Persian Gulf Shares of U.S. Oil Imports Rise in the Forecast

Figure 32. U.S. petroleum imports by source, 1995-2015 (million barrels per day)



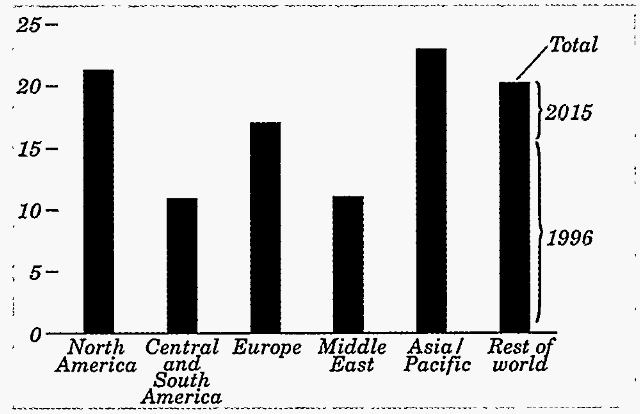
In the reference case, total U.S. oil imports increase from 8.8 million barrels per day in 1995 to 14.4 million in 2015 (Figure 32). Crude oil accounts for most of the increase before 2000, whereas imports of petroleum products make up a larger share after 2000. Product imports increase more rapidly, as U.S. production stabilizes and U.S. refineries lack the capacity to process a larger quantity of imported crude oil.

By 2000, OPEC accounts for more than one-half of total projected U.S. petroleum imports. After 2000, the OPEC share increases steadily, to about 57 percent in 2015. The Persian Gulf share of U.S. imports from OPEC increases from about 41 percent in 1995 to more than 50 percent in 2015. Crude oil imports from the North Sea increase slightly through 2000, then decline as North Sea production ebbs. Significant imports of petroleum from Canada and Mexico continue, and West Coast refiners are expected to import crude oil from the Far East to replace the modest volumes of Alaskan crude oil that will be exported.

Imports of light products are expected to almost double by 2015, to nearly 1.6 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.

Continued Growth in Oil Refining Capacity Seen for Asia/Pacific Region

Figure 33. Worldwide refining capacity by region, 1996 and 2015 (million barrels per day)



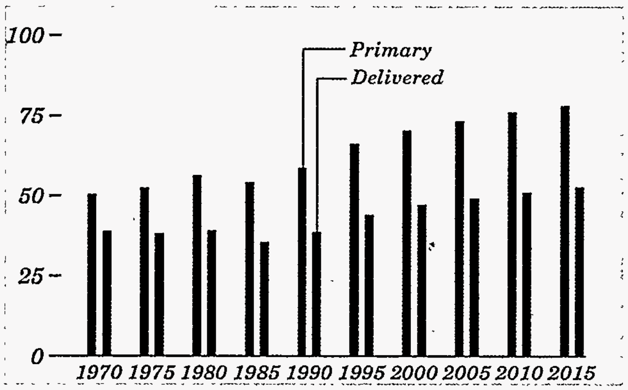
Worldwide crude oil distillation capacity was 73 million barrels per day at the beginning of 1996. To meet the growth in international oil demand in the reference case, worldwide refining capacity is expected to increase by nearly a third—to almost 97 million barrels per day—by 2015. Substantial growth in distillation capacity is expected in the Middle East, Central and South America, and the Asia/Pacific region (Figure 33).

The Asia/Pacific region has been the fastest growing refining center in the 1990s. It could pass Western Europe as the world's second largest refining center by the end of 1996 and, in terms of distillation capacity, surpass the United States by 2010. While not adding significantly to their distillation capacity, refiners in the United States and Europe have tended to improve product quality and enhance the usefulness of heavier oils through investment in downstream capacity.

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

Primary Energy Growth Projected To Stabilize Relative to Delivered Energy

Figure 34. Primary and delivered energy consumption, excluding transportation use, 1970-2015 (quadrillion Btu)



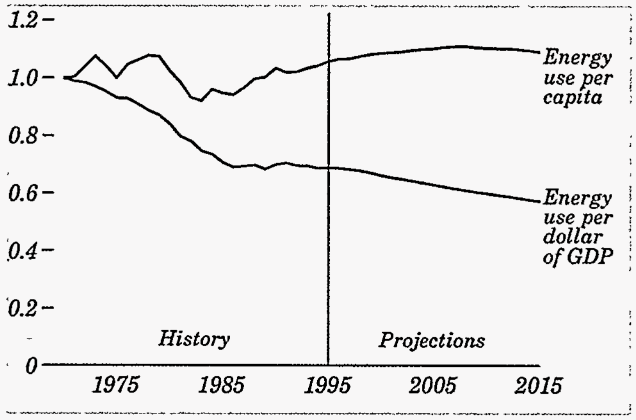
Net energy delivered to consumers represents only a part of total primary energy consumption. Primary consumption includes energy losses associated with the generation, transmission, and distribution of electricity, which are allocated to the end-use sectors (residential, commercial, and industrial) in proportion to each sector's share of electricity use [*26*].

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, growth in electricity use in applications such as space conditioning, consumer appliances, telecommunication equipment, and industrial machinery have resulted in a far greater divergence between total and delivered energy consumption estimates (Figure 34). This trend is expected to stabilize over the forecast horizon, as more efficient generating technologies offset increased demand for electricity. Projected primary energy consumption grows by 0.8 percent a year, while delivered energy consumption grows by 0.9 percent a year, 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 developing carbon stabilization policies, growth rates for primary energy consumption may be a more important consideration than those for delivered energy.

Projected Energy Use Grows More Slowly Than Gross Domestic Product

Figure 35. Energy use per capita and per dollar of gross domestic product, 1970-2015 (index, 1970 = 1)

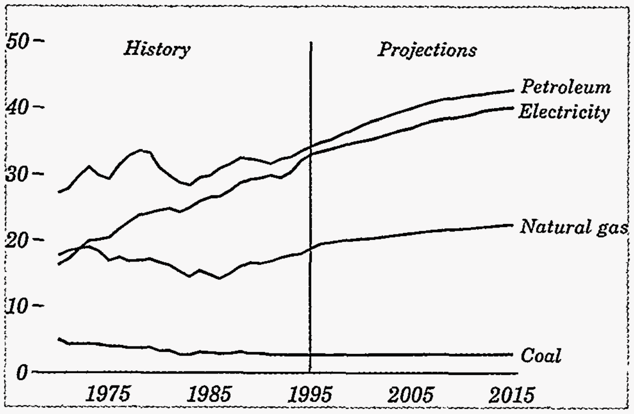


Energy intensity, as measured by primary energy consumption per dollar of GDP and on a per capita basis, declined between 1970 and the mid-1980s (Figure 35). While the overall GDP-based energy intensity of the economy is expected to decrease between now and 2015, the rate of decline is expected to diminish, as a result of relatively stable projected energy prices and increased use of electricity-based energy services. As electricity claims a greater share of energy use, projected consumption per dollar of GDP declines at a slower rate, because electricity use contributes both end-use consumption and energy losses to total energy consumption. Between 1995 and 2015, GDP is estimated to increase by 47 percent, compared with a 22-percent increase in primary energy use.

In the *AEO97* forecast, the demand for energy services increases markedly over current levels. The average home in 2015 is expected to be 4 percent larger and to rely more heavily on electricity-based technologies. Annual highway travel and air travel per capita in 2015 are expected to be 12 and 76 percent higher, respectively, than their current levels. Growth in demand for energy services notwithstanding, primary energy intensity on a per capita basis will remain essentially static through 2015, with efficiency improvements in many end-use energy applications making it possible to provide higher levels of service without significant increases in energy use per capita.

Petroleum, Electricity Claim Largest Shares of Future Energy Use

Figure 36. Energy use by fuel, 1970-2015 (quadrillion Btu)



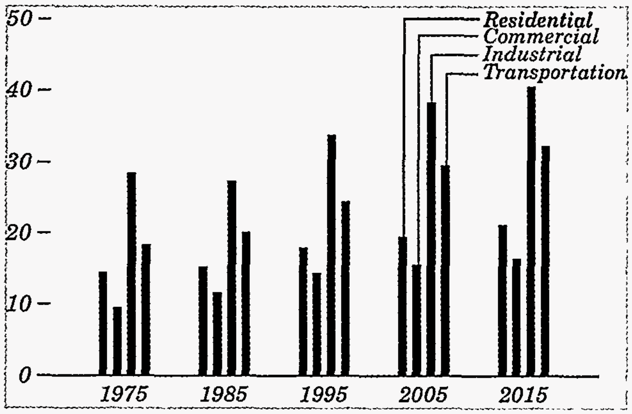
Petroleum products for transportation claim the greatest share of total energy consumption in the *AEO97* forecast (Figure 36). Growth in energy demand in the transportation sector, which averaged 2.0 percent a year during the 1970s, was moderated in the 1980s by rising fuel prices and by new Federal vehicle efficiency standards, which led to an unprecedented 2.1-percent annual increase in average vehicle fuel economy. In the *AEO97* forecast, fuel economy gains slow as a result of stable fuel prices and the absence of new legislative mandates. A growing vehicle population and increased travel cause demand increases 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. Demand for natural gas grows at about the same rate as 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 retains its share of energy consumption, meeting 20.1 percent of energy demand requirements in 2015.

Use of renewable energy from marketed sources (e.g., wood, wood wastes, and ethanol) increases by 1.4 percent a year. Use of nonmarketed renewable energy (geothermal and solar thermal) increases by about 7 percent a year but does not exceed 1 percent of energy consumption for space and water heating in the residential and commercial sectors.

Energy Use for Transportation Grows More Rapidly Than for Other Sectors

Figure 37. Energy use by sector, 1975-2015 (quadrillion Btu)



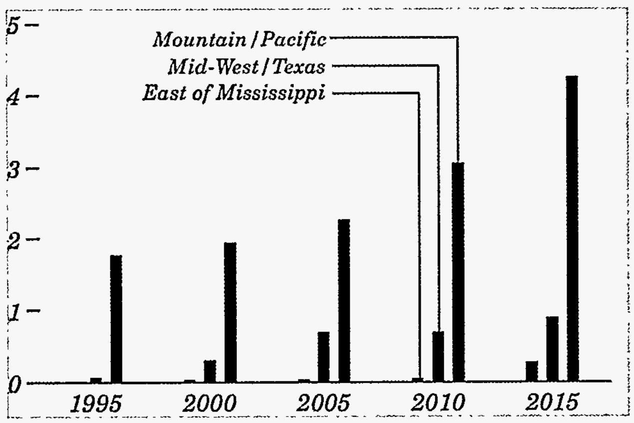
Primary energy use in the reference case is projected to reach 111 quadrillion Btu by 2015, 22 percent higher than the 1995 level. In the early 1980s, as energy prices rose, sectoral energy consumption grew relatively little (Figure 37). Between 1985 and 1995, however, stable energy prices contributed 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 modest 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 *AEO97* 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 3.1 percent lower than in the low world oil price case in 2015, as consumer choices favor more fuel-efficient vehicles and a slightly reduced demand for travel services. Varying economic growth affects overall energy demand in each of the end-use sectors to a greater extent [27]. By 2015, high economic growth assumptions result in a 14-percent increase in total annual energy use over its projected level in the low growth case.

Growth Expected for Wind Power, But Market Uncertainties Remain

Figure 71. Wind-powered electricity generating capacity by region, 1995-2015 (gigawatts)



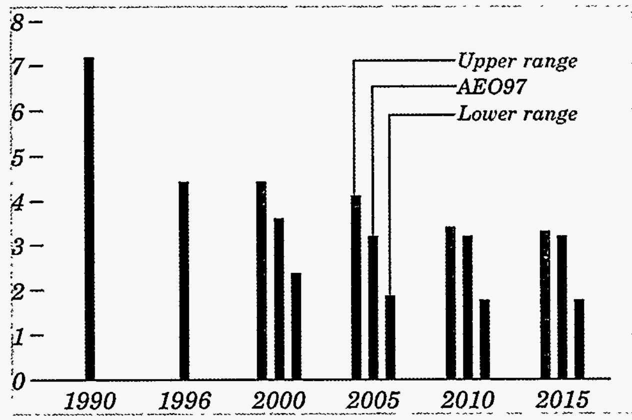
Wind capacity is projected to grow from the 1995 level of 1.8 gigawatts nationally to 5.4 gigawatts in 2015 (Figure 71), primarily in the West, where resources are favorable. Wind energy is considered a well-developed renewable energy technology, and improvements in both cost and performance have been seen in recent years; however, competition from fossil fuel technologies, especially natural gas combustion turbines, remains strong. Projections of low fossil fuel costs increase the uncertainty of wind power's future, as do the potentially competitive forces created by the emergence of restructured electricity markets, which tend to favor established technologies.

Much of the development of wind energy in the near to medium term will be in Europe, where stricter environmental laws, continued government support, and a commitment by the European Union to reach an 8-percent market share for renewables in the electricity market help the investment climate for wind energy. In the developing world, lack of an infrastructure provides development opportunities for wind technologies in small-scale, remote village applications.

Wind capacity factors are expected to improve and capital costs to decrease. The next generation of wind turbines, to be introduced during the 1997-1998 time frame, will have up to 750 kilowatts of capacity. The *AEO97* forecast assumes that turbines of about that size will be deployed between 1997 and 2000 and will continue to improve until 2005.

Role as Fuel Saver Possible for Wind-Powered Electricity Generation

Figure 72. Levelized costs of electricity from wind power, 1990-2015 (1995 cents per kilowatthour)

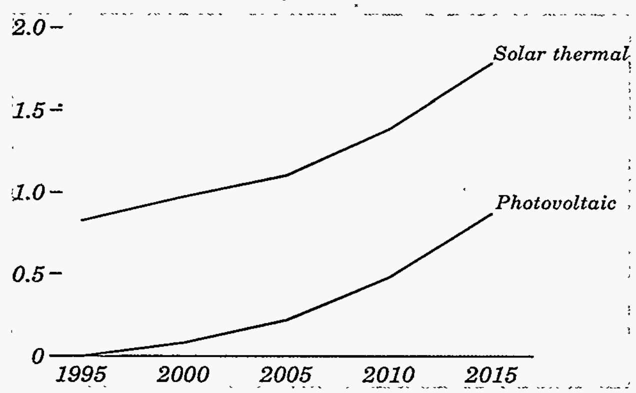


Industry targets for wind generation costs below 5 cents per kilowatthour appear to have been met (Figure 72). Also, EPACT provides a tax subsidy of 1.5 cents per kilowatthour for wind generation, effective for 10 years for wind units built before July 1999. Nevertheless, as the market for electricity changes, these cost levels may no longer be adequate to ensure market penetration. As indicated above, some analysts predict that major technology advances may permit the cost of wind-powered generation to drop below 3 cents, or even below 2 cents per kilowatthour by 2015. Such decreases could make wind energy competitive with the variable operating and fuel costs of some natural gas generation, so that electricity from wind would be cost-effective solely on the basis of its energy value.

Competing as a fuel saver could be important to wind power by offsetting the limitations that its intermittent nature imposes on capacity planning for individual utilities or for an electricity pool arrangement, such as those proposed under many restructuring scenarios. In addition, if a cap on carbon emissions were implemented, or if a carbon tax increased the operating costs of fossil fuel plants, then wind's economic viability could be greatly improved. Wind energy would also benefit from the development of inexpensive energy storage. Many State and national restructuring proposals contain minimum renewable portfolio provisions that could be beneficial to wind development, since in some regions wind is the most economically viable of the non-hydropower renewable technologies.

Modest Growth Expected for Solar Thermal, Photovoltaic Generation

Figure 73. Solar thermal and photovoltaic electricity generation, 1995-2015 (billion kilowatthours)

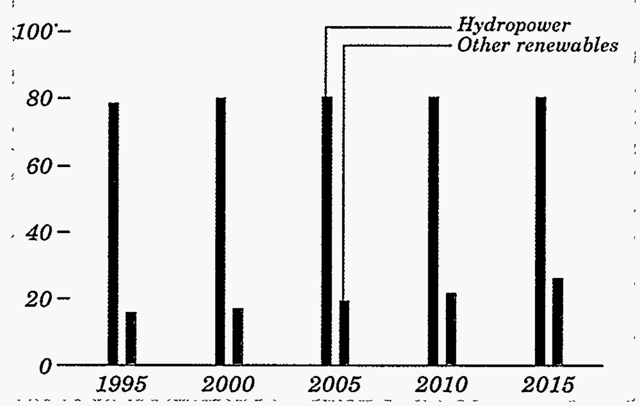


Generation from grid-connected solar thermal power is expected to grow from 0.8 billion kilowatthours in 1995 to almost 1.8 billion in 2015 (Figure 73), including new capacity and generation from central receiver, trough, and dish-Stirling technologies. Operation of Solar Two, a 10-megawatt central receiver station, began during 1996. Dish-Stirling technologies, which are modular and well suited for distributed generation, are expected to become more competitive, but solar thermal overall faces stiff competition from fossil-fueled and other renewable energy generating technologies in the forecast.

Solar photovoltaic (PV) generation has enjoyed dramatic cost and performance improvements over the past several decades. Grid-connected PV generation in the reference case forecast increases from a few million kilowatthours in 1995 to nearly 0.9 billion in 2015 (Figure 73). If improvements continue, PV could become a competitive electricity source in some instances for distributed generation as well as for meeting peak loads. Off-grid PV generation, which is not bought or sold in electricity markets and is not included in the *AEO97* projections, is also likely to continue growing rapidly, both domestically and outside the United States. Off-grid U.S. domestic capacity, almost all of it in very small units, is expected to increase by 5 to 10 megawatts a year through 2000, and at a more rapid pace thereafter. Further growth could occur if market restructuring raises consumer rates for peaking power or for additional power in distant locations, making self-generated PV more attractive to some consumers.

Little Growth Projected for Hydroelectric Generation

Figure 74. Electricity generating capacity from renewable sources, 1995-2015 (gigawatts)

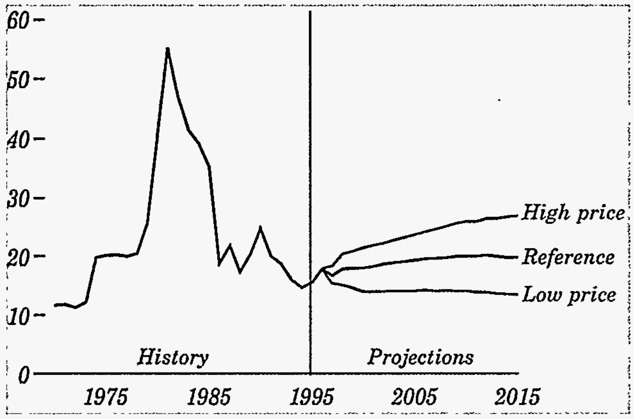


Conventional hydroelectric power is expected to remain a significant overall contributor to the Nation's electricity supply, providing about two-thirds of all the electricity derived from renewable resources through 2015 (Figure 74). In contrast to fossil fuels (coal and natural gas) and the other renewables, however, the Nation's conventional hydroelectric power supply is not expected to increase significantly at any time in the forecast. By 2015, the share of U.S. electric power provided by conventional hydropower is projected to decline to just under 7 percent, from more than 9 percent in 1995.

Small increases in hydroelectric generation will be achieved from a few new, small facilities and from upgrades (additional turbines, improved turbines or generators) at existing facilities. Those increases will be offset, however, by the closing of other facilities, reductions in generation in response to other water-use priorities, and growing concerns about negative environmental effects. Further, where generation continues, its economic value may be reduced, as water formerly used to generate electricity during valuable peak electricity seasons is shifted to much less valuable off-peak seasons, so that water releases can be used to accelerate fish passage downriver. Finally, concerns about the long-term future of hydroelectric power continue to grow, as market events and regulatory decisions—including those by the Federal Energy Regulatory Commission—constrain electricity production in favor of environmental and other priorities.

AEO97 Reference Case Projects Stable Oil Prices, Rising Consumption

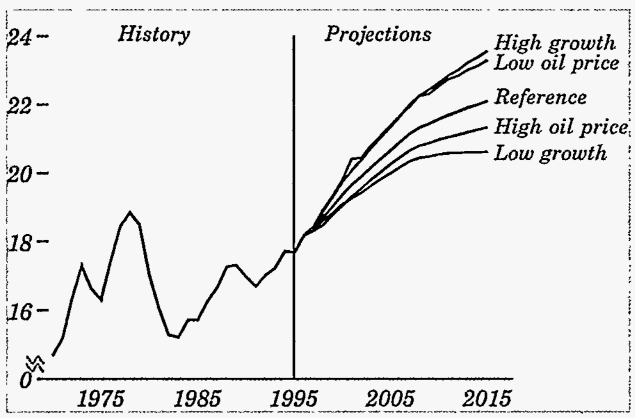
Figure 75. Lower 48 crude oil wellhead prices, 1970-2015 (1995 dollars per barrel)



From 1995 to 2015, wellhead prices for crude oil in the lower 48 States are projected to fall by 0.8 percent a year in the low world oil price case, and to grow by 1.2 and 2.8 percent a year in the reference and high price cases, respectively (Figure 75). The variation in world oil price assumptions leads to similar variation in projected domestic prices, which are determined largely by the international market.

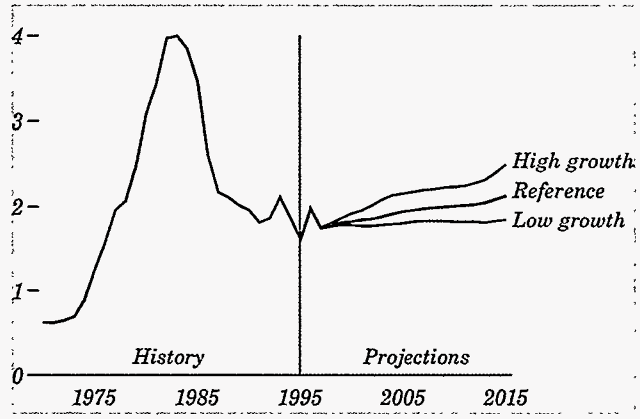
U.S. petroleum consumption continues to rise in all the *AEO97* cases (Figure 76). Total petroleum product supplied ranges from 20.6 million barrels per day in the low economic growth case to 23.6 million in the high growth case, as compared with 17.7 million in 1995. Petroleum continues as the primary source of energy in the United States, representing just under 40 percent of total U.S. energy consumption throughout the forecast.

Figure 76. U.S. petroleum consumption in five cases, 1970-2015 (million barrels per day)



Only Slight Increase Projected for Domestic Natural Gas Prices

Figure 77. Lower 48 natural gas wellhead prices, 1970-2015 (1995 dollars per thousand cubic feet)



Wellhead prices for natural gas in the lower 48 States increase by 0.6 and 2.2 percent a year in the low and high economic growth cases, respectively, compared with 1.4-percent annual growth in the reference case (Figure 77). 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. Because domestic natural gas prices are less responsive than oil prices to world oil prices (oil and gas do not compete directly in most markets), little variation is seen across the oil price cases.

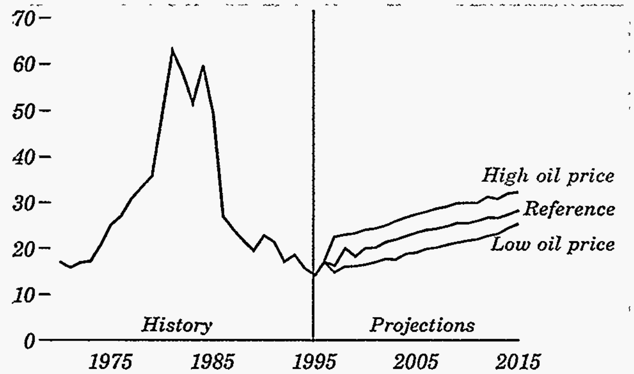
Natural gas production can be increased at substantially lower cost than was projected in previous *AEO* forecasts for several reasons, including: an increase in the inferred reserve base, based on a reassessment by the U.S. Geological Survey; and a reexamination of the impacts of technological progress on the discovery process, which allows more gas to be produced from fewer wells (Table 6).

Table 6. Economically recoverable oil and gas resources in 1990, measured under different technology assumptions

	Crude oil (billion barrels)		Natural gas (trillion cubic feet)	
Lower 48 resources	1990 technology	2015 technology	1990 technology	2015 technology
Proved	26	26	169	169
Unproved	96	119	936	1,322
Total	***122***	***145***	***1,105***	***1,491***

Small Drilling Increases Accompany Expanding Markets for Oil and Gas

Figure 78. Successful new lower 48 natural gas and oil wells in three cases, 1970-2015 (thousand successful wells)



Both exploratory and developmental drilling levels increase in the forecast (Figure 78). With rising prices and generally declining drilling costs, total crude oil and natural gas well completions grow at average annual rates of 3.5 and 4.8 percent in the low and high oil price cases, respectively. Changes in world oil price assumptions have a more pronounced effect on projected oil drilling than on gas drilling (Table 7).

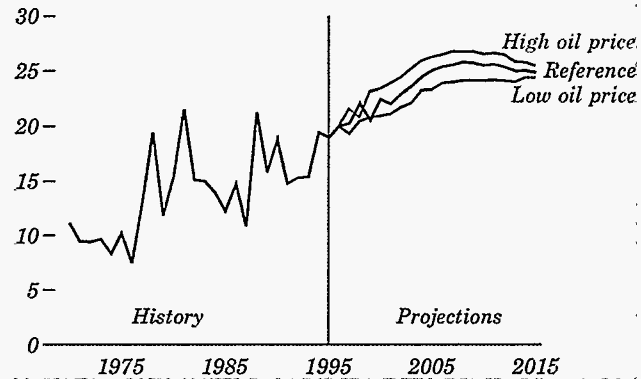
Natural gas drilling is projected to be more productive than oil drilling, because remaining recoverable gas resources are more abundant than oil resources. Over the past two decades, crude oil reserve additions have come primarily from older fields, whereas gas reserve additions have come from discoveries in both new and old fields. The future productivity of both oil and gas drilling is uncertain, however, because the extent of the Nation's oil and gas resources is uncertain [*33*].

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

	1995	2000	2010	2015
Natural gas				
Low oil price case		10.0	14.1	17.5
Reference case	7.4	11.0	15.5	18.4
High oil price case		11.6	17.0	19.8
Crude oil				
Low oil price case		6.4	7.5	7.9
Reference case	6.8	9.1	10.1	9.9
High oil price case		12.4	12.8	12.4

Natural Gas Reserve Additions Grow, Oil Additions Stabilize

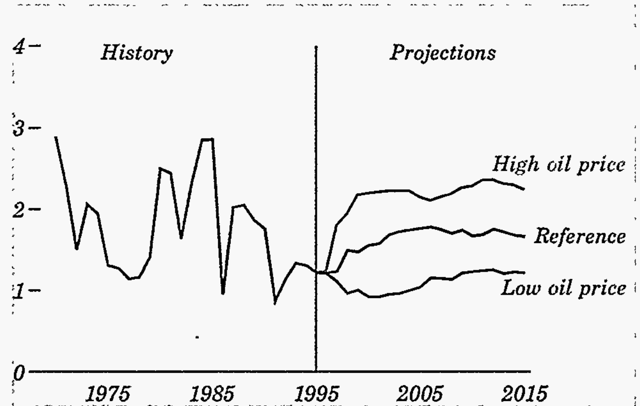
Figure 79. Lower 48 natural gas reserve additions in three cases, 1970-2015 (trillion cubic feet)



Higher drilling levels lead to significant increases in annual reserve additions in the forecast. Lower 48 natural gas reserve additions (Figure 79) increase by 1.3 and 1.5 percent a year in the low and high oil price cases, respectively, continuing the trend of the past two decades. Lower 48 oil reserve additions (Figure 80) decrease by 0.4 percent a year in the low world oil price case and increase by 3.1 percent a year in the high price case.

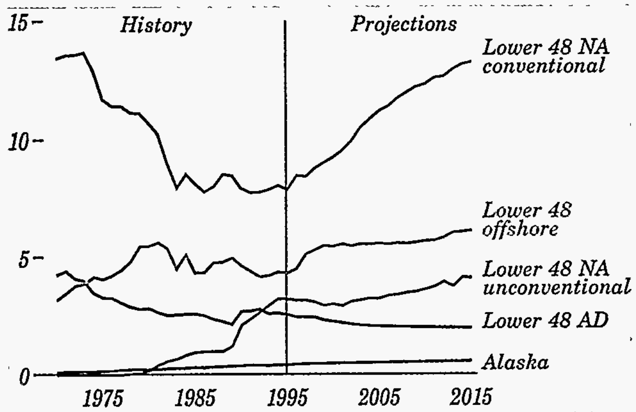
Natural gas reserve additions exceed production through 2012 in the reference case. Lower 48 reserves peak at 189.5 trillion cubic feet in 2013, then decline to 188.4 trillion by 2015, compared with the 1995 level of 155.6 trillion cubic feet. Despite a rise in oil reserve additions, production exceeds additions in the reference case, and oil reserves are depleted at a rate of 0.5 percent a year.

Figure 80. Lower 48 oil reserve additions in three cases, 1970-2015 (billion barrels)



Conventional Onshore Production Leads Increase in Natural Gas Supply

Figure 81. Natural gas production by source, 1970-2015 (trillion cubic feet)



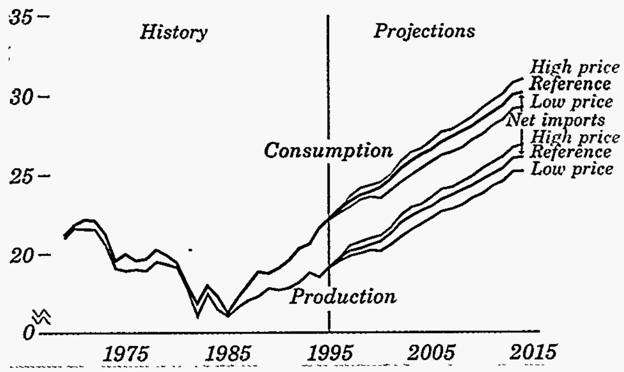
The continuing increase in domestic natural gas production over the forecast comes primarily from lower 48 onshore nonassociated (NA) sources (Figure 81). Conventional onshore production, which accounted for 42.9 percent of total U.S. domestic production in 1995, is projected to increase at an average annual rate of 2.6 percent over the 1995-2015 period. Natural gas production from unconventional sources increases at an average annual rate of 1.2 percent over the same period. Gas from offshore wells in the Gulf of Mexico also contributes significantly to production. The innovative use of cost-saving technology and the expected continuation of recent huge finds, particularly in the deep water off the Gulf of Mexico, have encouraged greater interest in this area.

Natural gas production from Alaska rises gradually in the forecast. Alaskan gas is not projected to be transported to the lower 48 States, however, because lower 48 prices are not projected to be high enough to support the required transport system within the forecast period. Expected Alaskan natural gas production does not include gas from the North Slope, which currently is being reinjected to support oil production. In the future, it may also be marketed as liquefied natural gas to Pacific Rim markets [*34*].

Production of associated/dissolved (AD) natural gas from lower 48 crude oil reservoirs generally declines, following the expected pattern of domestic crude oil production. AD gas accounts for less than 7.8 percent of total lower 48 production in 2015, compared with 14.2 percent in 1995.

Natural Gas Imports, Mostly from Canada, Increase Slightly

Figure 82. Natural gas production, consumption, and imports, 1970-2015 (trillion cubic feet per year)



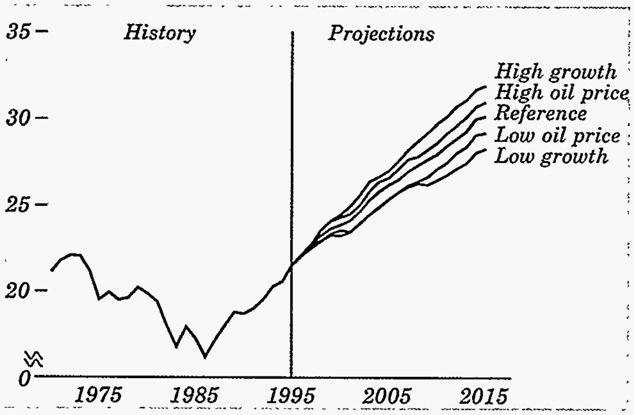
Natural gas imports are expected to grow in the forecast in all cases (Figure 82). In the reference case, net natural gas imports increase from 12.4 percent of total gas consumption in 1995 to 14.0 percent in 2015. Most of the increase is attributable to imports from Canada, primarily in response to readily available supplies and a 20.9-percent increase in projected pipeline capacity between the United States and Canada between 1995 and 2015.

Since 1984, U.S. natural gas trade with Mexico has consisted primarily of exports. That trend is expected to continue throughout the forecast, despite the North American Free Trade Agreement and the substantial estimated size of the Mexican natural gas resource base. There is significant uncertainty in the direction and pace of change in the Mexican natural gas market. Some of the unknowns that may affect the market include: economic growth and development, environmental concerns, issues related to Petroleos Mexicano's (PEMEX's) monopoly control and budgetary constraints, political and policy risks, and the overabundance of heavy fuel oil in Mexico's petroleum market.

Another potential source of gas imports is liquefied natural gas (LNG); however, given the projected low natural gas prices in the lower 48 markets, LNG is not expected to become a significant source of U.S. supply. LNG imports are projected to increase over the forecast at a modest rate, reaching a level of 0.36 trillion cubic feet in 2015, compared with 0.02 trillion cubic feet in 1995.

Gas Consumption for Electricity Generation Grows Steadily

Figure 83. Natural gas consumption in five cases, 1970-2015 (trillion cubic feet per year)

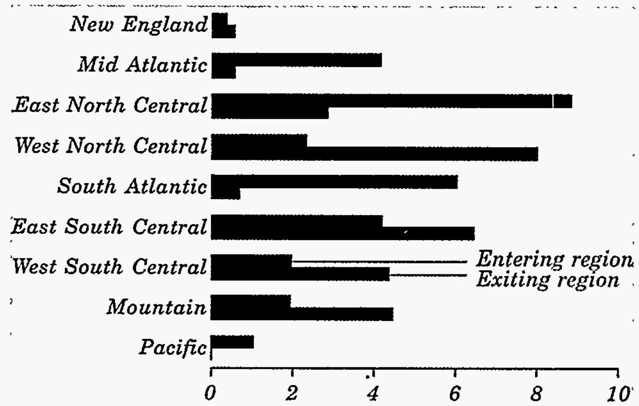


Natural gas consumption expands from 1995 to 2015 in all the *AEO97* cases (Figure 83). Domestic consumption ranges from 28.4 trillion cubic feet per year in the low economic growth case to 32.0 trillion in the high growth case in 2015, as compared with 21.6 trillion cubic feet in 1995. Growth is seen in all end-use sectors, with highest growth as a result of rising demand for electricity, including industrial cogeneration. More than half of the variation across cases is attributable to differences in gas consumption for electricity generation.

Total gas consumption in the electricity generation sector grows steadily throughout the forecast. In the reference case it more than doubles, from 3.5 trillion cubic feet a year in 1995 to 8.5 trillion in 2015. Restructuring of the electric utility industry is expected to open up new opportunities for gas-fired generation. In addition, growth is spurred by increased utilization of existing gas-fired power plants in the forecast and the addition of new turbines and combined-cycle facilities, which are less capital-intensive than coal, nuclear, or renewable electricity generation plants. Although projected coal prices to the electricity generation sector are lower than current prices, the natural gas combined-cycle share of new capacity is about four times the coal share. Stable fuel costs, lower capital costs, and projected improvements in gas turbine heat rates make the overall cost of gas-generated electricity per kilowatthour competitive with the cost of electricity from new coal-burning generators.

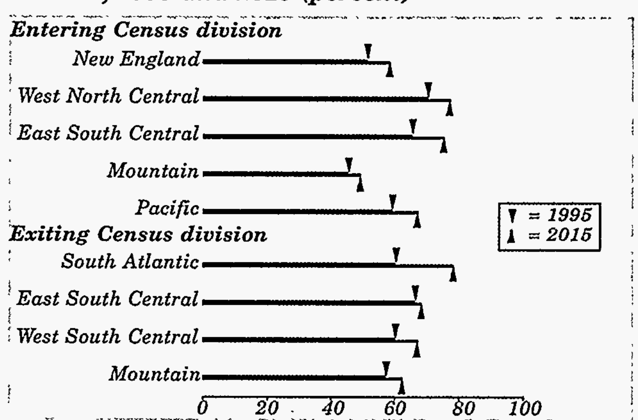
Gas Pipeline and Storage Capacity Projected To Increase

Figure 84. Pipeline capacity expansion by Census division, 1995-2015 (billion cubic feet per day)



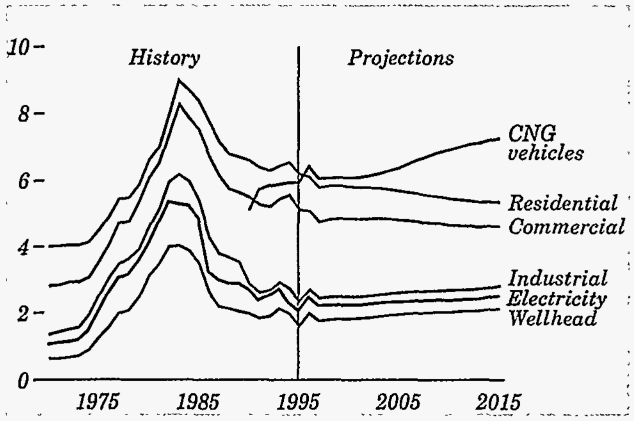
Although the boom in pipeline and storage construction of the late 1980s and early 1990s has slowed, new capacity will still be required. Pipeline capacity increases are projected in the reference case, both entering and exiting key regions (Figure 84). Storage capacity is also expected to grow in most regions, increasing overall by 54 percent over the forecast period. The strongest growth is projected for the first 5 years of the forecast, when planned pipeline additions to provide access to new supplies and service new markets come on line, and after 2005, when additional capacity will be needed to meet increased consumption in the eastern half of the United States. In some regions, growth in new pipeline construction is tempered by higher utilization of pipeline capacity (Figure 85).

Figure 85. Pipeline capacity utilization by Census division, 1995 and 2015 (percent)



Lower Prices Projected for Residential and Commercial Natural Gas Users

Figure 86. Natural gas end-use prices by sector, 1970-2015 (1995 dollars per thousand cubic feet)



While consumer prices to the industrial, electricity, and transportation sectors generally increase throughout the forecast period, prices to the residential and commercial sectors show significant decreases (Figure 86). The decreases in those sectors are caused primarily by projected reductions in the cost of capital and by efficiency improvements in the transmission and distribution segments of the industry as service providers adapt to a more competitive regulatory framework. In the industrial and electricity generation sectors, modest decreases in margins are overshadowed by increases in wellhead prices, and the overall trend is a slight rise in prices. The declines in margins reflect both Federal and State initiatives that foster an increasingly competitive market (see discussion on pages 9-10).

Compared with their rise and decline over the 1970-1995 period, transmission and distribution revenues in the natural gas industry are relatively stable in the forecast (Table 8), with declines in margins balanced by higher volumes.

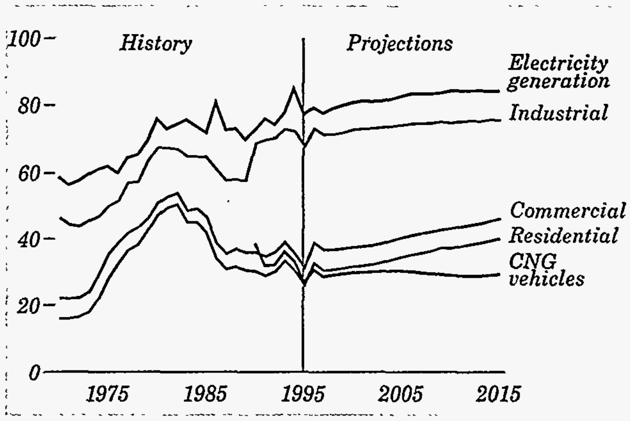
Table 8. Transmission and distribution revenues and margins, 1970, 1985, 1995, and 2015

	1970	1985	1995	2015
T&D revenues (billion 1995 dollars)	29.00	47.63	41.11	38.45
End-use consumption (trillion cubic feet)	19.02	15.81	19.74	27.60
Average margin (1995 dollars per thousand cubic feet)*	1.52	3.01	2.08	1.40

**Revenue divided by end-use consumption.*

Gas Transmission and Distribution Margins Expected To Decline

Figure 87. Wellhead share of natural gas end-use prices by sector, 1970-2015 (percent)



With transmission and distribution margins declining in most sectors, the wellhead shares of end-use prices increase in the forecast (Figure 87). The greatest impact is in the residential and commercial markets, where most customers rely on firm service.

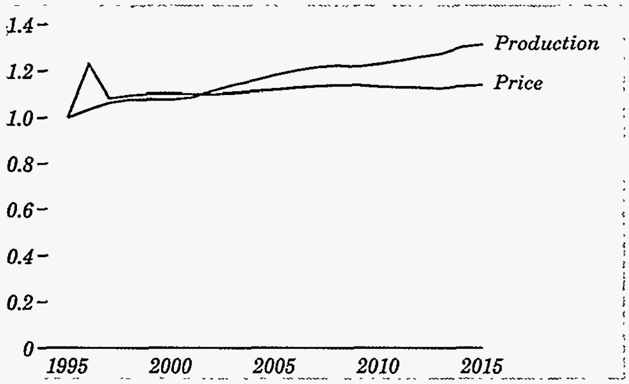
Changes have been seen historically not only in the wellhead price component of end-use prices but also in pipeline and local distribution company (LDC) margins (Table 9). The decline in pipeline margins results from continued depreciation of the pipeline infrastructure, a decline in the AA utility bond rate, increased utilization of pipeline capacity (which places downward pressure on unit costs), and the effects of a more competitive market resulting from restructuring. Although LDC margins in the residential and commercial sectors have increased historically, as the impacts of restructuring further affect the transmission segment of the market and begin to affect the distribution segment, reduced markups are projected for these sectors.

Table 9. Components of residential and commercial natural gas end-use prices, 1985-2015 (1995 dollars per thousand cubic feet)

Price Component	1985	1995	2000	2010	2015
Wellhead price	3.46	1.61	1.82	2.01	2.13
Citygate price	5.11	2.78	2.78	2.99	3.11
Pipeline margin	1.65	1.17	0.96	0.98	0.98
LDC margin					
Residential	3.23	3.38	2.99	2.42	2.21
Commercial	2.39	2.33	2.07	1.66	1.51
End-use price					
Residential	8.34	6.18	5.79	5.43	5.33
Commercial	7.50	5.10	4.83	4.64	4.61

Slow Economic Growth Would Lead to Stable Gas Prices, Higher Production

Figure 88. Lower 48 natural gas production and wellhead prices in the low economic growth case, 1995-2015 (index, 1995 = 1)

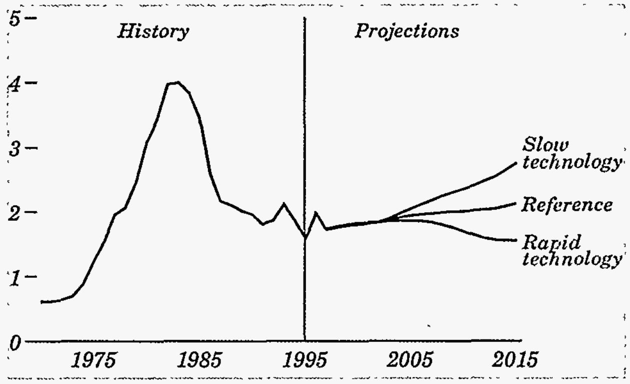


The potential impact of advances in oil and gas supply technology is most evident in the low economic growth case, where production increases by 1.4 percent a year with only a small increase in wellhead prices (Figure 88). As seen in the other *AEO97* cases, achieving greater increases in production requires a price stimulus in addition to the assumed reference levels of technological progress.

For parameters affected by technology, historical rates of change are generally assumed to continue throughout the forecast period in all the *AEO97* cases. Rapid and slow technological progress cases were created to assess the sensitivity of the *AEO97* projections to changes in the economically recoverable oil and gas resource base, exploration and development costs, and finding rates as a result of technological progress. Representative values for the affected parameters are presented in Table 10.

Technology Assumptions Have Strong Effects on Gas Price Projections

Figure 89. Lower 48 natural gas wellhead prices in three cases, 1970-2015 (1995 dollars per thousand cubic feet)



The two technology cases were run as fully integrated model runs. (Two other runs, with demands held constant, were produced to isolate the effects of demand feedback [see pages 26-29].) All other parameters in the model were kept at their reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about gas trade with Mexico.

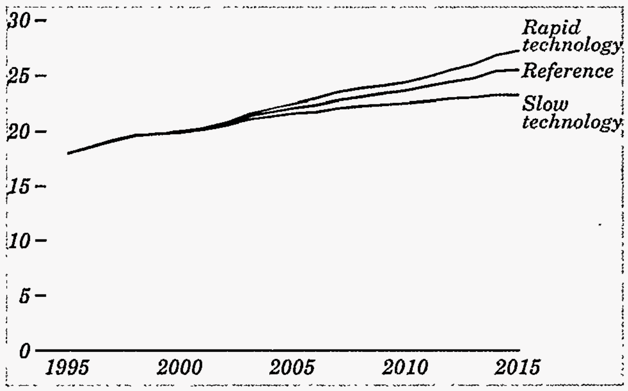
As shown in Figure 89, natural gas prices are highly sensitive to changes in assumptions about technological progress. For the first decade of the forecast, both price and production levels for lower 48 oil and natural gas are almost identical in the reference case and the two technological progress cases. By the year 2015, however, natural gas prices are 30 percent higher (at $2.77 per thousand cubic feet) in the slow technology case and 27 percent lower (at $1.55) in the rapid technology case than the reference case price of $2.13 per thousand cubic feet.

Table 10. Representative average annual rates of technological progress in alternative technology cases (percent)

	Natural gas						Crude oil					
	Slow technology		Reference		Rapid technology		Slow technology		Reference		Rapid technology	
Technology area	On-shore	Off-shore	On-shore	Off-shore	On-shore	Off-shore	On-shore	Off-shore	On-shore	Off-shore	On-shore	Off-shore
Costs												
Drilling	1.6	3.6	2.1	4.2	2.8	4.9	1.6	3.6	2.1	4.2	2.8	4.9
Lease equipment	0.7	1.1	1.4	1.9	2.1	2.6	0.7	1.1	1.4	1.9	2.1	2.6
Operating	0.0	0.9	0.6	1.2	1.3	1.7	0.0	0.9	0.6	1.2	1.3	1.7
Resources												
Inferred reserves	0.0	0.5	0.0	1.0	0.0	1.5	0.0	0.7	0.0	1.0	0.0	1.3
Undiscovered	0.6	1.4	1.8	3.0	3.0	4.5	0.5	2.0	1.4	3.0	2.2	3.9
Finding rates	2.4	5.0	4.2	10.2	6.0	15.3	1.8	6.5	3.2	9.6	4.6	12.6
Success rates	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Slow Technological Progress Could Reduce Market Share for Natural Gas

Figure 90. Lower 48 natural gas production in alternative technology cases, 1995-2015 (trillion cubic feet per day)



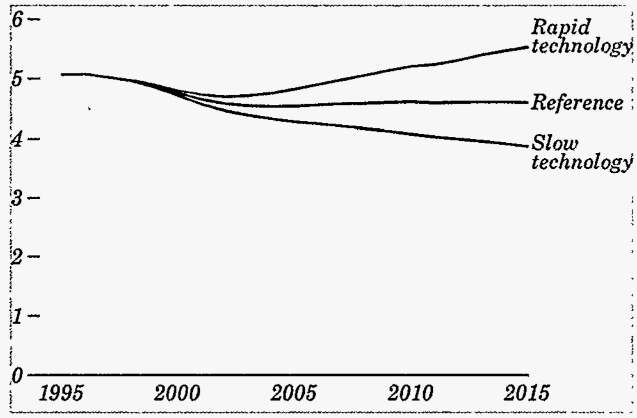
As was seen for wellhead prices, natural gas production levels in the alternative technology cases do not deviate significantly from the reference case in the first half of the forecast period (Figure 90). In the second half of the forecast, when investment in new capital stock plays a larger role, changes in production are more significant, as new investments in the industrial sector and electric power generation facilities respond to changes in natural gas prices.

In the rapid technology case, the natural gas share of fossil fuel inputs to electricity generation facilities in 2015 is 32 percent, compared with 22 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, since 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. The alternative technology cases also demonstrate the intense competition between natural gas and electricity, and between natural gas and steam coal, in the industrial sector.

Offshore production is particularly responsive to changes in the assumed levels of technological progress, particularly for oil. In the rapid technology case, the offshore share of total lower 48 oil production in 2015 is 37 percent, compared with 30 percent in the slow technology case.

For Oil, Both Production and Imports Change With Technology Assumptions

Figure 91. Lower 48 oil production in alternative technology cases, 1995-2015 (million barrels per day)



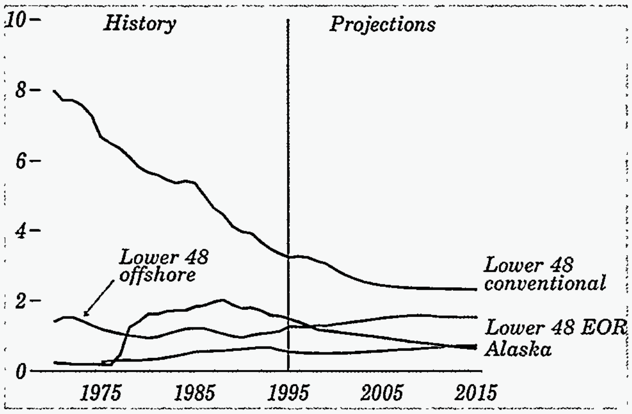
Domestic oil production is also sensitive to changes in the technological progress assumptions (Figure 91). In comparison with the projected 2015 production level of 5.2 million barrels a day in the reference case, oil production increases to 6.2 million barrels a day in the rapid technology case and decreases to 4.5 million in the slow technology case. The changes, in relative terms, are significantly greater than those seen for natural gas, primarily because of key differences between the oil and natural gas markets.

Domestic oil prices are determined largely by the international market. Thus, changes in U.S. oil production do not constitute a significant volume relative to the global market. Given the assumption that the changes in the levels of technology are isolated to U.S. oil producers, total oil supply largely adjusts to the changes in technological progress simply by adjusting imports of crude oil and other petroleum products. Net imports range from a low of 12.3 million barrels per day in the rapid technology case to a high of 14.4 million barrels per day in the slow technology case.

Unlike oil, natural gas is not easily transported between the United States and countries outside North America. Therefore, changes in gas production are determined more by the availability of supplies in North America than by the international market.

AEO97 Projections Include Continuing Decline in U.S. Oil Production

Figure 92. Crude oil production by source, 1970-2015 (million barrels per day)



Projected domestic crude oil production continues its historic decline throughout the forecast (Figure 92), declining by 1.1 percent a year, from 6.6 million barrels per day in 1995 to 5.2 million barrels per day in 2015 [*35*]. Conventional onshore production in the lower 48 States, which accounted for 49.4 percent of total U.S. crude oil production in 1995, is projected to decrease at an average annual rate of 1.6 percent over the forecast.

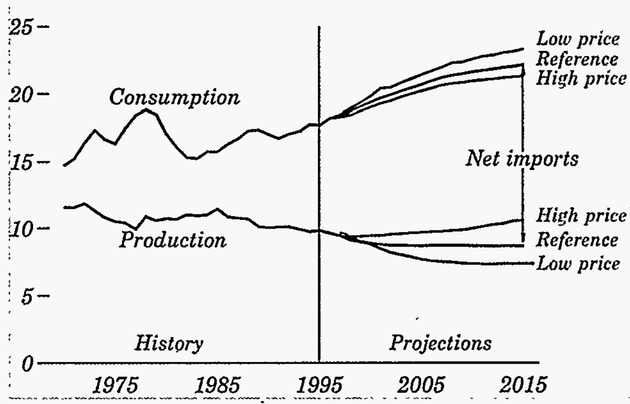
Crude oil production from Alaska is expected to decline at an average annual rate of 4.2 percent between 1995 and 2015. The overall decrease in Alaska's oil production is driven by the continued decline in production from Prudhoe Bay, the largest producing field, which historically has accounted for more than 60 percent of total Alaskan production.

Offshore production generally increases in the forecast, at an average annual rate of 1.0 percent. Because of technological advances and lower costs associated with deep exploration and production in the Gulf of Mexico, several projects are already underway, and additional projects are in the planning stages.

Increased production from enhanced oil recovery (EOR) slows the overall downward trend of oil production [*36*]. As oil prices rise, the expected profitability of EOR projects increases, and as a result, EOR production rises at an average annual rate of 1.3 percent over the 1995-2015 period.

Gap Between Oil Production and Consumption Widens in All Cases

Figure 93. Petroleum production, consumption, and imports, 1970-2015 (million barrels per day)



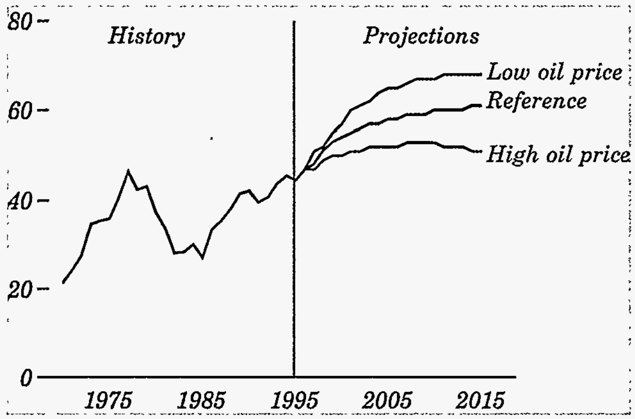
U.S. production of oil and natural gas liquids declines in all *AEO97* cases except the high oil price case (Figure 93), as recoverable domestic resources are depleted. In the low price case, production drops from its 1995 level of 9.8 million barrels per day to 7.3 million barrels per day in 2015. In the high price case, increased exploration and drilling bring the 2015 production level to 10.5 million barrels per day.

Growth in petroleum consumption is anticipated in all the *AEO97* projections. The greatest variation in consumption levels is seen in the economic growth cases, with an increase of 5.8 million barrels per day over the 1995 level in the high growth case, as compared with an increase of only 2.9 million barrels per day in the low growth case.

Additional petroleum imports will be needed to fill the widening gap between production and consumption. The projections for net petroleum imports in 2015 range from a high of 15.9 million barrels per day in the low oil price case—more than double the 1995 level of 7.9 million barrels per day—to a low of 10.8 million barrels per day in the high price case. The value of petroleum imports in 2015 ranges from $80.1 billion in the low price case to $116.2 billion in the high growth case. Total annual U.S. expenditures for petroleum imports, which reached a historical peak of $75.8 billion in 1980 [*37*], were $49.4 billion in 1995.

AEO97 Projects Growing Reliance on Imported Oil and Refined Products

Figure 94. Share of U.S. petroleum consumption supplied by net imports, 1970-2015 (percent)



Net imports of petroleum, which represented 44 percent of domestic petroleum consumption in 1995, close to the 1977 record level of 46 percent, are projected to reach 61 percent in 2015 in the reference case (Figure 94). The corresponding import shares of total consumption in 2015 are 51 percent in the high oil price case and 68 percent in the low price case.

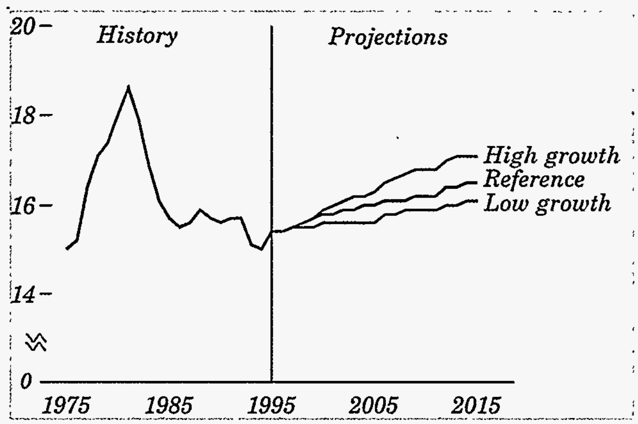
Although crude oil is expected to continue as the major component of petroleum imports, refined products represent a growing share. More imports will be needed as growth in demand for refined products exceeds the expansion of domestic refining capacity. Refined products make up 19 percent of net petroleum imports in 2015 in the high world oil price case and 26 percent in the low price case, as compared with their 10-percent share in 1995 (Table 11).

Table 11. Petroleum consumption and net imports, 1995 and 2015 (million barrels per day)

Year and projection	Product supplied	Net imports	Net crude imports	Net product imports
1995	17.7	7.9	7.1	0.8
2015				
Reference	22.1	13.5	10.2	3.2
Low oil price	23.3	15.9	11.8	4.1
High oil price	21.3	10.8	8.7	2.1
Low growth	20.6	12.3	9.9	2.5
High growth	23.6	14.6	10.6	3.9

U.S. Refining Capacity Expected To Rise, Despite Lack of New Refineries

Figure 95. Domestic refining capacity, 1975-2015 (million barrels per day)



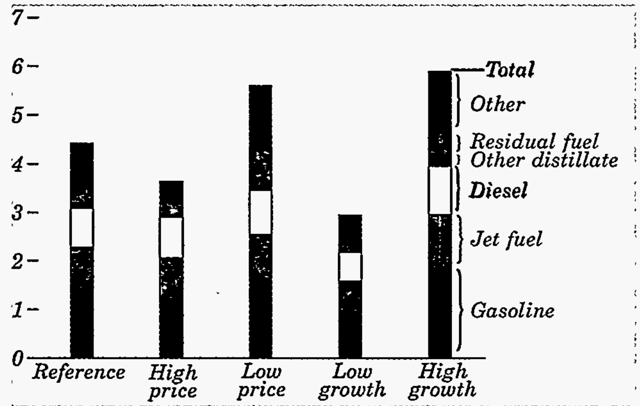
Falling demand for petroleum and the deregulation of the domestic refining industry in the 1980s led to 13 years of decline in U.S. refinery capacity [*38*]. That trend was broken in 1995 by a capacity increase of 0.4 million barrels per day over the 1994 level. Financial and legal considerations make it unlikely that new refineries will be built in the United States, but "capacity creep" at existing refineries is expected to increase total U.S. refining capacity in all the *AEO97* cases (Figure 95).

Distillation capacity is projected to grow from the 1995 level of 15.4 million barrels per day to 16.5 million in 2015 in the reference case, 16.1 million in the low economic growth case, and 17.1 million in the high growth case, as refining capacity returns to the levels of the late 1970s. Existing refineries will continue to be utilized intensively throughout the forecast, in a range from 92 to 94 percent of capacity. In comparison, the 1995 utilization rate was 92 percent, well above the rates of the 1980s and early 1990s.

Ongoing investment in equipment for desulfurization and fluid catalytic cracking will allow U.S. refineries to handle lower quality crude oils, which contain more sulfur. The added flexibility will become increasingly valuable as higher quality resources are depleted over time.

Transportation Fuels Drive Projected Growth in Petroleum Use

Figure 96. Change in petroleum products supplied in five cases, 1995 to 2015 (million barrels per day)



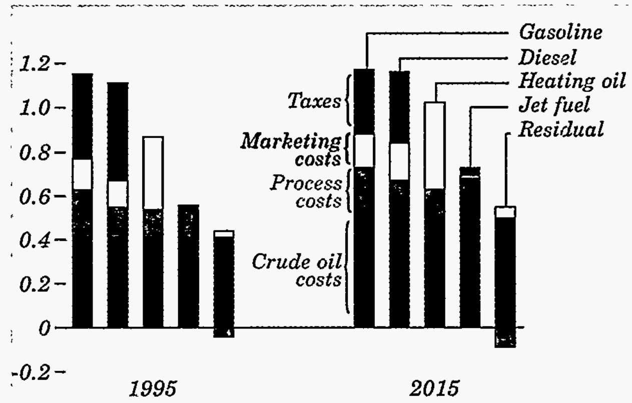
U.S. petroleum consumption is projected to increase by 4.4 million barrels per day between 1995 and 2015 in the reference case, compared with 2.9 million in the low economic growth case and 5.8 million in the high growth case (Figure 96). Industry will continue to account for about one-fourth of petroleum consumption, and two-thirds will be used for transportation.

About 80 percent of the growth in petroleum use in the forecast is attributable to the transportation sector. In addition, a shift in consumption patterns is expected within the transportation sector. Gasoline, which represented 66 percent of transportation petroleum consumption by volume in 1995, shrinks to a 60-percent share in 2015, as alternative fuels penetrate transportation markets. The share for diesel rises from 17 percent to 18 percent, and the jet fuel share rises from 13 percent to 16 percent.

In the low oil price case, a shift in petroleum consumption patterns is also seen, with residual fuel use rising from the 1995 level of 0.9 million barrels per day to 1.6 million in 2015. More competitive oil prices in this case cause electric utilities and other generators to use more residual fuel to fire boilers, displacing a portion of the natural gas and coal use seen in the other cases.

Crude Oil Costs and Taxes Dominate Refined Petroleum Product Prices

Figure 97. Components of refined product costs, 1995 and 2015 (1995 dollars per gallon)



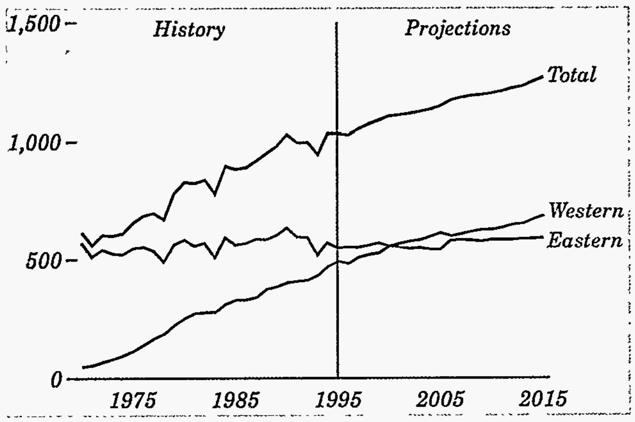
Refined product prices in the forecast continue to be dominated by crude oil costs (Figure 97). However, changes are projected in refining process costs, marketing costs, and taxes. State motor fuels taxes are assumed to keep up with inflation, as they have in the past. Federal taxes, which have increased sporadically in the past, are assumed to remain at nominal 1995 levels; the result is a decline in inflation-adjusted Federal taxes, which dampens the growth of gasoline and diesel prices. In contrast, Federal taxes on jet fuel show a real increase, with a tax of 4.3 cents per gallon beginning in 1996 as mandated in the Omnibus Budget Reconciliation Act of 1993. A similar tax was levied on other fuels in 1993.

The *AEO97* projections of product prices reflect investments related to compliance with refinery emissions, health, and safety regulations. These investments add 1 to 3 cents to the processing costs of light products (gasoline, distillate, jet fuel, kerosene, and liquefied petroleum gases).

The marketing cost of heating oil (the difference between wholesale and retail prices) is projected to be higher than in 1995 throughout the forecast. Marketing costs, which were at a historical low in 1995, are assumed to return to more normal levels in the forecast.

Western Mines Lead Projected Increase in U.S. Coal Production

Figure 98. Coal production by region, 1970-2015 (million short tons)



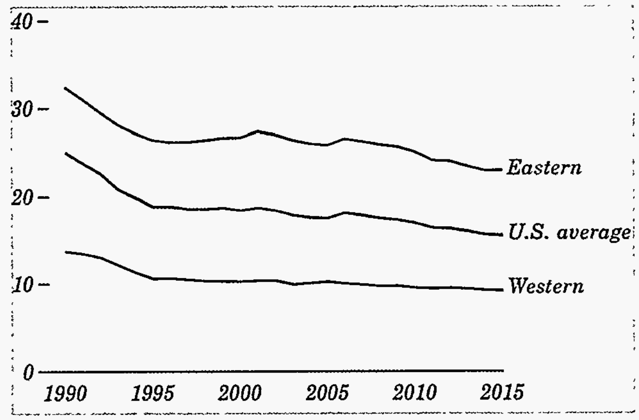
Major trends in the *AEO97* forecasts for coal can be contrasted with changes since 1970 [*39*]. For instance, eastern coal production, which fell from 568 million tons in 1970 to 544 million tons in 1995, is projected to increase to 586 million tons in 2015, a change of 0.4 percent per year (Figure 98). Nevertheless, eastern mines are losing market share to less expensive, lower sulfur coal from western mines. The eastern share of national production, which fell from 93 percent in 1970 to 53 percent in 1995, is projected to be 46 percent in 2015.

Total coal production grew from 613 million tons (14.6 quadrillion Btu) in 1970 to 1,033 million tons (22.0 quadrillion Btu) in 1995. In 2015, production is projected to reach 1,268 million tons (26.5 quadrillion Btu). Most of the growth is expected to come from western mines, where output grew by 10 percent a year from 45 million tons in 1970 to 489 million tons in 1995 (Figure 98). In the forecast, western mining grows by 1.7 percent a year, to 682 million tons in 2015.

The shift from eastern to western coals has been led by midwestern and southeastern utilities, which have reduced fuel costs while switching from high-sulfur eastern sources to coal from Wyoming, Colorado, and Utah. Low-sulfur, low-cost subbituminous coal from Wyoming can displace eastern bituminous coal in many larger, newer boilers. Consumers with smaller, older boilers often purchase suitable low-cost, low-sulfur bituminous coal from Colorado or Utah.

Minemouth Coal Prices Are Projected To Fall in All Regions

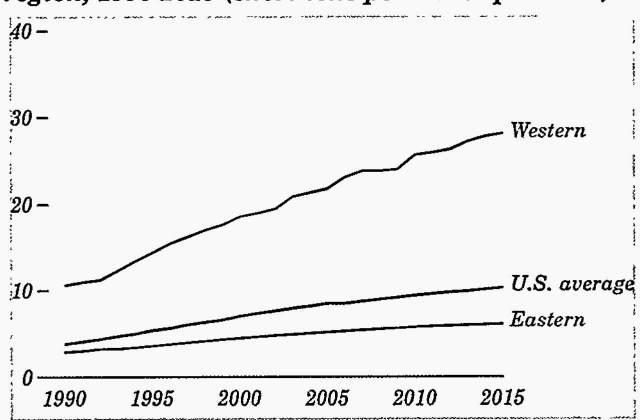
Figure 99. Average minemouth price of coal by region, 1990-2015 (1995 dollars per ton)



Minemouth coal prices declined by $3.45 per ton in 1995 dollars between 1970 and 1995, and they are projected to decline by another $3.37 between 1995 and 2015 (Figure 99). The price of coal delivered to electricity generators, which averaged $25.07 per ton in 1970 and $27.01 in 1995, falls to $22.47 per ton in 2015—a 0.9-percent annual decline between 1995 and 2015.

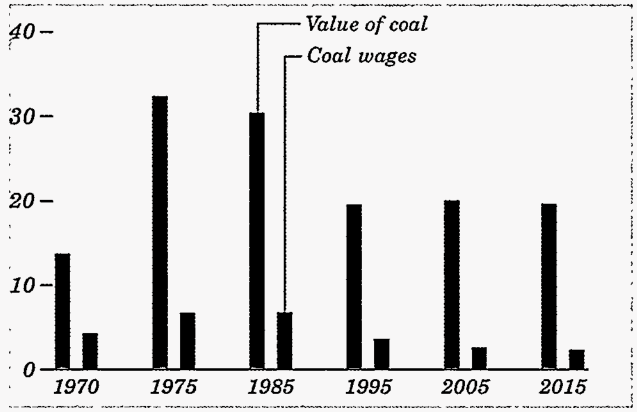
Minemouth prices decline by 1.0 percent a year between 1995 and 2015, as competition drives productivity improvements. Western coalfields, particularly those in the Powder River Basin in Wyoming and Montana, have large reserves of low-cost, low-sulfur coal. Average productivity (Figure 100) follows the trend in eastern productivity more closely than that for western productivity because eastern mines are more labor-intensive.

Figure 100. Coal mining labor productivity by region, 1990-2015 (short tons per miner per hour)



Continuing Increases in Productivity Are Projected To Reduce Labor Costs

Figure 101. Labor cost component of minemouth coal prices, 1970-2015 (billion 1995 dollars)



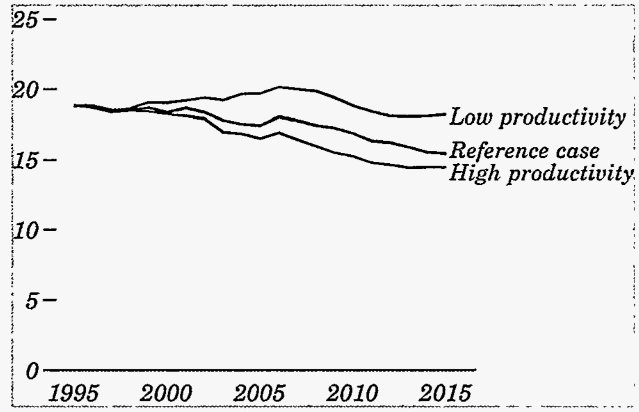
Gains in coal mine labor productivity will be achieved as a result of technology improvements, economies of scale, and better mine design. At the national level, however, average labor productivity will be influenced as much by changing regional production patterns as by technology advances, as the market share of more productive western mines grows. After 2005, the demand for lower sulfur coal will require mining of thinner, deeper seams in eastern mines, and productivity improvements in that region are expected to slow.

Slower productivity gains in eastern low-sulfur coal mining during the second decade of the forecast cause more consumers to turn to western low-sulfur supplies, except in States separated from western mines by the coalfields in the Appalachian mountains. Eastern seaboard consumers are partially protected from rising prices by their access to imported low-sulfur coal. Caught between low-cost western and imported coal supplies, eastern producers may find few chances to recoup the investments required to open new low-sulfur coal mines.

Wages are assumed to remain flat in 1995 dollars as labor demand declines. While productivity improved between 1970 and 1995, the number of miners fell by 1.9 percent a year, and a further decline of 2.2 percent a year is expected through 2015 (Figure 101). Thus, the contribution of wages to minemouth coal prices is projected to decline to 12 percent in 2015, as compared with the historical decline from 31 percent to 18 percent between 1970 and 1995.

Labor Productivity Assumptions Are Key to Production, Price Forecasts

Figure 102. Average minemouth coal prices in three cases, 1995-2015 (1995 dollars per ton)



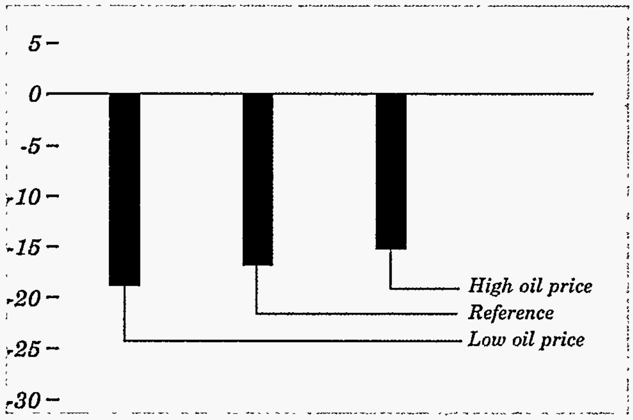
Assumptions about the rates of labor productivity change are key determinants of national prices and production, particularly as they affect eastern and western market shares. Alternative cases were used to explore the sensitivity of coal prices to changes in wages and in labor productivity improvement rates.

In the reference case, eastern labor productivity increases by 2.7 percent a year through 2015 and western productivity by 3.5 percent a year (Figure 102). In the high productivity case, a 6.7-percent annual improvement is projected, resulting in a 2015 national average minemouth price of $14.41 per ton (6.8 percent below the reference case price). The low productivity case, which assumes a 0.1-percent annual decline in productivity, yields a 2015 minemouth price of $18.26 per ton (18.1 percent above the price in the reference case).

The reference case assumes unchanging wages for miners (in 1995 dollars). For comparison, the high wage case projects a real increase of 0.5 percent a year and a 2015 minemouth price of $16.44 per ton, 6.3 percent above the reference case. In the low wage case, wages are assumed to fall by 0.5 percent a year, reducing the 2015 minemouth price to $14.55 per ton (5.9 percent below wages in the reference case). Delivered coal prices vary by similar amounts, but distribution patterns are not significantly affected. Domestic demand was held constant in the alternative cases, but coal exports varied by plus and minus 3 million tons in response to changes in U.S. prices.

Coal Transportation Costs Decline in the *AEO97* Forecasts

Figure 103. Percent change in coal transportation costs in three cases, 1995-2015

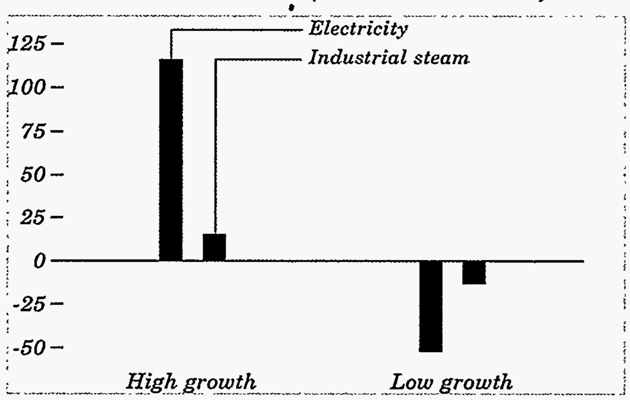


The competition between coal and other fuels, and among coalfields, is influenced by coal transportation costs. Changes in fuel costs affect transportation rates (Figure 103), but fuel efficiency also grows with other productivity improvements in the forecast. As a result, average coal transportation rates decline by 0.9 percent a year between 1995 and 2015. The most rapid declines are likely to occur in routes that originate in coalfields with the greatest production growth. Railroads are likely to reinvest profits from increasing coal traffic to reduce future costs and rates in regions with the best outlook. Thus, coalfields that are most successful at improving productivity and, therefore, lowering minemouth prices are likely to obtain the lowest transportation rates and, consequently, the largest markets at competitive delivered prices.

Regional differences in production and transportation costs are already affecting coal distribution patterns. Western coal is gaining share in midwestern and southeastern markets, and coal for export is moving along different domestic routes. Retirements of barge capacity have exceeded replacements in recent years, and the resulting increase in inland barge rates has caused some traffic to shift to rail or Great Lakes vessels for all or part of the journey from mines to U.S. ports of exit [*40*]. In spite of railroad mergers and consolidation in the barge industry, real coal transportation costs are projected to continue their historical decline, as competition among surviving carriers. forces technological improvements.

Stronger Economic Growth Would Lead to Higher Coal Consumption

Figure 104. Variation from reference case projection of coal demand in 2015 in two alternative cases (million short tons)



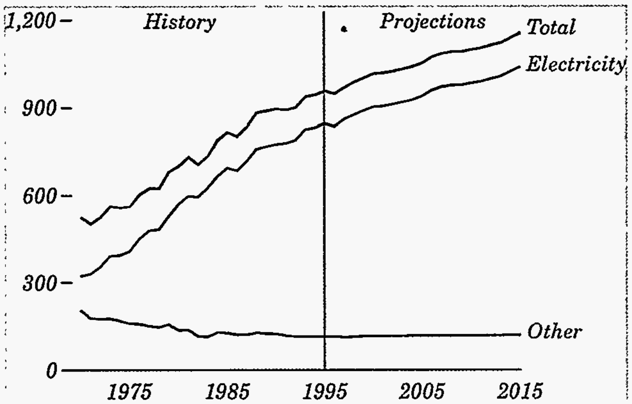
A strong positive correlation between economic growth and electricity demand accounts for the variation in electricity coal demand across the economic growth cases (Figure 104). Most of the variation in coal demand in the economic growth cases is accounted for by changes in coal- and gas-fired electricity generation.

The *AEO97* coal forecasts also vary with different assumptions about technology and world oil prices. Changes in world oil prices affect petroleum fuel costs associated with the extraction and transportation of coal and thus affect delivered coal prices. In the high oil price case, the average minemouth price of coal is 5.0 percent higher in 2015 than in the reference case, and in the low price case it is 4.1 percent lower. In the low oil price case, interfuel price competition leads to a slightly lower coal demand forecast, as oil-fired generation displaces some steam coal use.

Coal transportation costs are also affected by changes in fuel costs. In the world oil price cases, variations in fuel costs produce delivered coal costs to electricity generators that are 3.6 percent higher than the costs in the reference case in the high oil price case ($1.15 per million Btu in 2015) and 2.7 percent lower in the low price case ($1.08 per million Btu). About one-third of the differences are attributable to changes in coal transportation costs. In addition, the market share of western coal, which is 54 percent in the reference and low oil price cases, drops to 52 percent in the high price case.

Electricity Generation Determines Projected Increase in Total Coal Use

Figure 105. Electricity and other coal consumption, 1970-2015 (million short tons per year)



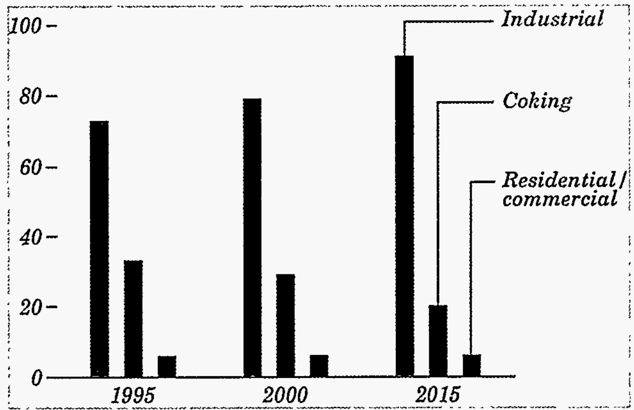
Domestic coal demand rises by 197 million tons in the forecast, from 959 million tons in 1995 to 1,156 million tons in 2015 (Figure 105), because of growth in coal use for electricity generation. Coal demand in other domestic end-use sectors increases by 5 million tons, as reduced coking coal consumption is offset by coal demand for industrial cogeneration.

Coal consumption for electricity generation (excluding industrial cogeneration but including independent power producers) rises from 847 million tons in 1995 to 1,039 million tons in 2015, 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 63 to 74 percent between 1995 and 2015. Coal consumption (in tons) per kilowatthour of generation is higher for subbituminous and lignite coals than for bituminous coal. Thus, the shift to western coal increases the tonnage per kilowatthour of generation in midwestern and southeastern regions. In the East, generators shift from higher to lower sulfur Appalachian bituminous coals that contain more energy (Btu) per short ton.

Although coal maintains its fuel cost advantage over both oil and natural gas, gas-fired generation is the most economical choice for new power generation through 2010 when capital, operating, and fuel costs are considered. Between 2010 and 2015, rising natural gas costs and nuclear retirements are projected to cause increasing demand for coal-fired baseload capacity.

Offsetting Changes Are Projected for Industrial Steam and Coking Coal Use

Figure 106. Non-electricity coal consumption by sector, 1995, 2000, and 2015 (million short tons)



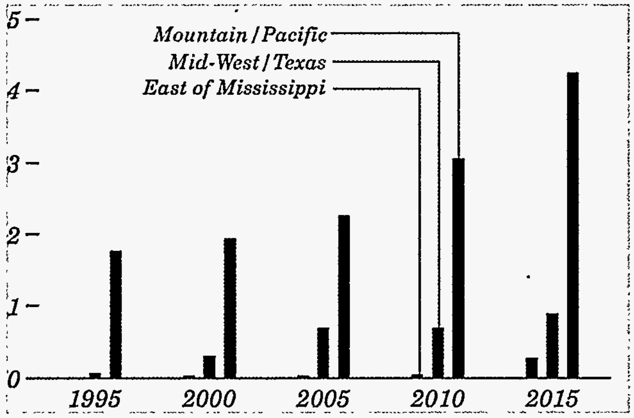
In the non-electricity sectors, an increase of 18 million tons in industrial steam coal consumption between 1995 and 2015 (1.1-percent annual growth) is offset by a decrease of 13 million tons in coking coal consumption (Figure 106). Increasing consumption of industrial steam coal results primarily from increased use of coal in the chemical and food-processing industries and from increased use of coal for cogeneration (the production of both electricity and usable heat for industrial processes).

The projected decline in domestic consumption of coking coal results from the displacement of raw steel production from integrated steel mills (which use coal coke for energy and as a material input) by increased production from minimills (which use electric arc furnaces that require no coal coke) and by increased imports of semi-finished steels. The amount of coke required per ton of pig iron produced is also declining, as process efficiency improves and injection of pulverized steam coal is used increasingly in blast furnaces. Domestic consumption of coking coal is projected to fall by 2.4 percent a year through 2015. Domestic production of coking coal declines slightly faster, as consumption of imported coking coal continues its historical slow increase.

While delivered energy consumption in the residential and commercial sectors grows by 0.8 percent and 0.9 percent a year, respectively, most of the growth is captured by electricity and natural gas. Coal consumption in these sectors remains constant, accounting for less than 1 percent of total U.S. coal demand.

Growth Expected for Wind Power, But Market Uncertainties Remain

Figure 71. Wind-powered electricity generating capacity by region, 1995-2015 (gigawatts)



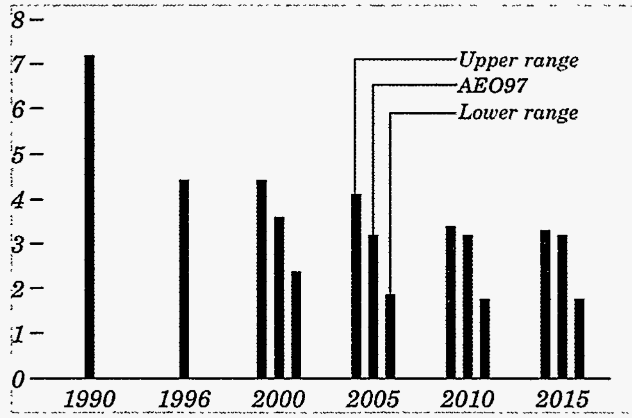
Wind capacity is projected to grow from the 1995 level of 1.8 gigawatts nationally to 5.4 gigawatts in 2015 (Figure 71), primarily in the West, where resources are favorable. Wind energy is considered a well-developed renewable energy technology, and improvements in both cost and performance have been seen in recent years; however, competition from fossil fuel technologies, especially natural gas combustion turbines, remains strong. Projections of low fossil fuel costs increase the uncertainty of wind power's future, as do the potentially competitive forces created by the emergence of restructured electricity markets, which tend to favor established technologies.

Much of the development of wind energy in the near to medium term will be in Europe, where stricter environmental laws, continued government support, and a commitment by the European Union to reach an 8-percent market share for renewables in the electricity market help the investment climate for wind energy. In the developing world, lack of an infrastructure provides development opportunities for wind technologies in small-scale, remote village applications.

Wind capacity factors are expected to improve and capital costs to decrease. The next generation of wind turbines, to be introduced during the 1997-1998 time frame, will have up to 750 kilowatts of capacity. The *AEO97* forecast assumes that turbines of about that size will be deployed between 1997 and 2000 and will continue to improve until 2005.

Role as Fuel Saver Possible for Wind-Powered Electricity Generation

Figure 72. Levelized costs of electricity from wind power, 1990-2015 (1995 cents per kilowatthour)

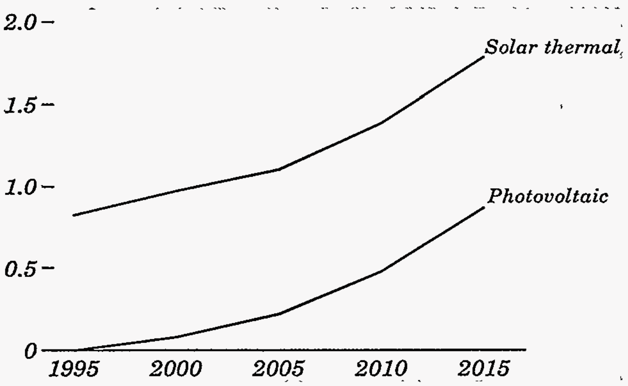


Industry targets for wind generation costs below 5 cents per kilowatthour appear to have been met (Figure 72). Also, EPACT provides a tax subsidy of 1.5 cents per kilowatthour for wind generation, effective for 10 years for wind units built before July 1999. Nevertheless, as the market for electricity changes, these cost levels may no longer be adequate to ensure market penetration. As indicated above, some analysts predict that major technology advances may permit the cost of wind-powered generation to drop below 3 cents, or even below 2 cents per kilowatthour by 2015. Such decreases could make wind energy competitive with the variable operating and fuel costs of some natural gas generation, so that electricity from wind would be cost-effective solely on the basis of its energy value.

Competing as a fuel saver could be important to wind power by offsetting the limitations that its intermittent nature imposes on capacity planning for individual utilities or for an electricity pool arrangement, such as those proposed under many restructuring scenarios. In addition, if a cap on carbon emissions were implemented, or if a carbon tax increased the operating costs of fossil fuel plants, then wind's economic viability could be greatly improved. Wind energy would also benefit from the development of inexpensive energy storage. Many State and national restructuring proposals contain minimum renewable portfolio provisions that could be beneficial to wind development, since in some regions wind is the most economically viable of the non-hydropower renewable technologies.

Modest Growth Expected for Solar Thermal, Photovoltaic Generation

Figure 73. Solar thermal and photovoltaic electricity generation, 1995-2015 (billion kilowatthours)

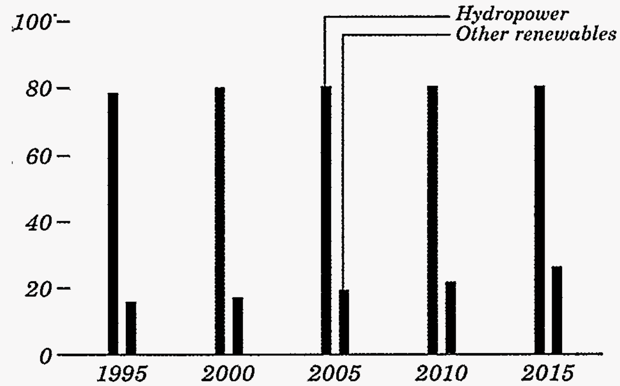


Generation from grid-connected solar thermal power is expected to grow from 0.8 billion kilowatthours in 1995 to almost 1.8 billion in 2015 (Figure 73), including new capacity and generation from central receiver, trough, and dish-Stirling technologies. Operation of Solar Two, a 10-megawatt central receiver station, began during 1996. Dish-Stirling technologies, which are modular and well suited for distributed generation, are expected to become more competitive, but solar thermal overall faces stiff competition from fossil-fueled and other renewable energy generating technologies in the forecast.

Solar photovoltaic (PV) generation has enjoyed dramatic cost and performance improvements over the past several decades. Grid-connected PV generation in the reference case forecast increases from a few million kilowatthours in 1995 to nearly 0.9 billion in 2015 (Figure 73). If improvements continue, PV could become a competitive electricity source in some instances for distributed generation as well as for meeting peak loads. Off-grid PV generation, which is not bought or sold in electricity markets and is not included in the *AEO97* projections, is also likely to continue growing rapidly, both domestically and outside the United States. Off-grid U.S. domestic capacity, almost all of it in very small units, is expected to increase by 5 to 10 megawatts a year through 2000, and at a more rapid pace thereafter. Further growth could occur if market restructuring raises consumer rates for peaking power or for additional power in distant locations, making self-generated PV more attractive to some consumers.

Little Growth Projected for Hydroelectric Generation

Figure 74. Electricity generating capacity from renewable sources, 1995-2015 (gigawatts)

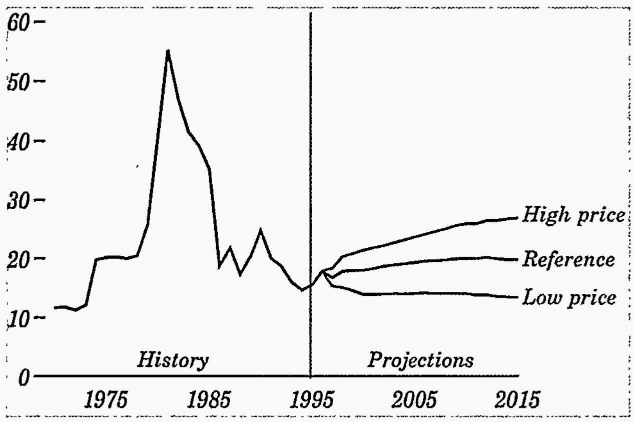


Conventional hydroelectric power is expected to remain a significant overall contributor to the Nation's electricity supply, providing about two-thirds of all the electricity derived from renewable resources through 2015 (Figure 74). In contrast to fossil fuels (coal and natural gas) and the other renewables, however, the Nation's conventional hydroelectric power supply is not expected to increase significantly at any time in the forecast. By 2015, the share of U.S. electric power provided by conventional hydropower is projected to decline to just under 7 percent, from more than 9 percent in 1995.

Small increases in hydroelectric generation will be achieved from a few new, small facilities and from upgrades (additional turbines, improved turbines or generators) at existing facilities. Those increases will be offset, however, by the closing of other facilities, reductions in generation in response to other water-use priorities, and growing concerns about negative environmental effects. Further, where generation continues, its economic value may be reduced, as water formerly used to generate electricity during valuable peak electricity seasons is shifted to much less valuable off-peak seasons, so that water releases can be used to accelerate fish passage downriver. Finally, concerns about the long-term future of hydroelectric power continue to grow, as market events and regulatory decisions—including those by the Federal Energy Regulatory Commission—constrain electricity production in favor of environmental and other priorities.

AEO97 Reference Case Projects Stable Oil Prices, Rising Consumption

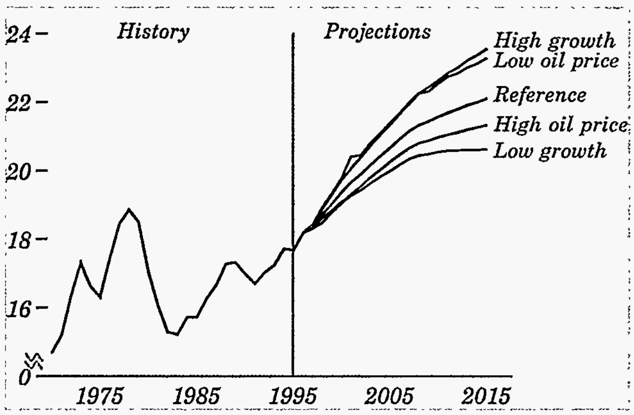
Figure 75. Lower 48 crude oil wellhead prices, 1970-2015 (1995 dollars per barrel)



From 1995 to 2015, wellhead prices for crude oil in the lower 48 States are projected to fall by 0.8 percent a year in the low world oil price case, and to grow by 1.2 and 2.8 percent a year in the reference and high price cases, respectively (Figure 75). The variation in world oil price assumptions leads to similar variation in projected domestic prices, which are determined largely by the international market.

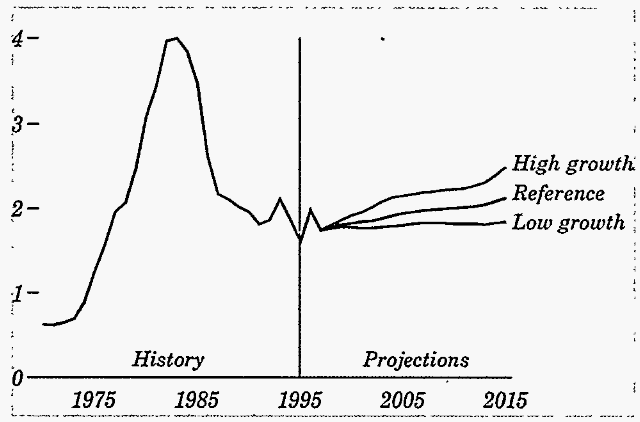
U.S. petroleum consumption continues to rise in all the *AEO97* cases (Figure 76). Total petroleum product supplied ranges from 20.6 million barrels per day in the low economic growth case to 23.6 million in the high growth case, as compared with 17.7 million in 1995. Petroleum continues as the primary source of energy in the United States, representing just under 40 percent of total U.S. energy consumption throughout the forecast.

Figure 76. U.S. petroleum consumption in five cases, 1970-2015 (million barrels per day)



Only Slight Increase Projected for Domestic Natural Gas Prices

Figure 77. Lower 48 natural gas wellhead prices, 1970-2015 (1995 dollars per thousand cubic feet)



Wellhead prices for natural gas in the lower 48 States increase by 0.6 and 2.2 percent a year in the low and high economic growth cases, respectively, compared with 1.4-percent annual growth in the reference case (Figure 77). 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. Because domestic natural gas prices are less responsive than oil prices to world oil prices (oil and gas do not compete directly in most markets), little variation is seen across the oil price cases.

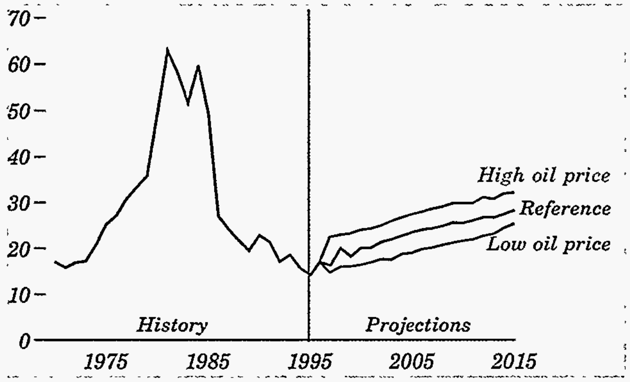
Natural gas production can be increased at substantially lower cost than was projected in previous *AEO* forecasts for several reasons, including: an increase in the inferred reserve base, based on a reassessment by the U.S. Geological Survey; and a reexamination of the impacts of technological progress on the discovery process, which allows more gas to be produced from fewer wells (Table 6).

Table 6. Economically recoverable oil and gas resources in 1990, measured under different technology assumptions

	Crude oil (billion barrels)		Natural gas (trillion cubic feet)	
Lower 48 resources	1990 technology	2015 technology	1990 technology	2015 technology
Proved	26	26	169	169
Unproved	96	119	936	1,322
Total	122	145	1,105	1,491

Small Drilling Increases Accompany Expanding Markets for Oil and Gas

Figure 78. Successful new lower 48 natural gas and oil wells in three cases, 1970-2015 (thousand successful wells)



Both exploratory and developmental drilling levels increase in the forecast (Figure 78). With rising prices and generally declining drilling costs, total crude oil and natural gas well completions grow at average annual rates of 3.5 and 4.8 percent in the low and high oil price cases, respectively. Changes in world oil price assumptions have a more pronounced effect on projected oil drilling than on gas drilling (Table 7).

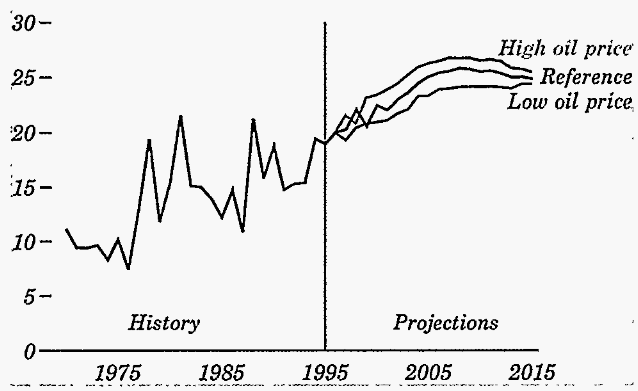
Natural gas drilling is projected to be more productive than oil drilling, because remaining recoverable gas resources are more abundant than oil resources. Over the past two decades, crude oil reserve additions have come primarily from older fields, whereas gas reserve additions have come from discoveries in both new and old fields. The future productivity of both oil and gas drilling is uncertain, however, because the extent of the Nation's oil and gas resources is uncertain [*33*].

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

	1995	2000	2010	2015
Natural gas				
Low oil price case		10.0	14.1	17.5
Reference case	7.4	11.0	15.5	18.4
High oil price case		11.6	17.0	19.8
Crude oil				
Low oil price case		6.4	7.5	7.9
Reference case	6.8	9.1	10.1	9.9
High oil price case		12.4	12.8	12.4

Natural Gas Reserve Additions Grow, Oil Additions Stabilize

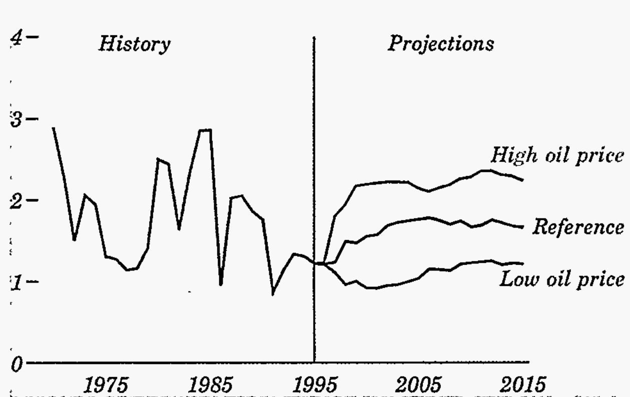
Figure 79. Lower 48 natural gas reserve additions in three cases, 1970-2015 (trillion cubic feet)



Higher drilling levels lead to significant increases in annual reserve additions in the forecast. Lower 48 natural gas reserve additions (Figure 79) increase by 1.3 and 1.5 percent a year in the low and high oil price cases, respectively, continuing the trend of the past two decades. Lower 48 oil reserve additions (Figure 80) decrease by 0.4 percent a year in the low world oil price case and increase by 3.1 percent a year in the high price case.

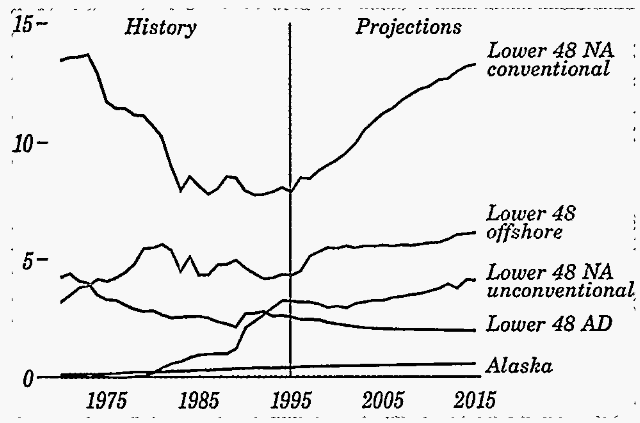
Natural gas reserve additions exceed production through 2012 in the reference case. Lower 48 reserves peak at 189.5 trillion cubic feet in 2013, then decline to 188.4 trillion by 2015, compared with the 1995 level of 155.6 trillion cubic feet. Despite a rise in oil reserve additions, production exceeds additions in the reference case, and oil reserves are depleted at a rate of 0.5 percent a year.

Figure 80. Lower 48 oil reserve additions in three cases, 1970-2015 (billion barrels)



Conventional Onshore Production Leads Increase in Natural Gas Supply

Figure 81. Natural gas production by source, 1970-2015 (trillion cubic feet)



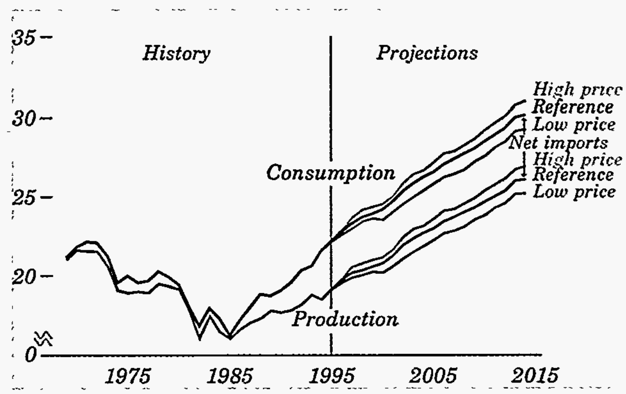
The continuing increase in domestic natural gas production over the forecast comes primarily from lower 48 onshore nonassociated (NA) sources (Figure 81). Conventional onshore production, which accounted for 42.9 percent of total U.S. domestic production in 1995, is projected to increase at an average annual rate of 2.6 percent over the 1995-2015 period. Natural gas production from unconventional sources increases at an average annual rate of 1.2 percent over the same period. Gas from offshore wells in the Gulf of Mexico also contributes significantly to production. The innovative use of cost-saving technology and the expected continuation of recent huge finds, particularly in the deep water off the Gulf of Mexico, have encouraged greater interest in this area.

Natural gas production from Alaska rises gradually in the forecast. Alaskan gas is not projected to be transported to the lower 48 States, however, because lower 48 prices are not projected to be high enough to support the required transport system within the forecast period. Expected Alaskan natural gas production does not include gas from the North Slope, which currently is being reinjected to support oil production. In the future, it may also be marketed as liquefied natural gas to Pacific Rim markets [*34*].

Production of associated/dissolved (AD) natural gas from lower 48 crude oil reservoirs generally declines, following the expected pattern of domestic crude oil production. AD gas accounts for less than 7.8 percent of total lower 48 production in 2015, compared with 14.2 percent in 1995.

Natural Gas Imports, Mostly from Canada, Increase Slightly

Figure 82. Natural gas production, consumption, and imports, 1970-2015 (trillion cubic feet per year)



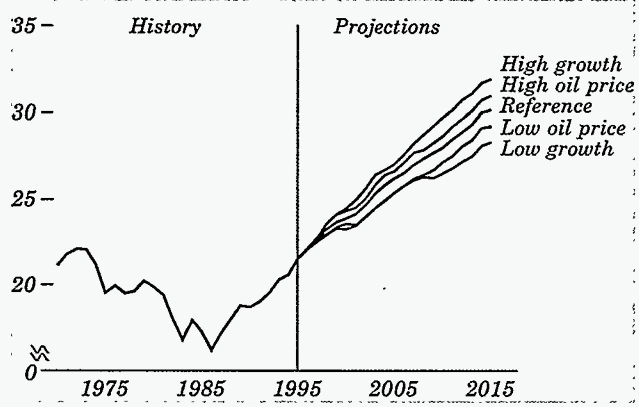
Natural gas imports are expected to grow in the forecast in all cases (Figure 82). In the reference case, net natural gas imports increase from 12.4 percent of total gas consumption in 1995 to 14.0 percent in 2015. Most of the increase is attributable to imports from Canada, primarily in response to readily available supplies and a 20.9-percent increase in projected pipeline capacity between the United States and Canada between 1995 and 2015.

Since 1984, U.S. natural gas trade with Mexico has consisted primarily of exports. That trend is expected to continue throughout the forecast, despite the North American Free Trade Agreement and the substantial estimated size of the Mexican natural gas resource base. There is significant uncertainty in the direction and pace of change in the Mexican natural gas market. Some of the unknowns that may affect the market include: economic growth and development, environmental concerns, issues related to Petroleos Mexicano's (PEMEX's) monopoly control and budgetary constraints, political and policy risks, and the overabundance of heavy fuel oil in Mexico's petroleum market.

Another potential source of gas imports is liquefied natural gas (LNG); however, given the projected low natural gas prices in the lower 48 markets, LNG is not expected to become a significant source of U.S. supply. LNG imports are projected to increase over the forecast at a modest rate, reaching a level of 0.36 trillion cubic feet in 2015, compared with 0.02 trillion cubic feet in 1995.

Gas Consumption for Electricity Generation Grows Steadily

Figure 83. Natural gas consumption in five cases, 1970-2015 (trillion cubic feet per year)

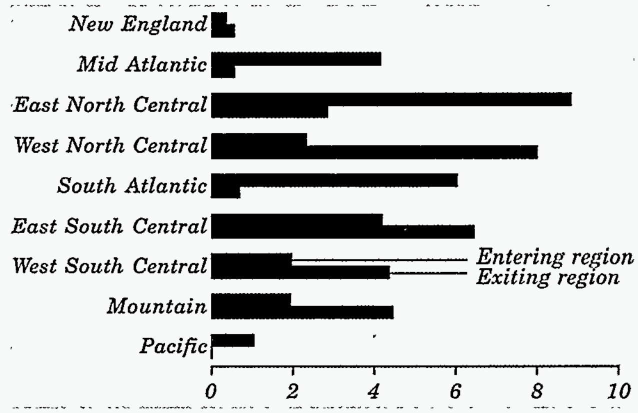


Natural gas consumption expands from 1995 to 2015 in all the *AEO97* cases (Figure 83). Domestic consumption ranges from 28.4 trillion cubic feet per year in the low economic growth case to 32.0 trillion in the high growth case in 2015, as compared with 21.6 trillion cubic feet in 1995. Growth is seen in all end-use sectors, with highest growth as a result of rising demand for electricity, including industrial cogeneration. More than half of the variation across cases is attributable to differences in gas consumption for electricity generation.

Total gas consumption in the electricity generation sector grows steadily throughout the forecast. In the reference case it more than doubles, from 3.5 trillion cubic feet a year in 1995 to 8.5 trillion in 2015. Restructuring of the electric utility industry is expected to open up new opportunities for gas-fired generation. In addition, growth is spurred by increased utilization of existing gas-fired power plants in the forecast and the addition of new turbines and combined-cycle facilities, which are less capital-intensive than coal, nuclear, or renewable electricity generation plants. Although projected coal prices to the electricity generation sector are lower than current prices, the natural gas combined-cycle share of new capacity is about four times the coal share. Stable fuel costs, lower capital costs, and projected improvements in gas turbine heat rates make the overall cost of gas-generated electricity per kilowatthour competitive with the cost of electricity from new coal-burning generators.

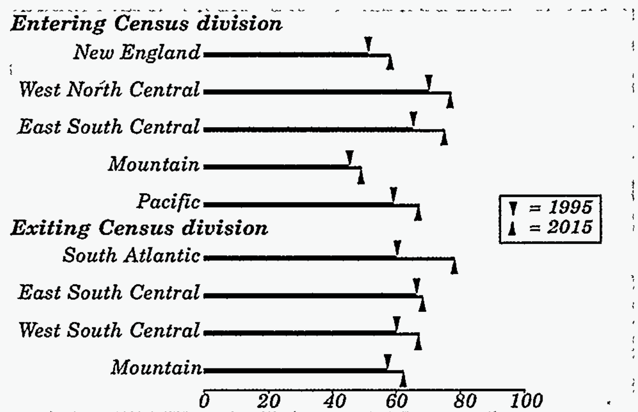
Gas Pipeline and Storage Capacity Projected To Increase

Figure 84. Pipeline capacity expansion by Census division, 1995-2015 (billion cubic feet per day)



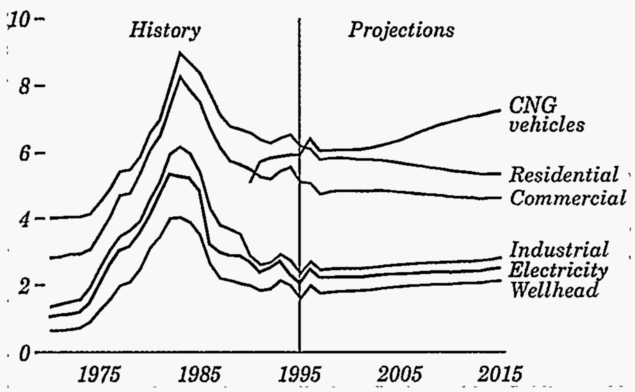
Although the boom in pipeline and storage construction of the late 1980s and early 1990s has slowed, new capacity will still be required. Pipeline capacity increases are projected in the reference case, both entering and exiting key regions (Figure 84). Storage capacity is also expected to grow in most regions, increasing overall by 54 percent over the forecast period. The strongest growth is projected for the first 5 years of the forecast, when planned pipeline additions to provide access to new supplies and service new markets come on line, and after 2005, when additional capacity will be needed to meet increased consumption in the eastern half of the United States. In some regions, growth in new pipeline construction is tempered by higher utilization of pipeline capacity (Figure 85).

Figure 85. Pipeline capacity utilization by Census division, 1995 and 2015 (percent)



Lower Prices Projected for Residential and Commercial Natural Gas Users

Figure 86. Natural gas end-use prices by sector, 1970-2015 (1995 dollars per thousand cubic feet)



While consumer prices to the industrial, electricity, and transportation sectors generally increase throughout the forecast period, prices to the residential and commercial sectors show significant decreases (Figure 86). The decreases in those sectors are caused primarily by projected reductions in the cost of capital and by efficiency improvements in the transmission and distribution segments of the industry as service providers adapt to a more competitive regulatory framework. In the industrial and electricity generation sectors, modest decreases in margins are overshadowed by increases in wellhead prices, and the overall trend is a slight rise in prices. The declines in margins reflect both Federal and State initiatives that foster an increasingly competitive market (see discussion on pages 9-10).

Compared with their rise and decline over the 1970-1995 period, transmission and distribution revenues in the natural gas industry are relatively stable in the forecast (Table 8), with declines in margins balanced by higher volumes.

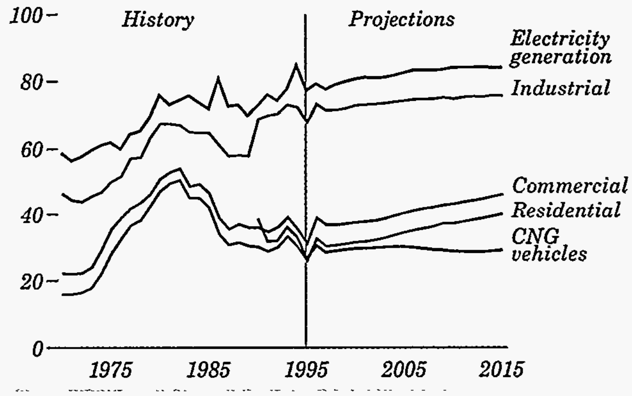
Table 8. Transmission and distribution revenues and margins, 1970, 1985, 1995, and 2015

	1970	1985	1995	2015
T&D revenues (billion 1995 dollars)	29.00	47.63	41.11	38.45
End-use consumption (trillion cubic feet)	19.02	15.81	19.74	27.60
Average margin (1995 dollars per thousand cubic feet)*	1.52	3.01	2.08	1.40

**Revenue divided by end-use consumption.*

Gas Transmission and Distribution Margins Expected To Decline

Figure 87. Wellhead share of natural gas end-use prices by sector, 1970-2015 (percent)



With transmission and distribution margins declining in most sectors, the wellhead shares of end-use prices increase in the forecast (Figure 87). The greatest impact is in the residential and commercial markets, where most customers rely on firm service.

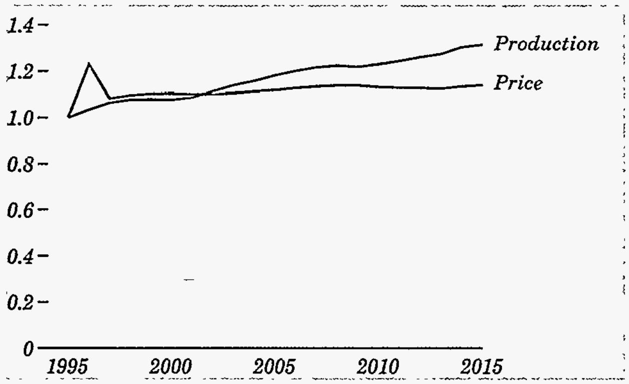
Changes have been seen historically not only in the wellhead price component of end-use prices but also in pipeline and local distribution company (LDC) margins (Table 9). The decline in pipeline margins results from continued depreciation of the pipeline infrastructure, a decline in the AA utility bond rate, increased utilization of pipeline capacity (which places downward pressure on unit costs), and the effects of a more competitive market resulting from restructuring. Although LDC margins in the residential and commercial sectors have increased historically, as the impacts of restructuring further affect the transmission segment of the market and begin to affect the distribution segment, reduced markups are projected for these sectors.

Table 9. Components of residential and commercial natural gas end-use prices, 1985-2015 (1995 dollars per thousand cubic feet)

Price Component	1985	1995	2000	2010	2015
Wellhead price	3.46	1.61	1.82	2.01	2.13
Citygate price	5.11	2.78	2.78	2.99	3.11
Pipeline margin	1.65	1.17	0.96	0.98	0.98
LDC margin					
Residential	3.23	3.38	2.99	2.42	2.21
Commercial	2.39	2.33	2.07	1.66	1.51
End-use price					
Residential	8.34	6.18	5.79	5.43	5.33
Commercial	7.50	5.10	4.83	4.64	4.61

Slow Economic Growth Would Lead to Stable Gas Prices, Higher Production

Figure 88. Lower 48 natural gas production and wellhead prices in the low economic growth case, 1995-2015 (index, 1995 = 1)

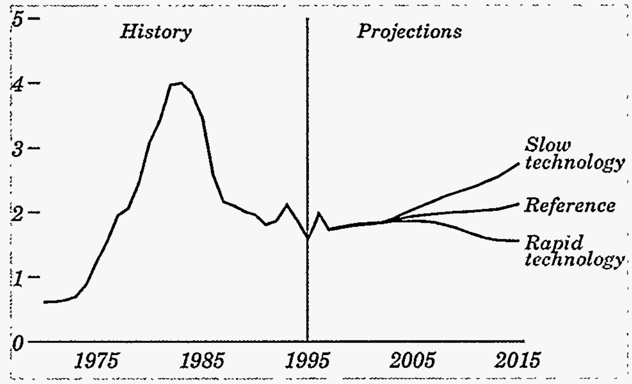


The potential impact of advances in oil and gas supply technology is most evident in the low economic growth case, where production increases by 1.4 percent a year with only a small increase in wellhead prices (Figure 88). As seen in the other *AEO97* cases, achieving greater increases in production requires a price stimulus in addition to the assumed reference levels of technological progress.

For parameters affected by technology, historical rates of change are generally assumed to continue throughout the forecast period in all the *AEO97* cases. Rapid and slow technological progress cases were created to assess the sensitivity of the *AEO97* projections to changes in the economically recoverable oil and gas resource base, exploration and development costs, and finding rates as a result of technological progress. Representative values for the affected parameters are presented in Table 10.

Technology Assumptions Have Strong Effects on Gas Price Projections

Figure 89. Lower 48 natural gas wellhead prices in three cases, 1970-2015 (1995 dollars per thousand cubic feet)



The two technology cases were run as fully integrated model runs. (Two other runs, with demands held constant, were produced to isolate the effects of demand feedback [see pages 26-29].) All other parameters in the model were kept at their reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about gas trade with Mexico.

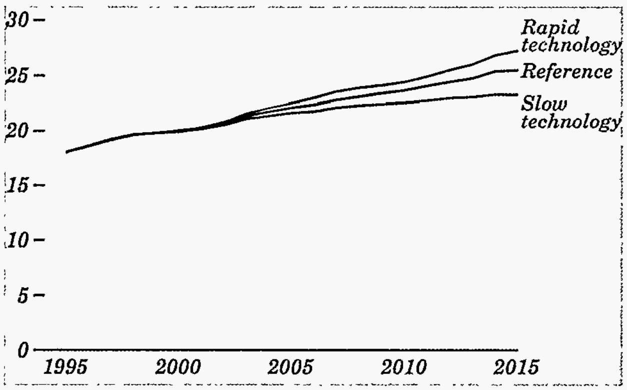
As shown in Figure 89, natural gas prices are highly sensitive to changes in assumptions about technological progress. For the first decade of the forecast, both price and production levels for lower 48 oil and natural gas are almost identical in the reference case and the two technological progress cases. By the year 2015, however, natural gas prices are 30 percent higher (at $2.77 per thousand cubic feet) in the slow technology case and 27 percent lower (at $1.55) in the rapid technology case than the reference case price of $2.13 per thousand cubic feet.

Table 10. Representative average annual rates of technological progress in alternative technology cases (percent)

	Natural gas						Crude oil					
	Slow technology		Reference		Rapid technology		Slow technology		Reference		Rapid technology	
Technology area	On-shore	Off-shore	On-shore	Off-shore	On-shore	Off-shore	On-shore	Off-shore	On-shore	Off-shore	On-shore	Off-shore
Costs												
Drilling	1.6	3.6	2.1	4.2	2.8	4.9	1.6	3.6	2.1	4.2	2.8	4.9
Lease equipment	0.7	1.1	1.4	1.9	2.1	2.6	0.7	1.1	1.4	1.9	2.1	2.6
Operating	0.0	0.9	0.6	1.2	1.3	1.7	0.0	0.9	0.6	1.2	1.3	1.7
Resources												
Inferred reserves	0.0	0.5	0.0	1.0	0.0	1.5	0.0	0.7	0.0	1.0	0.0	1.3
Undiscovered	0.6	1.4	1.8	3.0	3.0	4.5	0.5	2.0	1.4	3.0	2.2	3.9
Finding rates	2.4	5.0	4.2	10.2	6.0	15.3	1.8	6.5	3.2	9.6	4.6	12.6
Success rates	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Slow Technological Progress Could Reduce Market Share for Natural Gas

Figure 90. Lower 48 natural gas production in alternative technology cases, 1995-2015 (trillion cubic feet per day)



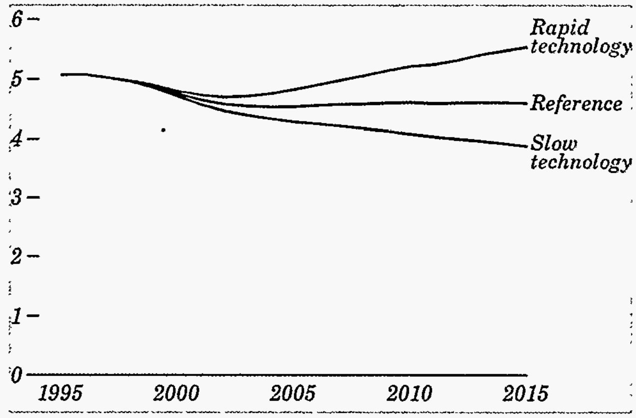
As was seen for wellhead prices, natural gas production levels in the alternative technology cases do not deviate significantly from the reference case in the first half of the forecast period (Figure 90). In the second half of the forecast, when investment in new capital stock plays a larger role, changes in production are more significant, as new investments in the industrial sector and electric power generation facilities respond to changes in natural gas prices.

In the rapid technology case, the natural gas share of fossil fuel inputs to electricity generation facilities in 2015 is 32 percent, compared with 22 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, since 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. The alternative technology cases also demonstrate the intense competition between natural gas and electricity, and between natural gas and steam coal, in the industrial sector.

Offshore production is particularly responsive to changes in the assumed levels of technological progress, particularly for oil. In the rapid technology case, the offshore share of total lower 48 oil production in 2015 is 37 percent, compared with 30 percent in the slow technology case.

For Oil, Both Production and Imports Change With Technology Assumptions

Figure 91. Lower 48 oil production in alternative technology cases, 1995-2015 (million barrels per day)



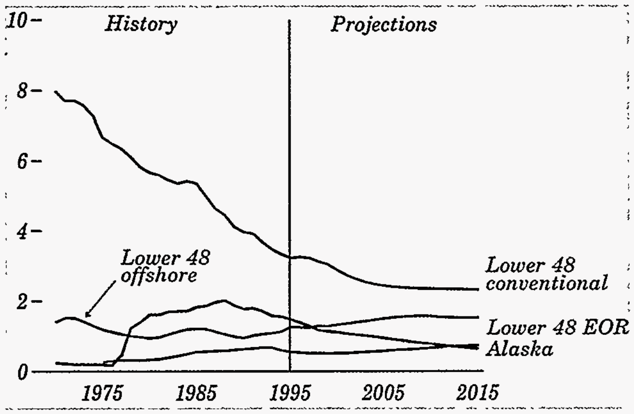
Domestic oil production is also sensitive to changes in the technological progress assumptions (Figure 91). In comparison with the projected 2015 production level of 5.2 million barrels a day in the reference case, oil production increases to 6.2 million barrels a day in the rapid technology case and decreases to 4.5 million in the slow technology case. The changes, in relative terms, are significantly greater than those seen for natural gas, primarily because of key differences between the oil and natural gas markets.

Domestic oil prices are determined largely by the international market. Thus, changes in U.S. oil production do not constitute a significant volume relative to the global market. Given the assumption that the changes in the levels of technology are isolated to U.S. oil producers, total oil supply largely adjusts to the changes in technological progress simply by adjusting imports of crude oil and other petroleum products. Net imports range from a low of 12.3 million barrels per day in the rapid technology case to a high of 14.4 million barrels per day in the slow technology case.

Unlike oil, natural gas is not easily transported between the United States and countries outside North America. Therefore, changes in gas production are determined more by the availability of supplies in North America than by the international market.

AEO97 Projections Include Continuing Decline in U.S. Oil Production

Figure 92. Crude oil production by source, 1970-2015 (million barrels per day)



Projected domestic crude oil production continues its historic decline throughout the forecast (Figure 92), declining by 1.1 percent a year, from 6.6 million barrels per day in 1995 to 5.2 million barrels per day in 2015 [*35*]. Conventional onshore production in the lower 48 States, which accounted for 49.4 percent of total U.S. crude oil production in 1995, is projected to decrease at an average annual rate of 1.6 percent over the forecast.

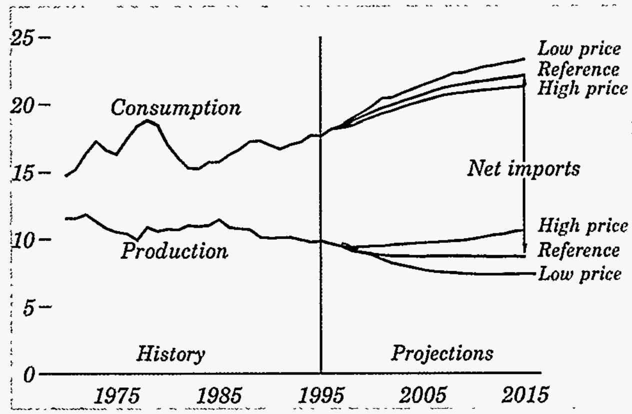
Crude oil production from Alaska is expected to decline at an average annual rate of 4.2 percent between 1995 and 2015. The overall decrease in Alaska's oil production is driven by the continued decline in production from Prudhoe Bay, the largest producing field, which historically has accounted for more than 60 percent of total Alaskan production.

Offshore production generally increases in the forecast, at an average annual rate of 1.0 percent. Because of technological advances and lower costs associated with deep exploration and production in the Gulf of Mexico, several projects are already underway, and additional projects are in the planning stages.

Increased production from enhanced oil recovery (EOR) slows the overall downward trend of oil production [*36*]. As oil prices rise, the expected profitability of EOR projects increases, and as a result, EOR production rises at an average annual rate of 1.3 percent over the 1995-2015 period.

Gap Between Oil Production and Consumption Widens in All Cases

Figure 93. Petroleum production, consumption, and imports, 1970-2015 (million barrels per day)



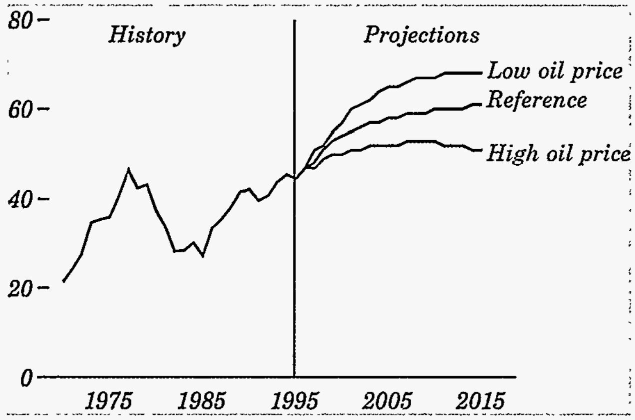
U.S. production of oil and natural gas liquids declines in all *AEO97* cases except the high oil price case (Figure 93), as recoverable domestic resources are depleted. In the low price case, production drops from its 1995 level of 9.8 million barrels per day to 7.3 million barrels per day in 2015. In the high price case, increased exploration and drilling bring the 2015 production level to 10.5 million barrels per day.

Growth in petroleum consumption is anticipated in all the *AEO97* projections. The greatest variation in consumption levels is seen in the economic growth cases, with an increase of 5.8 million barrels per day over the 1995 level in the high growth case, as compared with an increase of only 2.9 million barrels per day in the low growth case.

Additional petroleum imports will be needed to fill the widening gap between production and consumption. The projections for net petroleum imports in 2015 range from a high of 15.9 million barrels per day in the low oil price case—more than double the 1995 level of 7.9 million barrels per day—to a low of 10.8 million barrels per day in the high price case. The value of petroleum imports in 2015 ranges from $80.1 billion in the low price case to $116.2 billion in the high growth case. Total annual U.S. expenditures for petroleum imports, which reached a historical peak of $75.8 billion in 1980 [*37*], were $49.4 billion in 1995.

AEO97 Projects Growing Reliance on Imported Oil and Refined Products

Figure 94. Share of U.S. petroleum consumption supplied by net imports, 1970-2015 (percent)



Net imports of petroleum, which represented 44 percent of domestic petroleum consumption in 1995, close to the 1977 record level of 46 percent, are projected to reach 61 percent in 2015 in the reference case (Figure 94). The corresponding import shares of total consumption in 2015 are 51 percent in the high oil price case and 68 percent in the low price case.

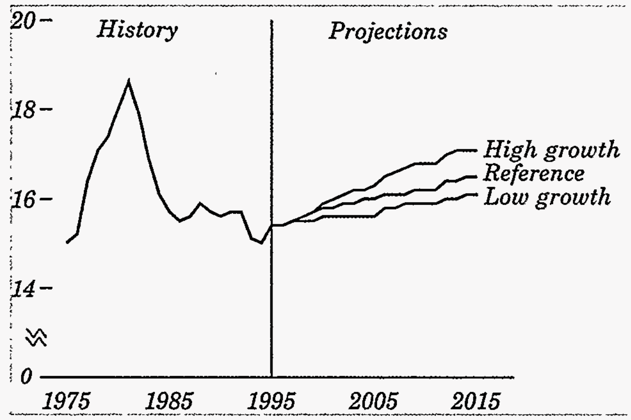
Although crude oil is expected to continue as the major component of petroleum imports, refined products represent a growing share. More imports will be needed as growth in demand for refined products exceeds the expansion of domestic refining capacity. Refined products make up 19 percent of net petroleum imports in 2015 in the high world oil price case and 26 percent in the low price case, as compared with their 10-percent share in 1995 (Table 11).

Table 11. Petroleum consumption and net imports, 1995 and 2015 (million barrels per day)

Year and projection	*Product supplied*	*Net imports*	*Net crude imports*	*Net product imports*
1995	*17.7*	*7.9*	*7.1*	*0.8*
2015				
Reference	*22.1*	*13.5*	*10.2*	*3.2*
Low oil price	*23.3*	*15.9*	*11.8*	*4.1*
High oil price	*21.3*	*10.8*	*8.7*	*2.1*
Low growth	*20.6*	*12.3*	*9.9*	*2.5*
High growth	*23.6*	*14.6*	*10.6*	*3.9*

U.S. Refining Capacity Expected To Rise, Despite Lack of New Refineries

Figure 95. Domestic refining capacity, 1975-2015 (million barrels per day)



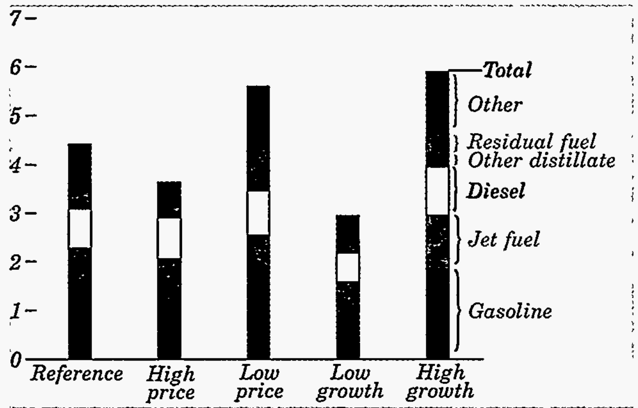
Falling demand for petroleum and the deregulation of the domestic refining industry in the 1980s led to 13 years of decline in U.S. refinery capacity [*38*]. That trend was broken in 1995 by a capacity increase of 0.4 million barrels per day over the 1994 level. Financial and legal considerations make it unlikely that new refineries will be built in the United States, but "capacity creep" at existing refineries is expected to increase total U.S. refining capacity in all the *AEO97* cases (Figure 95).

Distillation capacity is projected to grow from the 1995 level of 15.4 million barrels per day to 16.5 million in 2015 in the reference case, 16.1 million in the low economic growth case, and 17.1 million in the high growth case, as refining capacity returns to the levels of the late 1970s. Existing refineries will continue to be utilized intensively throughout the forecast, in a range from 92 to 94 percent of capacity. In comparison, the 1995 utilization rate was 92 percent, well above the rates of the 1980s and early 1990s.

Ongoing investment in equipment for desulfurization and fluid catalytic cracking will allow U.S. refineries to handle lower quality crude oils, which contain more sulfur. The added flexibility will become increasingly valuable as higher quality resources are depleted over time.

Transportation Fuels Drive Projected Growth in Petroleum Use

Figure 96. Change in petroleum products supplied in five cases, 1995 to 2015 (million barrels per day)



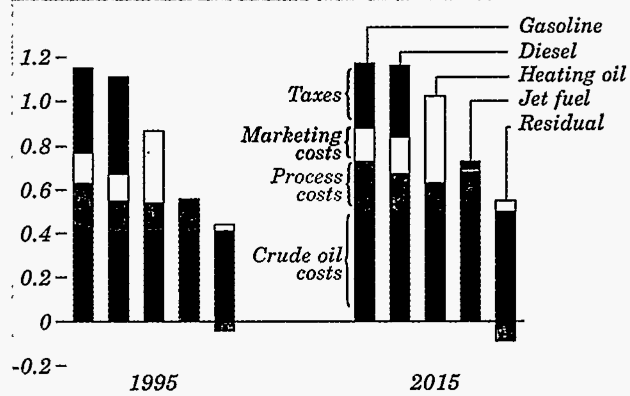
U.S. petroleum consumption is projected to increase by 4.4 million barrels per day between 1995 and 2015 in the reference case, compared with 2.9 million in the low economic growth case and 5.8 million in the high growth case (Figure 96). Industry will continue to account for about one-fourth of petroleum consumption, and two-thirds will be used for transportation.

About 80 percent of the growth in petroleum use in the forecast is attributable to the transportation sector. In addition, a shift in consumption patterns is expected within the transportation sector. Gasoline, which represented 66 percent of transportation petroleum consumption by volume in 1995, shrinks to a 60-percent share in 2015, as alternative fuels penetrate transportation markets. The share for diesel rises from 17 percent to 18 percent, and the jet fuel share rises from 13 percent to 16 percent.

In the low oil price case, a shift in petroleum consumption patterns is also seen, with residual fuel use rising from the 1995 level of 0.9 million barrels per day to 1.6 million in 2015. More competitive oil prices in this case cause electric utilities and other generators to use more residual fuel to fire boilers, displacing a portion of the natural gas and coal use seen in the other cases.

Crude Oil Costs and Taxes Dominate Refined Petroleum Product Prices

Figure 97. Components of refined product costs, 1995 and 2015 (1995 dollars per gallon)



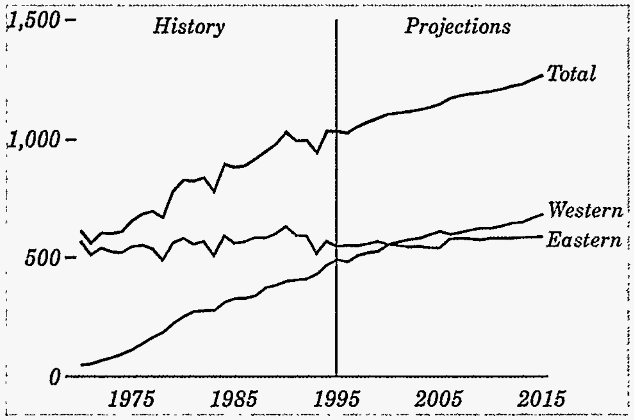
Refined product prices in the forecast continue to be dominated by crude oil costs (Figure 97). However, changes are projected in refining process costs, marketing costs, and taxes. State motor fuels taxes are assumed to keep up with inflation, as they have in the past. Federal taxes, which have increased sporadically in the past, are assumed to remain at nominal 1995 levels; the result is a decline in inflation-adjusted Federal taxes, which dampens the growth of gasoline and diesel prices. In contrast, Federal taxes on jet fuel show a real increase, with a tax of 4.3 cents per gallon beginning in 1996 as mandated in the Omnibus Budget Reconciliation Act of 1993. A similar tax was levied on other fuels in 1993.

The *AEO97* projections of product prices reflect investments related to compliance with refinery emissions, health, and safety regulations. These investments add 1 to 3 cents to the processing costs of light products (gasoline, distillate, jet fuel, kerosene, and liquefied petroleum gases).

The marketing cost of heating oil (the difference between wholesale and retail prices) is projected to be higher than in 1995 throughout the forecast. Marketing costs, which were at a historical low in 1995, are assumed to return to more normal levels in the forecast.

Western Mines Lead Projected Increase in U.S. Coal Production

Figure 98. Coal production by region, 1970-2015 (million short tons)



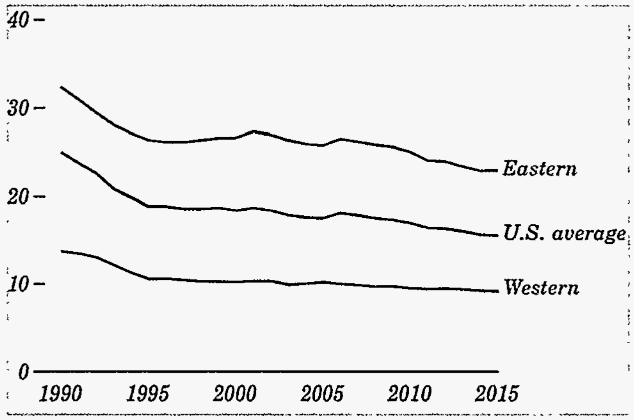
Major trends in the *AEO97* forecasts for coal can be contrasted with changes since 1970 [*39*]. For instance, eastern coal production, which fell from 568 million tons in 1970 to 544 million tons in 1995, is projected to increase to 586 million tons in 2015, a change of 0.4 percent per year (Figure 98). Nevertheless, eastern mines are losing market share to less expensive, lower sulfur coal from western mines. The eastern share of national production, which fell from 93 percent in 1970 to 53 percent in 1995, is projected to be 46 percent in 2015.

Total coal production grew from 613 million tons (14.6 quadrillion Btu) in 1970 to 1,033 million tons (22.0 quadrillion Btu) in 1995. In 2015, production is projected to reach 1,268 million tons (26.5 quadrillion Btu). Most of the growth is expected to come from western mines, where output grew by 10 percent a year from 45 million tons in 1970 to 489 million tons in 1995 (Figure 98). In the forecast, western mining grows by 1.7 percent a year, to 682 million tons in 2015.

The shift from eastern to western coals has been led by midwestern and southeastern utilities, which have reduced fuel costs while switching from high-sulfur eastern sources to coal from Wyoming, Colorado, and Utah. Low-sulfur, low-cost subbituminous coal from Wyoming can displace eastern bituminous coal in many larger, newer boilers. Consumers with smaller, older boilers often purchase suitable low-cost, low-sulfur bituminous coal from Colorado or Utah.

Minemouth Coal Prices Are Projected To Fall in All Regions

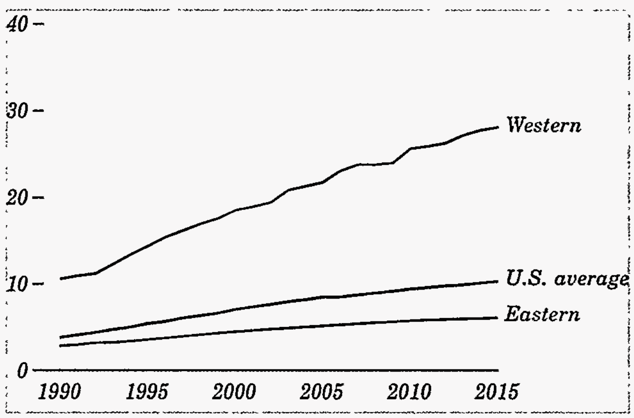
Figure 99. Average minemouth price of coal by region, 1990-2015 (1995 dollars per ton)



Minemouth coal prices declined by $3.45 per ton in 1995 dollars between 1970 and 1995, and they are projected to decline by another $3.37 between 1995 and 2015 (Figure 99). The price of coal delivered to electricity generators, which averaged $25.07 per ton in 1970 and $27.01 in 1995, falls to $22.47 per ton in 2015—a 0.9-percent annual decline between 1995 and 2015.

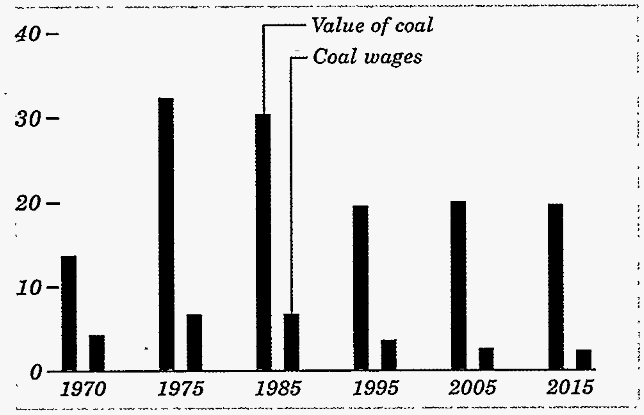
Minemouth prices decline by 1.0 percent a year between 1995 and 2015, as competition drives productivity improvements. Western coalfields, particularly those in the Powder River Basin in Wyoming and Montana, have large reserves of low-cost, low-sulfur coal. Average productivity (Figure 100) follows the trend in eastern productivity more closely than that for western productivity because eastern mines are more labor-intensive.

Figure 100. Coal mining labor productivity by region, 1990-2015 (short tons per miner per hour)



Continuing Increases in Productivity Are Projected To Reduce Labor Costs

Figure 101. Labor cost component of minemouth coal prices, 1970-2015 (billion 1995 dollars)



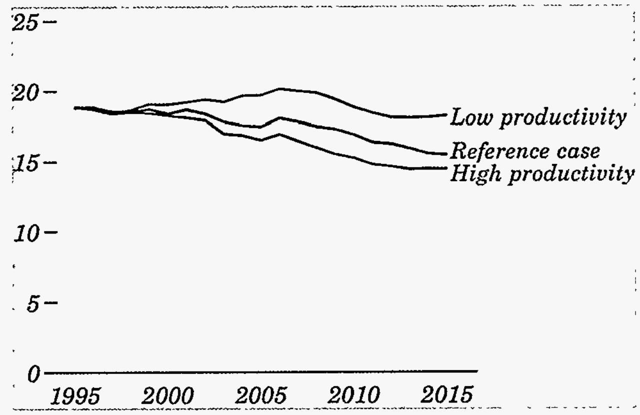
Gains in coal mine labor productivity will be achieved as a result of technology improvements, economies of scale, and better mine design. At the national level, however, average labor productivity will be influenced as much by changing regional production patterns as by technology advances, as the market share of more productive western mines grows. After 2005, the demand for lower sulfur coal will require mining of thinner, deeper seams in eastern mines, and productivity improvements in that region are expected to slow.

Slower productivity gains in eastern low-sulfur coal mining during the second decade of the forecast cause more consumers to turn to western low-sulfur supplies, except in States separated from western mines by the coalfields in the Appalachian mountains. Eastern seaboard consumers are partially protected from rising prices by their access to imported low-sulfur coal. Caught between low-cost western and imported coal supplies, eastern producers may find few chances to recoup the investments required to open new low-sulfur coal mines.

Wages are assumed to remain flat in 1995 dollars as labor demand declines. While productivity improved between 1970 and 1995, the number of miners fell by 1.9 percent a year, and a further decline of 2.2 percent a year is expected through 2015 (Figure 101). Thus, the contribution of wages to minemouth coal prices is projected to decline to 12 percent in 2015, as compared with the historical decline from 31 percent to 18 percent between 1970 and 1995.

Labor Productivity Assumptions Are Key to Production, Price Forecasts

Figure 102. Average minemouth coal prices in three cases, 1995-2015 (1995 dollars per ton)



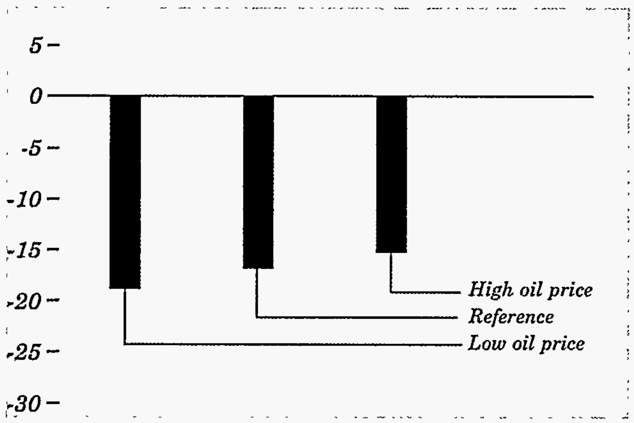
Assumptions about the rates of labor productivity change are key determinants of national prices and production, particularly as they affect eastern and western market shares. Alternative cases were used to explore the sensitivity of coal prices to changes in wages and in labor productivity improvement rates.

In the reference case, eastern labor productivity increases by 2.7 percent a year through 2015 and western productivity by 3.5 percent a year (Figure 102). In the high productivity case, a 6.7-percent annual improvement is projected, resulting in a 2015 national average minemouth price of $14.41 per ton (6.8 percent below the reference case price). The low productivity case, which assumes a 0.1-percent annual decline in productivity, yields a 2015 minemouth price of $18.26 per ton (18.1 percent above the price in the reference case).

The reference case assumes unchanging wages for miners (in 1995 dollars). For comparison, the high wage case projects a real increase of 0.5 percent a year and a 2015 minemouth price of $16.44 per ton, 6.3 percent above the reference case. In the low wage case, wages are assumed to fall by 0.5 percent a year, reducing the 2015 minemouth price to $14.55 per ton (5.9 percent below wages in the reference case). Delivered coal prices vary by similar amounts, but distribution patterns are not significantly affected. Domestic demand was held constant in the alternative cases, but coal exports varied by plus and minus 3 million tons in response to changes in U.S. prices.

Coal Transportation Costs Decline in the *AEO97* Forecasts

Figure 103. Percent change in coal transportation costs in three cases, 1995-2015

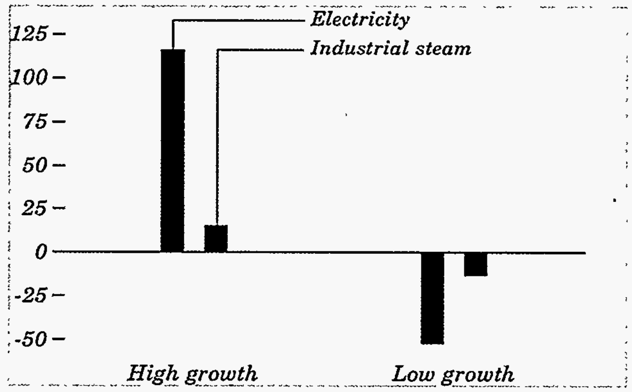


The competition between coal and other fuels, and among coalfields, is influenced by coal transportation costs. Changes in fuel costs affect transportation rates (Figure 103), but fuel efficiency also grows with other productivity improvements in the forecast. As a result, average coal transportation rates decline by 0.9 percent a year between 1995 and 2015. The most rapid declines are likely to occur in routes that originate in coalfields with the greatest production growth. Railroads are likely to reinvest profits from increasing coal traffic to reduce future costs and rates in regions with the best outlook. Thus, coalfields that are most successful at improving productivity and, therefore, lowering minemouth prices are likely to obtain the lowest transportation rates and, consequently, the largest markets at competitive delivered prices.

Regional differences in production and transportation costs are already affecting coal distribution patterns. Western coal is gaining share in midwestern and southeastern markets, and coal for export is moving along different domestic routes. Retirements of barge capacity have exceeded replacements in recent years, and the resulting increase in inland barge rates has caused some traffic to shift to rail or Great Lakes vessels for all or part of the journey from mines to U.S. ports of exit [*40*]. In spite of railroad mergers and consolidation in the barge industry, real coal transportation costs are projected to continue their historical decline, as competition among surviving carriers forces technological improvements.

Stronger Economic Growth Would Lead to Higher Coal Consumption

Figure 104. Variation from reference case projection of coal demand in 2015 in two alternative cases (million short tons)



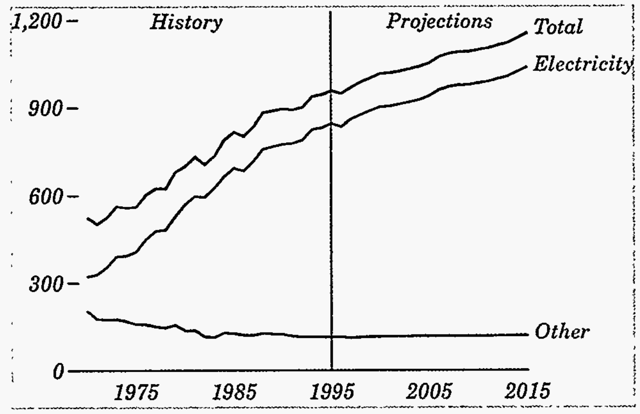
A strong positive correlation between economic growth and electricity demand accounts for the variation in electricity coal demand across the economic growth cases (Figure 104). Most of the variation in coal demand in the economic growth cases is accounted for by changes in coal- and gas-fired electricity generation.

The *AEO97* coal forecasts also vary with different assumptions about technology and world oil prices. Changes in world oil prices affect petroleum fuel costs associated with the extraction and transportation of coal and thus affect delivered coal prices. In the high oil price case, the average minemouth price of coal is 5.0 percent higher in 2015 than in the reference case, and in the low price case it is 4.1 percent lower. In the low oil price case, interfuel price competition leads to a slightly lower coal demand forecast, as oil-fired generation displaces some steam coal use.

Coal transportation costs are also affected by changes in fuel costs. In the world oil price cases, variations in fuel costs produce delivered coal costs to electricity generators that are 3.6 percent higher than the costs in the reference case in the high oil price case ($1.15 per million Btu in 2015) and 2.7 percent lower in the low price case ($1.08 per million Btu). About one-third of the differences are attributable to changes in coal transportation costs. In addition, the market share of western coal, which is 54 percent in the reference and low oil price cases, drops to 52 percent in the high price case.

Electricity Generation Determines Projected Increase in Total Coal Use

Figure 105. Electricity and other coal consumption, 1970-2015 (million short tons per year)



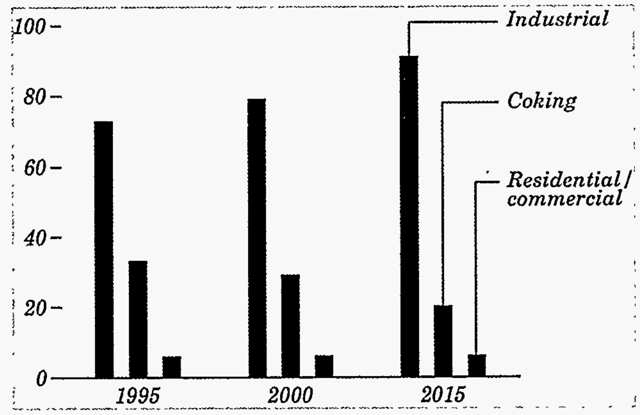
Domestic coal demand rises by 197 million tons in the forecast, from 959 million tons in 1995 to 1,156 million tons in 2015 (Figure 105), because of growth in coal use for electricity generation. Coal demand in other domestic end-use sectors increases by 5 million tons, as reduced coking coal consumption is offset by coal demand for industrial cogeneration.

Coal consumption for electricity generation (excluding industrial cogeneration but including independent power producers) rises from 847 million tons in 1995 to 1,039 million tons in 2015, 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 63 to 74 percent between 1995 and 2015. Coal consumption (in tons) per kilowatthour of generation is higher for subbituminous and lignite coals than for bituminous coal. Thus, the shift to western coal increases the tonnage per kilowatthour of generation in midwestern and southeastern regions. In the East, generators shift from higher to lower sulfur Appalachian bituminous coals that contain more energy (Btu) per short ton.

Although coal maintains its fuel cost advantage over both oil and natural gas, gas-fired generation is the most economical choice for new power generation through 2010 when capital, operating, and fuel costs are considered. Between 2010 and 2015, rising natural gas costs and nuclear retirements are projected to cause increasing demand for coal-fired baseload capacity.

Offsetting Changes Are Projected for Industrial Steam and Coking Coal Use

Figure 106. Non-electricity coal consumption by sector, 1995, 2000, and 2015 (million short tons)



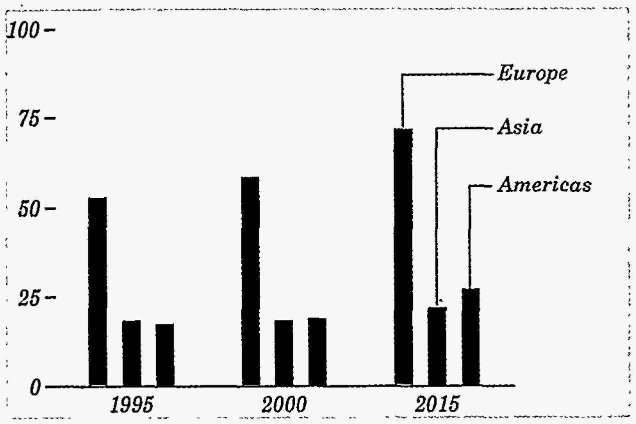
In the non-electricity sectors, an increase of 18 million tons in industrial steam coal consumption between 1995 and 2015 (1.1-percent annual growth) is offset by a decrease of 13 million tons in coking coal consumption (Figure 106). Increasing consumption of industrial steam coal results primarily from increased use of coal in the chemical and food-processing industries and from increased use of coal for cogeneration (the production of both electricity and usable heat for industrial processes).

The projected decline in domestic consumption of coking coal results from the displacement of raw steel production from integrated steel mills (which use coal coke for energy and as a material input) by increased production from minimills (which use electric arc furnaces that require no coal coke) and by increased imports of semi-finished steels. The amount of coke required per ton of pig iron produced is also declining, as process efficiency improves and injection of pulverized steam coal is used increasingly in blast furnaces. Domestic consumption of coking coal is projected to fall by 2.4 percent a year through 2015. Domestic production of coking coal declines slightly faster, as consumption of imported coking coal continues its historical slow increase.

While delivered energy consumption in the residential and commercial sectors grows by 0.8 percent and 0.9 percent a year, respectively, most of the growth is captured by electricity and natural gas. Coal consumption in these sectors remains constant, accounting for less than 1 percent of total U.S. coal demand.

U.S. Coal Exports to Europe, Asia, and the Americas Are Projected To Rise

Figure 107. U.S. coal exports by destination, 1995, 2000, and 2015 (million short tons)



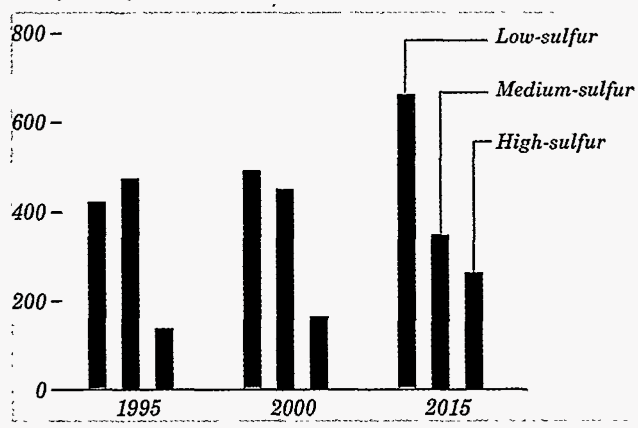
U.S. coal exports rise in the forecast from 89 million tons in 1995 to 121 million in 2015 (Figure 107), as a result of higher demand for steam coal imports in Europe. Exports of metallurgical coal remain flat between 1995 and 2015, at 52 million tons a year. Metallurgical exports to other regions do not increase significantly, since worldwide trade in metallurgical coal remains essentially unchanged.

U.S. steam coal exports to Europe increase from 23 million tons in 1995 to 47 million in 2015 (3.5-percent annual growth). Steam coal imports to Europe from all sources rise by 1.6 percent a year, from 120 million tons in 1995 to 166 million tons in 2015. Reduction of subsidies for European coal producers fosters more imports, but environmental considerations restrain growth in electricity sector coal demand and, consequently, steam coal imports.

U.S. coal exports to Asia increase by 0.9 percent a year, from 18 million tons in 1995 to 22 million tons in 2015, with metallurgical exports decreasing by 0.4 percent and steam coal exports rising by 2.3 percent annually. Coal imports to Asia from all sources rise in the forecast by 2.3 percent a year, from 248 million tons in 1995 to 394 million tons in 2015. The increase is made up mostly of steam coal exports, which increase by 3.6 percent a year as Pacific Rim nations without indigenous fossil resources base electricity generation on imported coal. Most of the growth in Asian imports is projected to be supplied by Australia, South Africa, and Indonesia.

Clean Air Standards Promote Low-Sulfur Coal Use for Electricity

Figure 108. Coal distribution by sulfur content, 1995, 2000, and 2015 (million short tons)



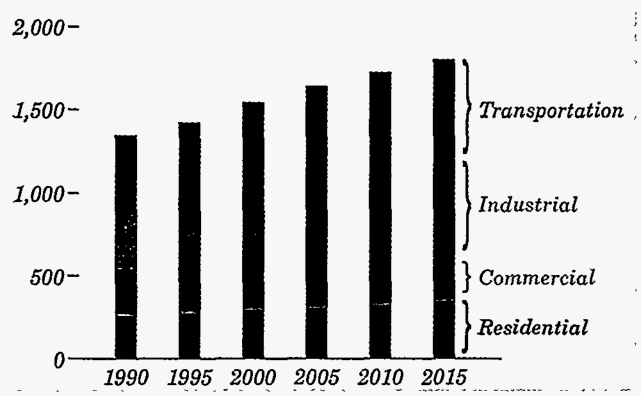
Phase 1 of the Clean Air Act Amendments of 1990, which began in 1995, requires that 261 coal-fired generators reduce their emissions to about 2.5 pounds of sulfur dioxide per million Btu of fuel input. Beginning on January 1, 2000, Phase 2 imposes a permanent cap on sulfur dioxide emissions, at an average level of 1.2 pounds per million Btu of heat input for all units built before 1990.

Generators have five options for bringing coal-fired units into compliance: (1) retrofitting with flue gas desulfurization equipment, (2) boiler repowering with new technologies that emit less sulfur dioxide, (3) transfer or purchase of emissions allowances, (4) reduction of plant utilization, and (5) full or partial switching to lower sulfur fuels. Between 1995 and 2015, compliance strategies for Phases 1 and 2 are projected to reduce the composite sulfur content of all coal produced (Figure 108). While low-sulfur coal displaces high-sulfur coal throughout the forecast, high-sulfur coal displaces more expensive medium-sulfur coal as compliance strategies shift from fuel switching to flue gas desulfurization in Phase 2.

A decision to regulate air toxic emissions could require utilities to install equipment for removing them from combustion gases. On the supply side, such regulation might result in interregional switching to coals with lower levels of toxic trace elements. Either approach is likely to encourage more intensive coal preparation to reduce the content of several air toxic elements associated with sulfide minerals in coal ash.

Continued Increase Is Projected for Overall U.S. Carbon Emissions

Figure 109. Carbon emissions by sector, 1990-2015 (million metric tons per year)



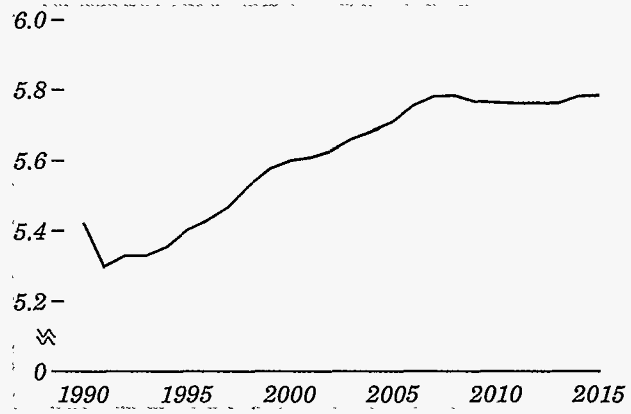
Carbon emissions from energy use are projected to increase by an average of 1.2 percent a year from 1995 to 2015, reaching 1,799 million metric tons (Figure 109). This is slightly higher than the *AEO96* projection, due to higher energy consumption and a reduced share of renewable fuels in the projections.

Increasing concentrations of greenhouse gases—carbon dioxide, methane, nitrous oxide, and others—may increase the Earth's temperature and, in turn, affect the climate. The *AEO97* projections include analysis of the Climate Change Action Plan (CCAP), developed by the Clinton Administration to stabilize U.S. greenhouse gas emissions by 2000 at 1990 levels. Emissions from fuel combustion, the primary source of carbon emissions, were about 1,340 million metric tons in 1990. The analysis includes only fuel combustion and does not account for sinks that absorb carbon. The analysis does not include the 13 CCAP actions that are not related to energy fuels, nor does it include any future mitigation actions that may be proposed.

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

Slower Rise in Per Capita Emissions Fails To Offset Population Growth

Figure 110. Carbon emissions per capita, 1990-2015 (metric tons per person)



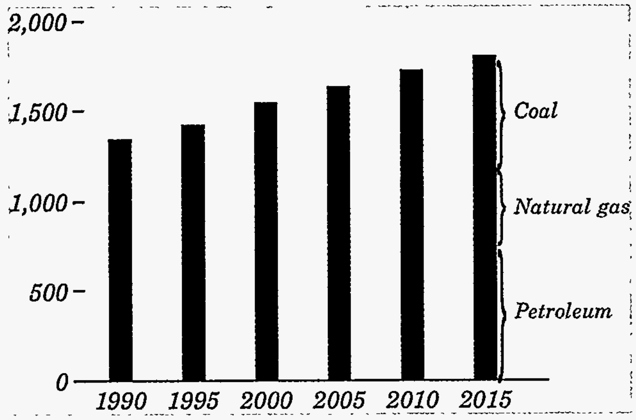
U.S. carbon emissions from energy use are projected to grow at an average annual rate of 1.2 percent; however, per capita emissions grow by only 0.3 percent a year (Figure 110). To achieve stabilization of total emissions, population growth would need to be offset by reductions in per capita emissions.

Emissions in the residential sector, including emissions from the generation of electricity used in the sector, are projected to increase by 1.2 percent a year, reflecting the ongoing trends of electrification and penetration of new appliances and services. Significant growth in office equipment and other uses is also projected in the commercial sector, but growth in consumption—and in emissions, which increase by 1.0 percent a year—is likely to be moderated by slow growth in floorspace, coupled with efficiency standards, voluntary efficiency programs, and technology improvements. Transportation emissions grow at an average annual rate of 1.4 percent as a result of increases in vehicle-miles traveled and air travel, combined with slow growth in the average light-duty fleet efficiency. Industrial emissions are projected to grow by only 1.0 percent a year, as shifts to less energy-intensive industries and efficiency gains moderate growth in energy use.

Further reductions in emissions could result from Climate Wise and Climate Challenge, voluntary programs for emissions reductions by industry and electric utilities, which are cosponsored by the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy.

Petroleum, Coal Are the Leading Energy Sources of Carbon Emissions

Figure 111. Carbon emissions by fuel, 1990-2015 (million metric tons per year)



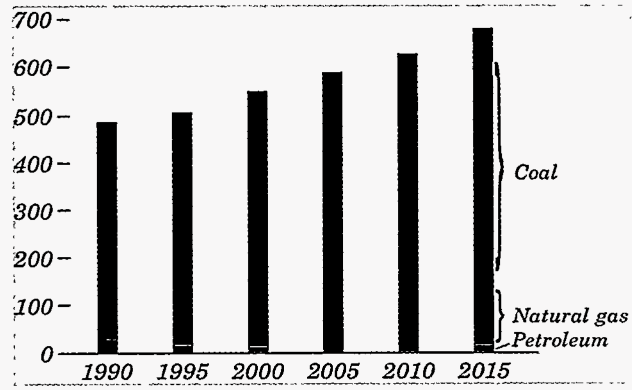
Petroleum products are the leading source of carbon emissions from energy use. In 2015, petroleum is projected to contribute 747 million metric tons of carbon to the total 1,799 million tons, a 42-percent share (Figure 111). Nearly 80 percent (587 million metric tons) of the petroleum emissions result 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 607 million metric tons in 2015, or 34 percent of the total. The share declines from 36 percent in 1995 because coal consumption increases at a slower rate through 2015 than consumption of petroleum and natural gas, the sources of virtually all other energy-related carbon emissions. Most of the increases in coal emissions result from electricity generation. A slight increase in emissions from industrial steam coal use is offset by a decline in emissions from coking coal.

In 2015, natural gas use is projected to produce 444 million metric tons of carbon emissions, a 25-percent share. Of the fossil fuels, natural gas consumption and emissions increase most rapidly through 2015, at an average annual rate of 1.7 percent. However, natural gas produces only about half the carbon emissions of coal per unit of input. Average emissions from petroleum use are between those for coal and natural gas. The use of renewable fuels and nuclear generation, which emit little or no carbon, mitigates the growth of emissions.

Coal Is the Main Source of Carbon Emissions from Electricity Generation

Figure 112. Carbon emissions from electricity generation by fuel, 1990-2015 (million metric tons per year)



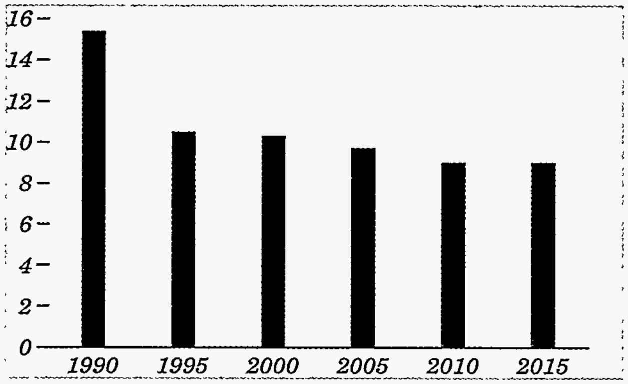
Electricity use is a major cause of carbon emissions. Although electricity produces no emissions at the point of use, its generation currently accounts for 36 percent of total carbon emissions, and that share is expected to increase to 38 percent in 2015. Coal, which accounts for about 50 percent of electricity generation in 2015 (excluding cogeneration), produces 80 percent of electricity-related carbon emissions (Figure 112). In 2015, gas-fired generation accounts for 29 percent of total electricity but only 18 percent of electricity-related carbon emissions.

Between 1995 and 2015, 38 gigawatts of nuclear capacity are expected to be retired, resulting in a 33-percent decline in nuclear generation. To compensate for the loss of baseload capacity and meet rising demand, 294 gigawatts of new fossil-fueled capacity (excluding cogeneration) will be needed. Increased generation from fossil fuels will raise carbon emissions by 172 million metric tons, or 34 percent, from 1995 levels. Although the use of renewable technologies grows, their intermittent nature prevents them from compensating completely for the losses in baseload nuclear capacity.

The projections include activities under the Climate Challenge program, such as fuel switching, repowering, life extension, and demand-side management, to the extent that such plans have been announced, but they do not include offset activities. Additional use of lower carbon fuels, reduced electricity demand growth, or improved technologies all could contribute to lower emissions than are projected here.

Cap on Electricity Sulfur Dioxide Emissions Is Expected To Be Met

Figure 113. Sulfur dioxide emissions from electricity generation, 1990-2015 (million tons per year)



CAAA90 calls for emissions of sulfur dioxide (SO_2) by electricity generators to be reduced to 12 million short tons in 1995 and to 8.9 million tons a year in 2000 and thereafter. More than 95 percent of the SO_2 produced by generators results from coal combustion, with the rest from residual oil.

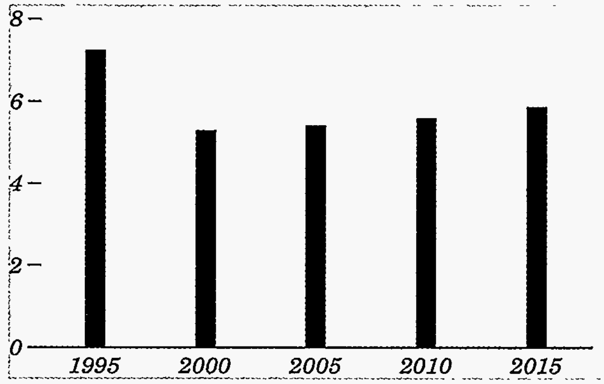
In Phase 1, 261 generating units at 110 plants were issued tradeable emissions allowances permitting SO_2 emissions to reach a fixed amount per year—generally less than the plant's historical emissions. Allowances may also be banked for use in future years. Switching to lower sulfur, subbituminous coal was the option chosen by more than half of the generators. In Phase 2, beginning in 2000, emissions constraints on Phase 1 plants will be tightened, and limits will be set for the remaining 2,500 boilers at 1,000 plants. With allowance banking, emissions are expected to decline from 10.5 million tons in 1995 to 10.3 million in 2000 (Figure 113). Since allowance prices are projected to increase after 2000, it is expected that 23 gigawatts of capacity—about 77 300-megawatt plants—will be retrofitted with scrubbers to achieve the Phase 2 goal (Table 12).

Table 12. Scrubber retrofits, allowance costs, and banked allowances, 2000-2015

Forecast	*2000*	*2005*	*2010*	*2015*
Cumulative retrofits from 1995 (gigawatts of capacity)	*0*	*0*	*22.9*	*22.9*
Allowance costs (1995 dollars per ton SO_2)	*147*	*212*	*79*	*79*
Cumulative banked allowances (million tons SO_2)	*7.5*	*2.5*	*0*	*0*

Nitrogen Oxide Emissions Are Reduced by New Regulations

Figure 114. Nitrogen oxide emissions from electricity generation, 1995-2015 (million tons per year)



CAAA90 also directed the EPA to study and issue standards for nitrogen oxide (NO_x) emissions, which are precursors to acid rain and ground-level ozone. In response, EPA promulgated regulations that impose NO_x emissions limits on electricity generators, based on specific boiler technologies. Combined with other NO_x reduction programs, such as those for mobile sources, the goal of the regulations is to reduce NO_x emissions in 2000 by about 2 million tons from what they would otherwise have been. Under current regulations, NO_x emissions by electricity generators are projected to decline by 1.4 million tons between 1995 and 2015 (Figure 114).

There are two phases to the program to reduce NO_x emissions from coal-fired plants, which produce most of the NO_x from electricity generation. In Phase 1, between 1996 and 1999, NO_x emission limits are applied to dry-bottom wall-fired and tangentially-fired boilers, designated as Group 1 boilers, by using available control technologies. In Phase 2, which begins in 2000, the emissions limits on the Group 1 boilers will be lowered slightly. In addition, in Phase 2, limits will be set for Group 2 boilers, which are coal-fired boilers that use other technologies.

Additional mitigation strategies could include voluntary programs or an emissions allowance program similar to that for SO_2. Increased use of other fossil and renewable fuels for generation or technology advances that increase efficiency or produce less emissions could also reduce emissions from those projected here.

Forecast Comparisons

Three other organizations—Data Resources, Inc. (DRI), the WEFA Group (WEFA), and the Gas Research Institute (GRI)—also produce comprehensive energy projections with a time horizon similar to that of *AEO97*. The most recent projections from these organizations and others that concentrate on electricity, petroleum, natural gas, and international oil markets are compared to the *AEO97* projections in this section.

Economic Growth

Differences in long-run economic forecasts can be traced primarily to different views of the major supply-side determinants of growth: labor force and productivity change. Other forecasts are presented in Table 13. From an energy perspective, other forecasters also include different views of energy prices: typically, lower energy prices are assumed for the optimistic growth cases and higher energy prices for the pessimistic cases. For *AEO97*, reference case energy prices are used for both the high and low economic growth cases. The WEFA forecast shows the highest economic growth, including higher growth rates for both labor force participation and productivity. The *AEO97* long-run forecast of economic growth is higher than the *AEO96* forecast by 0.2 percent, when compared on a similar basis, with a projected annual growth rate for GDP of 1.9 percent from 1995 to 2015.

Table 13. Forecasts of economic growth, 1995-2015

Forecast	*Average annual percentage growth*		
	Real GDP	*Labor force*	*Productivity*
AEO97			
Low growth	1.4	0.7	0.7
Reference	1.9	1.0	0.9
High growth	2.4	1.2	1.2
DRI			
Low	1.4	0.7	0.7
Reference	1.9	1.0	0.9
High	2.4	1.2	1.2
WEFA			
Reference	2.2	1.2	1.3

In the 1996 *Economic Report of the President*, real GDP growth of 2.3 percent a year between 1995 and 2002 was projected. *AEO97* projects annual growth of 2.2 percent over the same period.

World Oil Prices

Comparisons with other oil price forecasts—including the International Energy Agency (IEA), Petroleum Economics Ltd. (PEL), and Petroleum Industry Research Associates, Inc. (PIRA)—are shown in Table 14. The range between the *AEO97* low and high world oil price cases for 2010 and 2015 spans the range of other published forecasts, and the *AEO97* reference case prices are near the middle of the range for all the forecasts.

Table 14. Forecasts of world oil prices, 1995-2015

Forecast	*1995 dollars per barrel*				
	1995	*2000*	*2005*	*2010*	*2015*
AEO97 reference	17.26	18.20	19.72	20.41	20.98
AEO97 high price	17.26	21.69	24.13	26.44	28.23
AEO97 low price	17.26	14.08	14.08	14.03	13.99
DRI	16.80	16.07	18.60	20.96	22.64
DRI low	16.80	16.07	16.07	16.07	16.07
IEA1	17.00	17.72	25.53	25.53	NA
IEA2	17.00	17.72	17.36	17.36	NA
PEL	16.75	17.00	20.00	20.00	NA
PIRA	18.40	15.97	15.66	NA	NA
WEFA	17.23	17.96	19.91	22.04	24.14
GRI	17.24	16.68	16.68	16.68	16.68

NA = not available.

Total Energy Consumption

The *AEO97* forecast of end-use sector energy consumption over the next two decades shows far less volatility than has occurred historically. Between 1974 and 1984, volatile world oil markets dampened domestic oil consumption. Consumers switched to electricity-based technologies in the buildings sector, while in the transportation sector new car fuel efficiency nearly doubled. Natural gas use declined as a result of high prices and limitations on new gas hookups. Between 1984 and 1995, however, both petroleum and natural gas consumption rebounded, bolstered by plentiful supplies and declining real energy prices. As a consequence, new car fuel efficiency in 1995 was less than 2 miles per gallon higher than in 1984, and natural gas use (residential, commercial, and industrial) was almost 25 percent higher than it was in 1984.

Given potentially different assumptions about, for example, technological developments over the next 20 years, the forecasts from DRI, GRI, and WEFA have remarkable similarities to those in *AEO97*. Electricity is expected to remain the fastest growing source of delivered energy (Table 15), although its rate of growth is down sharply from historical rates in each of the forecasts, because many traditional

Table 15. Forecasts of average annual growth rates for energy consumption (percent)

Energy use	History 1974-1984	History 1984-1995	Projections AEO97 (1995-2015)	DRI (1995-2015)	GRI (1995-2015)	WEFA (1995-2013)
Petroleum*	-0.1	1.2	1.1	1.0	1.1	1.0
Natural gas*	-1.7	1.9	0.9	0.9	1.3	0.4
Coal*	-3.0	-1.4	0.3	0.9	-0.1	0.0
Electricity	3.0	2.5	1.5	1.4	1.8	1.8
Delivered energy	-0.4	2.0	1.1	1.0	1.2	0.9
Electricity losses	2.5	1.5	0.7	1.0	1.3	1.2
Primary energy	0.2	1.8	1.0	1.0	1.2	1.0

*Excludes consumption by electric utilities.

uses of electricity (such as for air conditioning) approach saturation while average equipment efficiencies rise. Growth in petroleum and natural gas consumption also generally slows as overall population growth declines, the population ages, and economic expansion slows.

Residential and Commercial Sectors

Growth rates in energy demand for the residential and commercial sectors are expected to decrease by more than 50 percent from the rates between 1984 and 1995, 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 in the residential sector and personal computers in the commercial sector, where they are already being used extensively.

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 16). Natural gas use also grows but at lower rates, and petroleum use continues to fall.

Industrial Sector

In all the forecasts, the industrial sector shows slower growth in primary energy consumption than it did between 1984 and 1995 (Table 17). The decline is attributable to lower growth for GDP and manufacturing output. In addition, there has been

Table 16. Forecasts of average annual growth in residential and commercial energy demand (percent)

Forecast	History 1984-1995	Projections AEO97 (1995-2015)	DRI (1995-2015)	GRI (1995-2015)	WEFA (1995-2013)
Residential					
Petroleum	-0.1	-0.3	-1.0	-1.0	-0.3
Natural gas	0.6	0.7	0.6	0.7	0.0
Electricity	2.7	1.6	0.9	1.7	2.0
Delivered energy	1.7	0.8	0.5	0.7	0.7
Electricity losses	2.2	0.8	0.5	1.1	1.2
Primary energy	1.9	0.8	0.5	0.9	1.0
Commercial					
Petroleum	-5.1	-0.7	-1.5	-1.7	-0.5
Natural gas	1.8	0.7	0.9	0.9	0.3
Electricity	3.3	1.3	1.5	1.9	1.7
Delivered energy	1.3	0.9	1.0	1.1	0.9
Electricity losses	2.8	0.5	1.1	1.3	1.1
Primary energy	2.1	0.7	1.1	1.2	1.0

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 1995 reflect a shift from petroleum products and coal to a greater reliance on natural gas and electricity. Natural gas use grows more slowly than in recent history across the forecasts, because much of the potential for fuel switching was realized during the 1980s. A key uncertainty in industrial coal forecasts is the environmental acceptability of coal as a boiler fuel.

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

Forecast	History 1984-1995	Projections AEO97 (1995-2015)	DRI (1995-2015)	GRI (1995-2015)	WEFA (1995-2013)
Petroleum	0.7	0.9	1.2	1.3	0.7
Natural gas	2.7	0.9	0.9	1.5	0.4
Coal	-1.2	0.3	1.0	0.0	0.0
Electricity	1.7	1.5	1.8	2.0	1.6
Delivered energy	2.3	1.0	1.1	1.3	0.7
Electricity losses	0.7	0.7	1.3	1.4	1.0
Primary energy	2.0	0.9	1.1	1.4	0.8

Transportation Sector

Overall fuel consumption in the transportation sector is expected to grow more slowly than in the recent past in each of the alternative forecasts (Table 18). All the forecasts anticipate continued rapid growth in air travel as well as significant increases in aircraft efficiency, while growth in light-duty vehicle travel slows considerably.

Table 18. Forecasts of average annual growth in transportation energy demand (percent)

Forecast	History 1975-1984	1984-1995	Projections AEO97 (1995-2015)	DRI (1995-2015)	GRI (1995-2015)	WEFA (1995-2013)
Consumption						
Motor gasoline	0.1	1.4	0.8	0.6	0.6	0.8
Diesel fuel	4.5	3.1	1.5	1.5	1.7	1.9
Jet fuel	1.9	2.4	2.3	1.7	2.1	1.5
Residual fuel	1.4	2.7	2.5	2.7	2.6	2.2
All energy	0.9	1.9	1.4	1.2	1.3	1.2
Key indicators						
Car and light truck travel	2.8	3.1	1.4	1.6	1.5	NA
Air travel (revenue passenger-miles)	7.0	5.6	3.2	4.1	3.1	NA
Average new car fuel efficiency	4.5	0.4	0.9	0.6	0.8	NA
Gasoline prices	1.8	-3.1	0.1	0.7	0.2	0.8

NA = not available.

Electricity

Comparison across forecasts shows considerable variation in projected electricity sales (Table 19). Sales projections for 2015 range from 1,256 billion kilowatthours (DRI) to 1,489 billion kilowatthours (WEFA) for the residential sector, as compared with the *AEO97* reference case value of 1,421 billion kilowatthours. The forecasts for total electricity sales in 2015 range from 3,989 billion kilowatthours (DRI) to 4,342 billion kilowatthours (GRI), compared with 4,044 billion kilowatthours in the *AEO97* reference case. Different assumptions governing expected economic activity, coupled with diversity in the estimation of penetration rates of energy-efficient technologies, are the primary reasons for variation among the forecasts.

With the exception of WEFA, 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 2015.

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. *AEO97* assumes that competitive pressures and FERC Orders 888 and 889 will push average costs and prices down somewhat, but not to the extent that would be achieved under a full restructuring of the industry. *AEO97* assumes that increased competition in the electric power industry will lead to lower operating and maintenance costs, lower general and administrative costs, lower fossil fuel prices, 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 *AEO97* mix of capacity among fuels is similar to those in the other forecasts, small differences in sectoral demands across the forecasts lead to significant changes in capacity mix. For example, growth in the residential sector, coupled with an oversupply of baseload capacity, results in a need for more peaking and intermediate capacity than baseload capacity. Consequently, generators are expected to plan for more combustion turbine and fuel cell technology than coal, oil, or gas steam capacity. With a higher projection of residential demand growth than in most of the other forecasts, *AEO97* projects more oil and gas capacity in 2015.

Natural Gas

The diversity among published forecasts of natural gas prices, production, consumption, and imports (Table 20) indicates the uncertainty of future market trends. The underlying assumptions that shape the forecasts should be considered when different projections are compared. The forecasts for total natural gas consumption in 2015 vary from a high of 31.95 trillion cubic feet in the *AEO97* high economic growth case to a low of 28.0 trillion cubic feet in the DRI forecast.

Both GRI and the American Gas Association (AGA) show a flat price forecast between 2010 and 2015, whereas the *AEO97* reference case shows a slight rise during the same period, from $2.01 per thousand cubic feet in 2010 to $2.13 per thousand cubic feet in 2015.

Table 19. Comparison of electricity forecasts (billion kilowatthours, except where noted)

Projection	AEO97			Other forecasts		
	Reference	Low economic growth	High economic growth	WEFA[a]	GRI	DRI
2010						
Average end-use price (1995 cents per kilowatthour)	6.40	6.20	6.60	7.30	5.58	5.30
Residential	7.80	7.50	8.00	8.50	6.75	6.60
Commercial	7.20	6.80	7.40	8.00	6.26	5.70
Industrial	4.50	4.30	4.60	5.20	3.91	3.90
Net energy for load	4,066	3,879	4,309	4,183	4,417	4,274
Coal	1,942	1,881	2,058	2,156	2,248	2,073
Oil	58	56	60	89	53	66
Natural gas	892	775	1,008	496	538	487
Nuclear	614	614	614	656	645	659
Hydroelectric/other[b]	368	364	375	269	305	306
Nonutility sales to grid[c]	161	158	164	491	548	653
Net imports	31	31	31	27	80	31
Electricity sales	3,784	3,611	4,011	3,913	4,073	3,777
Residential	1,307	1,251	1,366	1,401	1,351	1,194
Commercial/other[d]	1,188	1,181	1,235	1,232	1,291	1,206
Industrial	1,289	1,181	1,409	1,280	1,432	1,377
Capability (gigawatts)[e]	921.7	883.6	968.8	994.0	940.4	903.0
Coal	313.3	307.4	327.0	443.9	364.0	351.8
Oil and gas	394.8	363.5	425.9	333.2	346.5	329.0
Nuclear	88.9	88.9	88.9	99.1	101.6	105.3
Hydroelectric/other[b]	124.8	123.7	127.2	117.8	128.3	116.8
2015						
Average end-use price (1995 cents per kilowatthour)	6.30	6.00	6.50	7.30	5.40	5.30
Residential	7.60	7.20	7.80	8.60	6.56	6.60
Commercial	6.90	6.50	7.20	8.10	5.99	5.60
Industrial	4.30	4.00	4.50	5.30	3.27	3.90
Net energy for load	4,329	4,060	4,677	4,418	4,705	4,511
Coal	2,052	1,948	2,287	2,339	2,474	2,269
Oil	64	59	73	86	64	79
Natural gas	1,184	1,042	1,267	473	599	539
Nuclear	448	448	448	656	431	444
Hydroelectric/other[b]	391	377	407	269	313	307
Nonutility sales to grid[c]	163	159	168	569	744	841
Net imports	27	27	27	27	79	32
Electricity sales	4,044	3,793	4,371	4,132	4,342	3,989
Residential	1,421	1,339	1,504	1,489	1,448	1,256
Commercial/other[d]	1,269	1,256	1,340	1,299	1,395	1,307
Industrial	1,354	1,198	1,527	1,344	1,499	1,426
Capability (gigawatts)[e]	969.6	914.8	1,038.3	1,056.3	970.9	938.0
Coal	324.9	312.9	359.1	506.6	410.1	388.4
Oil and gas	452.6	412.1	482.6	332.8	356.9	361.1
Nuclear	62.7	62.7	62.7	99.1	69.1	72.3
Hydroelectric/other[b]	129.4	127.0	133.9	117.8	134.3	116.3

[a]WEFA forecasts for 2013 are shown here for the year 2015.

[b]"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.

[c]For *AEO97*, includes only net sales from cogeneration; for the other forecasts, also includes nonutility sales to the grid.

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

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

Sources: **AEO97:** AEO97 National Energy Modeling System, runs AEO97B.D100296K (reference case), LMAC97.D100396A (low economic growth case), and HMAC97.D100296A (high economic growth case). **WEFA:** The WEFA Group, *U.S. Energy Report* (Spring-Summer 1996). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1997 Edition (August 1996). **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook, Spring-Summer 1996* (April 1996).

Table 20. Comparison of natural gas forecasts (trillion cubic feet, except where noted)

Projection	AEO97			Other forecasts			
	Reference	Low economic growth	High economic growth	WEFA	GRI	DRI	AGA
			2010				
Lower 48 wellhead price (1995 dollars per thousand cubic feet)	2.01	1.81	2.23	2.43	1.65	2.22	2.10[a]
Dry gas production	24.25	22.75	26.00	21.68	24.15	23.39	23.01
Net imports	3.92	3.92	3.92	3.81	3.59	3.65	3.75
Consumption	28.01	26.52	29.75	25.58	28.03	26.69	26.76
Residential	5.42	5.22	5.62	4.75	5.33	5.27	6.07
Commercial	3.44	3.41	3.56	3.18	3.49[b]	3.44	3.50
Industrial[b]	9.56	9.14	10.02	9.76	12.12[c]	10.71	9.95
Electricity generators	6.94	6.23	7.72	4.96	5.72	4.50	4.97
Other	2.65[c]	2.52[c]	2.83[c]	2.52[c]	1.36	2.76[c]	2.27[c]
End-use prices (1995 dollars per thousand cubic feet)							
Residential	5.43	5.25	5.62	6.97	5.52	6.66	5.71
Commercial	4.64	4.42	4.86	5.87	4.56[b]	5.54	4.78
Industrial[b]	2.69	2.46	2.93	3.76	2.32	3.47[d]	2.42
Electricity generators	2.38	2.17	2.62	2.74	2.03	2.62	2.33
Transportation	6.93	6.71	7.17	NA	NA	NA	NA
			2015				
Lower 48 wellhead price (1995 dollars per thousand cubic feet)	2.13	1.83	2.49	NA	1.65	2.38	2.10[a]
Dry gas production	26.10	24.29	27.89	NA	26.48	24.54	24.39
Net imports	4.23	4.23	4.23	NA	3.49	3.82	3.75
Consumption	30.16	28.35	31.95	NA	30.16	28.00	28.14
Residential	5.57	5.31	5.83	NA	5.53[b]	5.48	6.29
Commercial	3.55	3.51	3.73	NA	3.69[b]	3.55	3.51
Industrial[b]	9.65	9.10	10.23	NA	13.00[c]	11.29	9.73
Electricity generators	8.52	7.74	9.11	NA	6.40	4.60	6.09
Other	2.86[c]	2.69[c]	3.05[c]	NA	1.55	3.08[c]	2.50[c]
End-use prices (1995 dollars per thousand cubic feet)							
Residential	5.33	5.05	5.64	NA	5.36	6.72	5.54
Commercial	4.61	4.27	4.95	NA	4.45[b]	5.62	4.70
Industrial[b]	2.82	2.48	3.20	NA	2.31	3.62[d]	2.39
Electricity generators	2.52	2.19	2.88	NA	2.01	2.76	2.28
Transportation	7.27	6.95	7.63	NA	NA	NA	NA

[a]Average acquisition price.
[b]includes gas consumed in cogeneration.
[c]Includes lease and plant fuels.
[d]On-system sales.
NA.= Not available.

Sources: **AEO97:** AEO97 National Energy Modeling System, runs AEO97B.D100296K (reference case), LMAC97.D100396A (low economic growth case), and HMAC97.D100296A (high economic growth case). **WEFA:** The WEFA Group, *U.S. Energy Report* (Spring-Summer 1996). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1997 Edition (August 1996). **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook, Spring-Summer 1996* (April 1996). **AGA:** American Gas Association, *1996 AGA-TERA Base Case* (August 1996).

Petroleum

The *AEO97* high and low world oil price cases bound the 2010 and 2015 results of five other petroleum forecasts (Table 21)—the *AEO97* reference case, WEFA, GRI, DRI, and Independent Petroleum Association of America (IPAA). The *AEO97* high price case has the highest oil prices and domestic production in 2015 and the third lowest petroleum demand of the seven forecasts. Conversely, the *AEO97* low price case has the lowest oil prices and production and the highest demand.

The percentage of petroleum consumption from imports, which is an indicator of the relative direction of production, net imports, and consumption, ranges between 53 percent in the high price case and 67 percent in the low price case in 2010. The range is between 51 percent and 68 percent for the high and low oil price cases in 2015.

The *AEO97* reference case for petroleum is most similar to the DRI projections. The *AEO97* reference case projection shows the percentage of U.S. consumption from imports at 60 percent in 2010 and 61 percent in 2015, compared with 58 percent and 60 percent, respectively, in the DRI forecast. WEFA, which projects lower petroleum demand, shows 62 percent of consumption supplied by imports in 2010. The WEFA forecast does not extend to 2015.

Other than the *AEO97* high price case, GRI and IPAA project the lowest percentage of imports, with projections of 57 percent and 56 percent, respectively, for 2010 and, in the GRI projections, 55 percent for 2015. The IPAA forecast ends in 2010. Distinguishing factors of the GRI forecasts are oil prices lower than those in all but the *AEO97* low oil price case and domestic production higher than in all but the *AEO97* high price case. The import shares in the IPAA forecast are the result of relatively low petroleum consumption—similar to that in the *AEO97* high price case—coupled with domestic production in the range of the *AEO97* reference case and DRI.

Coal

GRI, DRI, and WEFA project coal production in 2010 at levels more comparable with that in the *AEO97* high growth case than that in the reference case, primarily due to higher forecasts of electricity sector coal consumption after 2000. In the GRI forecast, the delivered price to electric utilities is $0.01 per million Btu lower than that in the *AEO97* high growth case, while consumption is projected to be 23 million tons higher. However, in the DRI forecast, the delivered price to electric utilities is $0.10 per million Btu lower than in the *AEO97* high growth case, although electricity coal consumption, when adjusted to include 9 million tons consumed by independent power producers, is 7 million tons lower than in the *AEO97* high growth case. In the WEFA forecast for 2010, electricity consumption is 111 million tons higher than in the *AEO97* high growth case due to projected consumption by nonutility generators of 98 million tons. WEFA's delivered price to the electricity sector is $0.19 per million Btu higher than the price in any other forecast.

All the other forecasts include lower projections of net coal exports in 2010 and higher forecasts of domestic coking coal consumption due to less rapid retirement of existing coke oven capacity. The three *AEO97* cases nearly bracket the other projected levels of industrial/other coal consumption in the other forecasts (after adjusting the DRI forecast downward to exclude the consumption of independent power producers).

DRI reports 2015 values with approximately the same relative differences from the *AEO97* high growth case forecast as in 2010. DRI's total production is slightly higher due to higher electricity consumption (again, after transferring 64 million tons of independent power producer consumption from the industrial/ other category), slightly higher coking coal and industrial/other consumption and lower net exports. DRI's projected cost of coal delivered to electric utilities in 2015 is $0.09 per million Btu lower than the cost in the *AEO97* high growth case.

The WEFA forecast extends to 2013. Its production and consumption projections for 2013 are higher than those in all the *AEO97* cases and in the DRI forecast for 2015, with two exceptions: (1) net coal exports total only 88 million tons (less than the 1995 historical level), and (2) industrial consumption is only 84 million tons, comparable with consumption in the *AEO97* low growth case. The higher production and consumption values are due to combined utility and nonutility electricity consumption of 1,289 million tons. The delivered coal price to the electricity generation sector is $0.27 to $0.34 per million Btu higher than that in the *AEO97* cases and $0.36 per million Btu higher than that in the DRI forecast for 2015.

The GRI forecast for 2015 projects production similar to the DRI forecast, but is based on higher consumption by the electricity generation sector and lower consumption by industry, combined with the lowest projection for net exports. The GRI delivered price to the electricity sector is between the WEFA and DRI projections and slightly lower than the *AEO97* values. The minemouth prices reported by GRI are for coal delivered to electric utilities.

Table 21. Comparison of petroleum forecasts (million barrels per day, except where noted)

Projection	AEO97			Other forecasts			
	Reference	Low world oil price	High world oil price	WEFA	GRI	DRI	IPAA
2010							
World oil price (1995 dollars per barrel)	20.41	14.03	26.44	22.04	16.50[a]	20.95	NA
Crude oil and NGL production	7.67	6.28	8.87	6.51	8.25	7.52	7.58
Crude oil	5.39	4.07	6.53	4.69	6.41	5.57[b]	5.54
Natural gas liquids	2.28	2.21	2.34	1.82	1.84	1.95	2.04
Total net imports	12.90	15.18	11.01	12.82	11.78	12.41	11.83
Petroleum demand	21.60	22.55	20.96	20.73	20.82	21.28	21.02
Motor gasoline	9.17	9.36	9.03	8.73	7.77	9.00	8.99
Jet fuel	2.25	2.28	2.23	1.91	2.05	1.97	1.98
Distillate fuel	3.99	4.05	3.97	4.07	3.89	3.86	3.95
Residual fuel	1.11	1.48	1.02	1.09	1.64	1.02	1.15
Other	5.07	5.37	4.72	4.93	5.49	5.44	4.94
Import share of product supplied (percent)	60	67	53	62	57	58	56
2015							
World oil price (1995 dollars per barrel)	20.98	13.99	28.23	NA	16.50[a]	22.63	NA
Crude oil and NGL production	7.67	6.33	9.41	NA	8.87	7.47	NA
Crude oil	5.23	3.97	6.89	NA	7.08	5.44[b]	NA
Natural gas liquids	2.44	2.36	2.52	NA	1.79	2.03	NA
Total net imports	13.46	15.94	10.83	NA	11.93	13.07	NA
Petroleum demand	22.12	23.28	21.30	NA	21.53	21.95	NA
Motor gasoline	9.19	9.42	9.00	NA	7.62	8.93	NA
Jet fuel	2.39	2.42	2.36	NA	2.20	2.12	NA
Distillate fuel	4.12	4.21	4.10	NA	4.14	4.14	NA
Residual fuel	1.20	1.64	1.07	NA	1.73	0.99	NA
Other	5.21	5.59	4.78	NA	5.84	5.77	NA
Import share of product supplied (percent)	61	68	51	NA	55	60	NA

[a]Composite of U.S. refiners' acquisition cost.
[b]Includes shale and other.
NA = Not available.
Sources: **AEO97:** AEO97 National Energy Modeling System, runs AEO97B.D100296K (reference case), LWOP97.D100696A (low world oil price case), and HWOP97.D100296B (high world oil price case). **WEFA:** The WEFA Group, *U.S. Energy Report* (Spring-Summer 1996). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1997 Edition (August 1996). **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook, Spring-Summer 1996* (April 1996). **IPAA:** Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Run Report* (April 1996).

Table 22. Comparison of coal forecasts (million short tons, except where noted)

Projection	AEO97			Other forecasts		
	Reference	Low economic growth	High economic growth	WEFA[a]	GRI	DRI
			2010			
Production	1,201	1,161	1,275	1,351	1,262	1,267
Consumption by sector						
Electricity generation[b]	983	953	1,046	1,157	1,069	1,039
Coking plants	23	23	23	32	30	26
Industrial/other	93	84	103	84	98	111
Total	1,099	1,060	1,172	1,273	1,197	1,177
Net coal exports	103	103	103	84	61	89
Minemouth price						
(1995 dollars per short ton)	16.92	16.80	16.64	18.20	NA	NA
(1995 dollars per million Btu)	0.81	0.80	0.80	0.84	0.63	NA
Average delivered price, electricity						
(1995 dollars per short ton)	24.23	23.89	24.19	NA	NA	22.65
(1995 dollars per million Btu)	1.20	1.18	1.20	1.39	1.17	1.10
			2015			
Production	1,268	1,197	1,399	1,484	1,415	1,412
Consumption by sector						
Electricity generation[b]	1,039	987	1,155	1,289	1,218	1,177
Coking plants	20	20	20	32	29	24
Industrial/other	97	84	112	84	97	114
Total	1,156	1,091	1,288	1,405	1,354	1,315
Net coal exports	112	112	112	88	62	95
Minemouth price						
(1995 dollars per short ton)	15.46	15.32	15.90	18.34	NA	NA
(1995 dollars per million Btu)	0.74	0.73	0.77	0.85	0.62	NA
Average delivered price, electricity						
(1995 dollars per short ton)	22.47	21.92	23.08	NA	NA	21.76
(1995 dollars per million Btu)	1.11	1.08	1.15	1.42	1.13	1.06

[a]WEFA forecasts for 2013 are shown here for the year 2015.

[b]The DRI forecast for electricity generation has been adjusted to include coal consumed by independent power producers, reported by DRI under industrial/other: 9 million tons in 2010 and 64 million tons in 2015. The WEFA values for electricity coal consumption include nonutility generation consumption of 98 million tons in 2010 and 140 million tons in 2013 (reported under 2015).

NA = Not available.

Sources: **AEO97:** AEO97 National Energy Modeling System, runs AEO97B.D100296K (reference case), LMAC97.D100396A (low economic growth case), and HMAC97.D100296A (high economic growth case). **WEFA:** The WEFA Group, *U.S. Energy Report* (Spring-Summer 1996). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1997 Edition (August 1996). **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook, Spring-Summer 1996* (April 1996).

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List of Acronyms

AD	Associated-dissolved (natural gas)
AEO	*Annual Energy Outlook*
AEO96	*Annual Energy Outlook 1996*
AEO97	*Annual Energy Outlook 1997*
AFV	Alternative-fuel vehicle
AGA	American Gas Association
BPA	Bonneville Power Administration
Btu	British thermal unit
CAAA90	Clean Air Act Amendments of 1990
CCAP	Climate Change Action Plan
CNG	Compressed natural gas
CTC	Competitive transition charge
DOE	U.S. Department of Energy
DRI	Data Resources, Inc./McGraw Hill
EIA	Energy Information Administration
EIS	Environmental impact statement
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPACT	Energy Policy Act of 1992
EWG	Exempt wholesale generator
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
GDP	Gross domestic product
GRI	Gas Research Institute
IEA	International Energy Agency
IPAA	Independent Petroleum Association of America
IPP	Independent power producer
ISO	Independent system operator
LDC	Local distribution company
LEVP	Low Emissions Vehicle Program
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
M85	An 85-percent methanol fuel
MPUC	Massachusetts Public Utility Commission
MSW	Municipal solid waste
NA	Nonassociated (natural gas)
NAECA	National Appliance Energy Conservation Act of 1987
NEMS	National Energy Modeling System
NERA	National Economic Research Associates, Inc.
NERC	National Electric Reliability Council
NGL	Natural gas liquid
NOPR	Notice of Proposed Rulemaking
NRC	Natural Resources Canada
NWS	NatWest Securities, Ltd.
NYMEX	New York Mercantile Exchange
NYPSC	New York Public Service Commission
OTAG	Ozone Transport Assessment Group
PEL	Petroleum Economics, Ltd.
PEMEX	Petroleos Mexicano
PIRA	Petroleum Industry Research Associates, Inc.
PURPA	Public Utility Regulatory Policies Act of 1978
PV	Photovoltaic
QF	Qualifying facility
RFG	Reformulated gasoline
SPR	Strategic Petroleum Reserve
STEO	*Short-Term Energy Outlook*
WEFA	The WEFA Group (formerly the Wharton Econometric Forecasting Associates)

Text notes

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1. Energy Information Administration, *Voluntary Reporting of Greenhouse Gases 1995*, DOE/EIA-0608(95) (Washington, DC, July 1996).

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2. The 4.3-cents-per-gallon tax is in nominal terms.
3. Energy Information Administration, *Voluntary Reporting of Greenhouse Gases 1995*, DOE/EIA-0608(95) (Washington, DC, July 1996).

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4. Significant portions of the material in this discussion are taken from the EIA report *Natural Gas 1996: Issues and Trends*, DOE/EIA-0560(96), to be published in December 1996. The reader is referred to that report for more in-depth analysis of the issues discussed here.
5. Texas Eastern Transmission Corporation, FERC Docket No. CP95-218 (January 31, 1996).
6. Order 636, issued by the Federal Energy Regulatory Commission (FERC) on April 8, 1992, has transformed the interstate natural gas pipeline industry. Under Order 636, interstate pipeline companies were restructured and required to separate their merchant (sales of gas) and transportation functions. Although pipeline companies still can make gas sales, transportation is now their primary function. Oversight of gas sales and marketing activity by FERC has been reduced significantly, but gas sales by interstate pipeline companies and interstate transportation of natural gas remain subject to FERC jurisdiction.

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7. U.S. Environmental Protection Agency, Nitrogen Oxide Emission Reduction Program.

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8. Federal Energy Regulatory Commission, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Final Environmental Impact Statement, FERC/EIS-0096 (Washington, DC, April 1996).
9. Energy Information Administration, *An Analysis of FERC's Final Environmental Impact Statement for Electricity Open Access and Recovery of Stranded Costs*, SR/OIAF/96-03 (Washington, DC, September 1996).
10. Estimated from Energy Information Administration, Form EIA-782C, "Monthly Report of Prime Supplier Sales of Petroleum Products Sold for Local Consumption" (January-December 1995).

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11. Pursuant to telephone conversation with Mitchell Baer, Senior Regulatory Analyst, American Petroleum Institute (September 1996).
12. Senator Thomas Daschle, speech at the World Conference on Transportation Fuel Quality (Washington, DC, October 7, 1996).
13. Mary Dade, Chairman of the Ozone Transportation Assessment Group, speech at the World Conference on Transportation Fuel Quality (Washington, DC, October 8, 1996).

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14. For a detailed description of the factors influencing the emergence of a competitive electric power industry in the United States, see Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, in preparation.
15. Energy Information Administration, Office of Integrated Analysis and Forecasting, *Electricity Prices in a Competitive Environment: Determinants and Impacts*, in preparation.

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16. Federal Highway Administration, Office of Highway Information Management, *Nationwide Personal Transportation Survey: 1990 NPTS Databook* (Washington, DC, November 1993).

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17. The CAFE standard for cars has remained at 27.5 miles per gallon since 1990. The standard for light trucks is now 20.5 miles per gallon. The standard had been eased to 26.0 miles per gallon between 1985 and 1988 and 26.5 miles per gallon in 1989. See National Highway Traffic Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, September 1994).
18. U.S. Department of Energy, Office of Transportation Technologies, *Transportation Energy Data Book*, Edition 15 (Washington, DC, May 1995), pp. 2-52.

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19. U.S. Department of Commerce, Technology Administration, PNGV Secretariat, *Partnership for a New Generation of Vehicles Program Plan* (Washington, DC, November 1995).

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20. Since the publication of *AEO96*, the Bureau of Economic Analysis has revised the measurement of real GDP. Previously, GDP calculations were based on fixed-weighted measures of output and prices, and the base year was updated every 5 years. The weights used to calculate aggregate GDP from its components were the prices prevailing in the base year. Since all components of GDP do not grow at the same rate, a bias would occur in the aggregate rate, especially for years further from the base year. The "chain-weighted" measure now used captures yearly changes in the relative growth of the components of GDP. The following comparison illustrates the impact of the revised measure: using the old 1987 fixed-weight GDP

measure, *AEO97* has an average annual GDP growth rate of 2.3 percent from 1995 to 2010; however, using the 1992 chain-weighted measure yields an annual growth rate of 1.9 percent. See Bureau of Economic Analysis, "Preview of the Comprehensive Revision of the National Income and Product Accounts: BEA's New Featured Measures of Output and Prices," *Survey of Current Business* (July 1995), p. 31.

21. U.S. Department of Commerce, Bureau of the Census.

22. Only portions of the national economic statistics have been converted to 1992 chain-weighted dollars. Because the national input-output matrix for manufacturing industries, which underlies the projections in Figure 25, is still available only in 1987 fixed-weight dollars, the growth rates shown in the figure are based on 1987 fixed-weight dollars. The use of fixed-weight dollars is not expected to affect the picture of relative growth rates shown in the figure. Similarly, because only a limited set of historical data for GDP and related statistics are available, Figure 27 is based on fixed-weight dollars to give a longer historical perspective on the changes in GDP growth rates. The use of chain-weighted dollars would change the values in the figure slightly but would not affect the overall shape of the curve.

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23. DRI/McGraw-Hill, "Winter Long-Term Forecast," *Review of the U.S. Economy, February 1996*, (Lexington, MA, 1996).

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24. 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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25. Energy Information Administration, *International Energy Outlook 1996*, DOE/EIA-0484(96) (Washington, DC, May 1996).

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26. 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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27. 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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28. Commercial buildings and energy use data from Energy Information Administration, Form EIA-871A, "Commercial Buildings Energy Consumption Survey" (1992).

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29. 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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30. 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. Over the past decade, horsepower increases for passenger vehicles have outpaced those for commercial light-duty vehicles. This trend is expected to continue.

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31. For example, Corporate Average Fuel Economy (CAFE) standards for new vehicles are always met.

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32. Values for incremental investments are given in undiscounted real dollars.

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33. 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. *AEO97* does not examine the implications of geological resource uncertainty. The figures cited above are taken from U.S. Geological Survey, National Oil and Gas Resource Assessment Team, *1995 National Assessment of United States Oil and Gas Resources*, U.S. Geological Survey Circular 1118 (Washington, DC, 1995), p. 2. The cited numbers exclude natural gas liquids resources, for which the corresponding USGS estimates are 7.2, 5.8, and 8.9 billion barrels.

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34. Substantial uncertainty surrounds the ultimate use of North Slope gas. However, projected low gas prices in the lower 48 markets justify the *AEO97* perspective that does not consider it a significant factor affecting domestic energy markets, especially natural gas markets.

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35. 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.

36. 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.

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

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

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39. Historical data from Energy Information Administration, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996).

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40. Energy Information Administration, *Quarterly Coal Report*, October-December 1995, DOE/EIA-0121(95/4Q) (Washington, DC, May 1996).

Table notes

Note: Tables indicated as sources in these notes refer to the tables in Appendixes A, B, C, and F of this report.

Table 1. Summary of results for five cases (page 6): Tables A1, A8, A20, B1, B8, B20, C1, C8, and C20.

Table 2. NO_x emissions standards under the Clean Air Act Amendments of 1990 (page 11): U.S. Environmental Protection Agency, Nitrogen Oxide Emission Reduction Program.

Table 3. New car and light truck horsepower ratings and market shares, 1985, 1995, 2005, and 2015 (page 43): **1995:** U.S. Department of Transportation, National Highway Traffic Safety Administration, *Mid-Model Year Fuel Economy: Reports From Auto Manufacturers* (1995). **2005 and 2015:** AEO97 National Energy Modeling System, run AEO97B.D100296K.

Table 4. Market shares of alternative-fuel light-duty vehicles by technology type, 2015 (page 44): U.S. Department of Energy, Office of Policy, *Technical Report Fourteen: Market Potential and Impacts of Alternative Fuel Use in Light-Duty Vehicles: A 2000/2010 Analysis* (Draft, 1995). California Air Resources Board, "Proposed Regulations for Low-Emission Vehicles and Clean Fuels, Staff Report" (Sacramento, CA, August 13, 1990). U.S. Department of Commerce, Bureau of the Census, *Truck Inventory and Use Survey, 1992*, TC92-T-52 (Washington, DC, May 1995). Energy Information Administration, *Describing Current and Potential Markets for Alternative Fuel Vehicles*, DOE/EIA-0604 (Washington, DC, March 1996). Energy Information Administration, *Alternatives to Traditional Transportation Fuels 1994*, Vol. 1, DOE/EIA-0585(94)/1 (Washington, DC, February 1996). AEO97 National Energy Modeling System, run AEO97B.D100296K.

Table 5. Costs of producing electricity from new plants, 2000 and 2015 (page 51): AEO97 National Energy Modeling System, run AEO97B.D100296K.

Table 6. Economically recoverable oil and gas resources in 1990, measured under different technology assumptions (page 57): Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 7. Natural gas and crude oil drilling in three cases (page 58): AEO97 National Energy Modeling System, runs AEO97B.D100296K, LWOP96.D101995B, and HWOP97.D100296B.

Table 8. Transmission and distribution revenues and margins, 1970, 1985, 1995, and 2015 (page 61): **History:** Energy Information Administration, *Annual Energy Review 1994*, DOE/EIA-0384(94) (Washington, DC, July 1995). **Projections:** AEO97 National Energy Modeling System, run AEO97B.D100296K. End-use consumption is net of pipeline and lease and plant fuels.

Table 9. Components of residential and commercial natural gas end-use prices, 1985-2015 (page 61): **History:** Energy Information Administration, *Annual Energy Review 1987*, DOE/EIA-0384(87) (Washington, DC, July 1988); *Annual Energy Review 1994*, DOE/EIA-0384(94) (Washington, DC, July 1995); and *Natural Gas Monthly*, June 1995, DOE/EIA-0130(95/06) (Washington, DC, June 1995). **Projections:** AEO97 National Energy Modeling System, run AEO97B.D100296K.

Notes and Sources

Table 10. Representative average annual rates of technological progress in alternative technology cases (page 62): Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 11. Petroleum consumption and net imports, 1995 and 2015 (page 65): **1995:** Energy Information Administration, *Petroleum Supply Annual 1995*, DOE/EIA-0340(95)/1 (Washington, DC, May 1996). **2015:** Tables A11, B11, and C11.

Table 12. Scrubber retrofits, allowance costs, and banked allowances, 2000-2015 (page 74): AEO97 National Energy Modeling System, run AEO97B.D100296K.

Table 13. Forecasts of economic growth, 1995-2015 (page 76): ***AEO97:*** Table B20. **DRI:** DRI/McGraw-Hill, *Review of the U.S. Economy, February 1996*, "Winter Long Term Forecast" (Lexington, MA, 1996). **WEFA:** The WEFA Group, *U.S. Long-Term Economic Outlook* (Second Quarter 1996).

Table 14. Forecasts of world oil prices, 1995-2015 (page 76): **AEO97:** Tables A1 and C1. **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook, Spring-Summer 1996* (April 1996). **IEA1:** International Energy Agency, *World Energy Outlook, 1996: Capacity Constraints Case.* **IEA2:** International Energy Agency, *World Energy Outlook, 1996: Energy Savings Case.* **PEL:** Petroleum Economics, Ltd., *Oil and Energy Outlook to 2010* (December 1995). (Price is for Brent crude.) **WEFA:** The WEFA Group, *U.S. Energy Report* (Spring-Summer 1996). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1997 Edition (August 1996).

Table 15. Forecasts of average annual growth rates for energy consumption (page 77): ***AEO97:*** Table A2. **DRI:** DRI/McGraw Hill, *World Energy Service: U.S. Outlook, Spring-Summer 1996* (April 1996). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1997 Edition (August 1996). **WEFA:** The WEFA Group, *U.S. Energy Report* (Spring-Summer 1996). **Note:** Delivered energy includes petroleum, natural gas, coal, and electricity (excluding generation and transmission losses) consumed in the residential, commercial, industrial, and transportation sectors.

Table 16. Forecasts of average annual growth in residential and commercial energy demand (page 77): ***AEO97:*** Table A2. **DRI:** DRI/McGraw Hill, *World Energy Service: U.S. Outlook, Spring-Summer 1996* (April 1996). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1997 Edition (August 1996). **WEFA:** The WEFA Group, *U.S. Energy Report* (Spring-Summer 1996).

Table 17. Forecasts of average annual growth in industrial energy demand (page 77): ***AEO97:*** Table A2. **DRI:** DRI/McGraw Hill, *World Energy Service: U.S. Outlook, Spring-Summer 1996* (April 1996). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1997 Edition (August 1996). **WEFA:** The WEFA Group, *U.S. Energy Report* (Spring-Summer 1996).

Table 18. Forecasts of average annual growth in transportation energy demand (page 78): ***AEO97:*** Table A2. **DRI:** DRI/McGraw Hill, *World Energy Service: U.S. Outlook, Spring-Summer 1996* (April 1996). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1997 Edition (August 1996). **WEFA:** The WEFA Group, *U.S. Energy Report* (Spring-Summer 1996).

Table 19. Comparison of electricity forecasts (page 79): **AEO97:** AEO97 National Energy Modeling System, runs AEO97B.D100296K, LMAC97.D100396A, and HMAC97.D100296A. **WEFA:** The WEFA Group, *U.S. Energy Report* (Spring-Summer 1996). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1997 Edition (August 1996). **DRI:** DRI/McGraw-Hill, DRI/McGraw-Hill, *World Energy Service: U.S. Outlook, Spring-Summer 1996* (April 1996).

Table 20. Comparison of natural gas forecasts (page 80): **AEO97:** Tables B13 and B14. **WEFA:** The WEFA Group, *U.S. Energy Report* (Spring-Summer 1996). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1997 Edition (August 1996). **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook, Spring-Summer 1996* (April 1996). **AGA:** American Gas Association, *1996 AGA-TERA Base Case* (August 1996).

Table 21. Comparison of petroleum forecasts (page 82): **AEO97:** Table C11. **WEFA:** The WEFA Group, *U.S. Energy Report* (Spring-Summer 1996). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1997 Edition (August 1996). **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook, Spring-Summer 1996* (April 1996). **IPAA:** Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Run Report* (April 1996).

Table 22. Comparison of coal forecasts (page 83): **AEO97:** Table B16. **WEFA:** The WEFA Group, *U.S. Energy Report* (Spring-Summer 1996). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1997 Edition (August 1996). **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook, Spring-Summer 1996* (April 1996).

Figure notes

Note: Tables indicated as sources in these notes refer to the tables in Appendixes A, B, C, and F of this report.

Figure 1. Fuel price projections, 1995-2015: AEO96 and AEO97 compared (page 2): ***AEO96* projections:** Energy Information Administration, *Annual Energy Outlook 1996*, DOE/EIA-0383(96) (Washington, DC, January 1996). ***AEO97* projections:** Tables A1 and A8.

Figure 2. Energy production by fuel, 1970-2015 (page 2): **History:** Energy Information Administration, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections:** Tables A1 and A18. **Note:** Data for non-electric utility use of renewable energy were collected beginning in 1990.

Figure 3. Net energy imports by fuel, 1970-2015 (page 3): **History:** Energy Information Administration, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections:** Table A1.

Figure 4. Energy consumption by fuel, 1970-2015 (page 3): **History:** Energy Information Administration, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections:** Tables A1 and A18. **Note:** Data for non-electric utility use of renewable energy were collected beginning in 1990.

Figure 5. Electricity generation by fuel, 1970-2015 (page 4): **History:** Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report"; Energy Information Administration, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996); and Edison Electric Institute. **Projections:** Table A8.

Figure 6. Energy use per capita and per dollar of gross domestic product, 1970-2015 (page 5): **History:** Energy Information Administration, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections:** Table A2.

Figure 7. U.S. carbon emissions by sector and fuel, 1990-2015 (page 5): **History:** Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1987-1994*, DOE/EIA-0573(94) (Washington, DC, October 1995). **Projections:** Table A19.

Figure 8. Comparison of average natural gas transmission and distribution margins, 1970-2015 (page 10): **History:** Derived from Energy Information Administration, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections:** Table A14.

Figure 9. Nitrogen oxide emissions, 1994-2015 (page 11): AEO97 National Energy Modeling System, run AEO97B.D100296K.

Figure 10. Changes in oil consumption for transportation and other uses, 1980-2015 (page 22): **History:** Oak Ridge National Laboratory, *Transportation Energy Data Book*, Edition 16 (Oak Ridge, TN, July 1996). **Projections:** AEO97 National Energy Modeling System, run AEO97B.D100296K.

Figure 11. Changes in carbon emissions, 1990-2015 (page 22): **History:** Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1987-1994*, DOE/EIA-0573(94) (Washington, DC, October 1995). **Projections:** AEO97 National Energy Modeling System, run AEO97B.D100296K.

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Appendixes

Reference Case Forecast

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

Supply, Disposition, and Prices	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Production							
Crude Oil and Lease Condensate	14.10	13.89	12.42	11.62	11.41	11.08	-1.1%
Natural Gas Plant Liquids	2.47	2.37	2.71	3.01	3.04	3.47	1.9%
Dry Natural Gas	19.27	19.01	21.11	23.30	24.93	26.83	1.7%
Coal	22.07	21.98	23.33	23.99	25.16	26.46	0.9%
Nuclear Power	6.84	7.19	7.33	6.98	6.55	4.79	-2.0%
Renewable Energy[1]	5.82	6.29	6.54	6.88	7.25	7.71	1.0%
Other[2]	0.98	1.34	0.45	0.42	0.39	0.42	-5.7%
Total	71.55	72.08	73.89	76.19	78.73	80.75	0.6%
Imports							
Crude Oil[3]	15.35	15.69	19.22	20.72	21.19	22.23	1.8%
Petroleum Products[4]	3.93	3.19	4.97	6.79	8.23	8.35	4.9%
Natural Gas	2.68	2.90	3.75	3.98	4.23	4.55	2.3%
Other Imports[5]	0.67	0.60	0.68	0.67	0.67	0.64	0.4%
Total	22.63	22.38	28.62	32.16	34.31	35.77	2.4%
Exports							
Petroleum[6]	2.00	2.02	1.79	1.92	1.94	1.97	-0.1%
Natural Gas	0.17	0.16	0.21	0.21	0.22	0.22	1.7%
Coal	1.88	2.27	2.44	2.59	2.82	3.04	1.5%
Total	4.04	4.45	4.44	4.73	4.98	5.24	0.8%
Discrepancy[7]	-1.40	0.91	-0.22	-0.26	-0.17	-0.40	N/A
Consumption							
Petroleum Products[8]	34.77	34.92	37.92	40.46	42.24	43.26	1.1%
Natural Gas	21.35	22.18	24.52	26.94	28.77	30.97	1.7%
Coal	19.50	19.95	21.13	21.72	22.68	23.76	0.9%
Nuclear Power	6.84	7.19	7.33	6.98	6.55	4.79	-2.0%
Renewable Energy[1]	5.82	6.30	6.54	6.88	7.25	7.71	1.0%
Other[9]	0.46	0.39	0.41	0.38	0.39	0.37	-0.3%
Total	88.74	90.93	97.85	103.36	107.89	110.87	1.0%
Net Imports - Petroleum	17.28	16.87	22.41	25.59	27.48	28.60	2.7%
Prices (1995 dollars per unit)							
World Oil Price (dollars per barrel)[10]	15.94	17.26	18.20	19.72	20.41	20.98	1.0%
Gas Wellhead Price (dollars per Mcf)[11]	1.97	1.61	1.82	1.94	2.01	2.13	1.4%
Coal Minemouth Price (dollars per ton)	19.89	18.83	18.38	17.47	16.92	15.46	-1.0%

[1]Includes utility and nonutility grid-connected electricity from hydroelectric, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes nonmarketed renewable energy. 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. Figures for 1994 and 1995 may differ from published data due to internal conversion factors.
Sources: 1994 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1994*, DOE/EIA-0131(94) (Washington, DC, November 1995). 1994 coal minemouth prices: EIA, *Coal Industry Annual 1994*, DOE/EIA-0584(94) (Washington, DC, October 1995). Other 1994 values: EIA, *Annual Energy Review 1994*, DOE/EIA-0384(94) (Washington, DC, July 1995). 1995 natural gas price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). 1995 natural gas supply derived from: EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC November 1996). 1995 coal minemouth price, coal production, and exports derived from: EIA, *Monthly Energy Review*, DOE/EIA-0035(96/08) (Washington, DC, August 1996). Other 1995 values: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections:** EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

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

Sector and Source	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Energy Consumption							
Residential							
Distillate Fuel	0.88	0.85	0.83	0.78	0.75	0.73	-0.8%
Kerosene	0.06	0.07	0.07	0.07	0.07	0.06	-0.6%
Liquefied Petroleum Gas	0.40	0.40	0.43	0.44	0.45	0.46	0.7%
Petroleum Subtotal	1.34	1.32	1.33	1.29	1.26	1.25	-0.3%
Natural Gas	4.98	5.01	5.33	5.43	5.57	5.73	0.7%
Coal	0.06	0.05	0.05	0.05	0.04	0.04	-1.3%
Renewable Energy[1]	0.56	0.57	0.57	0.56	0.55	0.54	-0.3%
Electricity	3.44	3.56	3.88	4.14	4.46	4.85	1.6%
Delivered Energy	10.38	10.51	11.16	11.46	11.89	12.41	0.8%
Electricity Related Losses	7.60	7.92	8.25	8.55	8.95	9.22	0.8%
Total	17.98	18.43	19.41	20.02	20.83	21.63	0.8%
Commercial							
Distillate Fuel	0.46	0.41	0.37	0.36	0.35	0.34	-0.9%
Residual Fuel	0.17	0.17	0.13	0.13	0.14	0.14	-0.9%
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.4%
Liquefied Petroleum Gas	0.05	0.05	0.06	0.06	0.06	0.06	0.9%
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.02	-0.3%
Petroleum Subtotal	0.73	0.67	0.60	0.60	0.59	0.59	-0.7%
Natural Gas	2.96	3.16	3.36	3.44	3.54	3.65	0.7%
Coal	0.08	0.08	0.08	0.08	0.09	0.09	0.6%
Renewable Energy[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.8%
Electricity	3.11	3.23	3.50	3.71	3.91	4.16	1.3%
Delivered Energy	6.88	7.15	7.54	7.84	8.13	8.50	0.9%
Electricity Related Losses	6.87	7.18	7.44	7.67	7.85	7.91	0.5%
Total	13.75	14.33	14.98	15.51	15.98	16.40	0.7%
Industrial[4]							
Distillate Fuel	1.11	1.15	1.26	1.39	1.47	1.55	1.5%
Liquefied Petroleum Gas	2.00	2.01	2.08	2.20	2.28	2.35	0.8%
Petrochemical Feedstocks	1.24	1.16	1.25	1.30	1.35	1.40	0.9%
Residual Fuel	0.43	0.34	0.28	0.31	0.33	0.35	0.2%
Motor Gasoline[2]	0.19	0.20	0.22	0.24	0.26	0.27	1.6%
Other Petroleum[5]	3.89	3.83	4.19	4.33	4.43	4.48	0.8%
Petroleum Subtotal	8.85	8.68	9.28	9.77	10.13	10.41	0.9%
Natural Gas[6]	9.38	9.74	10.62	11.04	11.42	11.63	0.9%
Metallurgical Coal	0.85	0.88	0.79	0.69	0.62	0.55	-2.4%
Steam Coal	1.53	1.59	1.72	1.82	1.89	1.97	1.1%
Net Coal Coke Imports	0.02	0.03	0.08	0.11	0.13	0.15	9.0%
Coal Subtotal	2.40	2.51	2.58	2.62	2.64	2.67	0.3%
Renewable Energy[7]	1.71	1.74	1.91	2.12	2.28	2.40	1.6%
Electricity	3.44	3.46	3.83	4.16	4.40	4.62	1.5%
Delivered Energy	25.78	26.12	28.22	29.70	30.87	31.73	1.0%
Electricity Related Losses	7.59	7.69	8.15	8.59	8.82	8.79	0.7%
Total	33.37	33.81	36.37	38.28	39.69	40.51	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 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Transportation							
Distillate Fuel	4.18	4.42	4.97	5.46	5.78	6.00	1.5%
Jet Fuel [8]	3.15	3.13	3.83	4.26	4.67	4.95	2.3%
Motor Gasoline[2]	14.36	14.65	15.76	16.61	17.09	17.11	0.8%
Residual Fuel	0.90	1.08	1.29	1.47	1.64	1.78	2.5%
Liquefied Petroleum Gas	0.03	0.03	0.04	0.11	0.18	0.21	10.7%
Other Petroleum[9]	0.25	0.26	0.29	0.31	0.33	0.34	1.4%
Petroleum Subtotal	22.86	23.56	26.17	28.22	29.69	30.39	1.3%
Pipeline Fuel Natural Gas	0.70	0.72	0.77	0.84	0.88	0.93	1.3%
Compressed Natural Gas	0.01	0.01	0.06	0.18	0.26	0.31	18.7%
Renewable Energy (E85)[10]	0.00	0.00	0.00	0.02	0.07	0.10	22.7%
Methanol [11]	0.00	0.00	0.00	0.03	0.07	0.09	22.5%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	15.6%
Electricity	0.02	0.02	0.02	0.08	0.14	0.17	11.4%
Delivered Energy	23.60	24.31	27.04	29.38	31.11	31.99	1.4%
Electricity Related Losses	0.04	0.04	0.05	0.17	0.28	0.32	10.5%
Total	23.64	24.36	27.09	29.55	31.39	32.32	1.4%
Delivered Energy Consumption for All Sectors							
Distillate Fuel	6.63	6.82	7.43	7.98	8.35	8.62	1.2%
Kerosene	0.10	0.11	0.11	0.11	0.11	0.11	-0.3%
Jet Fuel [8]	3.15	3.13	3.83	4.26	4.67	4.95	2.3%
Liquefied Petroleum Gas	2.47	2.49	2.61	2.81	2.97	3.09	1.1%
Motor Gasoline[2]	14.57	14.87	16.00	16.88	17.38	17.40	0.8%
Petrochemical Feedstocks	1.24	1.16	1.25	1.30	1.35	1.40	0.9%
Residual Fuel	1.50	1.58	1.71	1.92	2.11	2.27	1.8%
Other Petroleum[12]	4.12	4.07	4.46	4.62	4.74	4.80	0.8%
Petroleum Subtotal	33.78	34.24	37.39	39.88	41.67	42.63	1.1%
Natural Gas[6]	18.03	18.64	20.13	20.93	21.68	22.26	0.9%
Metallurgical Coal	0.85	0.88	0.79	0.69	0.62	0.55	-2.4%
Steam Coal	1.66	1.73	1.85	1.95	2.02	2.10	1.0%
Net Coal Coke Imports	0.02	0.03	0.08	0.11	0.13	0.15	9.0%
Coal Subtotal	2.54	2.64	2.71	2.75	2.77	2.80	0.3%
Renewable Energy[13]	2.28	2.31	2.48	2.70	2.90	3.04	1.4%
Methanol [11]	0.00	0.00	0.00	0.03	0.07	0.09	22.5%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	15.6%
Electricity	10.01	10.26	11.23	12.09	12.91	13.80	1.5%
Delivered Energy	66.63	68.10	73.95	78.38	81.99	84.62	1.1%
Electricity Related Losses	22.11	22.83	23.89	24.98	25.90	26.24	0.7%
Total	88.74	90.93	97.85	103.36	107.89	110.87	1.0%
Electric Generators[14]							
Distillate Fuel	0.09	0.08	0.09	0.12	0.14	0.15	3.1%
Residual Fuel	0.90	0.60	0.44	0.46	0.43	0.48	-1.1%
Petroleum Subtotal	0.99	0.68	0.53	0.58	0.57	0.63	-0.4%
Natural Gas	3.32	3.54	4.38	6.01	7.09	8.71	4.6%
Steam Coal	16.97	17.31	18.41	18.97	19.91	20.96	1.0%
Nuclear Power	6.84	7.19	7.33	6.98	6.55	4.79	-2.0%
Renewable Energy[15]	3.54	3.99	4.05	4.18	4.36	4.67	0.8%
Electricity Imports	0.46	0.39	0.41	0.36	0.32	0.28	-1.7%
Total	32.12	33.10	35.12	37.07	38.81	40.04	1.0%

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

Sector and Source	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Total Energy Consumption							
Distillate Fuel	6.72	6.90	7.51	8.11	8.49	8.77	1.2%
Kerosene	0.10	0.11	0.11	0.11	0.11	0.11	-0.3%
Jet Fuel [8]	3.15	3.13	3.83	4.26	4.67	4.95	2.3%
Liquefied Petroleum Gas	2.47	2.49	2.61	2.81	2.97	3.09	1.1%
Motor Gasoline[2]	14.57	14.87	16.00	16.88	17.38	17.40	0.8%
Petrochemical Feedstocks	1.24	1.16	1.25	1.30	1.35	1.40	0.9%
Residual Fuel	2.40	2.18	2.15	2.38	2.54	2.75	1.2%
Other Petroleum[12]	4.12	4.07	4.46	4.62	4.74	4.80	0.8%
Petroleum Subtotal	34.77	34.92	37.92	40.46	42.24	43.26	1.1%
Natural Gas	21.35	22.18	24.52	26.94	28.77	30.97	1.7%
Metallurgical Coal	0.85	0.88	0.79	0.69	0.62	0.55	-2.4%
Steam Coal	18.63	19.04	20.26	20.92	21.94	23.06	1.0%
Net Coal Coke Imports	0.02	0.03	0.08	0.11	0.13	0.15	9.0%
Coal Subtotal	19.50	19.95	21.13	21.72	22.68	23.76	0.9%
Nuclear Power	6.84	7.19	7.33	6.98	6.55	4.79	-2.0%
Renewable Energy[16]	5.82	6.30	6.54	6.88	7.25	7.71	1.0%
Methanol [11]	0.00	0.00	0.00	0.03	0.07	0.09	22.5%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	15.6%
Electricity Imports	0.46	0.39	0.41	0.36	0.32	0.28	-1.7%
Total	88.74	90.93	97.85	103.36	107.89	110.87	1.0%
Energy Use and Related Statistics							
Delivered Energy Use	66.63	68.10	73.95	78.38	81.99	84.62	1.1%
Total Energy Use	88.74	90.93	97.85	103.35	107.87	110.83	1.0%
Population (millions)	261.03	263.58	275.62	287.12	298.92	311.19	0.8%
Gross Domestic Product (billion 1992 dollars)	6604.23	6738.95	7543.85	8389.54	9185.32	9879.75	1.9%

[1]Includes wood used for residential heating. See Table A18 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps and solar thermal hot water heating.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector electricity cogenerated by using wood and wood waste, municipal solid waste, and other biomass. See Table A18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating.
[4]Fuel consumption includes consumption for cogeneration.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Includes lease and plant fuel.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[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]Only M85 (85 percent methanol).
[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 electric utilities and for self use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps and solar thermal hot water heaters.
[14]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity as a by-product of other processes.
[15]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, E85, wind, photovoltaic and solar thermal sources.
[16]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 nonmarketed renewable energy consumption for geothermal heat pumps and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1994 and 1995 may differ from published data due to internal conversion factors. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1994 natural gas lease, plant, and pipeline fuel values: Energy Information Administration (EIA), *Natural Gas Annual 1994*, DOE/EIA-0131(94) (Washington, DC, November 1995). 1995 natural gas lease, plant, and pipeline fuel values: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). 1995 transportation sector compressed natural gas consumption: EIA, AEO97 National Energy Modeling System run AEO97B.D100296K. 1994 and 1995 electric utility fuel consumption: EIA, *Electric Power Annual, Volume I*, DOE/EIA-0348(95)/1 (Washington, DC, July 1996). 1994 and 1995 nonutility consumption estimates: EIA Form 867, "Annual Nonutility Power Producer Report." Other 1994 values derived from: EIA, *State Energy Data Report 1993*, DOE/EIA-0214(93) (Washington, DC, July 1995) and Office of Coal, Nuclear, Electric, and Alternative Fuels estimates. Other 1995 values: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

Table A3. Energy Prices by Sector and Source
(1995 Dollars per Million Btu)

Sector and Source	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Residential	13.18	12.87	12.73	12.70	12.61	12.55	-0.1%
Primary Energy	6.64	6.28	6.16	6.09	5.95	5.83	-0.4%
Petroleum Products	7.76	7.51	8.48	8.75	9.08	8.95	0.9%
Distillate Fuel	6.49	6.24	7.03	7.28	7.45	7.33	0.8%
Liquefied Petroleum Gas	10.63	10.29	11.29	11.40	11.85	11.57	0.6%
Natural Gas	6.39	6.01	5.63	5.49	5.27	5.18	-0.7%
Electricity	25.29	24.67	24.09	23.49	22.88	22.28	-0.5%
Commercial	13.50	13.12	12.86	12.60	12.48	12.28	-0.3%
Primary Energy	5.21	4.82	4.70	4.69	4.59	4.54	-0.3%
Petroleum Products	4.59	4.58	5.15	5.34	5.52	5.42	0.8%
Distillate Fuel	4.54	4.39	5.06	5.28	5.44	5.32	1.0%
Residual Fuel	2.82	2.99	2.72	2.87	2.98	3.03	0.1%
Natural Gas[1]	5.46	4.96	4.70	4.65	4.51	4.48	-0.5%
Electricity	23.53	23.19	22.29	21.38	20.98	20.35	-0.7%
Industrial[2]	5.21	5.02	4.87	4.96	5.05	4.99	0.0%
Primary Energy	3.47	3.36	3.20	3.34	3.47	3.47	0.2%
Petroleum Products	4.70	4.92	4.41	4.60	4.80	4.68	-0.3%
Distillate Fuel	4.70	4.61	4.97	5.21	5.38	5.29	0.7%
Liquefied Petroleum Gas	6.33	6.53	5.98	6.00	6.28	5.95	-0.5%
Residual Fuel	2.55	2.55	2.73	2.92	3.03	3.01	0.8%
Natural Gas[3]	2.66	2.28	2.42	2.54	2.61	2.74	0.9%
Metallurgical Coal	1.78	1.75	1.74	1.72	1.58	1.48	-0.8%
Steam Coal	1.64	1.48	1.49	1.44	1.37	1.30	-0.7%
Electricity	15.00	14.54	14.10	13.46	13.13	12.56	-0.7%
Transportation	7.97	7.92	8.39	8.51	8.55	8.21	0.2%
Primary Energy	7.96	7.92	8.39	8.49	8.53	8.18	0.2%
Petroleum Products	7.96	7.92	8.39	8.51	8.54	8.19	0.2%
Distillate Fuel[4]	8.23	8.03	8.67	8.70	8.68	8.38	0.2%
Jet Fuel[5]	4.05	3.85	5.13	5.46	5.65	5.45	1.7%
Motor Gasoline[6]	9.20	9.23	9.65	9.79	9.85	9.49	0.1%
Residual Fuel	2.08	2.44	2.66	2.90	3.16	3.08	1.2%
Natural Gas[7]	5.77	5.77	5.91	6.20	6.73	7.07	1.0%
Electricity	15.31	15.14	15.01	14.45	14.25	13.85	-0.4%
Total End-Use Energy	8.39	8.22	8.28	8.31	8.34	8.18	0.0%
Primary Energy	7.98	7.82	7.93	7.98	8.01	7.82	0.0%
Electricity	21.19	20.77	20.11	19.33	18.89	18.34	-0.6%
Electric Generators[8]							
Fossil Fuel Average	1.59	1.48	1.50	1.53	1.54	1.55	0.2%
Petroleum Products	2.76	2.78	3.09	3.35	3.59	3.52	1.2%
Distillate Fuel	4.07	3.94	4.52	4.77	4.92	4.83	1.0%
Residual Fuel	2.63	2.62	2.81	2.97	3.15	3.11	0.9%
Natural Gas	2.29	2.01	2.19	2.28	2.32	2.47	1.0%
Steam Coal	1.38	1.32	1.29	1.24	1.20	1.11	-0.9%

Table A3. Energy Prices by Sector and Source (Continued)
(1995 Dollars per Million Btu)

Sector and Source	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Average Price to All Users[9]							
Petroleum Products	6.98	7.07	7.37	7.52	7.62	7.33	0.2%
Distillate Fuel [4]	7.11	6.98	7.64	7.75	7.80	7.56	0.4%
Jet Fuel	4.05	3.85	5.13	5.46	5.65	5.45	1.7%
Liquefied Petroleum Gas	7.09	7.20	7.05	7.20	7.61	7.32	0.1%
Motor Gasoline[6]	9.20	9.23	9.63	9.77	9.83	9.47	0.1%
Residual Fuel	2.43	2.55	2.70	2.91	3.13	3.07	0.9%
Natural Gas	3.98	3.57	3.49	3.45	3.39	3.42	-0.2%
Coal	1.42	1.35	1.31	1.25	1.21	1.13	-0.9%
Electricity	21.19	20.77	20.11	19.33	18.89	18.34	-0.6%

[1]Excludes independent power producers.
[2]Includes cogenerators.
[3]Excludes uses for lease and plant fuel.
[4]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[5]Kerosene-type jet fuel.
[6]Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[7]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[8]Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[9]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: 1994 and 1995 figures may differ from published data due to internal rounding.

Sources: 1994 prices for gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1994*, DOE/EIA-0487(94) (Washington, DC, August 1995). 1995 prices for gasoline, distillate, and jet fuel are based on prices in various 1995 issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(95/1-12) (Washington, DC, 1995). 1994 and 1995 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1993*, DOE/EIA-0376(93) (Washington, DC, December 1995). 1994 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Annual 1994*, DOE/EIA-0131(94) (Washington, DC, November 1995). 1994 electric generators natural gas delivered prices: Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 1994 and 1995 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1991*. 1995 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). Other 1995 natural gas delivered prices: EIA, AEO97 National Energy Modeling System run AEO97B.D100296K. Values for 1994 coal prices have been estimated from EIA, *State Energy Price and Expenditure Report 1993*, DOE/EIA-0376(93) (Washington, DC, December 1995) by use of consumption quantities aggregated from EIA, *State Energy Data Report 1993, Consumption Estimates*, DOE/EIA-0214(93) (Washington, DC, July 1995). Values for 1995 coal prices have been estimated from EIA, *State Energy Price and Expenditure Report 1993*, DOE/EIA-0376(93) (Washington, DC, December 1995) by use of consumption quantities aggregated from EIA, *State Energy Data Report 1993, Consumption Estimates*, DOE/EIA-0214(93) (Washington, DC, July 1995). 1994 residential electricity prices derived from EIA, *Short Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). 1994 and 1995 electricity prices for commercial, industrial, and transportation: EIA, AEO97 National Energy Modeling System run AEO97B.D100296K. **Projections:** EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

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

Key Indicators and Consumption	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Household Characteristics							
Households (millions)							
Single-Family	67.79	68.66	72.62	76.85	80.93	85.07	1.1%
Multifamily	24.39	24.56	25.53	26.98	28.67	30.45	1.1%
Mobile Homes	5.69	5.83	6.30	6.64	6.89	7.12	1.0%
Total	97.88	99.06	104.45	110.47	116.49	122.65	1.1%
Housing Starts (millions)							
Single-Family	1.19	1.08	1.05	1.08	1.03	1.09	N/A
Multifamily	0.25	0.28	0.36	0.42	0.48	0.48	N/A
Mobile Homes	0.30	0.34	0.29	0.29	0.28	0.29	N/A
Total	1.75	1.70	1.70	1.80	1.79	1.86	N/A
Average House Square Footage	1637	1643	1666	1683	1696	1708	0.2%
Energy Intensity							
Million Btu Consumed per Household							
Delivered Energy Consumption	106.06	106.10	106.81	103.78	102.06	101.19	-0.2%
Electricity Related Losses	77.61	79.94	79.03	77.43	76.80	75.20	-0.3%
Total Energy Consumption	183.67	186.03	185.84	181.21	178.86	176.39	-0.3%
Thousand Btu Consumed per Square Foot							
Delivered Energy Consumption	64.77	64.57	64.13	61.65	60.16	59.26	-0.4%
Electricity Related Losses	47.40	48.65	47.45	46.00	45.27	44.04	-0.5%
Total Energy Consumption	112.17	113.22	111.58	107.64	105.43	103.29	-0.5%
Delivered Energy Consumption by Fuel							
Distillate							
Space Heating	0.78	0.76	0.73	0.69	0.65	0.63	-0.9%
Water Heating	0.10	0.09	0.10	0.10	0.10	0.10	0.2%
Other Uses[1]	0.00	0.00	0.00	0.00	0.00	0.00	0.5%
Delivered Energy	0.88	0.85	0.83	0.78	0.75	0.73	-0.8%
Liquefied Petroleum Gas							
Space Heating	0.29	0.30	0.31	0.32	0.32	0.32	0.4%
Water Heating	0.06	0.06	0.08	0.08	0.09	0.09	1.9%
Cooking[2]	0.03	0.03	0.03	0.03	0.03	0.03	-0.2%
Other Uses[3]	0.01	0.01	0.01	0.01	0.01	0.01	1.6%
Delivered Energy	0.40	0.40	0.43	0.44	0.45	0.46	0.7%
Natural Gas							
Space Heating	3.45	3.48	3.74	3.79	3.88	3.96	0.7%
Space Cooling	0.00	0.00	0.01	0.01	0.02	0.02	12.9%
Water Heating	1.25	1.25	1.30	1.34	1.39	1.45	0.7%
Cooking[2]	0.15	0.15	0.14	0.14	0.14	0.14	-0.3%
Clothes Dryers	0.04	0.05	0.05	0.05	0.05	0.05	0.6%
Other Uses[3]	0.09	0.09	0.09	0.10	0.10	0.11	1.1%
Delivered Energy	4.98	5.01	5.33	5.43	5.57	5.73	0.7%
Electricity							
Space Heating	0.42	0.43	0.46	0.47	0.48	0.49	0.7%
Space Cooling	0.45	0.48	0.47	0.48	0.49	0.51	0.3%
Water Heating	0.35	0.35	0.36	0.37	0.38	0.39	0.5%
Refrigeration	0.42	0.40	0.35	0.33	0.31	0.31	-1.3%
Cooking	0.12	0.12	0.13	0.13	0.14	0.14	0.7%
Clothes Dryers	0.18	0.18	0.19	0.20	0.21	0.22	0.9%
Freezers	0.14	0.13	0.11	0.09	0.08	0.08	-2.5%
Lighting	0.31	0.32	0.33	0.34	0.35	0.36	0.7%
Other Uses[4]	1.06	1.15	1.49	1.73	2.02	2.35	3.7%
Delivered Energy	3.44	3.56	3.88	4.14	4.46	4.85	1.6%

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

Key Indicators and Consumption	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Marketed Renewables							
Wood[5]	0.56	0.57	0.57	0.56	0.55	0.54	-0.3%
Delivered Energy	0.56	0.57	0.57	0.56	0.55	0.54	-0.3%
Other Fuels[6]	0.12	0.13	0.12	0.11	0.11	0.10	-0.9%
Delivered Energy Consumption by End-Use							
Space Heating	5.62	5.65	5.93	5.94	5.99	6.05	0.3%
Space Cooling	0.45	0.48	0.47	0.49	0.51	0.53	0.5%
Water Heating	1.76	1.75	1.83	1.88	1.95	2.03	0.7%
Refrigeration	0.42	0.40	0.35	0.33	0.31	0.31	-1.3%
Cooking	0.30	0.30	0.30	0.30	0.30	0.31	0.2%
Clothes Dryers	0.22	0.23	0.24	0.24	0.26	0.27	0.9%
Freezers	0.14	0.13	0.11	0.09	0.08	0.08	-2.5%
Lighting	0.31	0.32	0.33	0.34	0.35	0.36	0.7%
Other Uses[7]	1.15	1.24	1.59	1.84	2.14	2.47	3.5%
Delivered Energy	10.38	10.51	11.16	11.46	11.89	12.41	0.8%
Electricity Related Losses by End-Use							
Space Heating	0.92	0.95	0.97	0.97	0.96	0.94	-0.1%
Space Cooling	0.99	1.07	0.99	0.99	0.99	0.97	-0.5%
Water Heating	0.78	0.78	0.76	0.76	0.76	0.74	-0.2%
Refrigeration	0.92	0.90	0.75	0.67	0.62	0.59	-2.1%
Cooking	0.27	0.27	0.27	0.27	0.28	0.27	0.0%
Clothes Dryers	0.40	0.40	0.40	0.41	0.42	0.41	0.2%
Freezers	0.30	0.29	0.23	0.19	0.16	0.15	-3.3%
Lighting	0.69	0.70	0.70	0.71	0.71	0.69	-0.1%
Other Uses[7]	2.33	2.55	3.17	3.58	4.05	4.47	2.8%
Total Electricity Related Losses	7.60	7.92	8.25	8.55	8.95	9.22	0.8%
Total Energy Consumption by End-Use							
Space Heating	6.54	6.61	6.90	6.91	6.96	6.99	0.3%
Space Cooling	1.43	1.56	1.47	1.49	1.49	1.50	-0.2%
Water Heating	2.54	2.53	2.59	2.64	2.71	2.77	0.4%
Refrigeration	1.34	1.30	1.10	1.00	0.93	0.89	-1.9%
Cooking	0.58	0.58	0.57	0.57	0.58	0.59	0.1%
Clothes Dryers	0.62	0.63	0.64	0.65	0.67	0.68	0.4%
Freezers	0.44	0.42	0.34	0.28	0.24	0.23	-3.0%
Lighting	1.00	1.02	1.03	1.05	1.06	1.05	0.2%
Other Uses[7]	3.49	3.79	4.76	5.43	6.19	6.94	3.1%
Total	17.98	18.43	19.41	20.02	20.83	21.63	0.8%
Non-Marketed Renewables							
Geothermal[8]	0.01	0.01	0.02	0.04	0.05	0.07	9.4%
Solar[9]	0.01	0.01	0.01	0.01	0.01	0.01	-0.3%
Total	0.02	0.02	0.03	0.05	0.06	0.08	6.5%

[1]Includes such appliances as swimming pool and hot tub heaters.
[2]Does not include outdoor grills.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as microwave ovens, television sets, and dishwashers.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1993*.
[6]Includes kerosene and coal.
[7]Includes such appliances as swimming pool heaters, hot tub heaters, outdoor grills, outdoor lighting (natural gas), microwave ovens, television sets, and dishwashers.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1994 data derived from: Energy Information Administration (EIA), *State Energy Data Report 1993*, DOE/EIA-0214(93) (Washington, DC, July 1995). 1995: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

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

Key Indicators and Consumption	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Key Indicators							
Total Floor Space (billion square feet)							
Surviving	68.1	68.9	72.8	76.0	79.1	82.5	0.9%
New Additions	1.7	1.7	1.5	1.5	1.6	1.8	0.1%
Total	**69.8**	**70.7**	**74.3**	**77.5**	**80.7**	**84.2**	**0.9%**
Energy Consumption Intensity (thousand Btu per square foot)							
Delivered Energy Consumption	98.6	101.2	101.5	101.1	100.7	100.9	0.0%
Electricity Related Losses	98.4	101.6	100.1	99.0	97.3	93.9	-0.4%
Total Energy Consumption	197.0	202.8	201.6	200.1	198.0	194.8	-0.2%
Delivered Energy Consumption by Fuel							
Electricity							
Space Heating	0.11	0.11	0.12	0.12	0.12	0.13	0.7%
Space Cooling	0.53	0.58	0.52	0.52	0.52	0.53	-0.4%
Water Heating	0.17	0.17	0.16	0.15	0.14	0.13	-1.5%
Ventilation	0.17	0.17	0.18	0.18	0.19	0.20	0.7%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	-1.0%
Lighting	1.19	1.21	1.30	1.32	1.32	1.36	0.6%
Refrigeration	0.14	0.14	0.15	0.15	0.16	0.17	1.0%
Office Equipment (PC)	0.07	0.07	0.09	0.09	0.10	0.10	1.9%
Office Equipment (non-PC)	0.18	0.18	0.20	0.22	0.25	0.27	2.0%
Other Uses[1]	0.52	0.56	0.75	0.92	1.08	1.24	4.0%
Delivered Energy	**3.11**	**3.23**	**3.50**	**3.71**	**3.91**	**4.16**	**1.3%**
Natural Gas[2]							
Space Heating	1.26	1.30	1.33	1.34	1.36	1.38	0.3%
Space Cooling	0.02	0.03	0.03	0.03	0.03	0.03	0.8%
Water Heating	0.47	0.48	0.48	0.50	0.52	0.55	0.7%
Cooking	0.18	0.18	0.20	0.21	0.23	0.25	1.4%
Other Uses[3]	1.02	1.17	1.32	1.36	1.40	1.45	1.1%
Delivered Energy	**2.96**	**3.16**	**3.36**	**3.44**	**3.54**	**3.65**	**0.7%**
Distillate							
Space Heating	0.19	0.20	0.18	0.17	0.16	0.15	-1.2%
Water Heating	0.06	0.06	0.05	0.05	0.05	0.04	-1.2%
Other Uses[4]	0.22	0.15	0.14	0.14	0.14	0.14	-0.4%
Delivered Energy	**0.46**	**0.41**	**0.37**	**0.36**	**0.35**	**0.34**	**-0.9%**
Other Fuels[5]	**0.35**	**0.35**	**0.32**	**0.32**	**0.33**	**0.34**	**-0.1%**
Marketed Renewable Fuels							
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.8%
Delivered Energy	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.8%**
Delivered Energy Consumption by End-Use							
Space Heating	1.56	1.61	1.63	1.63	1.64	1.66	0.1%
Space Cooling	0.56	0.61	0.55	0.55	0.55	0.56	-0.4%
Water Heating	0.70	0.70	0.70	0.70	0.70	0.72	0.1%
Ventilation	0.17	0.17	0.18	0.18	0.19	0.20	0.7%
Cooking	0.21	0.22	0.23	0.24	0.26	0.27	1.1%
Lighting	1.19	1.21	1.30	1.32	1.32	1.36	0.6%
Refrigeration	0.14	0.14	0.15	0.15	0.16	0.17	1.0%
Office Equipment (PC)	0.07	0.07	0.09	0.09	0.10	0.10	1.9%
Office Equipment (non-PC)	0.18	0.18	0.20	0.22	0.25	0.27	2.0%
Other Uses[6]	2.11	2.24	2.52	2.75	2.96	3.18	1.8%
Delivered Energy	**6.88**	**7.15**	**7.54**	**7.84**	**8.13**	**8.50**	**0.9%**

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

Key Indicators and Consumption	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Electricity Related Losses by End-Use							
Space Heating	0.25	0.25	0.25	0.25	0.25	0.25	-0.1%
Space Cooling	1.18	1.29	1.11	1.07	1.05	1.01	-1.2%
Water Heating	0.38	0.38	0.35	0.31	0.28	0.24	-2.3%
Ventilation	0.37	0.38	0.37	0.37	0.38	0.37	-0.1%
Cooking	0.07	0.07	0.06	0.06	0.06	0.05	-1.8%
Lighting	2.63	2.68	2.77	2.72	2.65	2.58	-0.2%
Refrigeration	0.31	0.31	0.31	0.32	0.33	0.33	0.2%
Office Equipment (PC)	0.15	0.16	0.18	0.19	0.20	0.20	1.1%
Office Equipment (non-PC)	0.39	0.40	0.43	0.46	0.49	0.52	1.3%
Other Uses[6]	1.15	1.25	1.60	1.91	2.17	2.35	3.2%
Total Electricity Related Losses	**6.87**	**7.18**	**7.44**	**7.67**	**7.85**	**7.91**	**0.5%**
Total Energy Consumption by End-Use							
Space Heating	1.81	1.87	1.88	1.88	1.89	1.91	0.1%
Space Cooling	1.74	1.89	1.66	1.62	1.60	1.58	-0.9%
Water Heating	1.08	1.09	1.04	1.01	0.98	0.96	-0.6%
Ventilation	0.54	0.55	0.55	0.55	0.56	0.57	0.2%
Cooking	0.28	0.29	0.30	0.30	0.31	0.32	0.6%
Lighting	3.82	3.89	4.07	4.04	3.97	3.94	0.1%
Refrigeration	0.45	0.46	0.46	0.47	0.49	0.50	0.5%
Office Equipment (PC)	0.21	0.23	0.27	0.29	0.30	0.30	1.3%
Office Equipment (non-PC)	0.57	0.59	0.63	0.68	0.74	0.79	1.5%
Other Uses[6]	3.26	3.49	4.12	4.66	5.14	5.53	2.3%
Total	**13.75**	**14.33**	**14.98**	**15.51**	**15.98**	**16.40**	**0.7%**
Non-Marketed Renewable Fuels							
Solar[7]	0.01	0.01	0.02	0.03	0.03	0.04	5.8%
Total	**0.01**	**0.01**	**0.02**	**0.03**	**0.03**	**0.04**	**5.8%**

[1]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, and medical equipment.
[2]Excludes estimated consumption from independent power producers.
[3]Includes miscellaneous uses, such as district services, pumps, lighting, emergency electric generators, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, district services, and emergency electric generators.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes primary energy displaced by solar thermal water heaters.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1994 data derived from: Energy Information Administration (EIA), *State Energy Data Report 1993,* DOE/EIA-0214(93) (Washington, DC, July 1995). 1995: EIA, *Short-Term Energy Outlook,* DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

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

Key Indicators and Consumption	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Key Indicators							
Value of Gross Output (billion 1987 dollars)							
Manufacturing	2826	2907	3280	3709	4117	4441	2.1%
Nonmanufacturing	766	765	847	917	978	1028	1.5%
Total	3592	3672	4127	4626	5095	5469	2.0%
Energy Prices (1995 dollars per million Btu)							
Electricity	15.00	14.54	14.10	13.46	13.13	12.56	-0.7%
Natural Gas	2.66	2.28	2.42	2.54	2.61	2.74	0.9%
Steam Coal	1.47	1.48	1.49	1.44	1.37	1.30	-0.7%
Residual Oil	2.55	2.55	2.73	2.92	3.03	3.01	0.8%
Distillate Oil	4.70	4.61	4.97	5.21	5.38	5.29	0.7%
Liquefied Petroleum Gas	6.33	6.53	5.98	6.00	6.28	5.95	-0.5%
Motor Gasoline	9.18	9.18	8.34	8.63	8.85	8.65	-0.3%
Metallurgical Coal	1.71	1.75	1.74	1.72	1.58	1.48	-0.8%
Energy Consumption							
Consumption[1] (quadrillion Btu per year)							
Purchased Electricity	3.44	3.46	3.83	4.16	4.40	4.62	1.5%
Natural Gas[2]	9.38	9.74	10.62	11.04	11.42	11.63	0.9%
Steam Coal	1.53	1.59	1.72	1.82	1.89	1.97	1.1%
Metallurgical Coal and Coke[3]	0.87	0.91	0.87	0.80	0.75	0.70	-1.3%
Residual Fuel	0.43	0.34	0.28	0.31	0.33	0.35	0.2%
Distillate	1.11	1.15	1.26	1.39	1.47	1.55	1.5%
Liquefied Petroleum Gas	2.00	2.01	2.08	2.20	2.28	2.35	0.8%
Petrochemical Feedstocks	1.24	1.16	1.25	1.30	1.35	1.40	0.9%
Other Petroleum[4]	4.08	4.03	4.41	4.57	4.69	4.75	0.8%
Renewables[5]	1.71	1.74	1.91	2.12	2.28	2.40	1.6%
Delivered Energy	25.78	26.12	28.22	29.70	30.87	31.73	1.0%
Electricity Related Losses	7.59	7.69	8.15	8.59	8.82	8.79	0.7%
Total	33.37	33.81	36.37	38.28	39.69	40.51	0.9%
Consumption per Unit of Output[1] (thousand Btu per 1987 dollar)							
Purchased Electricity	0.96	0.94	0.93	0.90	0.86	0.84	-0.5%
Natural Gas[2]	2.61	2.65	2.57	2.39	2.24	2.13	-1.1%
Steam Coal	0.43	0.43	0.42	0.39	0.37	0.36	-0.9%
Metallurgical Coal and Coke[3]	0.24	0.25	0.21	0.17	0.15	0.13	-3.3%
Residual Fuel	0.12	0.09	0.07	0.07	0.06	0.06	-1.8%
Distillate	0.31	0.31	0.31	0.30	0.29	0.28	-0.5%
Liquefied Petroleum Gas	0.56	0.55	0.50	0.48	0.45	0.43	-1.2%
Petrochemical Feedstocks	0.34	0.32	0.30	0.28	0.27	0.26	-1.1%
Other Petroleum[4]	1.14	1.10	1.07	0.99	0.92	0.87	-1.2%
Renewables[5]	0.48	0.47	0.46	0.46	0.45	0.44	-0.4%
Delivered Energy	7.18	7.11	6.84	6.42	6.06	5.80	-1.0%
Electricity Related Losses	2.11	2.09	1.97	1.86	1.73	1.61	-1.3%
Total	9.29	9.21	8.81	8.28	7.79	7.41	-1.1%

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net coke coal imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1994 prices for gasoline and distillate are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1994*, DOE/EIA-0487(94) (Washington, DC, August 1995). 1995 prices for gasoline and distillate are based on prices in various issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(95/3-96/4) (Washington, DC, 1995 - 1996). 1994 and 1995 coal prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(96/08) (Washington, DC, August 1996). 1994 and 1995 electricity prices: EIA, AEO97 National Energy Modeling System run AEO97B.D100296K. Other 1994 values and 1995 prices derived from EIA, *State Energy Data Report 1993*, DOE/EIA-0214(93) (Washington, DC, July 1995). Other 1995 values: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Key Indicators							
Level of Travel (billions)							
Light-Duty Vehicles (vehicle miles traveled)	2200	2209	2375	2574	2767	2924	1.4%
Freight Trucks (vehicle miles traveled)	164	166	193	219	237	250	2.1%
Air (seat miles available)	946	927	1261	1493	1729	1923	3.7%
Rail (ton miles traveled)	1208	1181	1273	1368	1459	1535	1.3%
Marine (ton miles traveled)	820	871	932	989	1047	1099	1.2%
Energy Efficiency Indicators							
New Car (miles per gallon)[1]	28.0	27.5	28.0	29.8	31.5	32.6	0.9%
New Light Truck (miles per gallon)[1]	20.6	20.5	20.5	21.6	22.9	24.2	0.8%
Light-Duty Fleet (miles per gallon)[2]	20.0	19.7	19.6	19.8	20.4	21.3	0.4%
Aircraft Efficiency (seat miles per gallon)	50.4	50.8	53.3	55.8	58.2	60.6	0.9%
Freight Truck Efficiency (miles per gallon)	5.5	5.5	5.7	5.9	6.0	6.1	0.4%
Rail Efficiency (ton miles per thousand Btu)	2.6	2.6	2.7	2.9	3.0	3.2	1.0%
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.7	2.7	2.8	2.9	2.9	3.0	0.5%
Energy Use by Mode (quadrillion Btu per year)							
Light-Duty Vehicles	13.88	14.20	15.37	16.52	17.26	17.43	1.0%
Freight Trucks	5.26	5.43	5.94	6.47	6.80	7.07	1.3%
Air	3.20	3.18	3.87	4.30	4.71	5.00	2.3%
Rail	0.50	0.48	0.49	0.50	0.51	0.51	0.3%
Marine	1.43	1.63	1.88	2.09	2.30	2.46	2.1%
Pipeline Fuel	0.70	0.72	0.77	0.84	0.88	0.93	1.3%
Other[3]	0.20	0.21	0.25	0.27	0.29	0.30	1.6%
Total	23.60	24.31	27.04	29.38	31.11	31.99	1.4%

[1]Environmental Protection Agency rated miles per gallon.
[2]Combined car and light truck "on-the-road" estimate.
[3]Includes lubricants and aviation gasoline.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1994 pipeline fuel consumption: Energy Information Administration (EIA), *Natural Gas Annual 1994*, DOE/EIA-0131(94) (Washington, DC, November 1995). Other 1994 values: Federal Highway Administration, *Highway Statistics 1994* (Washington, DC, 1994); Oak Ridge National Laboratory, *Transportation Energy Data Book: 12, 13, 14, and 15*, (Oak Ridge, TN, May 1995); Federal Aviation Administration (FAA), *FAA Aviation Forecasts Fiscal Years 1993-2004*; National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance*, (Washington, DC, February 1995); EIA, *Residential Transportation Energy Consumption Survey 1991*, DOE/EIA-0464(91) (Washington, DC, December 1993); U.S. Dept. of Commerce, Bureau of the Census, "Truck Inventory and Use Survey," TC92-T-52, (Washington D.C., May 1995); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, D.C., March 1996); EIA, *Alternatives To Traditional Transportation Fuels 1994*, DOE/EIA-0585(94) (Washington, DC, February 1996); and EIA, *State Energy Data Report 1993*, DOE/EIA-0214(93) (Washington, DC, July 1995). 1995: FAA, *FAA Aviation Forecasts Fiscal Years 1993-2004*, (Washington, DC, February 1994); EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996); EIA, *Fuel Oil and Kerosene Sales 1995*, DOE/EIA-0535(95) (Washington, DC, September 1996); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

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

Supply, Disposition, and Prices	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Generation by Fuel Type							
Electric Generators[1]							
Coal	1648	1671	1797	1854	1942	2052	1.0%
Petroleum	93	64	53	58	58	64	0.0%
Natural Gas	303	322	478	705	892	1184	6.7%
Nuclear Power	640	673	687	654	614	448	-2.0%
Pumped Storage	-3	-2	-3	-3	-3	-3	3.2%
Renewable Sources[2]	308	354	353	361	371	394	0.5%
Total	2989	3083	3365	3629	3874	4139	1.5%
Non-Utility Generation for Own Use	22	22	22	22	22	22	0.0%
Cogenerators[3]							
Coal	47	43	46	48	50	51	0.8%
Petroleum	7	5	5	5	6	6	0.6%
Natural Gas	171	180	194	205	214	221	1.0%
Other Gaseous Fuels[4]	14	7	8	8	8	8	0.6%
Renewable Sources[2]	40	42	44	49	53	55	1.4%
Other[5]	3	3	3	4	4	4	0.7%
Total	282	279	300	319	333	344	1.0%
Sales to Utilities	153	148	154	158	161	163	0.5%
Generation for Own Use	129	132	145	161	172	181	1.6%
Net Imports	45	38	40	35	31	27	-1.7%
Electricity Sales by Sector							
Residential	1008	1043	1137	1214	1307	1421	1.6%
Commercial	912	946	1024	1089	1147	1219	1.3%
Industrial	1008	1013	1122	1218	1289	1354	1.5%
Transportation	6	6	7	24	41	50	11.4%
Total	2935	3008	3290	3545	3784	4044	1.5%
End-Use Prices (1995 cents per kilowatthour)[6]							
Residential	8.6	8.4	8.2	8.0	7.8	7.6	-0.5%
Commercial	8.0	7.9	7.6	7.3	7.2	6.9	-0.7%
Industrial	5.1	5.0	4.8	4.6	4.5	4.3	-0.7%
Transportation	5.2	5.2	5.1	4.9	4.9	4.7	-0.4%
All Sectors Average	7.2	7.1	6.9	6.6	6.4	6.3	-0.6%
Price Components (1995 cents per kilowatthour)							
Capital Component	2.7	2.6	2.6	2.5	2.3	2.2	-0.8%
Fuel Component	1.1	1.1	1.1	1.1	1.0	0.9	-1.1%
Operation and Maintenance Component	3.0	3.0	2.7	2.5	2.5	2.3	-1.2%
Wholesale Power Cost	0.4	0.4	0.5	0.6	0.7	0.8	4.2%
Total	7.2	7.1	6.9	6.6	6.4	6.3	-0.6%

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers, exempt wholesale generators, and generators at industrial and commercial facilities which provide electricity for on-site use and for sales to utilities.
[2]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar, and wind power.
[3]Includes cogeneration at facilities whose primary function is not electricity production. 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]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1994 and 1995 commercial and transportation sales derived from: Total transportation plus commercial sales come from Energy Information Administration (EIA), *State Energy Data Report 1993*, DOE/EIA-0214(93) (Washington, DC, July 1995), 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 15* (May 1995) which indicates the transportation value should be higher. 1994 and 1995 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). 1994 and 1995 residential electricity prices derived from EIA, *Short Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). 1994 and 1995 electricity prices for commercial, industrial, and transportation; price components; and projections: EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

Table A9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Electric Generators[2]							
Capability							
Coal Steam	303.6	304.9	298.7	298.2	304.0	315.4	0.2%
Other Fossil Steam[3]	141.3	139.6	120.2	102.6	99.9	96.1	-1.9%
Combined Cycle	13.5	14.7	43.2	73.5	107.5	153.0	12.4%
Combustion Turbine/Diesel	52.8	56.0	110.4	134.5	153.1	168.3	5.7%
Nuclear Power	99.1	99.2	99.1	94.7	88.9	62.7	-2.3%
Pumped Storage	19.0	19.9	19.9	19.9	19.9	19.9	N/A
Fuel Cells	0.0	0.0	0.0	2.0	2.1	2.1	53.5%
Renewable Sources[4]	87.4	88.0	90.5	92.2	94.1	98.3	0.6%
Total	716.7	722.2	781.9	817.5	869.4	915.8	1.2%
Cumulative Planned Additions[5]							
Coal Steam	0.1	1.4	3.7	3.7	5.3	5.3	6.8%
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combined Cycle	0.1	1.4	2.0	2.0	2.0	2.0	1.9%
Combustion Turbine/Diesel	0.3	3.2	4.5	4.5	4.5	4.5	1.6%
Nuclear Power	0.0	0.0	1.2	1.2	1.2	1.2	N/A
Pumped Storage	0.3	1.1	1.1	1.1	1.1	1.1	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[4]	0.3	0.7	2.6	2.9	2.9	2.9	7.0%
Total	1.1	8.0	15.2	15.5	17.1	17.1	3.9%
Cumulative Unplanned Additions[5]							
Coal Steam	0.0	0.0	2.0	9.5	16.4	31.6	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	27.6	58.0	91.9	137.5	N/A
Combustion Turbine/Diesel	0.0	0.1	53.5	78.2	97.1	113.5	39.8%
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	2.0	2.1	2.1	N/A
Renewable Sources[3]	0.0	0.0	0.4	1.8	3.9	8.4	N/A
Total	0.0	0.1	83.6	149.5	211.4	293.1	46.6%
Cumulative Total Additions	1.1	8.2	98.8	165.0	228.5	310.2	19.9%
Cumulative Retirements[6]	10.1	11.9	43.3	72.1	83.9	119.1	12.2%

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

Net Summer Capability[1]	Reference Case 1994	1995	2000	2005	2010	2015	Annual Growth 1995-2015 (percent)
Cogenerators[7]							
Capacity							
Coal	7.7	8.2	8.6	9.0	9.3	9.5	0.7%
Petroleum	0.8	0.9	0.9	0.9	1.0	1.0	0.6%
Natural Gas	28.2	28.9	30.6	32.1	33.3	34.2	0.8%
Other Gaseous Fuels	0.9	1.0	1.0	0.9	0.9	0.9	-0.1%
Renewable Sources[4]	6.1	6.2	6.6	7.3	7.8	8.2	1.4%
Other	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Total	43.9	45.1	47.6	50.2	52.3	53.8	0.9%
Cumulative Additions[5]	8.9	10.2	12.6	15.3	17.3	18.8	3.1%

[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, exempt wholesale generators, and generators at industrial and commercial facilities which produce electricity for on-site use and sales to utilities.

[3]Includes oil-, gas-, and dual-fired capability.

[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power.

[5]Cumulative additions after December 31, 1994. Non-zero utility planned additions in 1994 indicate units operational in 1994 but not supplying power to the grid.

[6]Cumulative total retirements from 1990.

[7]Nameplate capacity is reported for nonutilities on Form EIA-867, "Annual Power Producer Report." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.

N/A = Not applicable.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO97. Net summer capacity is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recent data available as of August 15, 1996. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: 1994 and 1995 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 1994 and 1995 and planned additions estimated based on EIA, Form EIA-867, "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

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

Electricity Trade	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Interregional Electricity Trade							
Gross Domestic Firm Power Sales	160.4	155.0	149.3	139.2	139.2	139.2	-0.5%
Gross Domestic Economy Sales	73.0	81.6	61.1	61.3	77.6	79.4	-0.1%
Gross Domestic Trade	233.4	236.6	210.4	200.5	216.8	218.6	-0.4%
Gross Domestic Firm Power Sales (million 1995 dollars)	7267.0	7023.5	6767.2	6309.0	6309.0	6309.0	-0.5%
Gross Domestic Economy Sales (million 1995 dollars)	1720.4	1958.3	1352.0	1420.8	1753.8	1831.4	-0.3%
Gross Domestic Sales (million 1995 dollars)	8987.4	8981.7	8119.2	7729.8	8062.8	8140.4	-0.5%
International Electricity Trade							
Firm Power Imports From Canada and Mexico	34.3	30.2	32.0	19.7	18.6	18.6	-2.4%
Economy Imports From Canada and Mexico	20.7	18.0	22.4	35.2	33.6	29.2	2.4%
Gross Imports From Canada and Mexico	55.0	48.3	54.4	54.8	52.2	47.9	0.0%
Firm Power Exports To Canada and Mexico	2.6	3.4	8.3	13.4	13.4	13.4	7.0%
Economy Exports To Canada and Mexico	7.7	7.2	6.4	7.0	7.7	7.7	0.3%
Gross Exports To Canada and Mexico	10.3	10.6	14.7	20.3	21.0	21.0	3.5%

Note: Totals may not equal sum of components due to independent rounding. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 1994 and 1995 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1994 and 1995 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." Firm/economy share: National Energy Board, *Annual Report 1993*. Planned interregional and international firm power sales: DOE Form IE-411, "Coordinated Bulk Power Supply Program Report" (April 1995). **Projections:** EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

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

Supply and Disposition	Reference Case 1994	1995	2000	2005	2010	2015	Annual Growth 1995-2015 (percent)
Crude Oil							
Domestic Crude Production[1]	6.66	6.56	5.87	5.49	5.39	5.23	-1.1%
Alaska	1.56	1.48	1.11	0.94	0.77	0.63	-4.2%
Lower 48 States	5.10	5.08	4.76	4.55	4.62	4.60	-0.5%
Net Imports	6.96	7.14	8.85	9.49	9.76	10.24	1.8%
Other Crude Supply[2]	0.24	0.28	0.00	0.00	0.00	0.00	N/A
Total Crude Supply	13.86	13.97	14.72	14.98	15.15	15.47	0.5%
Natural Gas Plant Liquids	1.73	1.76	1.96	2.14	2.28	2.44	1.6%
Other Inputs[3]	0.27	0.46	0.26	0.24	0.19	0.19	-4.4%
Refinery Processing Gain[4]	0.77	0.77	0.79	0.80	0.82	0.77	0.0%
Net Product Imports[5]	1.09	0.75	1.63	2.51	3.14	3.22	7.5%
Total Primary Supply[6]	17.72	17.73	19.36	20.67	21.58	22.10	1.1%
Refined Petroleum Products Supplied							
Motor Gasoline[7]	7.60	7.81	8.44	8.90	9.17	9.19	0.8%
Jet Fuel[8]	1.52	1.51	1.85	2.06	2.25	2.39	2.3%
Distillate Fuel[9]	3.16	3.25	3.53	3.81	3.99	4.12	1.2%
Residual Fuel	1.04	0.85	0.94	1.04	1.11	1.20	1.7%
Other[10]	4.36	4.32	4.62	4.87	5.07	5.21	0.9%
Total	17.69	17.73	19.38	20.68	21.60	22.12	1.1%
Refined Petroleum Products Supplied							
Residential and Commercial	1.10	1.07	1.05	1.03	1.02	1.01	-0.3%
Industrial[11]	4.65	4.58	4.88	5.13	5.33	5.48	0.9%
Transportation	11.51	11.79	13.22	14.26	15.00	15.35	1.3%
Electric Generators[12]	0.43	0.30	0.23	0.26	0.26	0.28	-0.3%
Total	17.69	17.73	19.38	20.68	21.60	22.12	1.1%
Discrepancy[13]	0.03	-0.01	-0.02	-0.01	-0.02	-0.02	N/A
World Oil Price (1995 dollars per barrel)[14]	15.94	17.26	18.20	19.72	20.41	20.98	1.0%
Import Share of Product Supplied	0.46	0.44	0.54	0.58	0.60	0.61	1.6%
Expenditures for Imported Crude Oil and Petroleum Products (billion 1995 dollars)	46.05	49.39	68.56	85.05	95.44	101.18	3.7%
Domestic Refinery Distillation Capacity	15.0	15.4	15.8	16.0	16.2	16.5	0.3%
Capacity Utilization Rate (percent)	93.0	92.0	93.4	94.1	94.0	94.0	0.1%

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.
[3]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, and other hydrocarbons.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net petroleum imports.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes naphtha and kerosene types.
[9]Includes distillate and kerosene.
[10]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.
[11]Includes consumption by cogenerators.
[12]Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[13]Balancing item. Includes unaccounted for supply, losses and gains.
[14]Average refiner acquisition cost for imported crude oil.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1994 and 1995 expenditures for imported crude oil and petroleum products based on internal calculations. Other 1994 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1994*, DOE/EIA-0340(94) (Washington, DC, May 1995). Other 1995 data: EIA, *Petroleum Supply Annual 1995*, DOE/EIA-0340(95) (Washington, DC, May 1996). **Projections:** EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

Table A12. Petroleum Product Prices
(1995 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
World Oil Price (dollars per barrel)	15.94	17.26	18.20	19.72	20.41	20.98	1.0%
Delivered Sector Product Prices							
Residential							
Distillate Fuel	90.0	86.5	97.6	100.9	103.3	101.7	0.8%
Liquefied Petroleum Gas	91.8	88.8	97.5	98.4	102.3	99.9	0.6%
Commercial							
Distillate Fuel	62.9	60.8	70.1	73.3	75.4	73.7	1.0%
Residual Fuel	42.3	44.7	40.7	42.9	44.6	45.3	0.1%
Residual Fuel (dollars per barrel)	17.75	18.78	17.10	18.02	18.73	19.02	0.1%
Industrial [1]							
Distillate Fuel	65.2	63.9	68.9	72.3	74.6	73.3	0.7%
Liquefied Petroleum Gas	54.6	56.4	51.6	51.8	54.2	51.4	-0.5%
Residual Fuel	38.2	38.2	40.8	43.7	45.3	45.1	0.8%
Residual Fuel (dollars per barrel)	16.04	16.06	17.13	18.36	19.04	18.95	0.8%
Transportation							
Distillate Fuel [2]	114.2	111.4	120.3	120.6	120.4	116.2	0.2%
Jet Fuel [3]	54.6	52.0	69.3	73.7	76.3	73.5	1.7%
Motor Gasoline[4]	115.0	114.8	119.4	121.2	121.8	117.4	0.1%
Residual Fuel	31.1	36.5	39.8	43.4	47.3	46.0	1.2%
Residual Fuel (dollars per barrel)	13.07	15.32	16.71	18.24	19.86	19.33	1.2%
Electric Generators[5]							
Distillate Fuel	56.5	54.7	62.7	66.1	68.3	67.0	1.0%
Residual Fuel	39.4	39.2	42.0	44.4	47.2	46.5	0.9%
Residual Fuel (dollars per barrel)	16.56	16.45	17.65	18.66	19.82	19.54	0.9%
Refined Petroleum Product Prices[6]							
Distillate Fuel [2]	98.6	96.8	106.0	107.5	108.2	104.9	0.4%
Jet Fuel [3]	54.6	52.0	69.3	73.7	76.3	73.5	1.7%
Liquefied Petroleum Gas	61.2	62.2	60.8	62.2	65.6	63.2	0.1%
Motor Gasoline[4]	115.0	114.8	119.2	120.9	121.6	117.2	0.1%
Residual Fuel	36.3	38.1	40.4	43.6	46.9	46.0	0.9%
Residual Fuel (dollars per barrel)	15.25	16.01	16.98	18.32	19.69	19.31	0.9%
Average	92.1	92.4	97.6	99.4	100.4	96.4	0.2%

[1]Includes cogenerators.
[2]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[3]Kerosene-type jet fuel.
[4]Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[5]Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Sources: 1994 prices for gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 1994*, DOE/EIA-0487(94) (Washington, DC, August 1995). 1995 prices for gasoline, distillate, and jet fuel are based on prices in various issues of EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(95/3-96/4) (Washington, DC, 1995-1996). 1994 and 1995 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1993*, DOE/EIA-0376(93) (Washington, DC, December 1995). **Projections:** EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

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

Supply and Disposition	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Production							
Dry Gas Production[1]	18.75	18.49	20.54	22.66	24.25	26.10	1.7%
Supplemental Natural Gas[2]	0.11	0.13	0.08	0.06	0.06	0.06	-3.7%
Net Imports	2.46	2.68	3.46	3.69	3.92	4.23	2.3%
Canada	2.51	2.79	3.44	3.52	3.74	4.06	1.9%
Mexico	-0.04	-0.05	-0.10	-0.11	-0.12	-0.12	3.9%
Liquefied Natural Gas	-0.01	-0.05	0.12	0.27	0.29	0.29	N/A
Total Supply	21.32	21.30	24.09	26.41	28.23	30.39	1.8%
Consumption by Sector							
Residential	4.84	4.87	5.18	5.27	5.42	5.57	0.7%
Commercial	2.87	3.07	3.26	3.34	3.44	3.55	0.7%
Industrial[3]	7.95	8.33	9.00	9.27	9.56	9.65	0.7%
Electric Generators[4]	3.25	3.46	4.29	5.88	6.94	8.52	4.6%
Lease and Plant Fuel[5]	1.16	1.14	1.32	1.45	1.55	1.65	1.9%
Pipeline Fuel	0.69	0.70	0.75	0.82	0.86	0.91	1.3%
Transportation[6]	0.01	0.01	0.05	0.18	0.25	0.30	18.7%
Total	20.77	21.58	23.86	26.22	28.01	30.16	1.7%
Discrepancy[7]	0.55	-0.28	0.23	0.19	0.22	0.23	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 as a by product of other processes.
[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, 1994 and 1995 values include net storage injections.

Btu = British thermal unit.

N/A = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1994 and 1995 may differ from published data due to internal conversion factors.

Sources: 1994 supply values and consumption as lease, plant, and pipeline fuel: Energy Information Administration (EIA), *Natural Gas Annual 1994*, DOE/EIA-0131(94) (Washington, DC, November 1995) with adjustments to end-use sector consumption levels based on Form EIA-867, "Annual Nonutility Power Producer Report." Other 1994 consumption derived from: EIA, *State Energy Data Report 1993*, DOE/EIA-0214(93) (Washington, DC, July 1995) with adjustments to end-use sector consumption levels based on Form EIA-867, "Annual Nonutility Power Producer Report." 1995 supplemental natural gas: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). 1995 imports and dry gas production derived from: EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). 1995 transportation sector consumption: EIA, AEO97 National Energy Modeling System run AEO97B.D100296K. Other 1995 consumption: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO97 National Energy Modeling System run AEO97B.D100296K. **Projections:** EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

Table A14. Natural Gas Prices, Margins, and Revenues
(1995 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Source Price							
Average Lower 48 Wellhead Price[1]	1.97	1.61	1.82	1.94	2.01	2.13	1.4%
Average Import Price	1.92	1.49	1.70	1.85	1.94	2.06	1.6%
Average[2]	1.96	1.59	1.80	1.93	2.00	2.12	1.4%
Delivered Prices							
Residential	6.58	6.18	5.79	5.65	5.43	5.33	-0.7%
Commercial	5.62	5.10	4.83	4.79	4.64	4.61	-0.5%
Industrial[3]	2.73	2.35	2.49	2.61	2.69	2.82	0.9%
Electric Generators[4]	2.34	2.06	2.24	2.33	2.38	2.52	1.0%
Transportation[5]	5.93	5.94	6.08	6.38	6.93	7.27	1.0%
Average[6]	4.09	3.67	3.59	3.55	3.49	3.52	-0.2%
Transmission and Distribution Margins[7]							
Residential	4.62	4.59	3.98	3.73	3.43	3.21	-1.8%
Commercial	3.66	3.51	3.03	2.86	2.64	2.49	-1.7%
Industrial[3]	0.77	0.76	0.69	0.68	0.69	0.70	-0.4%
Electric Generators[4]	0.38	0.47	0.43	0.41	0.38	0.40	-0.7%
Transportation[5]	3.97	4.35	4.28	4.45	4.93	5.15	0.9%
Average[6]	2.13	2.08	1.78	1.62	1.49	1.40	-2.0%
Transmission and Distribution Revenue (billion 1995 dollars)							
Residential	22.34	22.35	20.64	19.66	18.56	17.91	-1.1%
Commercial	10.50	10.79	9.89	9.56	9.08	8.85	-1.0%
Industrial[3]	6.12	6.31	6.18	6.32	6.57	6.72	0.3%
Electric Generators[4]	1.24	1.61	1.85	2.40	2.61	3.42	3.8%
Transportation[5]	0.04	0.04	0.23	0.79	1.25	1.56	19.7%
Total	40.23	41.11	38.79	38.73	38.08	38.45	-0.3%

[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 as a by product of other processes.
[5]Compressed natural gas used as a vehicle fuel.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

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

Sources: 1994 residential, commercial, and transportation delivered prices; average lower 48 wellhead price; and average import price: Energy Information Administration (EIA), *Natural Gas Annual 1994*, DOE/EIA-0131(94) (Washington, DC, November 1995). 1994 electric generators delivered price: Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 1994 and 1995 industrial delivered prices based on EIA, *Manufacturing Energy Consumption Survey 1991*. 1995 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). Other 1994 values, other 1995 values, and projections: EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

Table A15. Oil and Gas Supply

Production and Supply	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Crude Oil							
Lower 48 Average Wellhead Price[1] (1995 dollars per barrel)	14.66	15.58	18.00	19.36	20.02	19.85	1.2%
Production (million barrels per day)[2]							
U.S. Total	6.66	6.56	5.87	5.49	5.39	5.23	-1.1%
Lower 48 Onshore	3.96	3.82	3.43	3.04	3.04	3.07	-1.1%
Conventional	3.34	3.24	2.89	2.44	2.36	2.33	-1.6%
Enhanced Oil Recovery	0.62	0.58	0.54	0.60	0.69	0.75	1.3%
Lower 48 Offshore	1.14	1.26	1.33	1.50	1.57	1.53	1.0%
Alaska	1.56	1.48	1.11	0.94	0.77	0.63	-4.2%
Lower 48 End of Year Reserves (billion barrels)	17.82	17.18	15.13	15.26	15.51	15.61	-0.5%
Natural Gas							
Lower 48 Average Wellhead Price[1] (1995 dollars per thousand cubic feet)	1.97	1.61	1.82	1.94	2.01	2.13	1.4%
Production (trillion cubic feet)[3]							
U.S. Total	18.75	18.48	20.54	22.66	24.25	26.10	1.7%
Lower 48 Onshore	13.22	13.00	13.85	15.75	17.19	18.59	1.8%
Associated-Dissolved[4]	1.89	1.85	1.53	1.28	1.21	1.18	-2.2%
Non-Associated	11.34	11.15	12.31	14.47	15.98	17.40	2.2%
Conventional	8.08	7.92	9.29	11.21	12.33	13.28	2.6%
Unconventional	3.26	3.24	3.02	3.26	3.66	4.13	1.2%
Lower 48 Offshore	5.10	5.05	6.20	6.39	6.51	6.94	1.6%
Associated-Dissolved[4]	0.72	0.71	0.73	0.78	0.81	0.80	0.6%
Non-Associated	4.38	4.34	5.47	5.61	5.70	6.14	1.8%
Alaska	0.42	0.42	0.49	0.52	0.55	0.58	1.6%
U.S. End of Year Reserves (trillion cubic feet)	154.10	155.03	162.96	174.73	187.05	188.42	1.0%
Supplemental Gas Supplies (trillion cubic feet)[5]	0.11	0.13	0.08	0.06	0.06	0.06	-3.7%
Total Lower 48 Wells Completed (thousands)	21.00	18.52	29.15	34.33	37.60	41.75	4.1%

[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.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1994 and 1995 may differ from published data due to internal conversion factors.
Sources: 1994 lower 48 onshore, lower 48 offshore, Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 1994*, DOE/EIA-0340(94)/1 (Washington, DC, May 1995). 1994 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(94) (Washington, DC, October 1995). 1994 natural gas lower 48 average wellhead price, Alaska, total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 1994*, DOE/EIA-0131(94) (Washington, DC, November 1995). 1994 and 1995 crude oil lower 48 average wellhead price: EIA, Office of Integrated Analysis and Forecasting. 1994 and 1995 total wells completed: EIA, Office of Integrated Analysis and Forecasting. 1995 lower 48 onshore, lower 48 offshore, Alaska crude oil production: EIA, *Petroleum Supply Annual 1995*, DOE/EIA-0340(95) (Washington, DC, May 1996). 1995 natural gas lower 48 average wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/06) (Washington, DC, June 1996). 1995 total natural gas production derived from: EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). Other 1994 and 1995 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

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

Supply, Disposition, and Prices	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Production[1]							
Appalachia	445	435	452	441	479	494	0.6%
Interior	179	169	162	157	165	160	-0.3%
West	408	429	491	548	557	614	1.8%
East of the Mississippi	566	544	553	538	579	586	0.4%
West of the Mississippi	467	489	552	608	622	682	1.7%
Total	1034	1033	1105	1146	1201	1268	1.0%
Net Imports							
Imports	8	7	8	8	9	9	0.9%
Exports	71	89	96	102	111	121	1.6%
Total	-63	-81	-88	-94	-103	-112	1.6%
Total Supply[2]	971	951	1017	1052	1098	1156	1.0%
Consumption by Sector							
Residential and Commercial	6	6	6	6	6	6	0.0%
Industrial [3]	75	73	79	84	87	91	1.1%
Coke Plants	32	33	29	26	23	20	-2.4%
Electric Generators[4]	817	847	903	938	983	1039	1.0%
Total	930	959	1017	1054	1099	1156	0.9%
Discrepancy and Stock Change[5]	41	-8	0	-2	-1	-1	N/A
Average Minemouth Price							
(1995 dollars per short ton)	19.89	18.83	18.38	17.47	16.92	15.46	-1.0%
(1995 dollars per million Btu)	0.93	0.88	0.87	0.83	0.81	0.74	-0.9%
Delivered Prices (1995 dollars per short ton)[6]							
Industrial	33.34	32.30	32.34	31.18	29.72	28.12	-0.7%
Coke Plants	47.70	46.94	46.69	46.03	42.32	39.79	-0.8%
Electric Generators							
(1995 dollars per short ton)	28.72	27.01	26.39	24.97	24.23	22.47	-0.9%
(1995 dollars per million Btu)	1.38	1.32	1.29	1.24	1.20	1.11	-0.9%
Average	29.74	28.11	27.45	25.99	25.05	23.23	-0.9%
Exports[7]	40.91	39.51	39.08	37.96	35.47	32.91	-0.9%

[1]Includes anthracite, bituminous coal, and lignite.
[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 as a by-product of other processes.
[5]Balancing item: the sum of production, net imports, and net storage minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1994: Energy Information Administration (EIA), *Coal Industry Annual 1994*, DOE/EIA-0584(94) (Washington, DC, October 1995). 1995 data derived from: EIA, *Coal Industry Annual 1994*, DOE/EIA-0584(94) (Washington, DC, October 1995). **Projections:** EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

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

Capacity and Generation	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Electric Generators[1] (excluding cogenerators)							
Capability							
Conventional Hydropower	78.19	78.48	80.05	80.33	80.38	80.38	0.1%
Geothermal [2]	2.97	2.97	3.10	3.04	3.19	3.46	0.8%
Municipal Solid Waste	2.32	2.43	2.85	3.34	3.89	4.19	2.7%
Wood and Other Biomass[3]	1.78	1.86	1.86	2.00	2.21	3.92	3.8%
Solar Thermal	0.35	0.36	0.38	0.42	0.50	0.63	2.8%
Solar Photovoltaic	0.01	0.01	0.02	0.08	0.19	0.35	18.6%
Wind	1.79	1.83	2.26	2.97	3.78	5.39	5.6%
Total	**87.41**	**87.95**	**90.52**	**92.17**	**94.14**	**98.32**	**0.6%**
Generation (billion kilowatthours)							
Conventional Hydropower	259.92	309.82	301.51	303.59	304.11	304.21	-0.1%
Geothermal [2]	17.06	14.66	17.70	17.94	19.46	22.04	2.1%
Municipal Solid Waste	17.38	18.69	18.96	22.33	26.12	28.18	2.1%
Wood and Other Biomass[3]	9.40	7.12	8.61	9.24	10.73	22.72	6.0%
Solar Thermal	0.82	0.82	0.97	1.10	1.38	1.78	3.9%
Solar Photovoltaic	0.00	0.00	0.08	0.22	0.48	0.87	30.9%
Wind	3.48	3.17	4.93	6.80	9.15	13.80	7.6%
Total	**308.07**	**354.28**	**352.77**	**361.21**	**371.43**	**393.62**	**0.5%**
Cogenerators[4]							
Capability							
Municipal Solid Waste	0.40	0.41	0.41	0.43	0.44	0.45	0.6%
Biomass	5.71	5.79	6.17	6.88	7.38	7.75	1.5%
Total	**6.11**	**6.19**	**6.59**	**7.31**	**7.82**	**8.21**	**1.4%**
Generation (billion kilowatthours)							
Municipal Solid Waste	1.93	1.97	2.01	2.08	2.13	2.17	0.5%
Biomass	37.69	39.58	42.29	47.05	50.37	52.90	1.5%
Total	**39.62**	**41.55**	**44.30**	**49.12**	**52.50**	**55.07**	**1.4%**

[1]Includes grid-connected utilities and nonutilities other than cogenerators. These nonutility facilities include small power producers, exempt wholesale generators and generators at industrial and commercial facilities which do not produce steam for other uses.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes projections for energy crops after 2010.
[4]Cogenerators are facilities whose primary function is not electricity production.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO97. Net summer capability is used to be consistent with electric utility capacity estimates. Data for electric utility capacity data are the most recently available data as of August 15, 1996. Additional retirements are also determined on the basis of the size and age of the units. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: 1994 and 1995 electric utility capability: Energy Information Administration (EIA), Form EIA-860 "Annual Electric Utility Report." 1994 and 1995 nonutility and cogenerator capability: Form EIA-867, "Annual Nonutility Power Producer Report." 1994 and 1995 generation: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections:** EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

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

Sector and Source	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Marketed Renewable Energy[2]							
Residential	0.56	0.57	0.57	0.56	0.55	0.54	-0.3%
Wood	0.56	0.57	0.57	0.56	0.55	0.54	-0.3%
Commercial[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.8%
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.8%
Industrial[4]	1.71	1.74	1.91	2.12	2.28	2.40	1.6%
Conventional Hydroelectric	0.03	0.03	0.03	0.03	0.03	0.03	N/A
Municipal Solid Waste	0.00	0.00	0.00	0.01	0.01	0.01	1.0%
Biomass	1.67	1.70	1.87	2.08	2.24	2.36	1.7%
Transportation	0.09	0.08	0.10	0.10	0.10	0.15	3.5%
Ethanol used in E85[5]	0.00	0.00	0.00	0.02	0.06	0.09	22.7%
Ethanol used in Gasoline Blending	0.08	0.08	0.10	0.08	0.04	0.07	-0.7%
Electric Generators[6]	3.54	3.99	4.05	4.18	4.36	4.68	0.8%
Conventional Hydroelectric	2.67	3.18	3.10	3.12	3.13	3.13	-0.1%
Geothermal	0.45	0.39	0.49	0.52	0.58	0.69	3.0%
Municipal Solid Waste	0.28	0.31	0.31	0.37	0.43	0.46	2.1%
Biomass	0.10	0.07	0.09	0.10	0.11	0.23	6.0%
Solar Thermal	0.01	0.01	0.01	0.01	0.01	0.02	3.9%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.01	30.9%
Wind	0.04	0.03	0.05	0.07	0.09	0.14	7.6%
Total Marketed Renewable Energy	5.90	6.37	6.64	6.96	7.29	7.77	1.0%
Non-Marketed Renewable Energy[7] **Selected Consumption**							
Residential	0.02	0.02	0.03	0.05	0.06	0.08	6.5%
Solar Hot Water Heating	0.01	0.01	0.01	0.01	0.01	0.01	-0.3%
Geothermal Heat Pumps	0.01	0.01	0.02	0.04	0.05	0.07	9.4%
Commercial	0.01	0.01	0.02	0.03	0.03	0.04	5.8%
Solar Thermal	0.01	0.01	0.02	0.03	0.03	0.04	5.8%

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.

[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid.

[3]Value is less than 0.005 quadrillion Btu per year and rounds to zero.

[4]Includes all electricity production by industrial and other cogenerators for the grid and for own use.

[5]Excludes motor gasoline component of E85.

[6]Includes renewable energy delivered to the grid from electric utilities and nonutilities. Renewable energy used in generating electricity for own use is included in the individual sectoral electricity energy consumption values.

[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.

N/A = Not available.

Btu = British thermal unit.

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

Sources: 1994 ethanol: Energy Information Administration (EIA), *Annual Energy Review 1994*, DOE/EIA-0384(94) (Washington, DC, July 1995). 1994 and 1995 electric generators: EIA, Form EIA-860, "Annual Electric Utility Report," and EIA, Form EIA-867, "Annual Nonutility Power Producer Report." Other 1994: EIA, Office of Integrated Analysis and Forecasting. 1995 ethanol: EIA, *Petroleum Supply Annual 1995*, DOE/EIA-0340(95/1) (Washington, DC, May 1996). Other 1995: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

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

Sector and Source	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Residential							
Petroleum	25.3	25.0	25.0	24.3	23.7	23.4	-0.3%
Natural Gas	71.7	72.1	76.8	78.1	80.3	82.5	0.7%
Coal	1.4	1.4	1.3	1.2	1.1	1.1	-1.3%
Electricity	172.0	175.6	189.3	201.0	216.4	238.3	1.5%
Total	**270.5**	**274.0**	**292.4**	**304.6**	**321.4**	**345.3**	**1.2%**
Commercial							
Petroleum	14.5	13.4	11.9	11.8	11.7	11.7	-0.7%
Natural Gas	42.6	45.6	48.4	49.5	50.9	52.6	0.7%
Coal	2.0	2.0	2.1	2.2	2.3	2.3	0.7%
Electricity	155.6	159.3	170.6	180.2	189.9	204.4	1.3%
Total	**214.8**	**220.3**	**233.0**	**243.8**	**254.7**	**271.0**	**1.0%**
Industrial[1]							
Petroleum	95.6	92.4	99.2	104.9	108.9	111.9	1.0%
Natural Gas[2]	133.3	138.6	151.1	157.1	162.7	165.6	0.9%
Coal	60.2	62.8	63.4	63.6	63.5	63.8	0.1%
Electricity	172.0	170.5	186.8	201.7	213.4	227.1	1.4%
Total	**461.0**	**464.3**	**500.6**	**527.3**	**548.5**	**568.4**	**1.0%**
Transportation							
Petroleum	439.8	453.5	504.0	544.1	573.4	586.7	1.3%
Natural Gas[3]	10.3	10.5	11.9	14.8	16.5	17.9	2.7%
Other[4]	0.0	0.0	0.1	0.5	1.2	1.6	22.5%
Electricity	1.0	1.0	1.2	3.9	6.7	8.4	11.3%
Total	**451.1**	**465.1**	**517.2**	**563.3**	**597.7**	**614.5**	**1.4%**
Total Carbon Emissions[5]							
Petroleum	575.2	584.4	640.2	685.1	717.7	733.6	1.1%
Natural Gas	257.9	266.7	288.1	299.6	310.3	318.7	0.9%
Coal	63.6	66.2	66.8	67.0	66.9	67.2	0.1%
Other[4]	0.0	0.0	0.1	0.5	1.2	1.6	22.5%
Electricity	500.6	506.3	547.9	586.9	626.4	678.1	1.5%
Total	**1397.4**	**1423.7**	**1543.1**	**1638.9**	**1722.4**	**1799.3**	**1.2%**
Electric Generators[6]							
Petroleum	20.9	14.4	11.1	12.2	12.0	13.2	-0.4%
Natural Gas	47.4	50.9	63.1	86.5	102.1	125.4	4.6%
Coal	432.3	441.1	473.7	488.2	512.3	539.5	1.0%
Total	**500.6**	**506.3**	**547.9**	**586.9**	**626.4**	**678.1**	**1.5%**
Total Carbon Emissions[7]							
Petroleum	596.1	598.7	651.3	697.2	729.7	746.9	1.1%
Natural Gas	305.3	317.6	351.3	386.1	412.4	444.1	1.7%
Coal	495.9	507.3	540.5	555.2	579.2	606.7	0.9%
Other[4]	0.0	0.0	0.1	0.5	1.2	1.6	22.5%
Total	**1397.4**	**1423.7**	**1543.1**	**1638.9**	**1722.4**	**1799.3**	**1.2%**
Carbon Emissions (tons per person)	5.4	5.4	5.6	5.7	5.8	5.8	0.3%

[1]Includes consumption by cogenerators.
[2]Includes lease and plant fuel.
[3]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[4]"Other" includes methanol and liquid hydrogen.
[5]Measured for delivered energy consumption.
[6]Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[7]Measured for total energy consumption, with emissions for electric power generators distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Utility coal carbon emissions from Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States, 1987-1992*, DOE/EIA-0573 (Washington, DC, November 1994). Carbon coefficients from EIA, *Emissions of Greenhouse Gases in the United States 1995*, DOE/EIA-0573(95) (Washington, DC, October 1996). 1994 consumption estimates based on: EIA, *State Energy Data Report 1993*, DOE/EIA-0214(93) (Washington, DC, July 1995). 1995 consumption estimates based on: EIA, *Short Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

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

Indicators	Reference Case 1994	1995	2000	2005	2010	2015	Annual Growth 1995-2015 (percent)
GDP Implicit Price Deflator							
(Index 1992=1.000)	1.049	1.076	1.217	1.411	1.667	1.986	3.1%
Real Gross Domestic Product	6604	6739	7544	8390	9185	9880	1.9%
Real Consumption	4471	4579	5145	5673	6220	6708	1.9%
Real Investment	980	1011	1212	1366	1487	1592	2.3%
Real Government Spending	1260	1261	1292	1364	1440	1499	0.9%
Real Exports	715	775	1062	1395	1723	2037	5.0%
Real Imports	823	889	1166	1395	1661	1921	3.9%
Real Gross Domestic Product							
(1987 fixed-weighted dollars)	5522	5677	6492	7317	8145	8817	2.2%
Real Disposable Personal Income							
(1987 fixed-weighted dollars)	3894	4047	4598	5113	5644	6109	2.1%
Index of Manufacturing Gross Output							
(Index 1987=1.000)	1.211	1.246	1.406	1.590	1.765	1.904	2.1%
AA Utility Bond Rate (percent)	8.21	7.76	6.83	6.27	6.11	6.16	N/A
90-Day U.S. Government Treasury Bill Rate							
(percent)	4.25	5.49	5.02	4.31	4.15	4.04	N/A
Real Yield on Government 10 Year Bonds							
(percent)	5.44	5.22	3.34	2.07	1.35	1.24	N/A
Real 90-Day U.S. Government Treasury Bill Rate							
(percent)	1.98	2.94	2.30	1.10	0.71	0.35	N/A
Real Utility Bond Rate (percent)	5.94	5.21	4.12	3.06	2.67	2.46	N/A
Delivered Energy Intensity							
(thousand Btu per 1992 dollar of GDP)							
Delivered Energy	10.09	10.11	9.81	9.35	8.94	8.58	-0.8%
Total Energy	13.44	13.50	12.98	12.33	11.76	11.23	-0.9%
Consumer Price Index (1982-84=1.00)	1.48	1.52	1.76	2.08	2.49	3.01	3.5%
Employment Cost Index (June 1989=1.00)	1.18	1.22	1.42	1.66	1.99	2.39	3.4%
Unemployment Rate (percent)	6.10	5.59	5.25	5.64	5.70	5.67	N/A
Million Units							
Truck Deliveries, Light-Duty	6.06	6.10	6.81	7.03	7.32	7.73	1.2%
Unit Sales of Automobiles	8.99	8.67	9.55	10.14	10.07	9.89	0.7%
Millions of People							
Population with Armed Forces Overseas	261.0	263.6	275.6	287.1	298.9	311.2	0.8%
Population (aged 16 and over)	200.1	202.1	212.8	223.8	235.4	245.8	1.0%
Employment, Non-Agriculture	113.4	116.1	126.5	138.6	149.9	158.6	1.6%
Employment, Manufacturing	18.1	18.2	17.9	18.1	18.0	17.4	-0.2%
Labor Force	131.0	132.3	140.4	149.7	157.3	161.1	1.0%

GDP = Gross domestic product.
Btu = British thermal unit.
N/A = Not available.
Sources: 1994 and 1995: Data Resources Incorporated (DRI), DRI Trend0296. **Projections:** Energy Information Administration, AEO97 National Energy Modeling System run AEO97B.D100296K.

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

Supply and Disposition	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
World Oil Price (1995 dollars per barrel)[1]	15.94	17.26	18.20	19.72	20.41	20.98	1.0%
Production[2]							
OECD							
U.S. (50 states)	9.34	9.29	8.82	8.67	8.75	8.76	-0.3%
Canada	2.33	2.44	2.55	2.46	2.35	2.24	-0.4%
Mexico	3.18	3.09	3.20	3.13	3.07	3.00	-0.2%
OECD Europe[3]	6.13	6.55	6.92	6.05	5.20	4.25	-2.1%
Other OECD	0.73	0.74	0.76	0.71	0.65	0.60	-1.1%
Total OECD	21.70	22.11	22.25	21.01	20.02	18.84	-0.8%
Developing Countries							
Other South & Central America	2.82	3.06	4.06	4.18	3.99	3.81	1.1%
Pacific Rim	1.89	2.04	2.12	2.26	2.17	2.02	-0.1%
OPEC	27.50	28.07	33.04	42.10	50.64	60.35	3.9%
Other Developing Countries	3.82	4.05	5.11	5.07	4.72	4.28	0.3%
Total Developing Countries	36.02	37.21	44.33	53.61	61.51	70.45	3.2%
Eurasia							
Former Soviet Union	7.01	6.96	7.28	8.34	9.43	10.09	1.9%
Eastern Europe	0.30	0.31	0.27	0.23	0.21	0.18	-2.7%
China	2.94	3.02	3.14	3.04	3.00	2.94	-0.1%
Total Eurasia	10.25	10.29	10.69	11.62	12.64	13.21	1.3%
Total Production	67.98	69.62	77.27	86.24	94.17	102.50	2.0%
Consumption							
OECD							
U.S. (50 states)	17.72	17.73	19.39	20.68	21.60	22.12	1.1%
U.S. Territories	0.24	0.26	0.30	0.35	0.38	0.42	2.4%
Canada	1.73	1.76	1.88	2.01	2.14	2.29	1.3%
Mexico	1.94	1.96	2.12	2.39	2.69	3.02	2.2%
Japan	5.67	5.73	6.37	6.85	7.31	7.78	1.5%
Australia and New Zealand	0.92	0.96	1.02	1.10	1.17	1.24	1.3%
OECD Europe[3]	13.59	13.88	14.29	14.80	15.12	15.41	0.5%
Total OECD	41.80	42.28	45.38	48.18	50.41	52.28	1.1%
Developing Countries							
Other South and Central America	3.47	3.58	3.94	4.31	4.62	4.92	1.6%
Pacific Rim	4.64	4.87	5.79	7.72	9.07	10.73	4.0%
OPEC	4.74	4.94	5.62	6.30	7.06	7.91	2.4%
Other Developing Countries	4.60	4.79	6.05	7.20	7.95	8.75	3.1%
Total Developing Countries	17.46	18.19	21.42	25.53	28.70	32.31	2.9%

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

Supply and Disposition	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Eurasia							
Former Soviet Union	4.80	4.75	4.88	5.80	6.74	7.65	2.4%
Eastern Europe	1.35	1.39	1.49	1.51	1.72	1.96	1.7%
China	3.12	3.31	4.40	5.52	6.89	8.59	4.9%
Total Eurasia	9.28	9.46	10.78	12.84	15.36	18.21	3.3%
Total Consumption	68.53	69.92	77.57	86.54	94.47	102.80	1.9%
Non-OPEC Production	40.48	41.55	44.23	44.14	43.53	42.15	0.1%
Net Eurasia Exports	0.97	0.83	-0.09	-1.22	-2.72	-4.99	N/A
OPEC Market Share	0.40	0.40	0.43	0.49	0.54	0.59	1.9%

[1]Average refiner acquisition cost of imported crude oil.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol, liquids produced from coal and other sources, and refinery gains.
[3]OECD Europe includes the unified Germany.
N/A = Not available.
OECD = Organization for Economic Cooperation and Development - Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States (including territories).
Pacific Rim = Hong Kong, Malaysia, Philippines, Singapore, South Korea, Taiwan, and Thailand.
OPEC = Organization of Petroleum Exporting Countries - Algeria, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
Eurasia = Albania, Bulgaria, China, Czech Republic, Hungary, Poland, Romania, Slovak Republic, the Former Soviet Union, and the Former Yugoslavia.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1994 and 1995 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996).
Projections: EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

Economic Growth Case Comparisons

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

Supply, Disposition, and Prices	1995	Projections								
		2005			2010			2015		
		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	13.89	11.46	11.62	11.76	11.18	11.41	11.64	10.80	11.08	11.36
Natural Gas Plant Liquids	2.37	2.90	3.01	3.13	2.84	3.04	3.26	3.22	3.47	3.70
Dry Natural Gas	19.01	22.46	23.30	24.19	23.39	24.93	26.73	24.97	26.83	28.68
Coal	21.98	23.42	23.99	25.07	24.35	25.16	26.59	25.07	26.46	29.06
Nuclear Power	7.19	6.98	6.98	6.98	6.55	6.55	6.55	4.79	4.79	4.79
Renewable Energy[1]	6.29	6.73	6.88	7.04	7.00	7.25	7.51	7.22	7.71	8.18
Other[2]	1.34	0.41	0.42	0.41	0.39	0.39	0.42	0.40	0.42	0.45
Total	**72.08**	**74.36**	**76.19**	**78.58**	**75.70**	**78.73**	**82.69**	**76.47**	**80.75**	**86.21**
Imports										
Crude Oil[3]	15.69	20.16	20.72	21.33	20.94	21.19	22.13	21.39	22.23	23.09
Petroleum Products[4]	3.19	6.15	6.79	7.47	6.77	8.23	8.89	6.65	8.35	9.92
Natural Gas	2.90	3.98	3.98	3.98	4.23	4.23	4.23	4.55	4.55	4.55
Other Imports[5]	0.60	0.64	0.67	0.70	0.62	0.67	0.71	0.58	0.64	0.69
Total	**22.38**	**30.93**	**32.16**	**33.49**	**32.57**	**34.31**	**35.96**	**33.18**	**35.77**	**38.25**
Exports										
Petroleum[6]	2.02	1.80	1.92	2.16	1.84	1.94	2.01	1.83	1.97	2.09
Natural Gas	0.16	0.21	0.21	0.21	0.22	0.22	0.22	0.22	0.22	0.22
Coal	2.27	2.60	2.59	2.59	2.82	2.82	2.82	3.04	3.04	3.04
Total	**4.45**	**4.62**	**4.73**	**4.96**	**4.88**	**4.98**	**5.05**	**5.10**	**5.24**	**5.36**
Discrepancy[7]	**0.91**	**-0.34**	**-0.26**	**-0.27**	**-0.18**	**-0.17**	**-0.20**	**-0.31**	**-0.40**	**-0.42**
Consumption										
Petroleum Products[8]	34.92	39.09	40.46	41.77	40.18	42.24	44.27	40.33	43.26	46.11
Natural Gas	22.18	26.11	26.94	27.80	27.25	28.77	30.56	29.12	30.97	32.81
Coal	19.95	21.04	21.72	22.87	21.84	22.68	24.13	22.41	23.76	26.41
Nuclear Power	7.19	6.98	6.98	6.98	6.55	6.55	6.55	4.79	4.79	4.79
Renewable Energy[1]	6.30	6.73	6.88	7.04	7.00	7.25	7.51	7.23	7.71	8.18
Other[9]	0.39	0.38	0.38	0.38	0.39	0.39	0.39	0.36	0.37	0.38
Total	**90.93**	**100.33**	**103.36**	**106.85**	**103.21**	**107.89**	**113.41**	**104.23**	**110.87**	**118.67**
Net Imports - Petroleum	**16.87**	**24.51**	**25.59**	**26.65**	**25.88**	**27.48**	**29.01**	**26.21**	**28.60**	**30.92**
Prices (1995 dollars per unit)										
World Oil Price (dollars per barrel)[10]	17.26	18.93	19.72	20.54	19.43	20.41	21.37	19.78	20.98	22.21
Gas Wellhead Price (dollars per Mcf)[11]	1.61	1.79	1.94	2.15	1.81	2.01	2.23	1.83	2.13	2.49
Coal Minemouth Price (dollars per ton)	18.83	17.19	17.47	17.78	16.80	16.92	16.64	15.32	15.46	15.90

[1]Includes utility and nonutility grid-connected electricity from hydroelectric, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes nonmarketed renewable energy. 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.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors.

Sources: 1995 natural gas price: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). 1995 natural gas supply derived from: EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC November 1996). 1995 coal minemouth price, coal production, and exports derived from: EIA, *Monthly Energy Review*, DOE/EIA-0035(96/08) (Washington, DC, August 1996). Other 1995 values: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

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

Sector and Source	1995	Projections								
		2005			2010			2015		
		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	0.85	0.78	0.78	0.79	0.74	0.75	0.77	0.72	0.73	0.75
Kerosene	0.07	0.07	0.07	0.07	0.06	0.07	0.07	0.06	0.06	0.07
Liquefied Petroleum Gas	0.40	0.43	0.44	0.46	0.42	0.45	0.47	0.42	0.46	0.49
Petroleum Subtotal	1.32	1.27	1.29	1.32	1.23	1.26	1.31	1.20	1.25	1.31
Natural Gas	5.01	5.30	5.43	5.55	5.37	5.57	5.79	5.46	5.73	6.00
Coal	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04
Renewable Energy[1]	0.57	0.55	0.56	0.57	0.53	0.55	0.56	0.52	0.54	0.56
Electricity	3.56	4.02	4.14	4.27	4.27	4.46	4.66	4.57	4.85	5.13
Delivered Energy	**10.51**	**11.18**	**11.46**	**11.75**	**11.44**	**11.89**	**12.36**	**11.79**	**12.41**	**13.04**
Electricity Related Losses	7.92	8.35	8.55	8.76	8.68	8.95	9.26	8.83	9.22	9.74
Total	**18.43**	**19.54**	**20.02**	**20.51**	**20.12**	**20.83**	**21.62**	**20.63**	**21.63**	**22.78**
Commercial										
Distillate Fuel	0.41	0.36	0.36	0.36	0.35	0.35	0.36	0.34	0.34	0.35
Residual Fuel	0.17	0.13	0.13	0.14	0.13	0.14	0.14	0.14	0.14	0.15
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.07
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02
Petroleum Subtotal	0.67	0.60	0.60	0.61	0.59	0.59	0.61	0.58	0.59	0.61
Natural Gas	3.16	3.43	3.44	3.52	3.51	3.54	3.67	3.61	3.65	3.83
Coal	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.10
Renewable Energy[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	3.23	3.70	3.71	3.81	3.90	3.91	4.07	4.13	4.16	4.39
Delivered Energy	**7.15**	**7.81**	**7.84**	**8.02**	**8.08**	**8.13**	**8.44**	**8.41**	**8.50**	**8.94**
Electricity Related Losses	7.18	7.69	7.67	7.82	7.92	7.85	8.09	7.98	7.91	8.33
Total	**14.33**	**15.50**	**15.51**	**15.84**	**16.00**	**15.98**	**16.53**	**16.39**	**16.40**	**17.27**
Industrial[4]										
Distillate Fuel	1.15	1.32	1.39	1.46	1.37	1.47	1.58	1.41	1.55	1.69
Liquefied Petroleum Gas	2.01	2.11	2.20	2.29	2.14	2.28	2.43	2.16	2.35	2.55
Petrochemical Feedstocks	1.16	1.25	1.30	1.35	1.27	1.35	1.43	1.29	1.40	1.51
Residual Fuel	0.34	0.30	0.31	0.33	0.32	0.33	0.33	0.31	0.35	0.35
Motor Gasoline[2]	0.20	0.23	0.24	0.25	0.24	0.26	0.28	0.24	0.27	0.30
Other Petroleum[5]	3.83	4.13	4.33	4.45	4.20	4.43	4.63	4.22	4.48	4.70
Petroleum Subtotal	8.68	9.33	9.77	10.12	9.54	10.13	10.66	9.62	10.41	11.10
Natural Gas[6]	9.74	10.74	11.04	11.34	10.92	11.42	11.99	10.97	11.63	12.33
Metallurgical Coal	0.88	0.69	0.69	0.69	0.62	0.62	0.62	0.55	0.55	0.55
Steam Coal	1.59	1.70	1.82	1.99	1.70	1.89	2.12	1.68	1.97	2.30
Net Coal Coke Imports	0.03	0.07	0.11	0.14	0.09	0.13	0.18	0.09	0.15	0.20
Coal Subtotal	2.51	2.46	2.62	2.82	2.40	2.64	2.91	2.32	2.67	3.05
Renewable Energy[7]	1.74	2.02	2.12	2.21	2.12	2.28	2.43	2.17	2.40	2.62
Electricity	3.46	3.93	4.16	4.44	4.03	4.40	4.81	4.09	4.62	5.21
Delivered Energy	**26.12**	**28.49**	**29.70**	**30.93**	**29.01**	**30.87**	**32.81**	**29.17**	**31.73**	**34.30**
Electricity Related Losses	7.69	8.17	8.59	9.11	8.20	8.82	9.56	7.90	8.79	9.89
Total	**33.81**	**36.66**	**38.28**	**40.04**	**37.20**	**39.69**	**42.37**	**37.07**	**40.51**	**44.19**

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

Sector and Source	1995	Projections								
		2005			2010			2015		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Transportation										
Distillate Fuel	4.42	5.22	5.46	5.70	5.41	5.78	6.16	5.48	6.00	6.51
Jet Fuel [8]	3.13	4.07	4.26	4.45	4.33	4.67	5.00	4.44	4.95	5.43
Motor Gasoline[2]	14.65	16.23	16.61	16.98	16.49	17.09	17.67	16.25	17.11	17.92
Residual Fuel	1.08	1.42	1.47	1.52	1.56	1.64	1.72	1.66	1.78	1.90
Liquefied Petroleum Gas	0.03	0.11	0.11	0.12	0.16	0.18	0.19	0.20	0.21	0.23
Other Petroleum[9]	0.26	0.30	0.31	0.32	0.31	0.33	0.35	0.31	0.34	0.37
Petroleum Subtotal	23.56	27.35	28.22	29.09	28.27	29.69	31.09	28.34	30.39	32.36
Pipeline Fuel Natural Gas	0.72	0.82	0.84	0.86	0.84	0.88	0.94	0.88	0.93	1.00
Compressed Natural Gas	0.01	0.18	0.18	0.19	0.24	0.26	0.28	0.28	0.31	0.34
Renewable Energy (E85)[10]	0.00	0.02	0.02	0.03	0.07	0.07	0.08	0.09	0.10	0.11
Methanol [11]	0.00	0.03	0.03	0.03	0.06	0.07	0.07	0.08	0.09	0.10
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.08	0.08	0.08	0.13	0.14	0.14	0.16	0.17	0.18
Delivered Energy	24.31	28.47	29.38	30.28	29.61	31.11	32.60	29.84	31.99	34.09
Electricity Related Losses	0.04	0.16	0.17	0.17	0.27	0.28	0.29	0.31	0.32	0.34
Total	24.36	28.63	29.55	30.45	29.88	31.39	32.88	30.15	32.32	34.43
Delivered Energy Consumption for All Sectors										
Distillate Fuel	6.82	7.67	7.98	8.31	7.87	8.35	8.86	7.94	8.62	9.31
Kerosene	0.11	0.11	0.11	0.11	0.10	0.11	0.11	0.10	0.11	0.11
Jet Fuel [8]	3.13	4.07	4.26	4.45	4.33	4.67	5.00	4.44	4.95	5.43
Liquefied Petroleum Gas	2.49	2.70	2.81	2.92	2.79	2.97	3.15	2.84	3.09	3.34
Motor Gasoline[2]	14.87	16.48	16.88	17.26	16.76	17.38	17.98	16.52	17.40	18.24
Petrochemical Feedstocks	1.16	1.25	1.30	1.35	1.27	1.35	1.43	1.29	1.40	1.51
Residual Fuel	1.58	1.86	1.92	1.99	2.02	2.11	2.19	2.11	2.27	2.40
Other Petroleum[12]	4.07	4.42	4.62	4.75	4.49	4.74	4.96	4.51	4.80	5.05
Petroleum Subtotal	34.24	38.54	39.88	41.15	39.62	41.67	43.67	39.75	42.63	45.38
Natural Gas[6]	18.64	20.46	20.93	21.45	20.88	21.68	22.67	21.20	22.26	23.50
Metallurgical Coal	0.88	0.69	0.69	0.69	0.62	0.62	0.62	0.55	0.55	0.55
Steam Coal	1.73	1.83	1.95	2.12	1.83	2.02	2.25	1.81	2.10	2.44
Net Coal Coke Imports	0.03	0.07	0.11	0.14	0.09	0.13	0.18	0.09	0.15	0.20
Coal Subtotal	2.64	2.59	2.75	2.95	2.53	2.77	3.04	2.45	2.80	3.18
Renewable Energy[13]	2.31	2.59	2.70	2.81	2.72	2.90	3.07	2.79	3.04	3.29
Methanol [11]	0.00	0.03	0.03	0.03	0.06	0.07	0.07	0.08	0.09	0.10
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	10.26	11.74	12.09	12.60	12.32	12.91	13.68	12.94	13.80	14.91
Delivered Energy	68.10	75.96	78.38	80.98	78.14	81.99	86.20	79.22	84.62	90.37
Electricity Related Losses	22.83	24.38	24.98	25.86	25.07	25.90	27.21	25.02	26.24	28.31
Total	90.93	100.33	103.36	106.85	103.21	107.89	113.41	104.23	110.87	118.67
Electric Generators[14]										
Distillate Fuel	0.08	0.11	0.12	0.14	0.12	0.14	0.15	0.15	0.15	0.16
Residual Fuel	0.60	0.44	0.46	0.49	0.43	0.43	0.45	0.43	0.48	0.56
Petroleum Subtotal	0.68	0.55	0.58	0.62	0.56	0.57	0.60	0.58	0.63	0.73
Natural Gas	3.54	5.64	6.01	6.35	6.37	7.09	7.89	7.91	8.71	9.31
Steam Coal	17.31	18.45	18.97	19.92	19.31	19.91	21.09	19.96	20.96	23.22
Nuclear Power	7.19	6.98	6.98	6.98	6.55	6.55	6.55	4.79	4.79	4.79
Renewable Energy[15]	3.99	4.13	4.18	4.24	4.28	4.36	4.44	4.44	4.67	4.89
Electricity Imports	0.39	0.36	0.36	0.36	0.32	0.32	0.32	0.28	0.28	0.28
Total	33.10	36.11	37.07	38.46	37.39	38.81	40.89	37.96	40.04	43.22

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

Sector and Source	1995	Projections								
		2005			2010			2015		
		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	6.90	7.78	8.11	8.45	7.99	8.49	9.01	8.10	8.77	9.47
Kerosene	0.11	0.11	0.11	0.11	0.10	0.11	0.11	0.10	0.11	0.11
Jet Fuel [8]	3.13	4.07	4.26	4.45	4.33	4.67	5.00	4.44	4.95	5.43
Liquefied Petroleum Gas	2.49	2.70	2.81	2.92	2.79	2.97	3.15	2.84	3.09	3.34
Motor Gasoline[2]	14.87	16.48	16.88	17.26	16.76	17.38	17.98	16.52	17.40	18.24
Petrochemical Feedstocks	1.16	1.25	1.30	1.35	1.27	1.35	1.43	1.29	1.40	1.51
Residual Fuel	2.18	2.30	2.38	2.47	2.45	2.54	2.64	2.53	2.75	2.96
Other Petroleum[12]	4.07	4.42	4.62	4.75	4.49	4.74	4.96	4.51	4.80	5.05
Petroleum Subtotal	34.92	39.09	40.46	41.77	40.18	42.24	44.27	40.33	43.26	46.11
Natural Gas	22.18	26.11	26.94	27.80	27.25	28.77	30.56	29.12	30.97	32.81
Metallurgical Coal	0.88	0.69	0.69	0.69	0.62	0.62	0.62	0.55	0.55	0.55
Steam Coal	19.04	20.28	20.92	22.04	21.14	21.94	23.34	21.77	23.06	25.66
Net Coal Coke Imports	0.03	0.07	0.11	0.14	0.09	0.13	0.18	0.09	0.15	0.20
Coal Subtotal	19.95	21.04	21.72	22.87	21.84	22.68	24.13	22.41	23.76	26.41
Nuclear Power	7.19	6.98	6.98	6.98	6.55	6.55	6.55	4.79	4.79	4.79
Renewable Energy[16]	6.30	6.73	6.88	7.04	7.00	7.25	7.51	7.23	7.71	8.18
Methanol [11]	0.00	0.03	0.03	0.03	0.06	0.07	0.07	0.08	0.09	0.10
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.39	0.36	0.36	0.36	0.32	0.32	0.32	0.28	0.28	0.28
Total	90.93	100.33	103.36	106.85	103.21	107.89	113.41	104.23	110.87	118.67
Energy Use and Related Statistics										
Delivered Energy Use	68.10	75.96	78.38	80.98	78.14	81.99	86.20	79.22	84.62	90.37
Total Energy Use	90.93	100.33	103.35	106.83	103.19	107.87	113.39	104.20	110.83	118.64
Population (millions)	263.58	279.92	287.12	293.76	288.32	298.92	308.72	297.04	311.19	324.31
Gross Domestic Product (billion 1992 dollars)	6738.95	8013.05	8389.54	8766.55	8561.61	9185.32	9796.51	8981.64	9879.75	10766.37

[1]Includes wood used for residential heating. See Table B18 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps and solar thermal hot water heating.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector electricity cogenerated by using wood and wood waste, municipal solid waste, and other biomass. See Table B18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating.
[4]Fuel consumption includes consumption for cogeneration.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Includes lease and plant fuel.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[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]Only M85 (85 percent methanol).
[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 electric utilities and for self use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps and solar thermal hot water heaters.
[14]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity as a by-product of other processes.
[15]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, E85, wind, photovoltaic and solar thermal sources.
[16]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 nonmarketed renewable energy consumption for geothermal heat pumps and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1995 natural gas lease, plant, and pipeline fuel values: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). 1995 transportation sector compressed natural gas consumption: EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A. 1995 electric utility fuel consumption: EIA, *Electric Power Annual, Volume I*, DOE/EIA-0348(95)/1 (Washington, DC, July 1996). 1995 nonutility consumption estimates: EIA Form 867, "Annual Nonutility Power Producer Report." Other 1995 values: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996).
Projections: EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B3. Energy Prices by Sector and Source
(1995 Dollars per Million Btu)

Sector and Source	1995	Projections								
		2005			2010			2015		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential	12.87	12.26	12.70	13.00	12.08	12.61	12.94	11.86	12.55	13.07
Primary Energy	6.28	5.96	6.09	6.29	5.75	5.95	6.14	5.54	5.83	6.15
Petroleum Products	7.51	8.54	8.75	8.99	8.74	9.08	9.27	8.59	8.95	9.35
Distillate Fuel	6.24	7.12	7.28	7.46	7.20	7.45	7.63	7.09	7.33	7.68
Liquefied Petroleum Gas	10.29	11.15	11.40	11.69	11.47	11.85	11.97	11.17	11.57	11.96
Natural Gas	6.01	5.38	5.49	5.69	5.11	5.27	5.46	4.91	5.18	5.49
Electricity	24.67	22.62	23.49	23.89	21.93	22.88	23.37	21.13	22.28	22.98
Commercial	13.12	12.16	12.60	12.96	11.94	12.48	12.88	11.55	12.28	12.91
Primary Energy	4.82	4.54	4.69	4.89	4.38	4.59	4.79	4.23	4.54	4.86
Petroleum Products	4.58	5.18	5.34	5.52	5.28	5.52	5.69	5.17	5.42	5.73
Distillate Fuel	4.39	5.11	5.28	5.46	5.19	5.44	5.63	5.06	5.32	5.67
Residual Fuel	2.99	2.74	2.87	3.00	2.82	2.98	3.18	2.83	3.03	3.23
Natural Gas[1]	4.96	4.50	4.65	4.86	4.30	4.51	4.73	4.15	4.48	4.81
Electricity	23.19	20.61	21.38	21.88	20.06	20.98	21.55	19.16	20.35	21.25
Industrial[2]	5.02	4.72	4.96	5.22	4.72	5.05	5.30	4.55	4.99	5.43
Primary Energy	3.36	3.18	3.34	3.53	3.24	3.47	3.63	3.17	3.47	3.77
Petroleum Products	4.92	4.42	4.60	4.80	4.53	4.80	4.95	4.34	4.68	5.01
Distillate Fuel	4.61	5.04	5.21	5.40	5.14	5.38	5.58	5.02	5.29	5.66
Liquefied Petroleum Gas	6.53	5.75	6.00	6.29	5.94	6.28	6.33	5.51	5.95	6.33
Residual Fuel	2.55	2.80	2.92	3.05	2.85	3.03	3.19	2.82	3.01	3.27
Natural Gas[3]	2.28	2.37	2.54	2.77	2.39	2.61	2.85	2.41	2.74	3.11
Metallurgical Coal	1.75	1.69	1.72	1.75	1.54	1.58	1.60	1.43	1.48	1.52
Steam Coal	1.48	1.41	1.44	1.47	1.34	1.37	1.39	1.25	1.30	1.33
Electricity	14.54	12.93	13.46	13.82	12.53	13.13	13.52	11.75	12.56	13.20
Transportation	7.92	8.18	8.51	8.83	8.06	8.55	8.89	7.70	8.21	8.71
Primary Energy	7.92	8.16	8.49	8.81	8.03	8.53	8.87	7.66	8.18	8.68
Petroleum Products	7.92	8.18	8.51	8.83	8.04	8.54	8.88	7.67	8.19	8.70
Distillate Fuel[4]	8.03	8.32	8.70	9.02	8.17	8.68	9.06	7.80	8.38	8.94
Jet Fuel[5]	3.85	5.14	5.46	5.76	5.19	5.65	5.95	4.98	5.45	5.91
Motor Gasoline[6]	9.23	9.42	9.79	10.14	9.27	9.85	10.24	8.89	9.49	10.06
Residual Fuel	2.44	2.76	2.90	3.06	2.96	3.16	3.38	2.85	3.08	3.32
Natural Gas[7]	5.77	6.05	6.20	6.44	6.52	6.73	6.97	6.75	7.07	7.41
Electricity	15.14	14.08	14.45	14.54	13.85	14.25	14.36	13.37	13.85	14.05
Total End-Use Energy	8.22	8.01	8.31	8.59	7.93	8.34	8.63	7.69	8.18	8.65
Primary Energy	7.82	7.68	7.98	8.27	7.60	8.01	8.31	7.33	7.82	8.29
Electricity	20.77	18.68	19.33	19.67	18.18	18.89	19.27	17.44	18.34	18.95
Electric Generators[8]										
Fossil Fuel Average	1.48	1.47	1.53	1.60	1.46	1.54	1.62	1.43	1.55	1.67
Petroleum Products	2.78	3.19	3.35	3.49	3.35	3.59	3.78	3.36	3.52	3.76
Distillate Fuel	3.94	4.59	4.77	4.93	4.66	4.92	5.11	4.54	4.83	5.19
Residual Fuel	2.62	2.86	2.97	3.09	2.97	3.15	3.34	2.93	3.11	3.34
Natural Gas	2.01	2.13	2.28	2.48	2.13	2.32	2.57	2.14	2.47	2.82
Steam Coal	1.32	1.22	1.24	1.26	1.18	1.20	1.20	1.08	1.11	1.15

Table B3. Energy Prices by Sector and Source (Continued)
(1995 Dollars per Million Btu)

Sector and Source	1995	Projections								
		2005			2010			2015		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Average Price to All Users[9]										
Petroleum Products	7.07	7.25	7.52	7.80	7.19	7.62	7.90	6.88	7.33	7.78
Distillate Fuel[4]	6.98	7.45	7.75	8.03	7.38	7.80	8.13	7.07	7.56	8.07
Jet Fuel	3.85	5.14	5.46	5.76	5.19	5.65	5.95	4.98	5.45	5.91
Liquefied Petroleum Gas	7.20	6.95	7.20	7.49	7.24	7.61	7.68	6.87	7.32	7.71
Motor Gasoline[6]	9.23	9.41	9.77	10.12	9.26	9.83	10.22	8.88	9.47	10.04
Residual Fuel	2.55	2.78	2.91	3.06	2.94	3.13	3.34	2.86	3.07	3.31
Natural Gas	3.57	3.32	3.45	3.65	3.22	3.39	3.60	3.12	3.42	3.76
Coal	1.35	1.24	1.25	1.28	1.19	1.21	1.22	1.10	1.13	1.17
Electricity	20.77	18.68	19.33	19.67	18.18	18.89	19.27	17.44	18.34	18.95

[1]Excludes independent power producers.
[2]Includes cogenerators.
[3]Excludes uses for lease and plant fuel.
[4]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[5]Kerosene-type jet fuel.
[6]Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[7]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[8]Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[9]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: 1995 figures may differ from published data due to internal rounding.
Sources: 1995 prices for gasoline, distillate, and jet fuel are based on prices in various 1995 issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly,* DOE/EIA-0380(95/1-12) (Washington, DC, 1995). 1995 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1993,* DOE/EIA-0376(93) (Washington, DC, December 1995). 1995 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1991.* 1995 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly,* DOE/EIA-0130(96/6) (Washington, DC, June 1996). Other 1995 natural gas delivered prices: EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A. Values for 1995 coal prices have been estimated from EIA, *State Energy Price and Expenditure Report 1993,* DOE/EIA-0376(93) (Washington, DC, December 1995) by use of consumption quantities aggregated from EIA, *State Energy Data Report 1993, Consumption Estimates,* DOE/EIA-0214(93) (Washington, DC, July 1995). 1995 electricity prices for commercial, industrial, and transportation: EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A. **Projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

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

Key Indicators and Consumption	1995	Projections								
		2005			2010			2015		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Household Characteristics										
Households (millions)										
Single-Family	68.66	74.60	76.85	79.19	77.43	80.93	84.49	80.21	85.07	89.99
Multifamily	24.56	26.14	26.98	27.89	27.27	28.67	30.10	28.47	30.45	32.45
Mobile Homes	5.83	6.43	6.64	6.83	6.57	6.89	7.20	6.68	7.12	7.55
Total	**99.06**	**107.17**	**110.47**	**113.91**	**111.27**	**116.49**	**121.78**	**115.36**	**122.65**	**130.00**
Housing Starts (millions)										
Single-Family	1.08	0.83	1.08	1.33	0.77	1.03	1.29	0.80	1.09	1.39
Multifamily	0.28	0.31	0.42	0.53	0.36	0.48	0.59	0.35	0.48	0.60
Mobile Homes	0.34	0.26	0.29	0.32	0.24	0.28	0.31	0.25	0.29	0.33
Total	**1.70**	**1.40**	**1.80**	**2.18**	**1.37**	**1.79**	**2.19**	**1.40**	**1.86**	**2.32**
Average House Square Footage	**1643**	**1677**	**1683**	**1690**	**1688**	**1696**	**1705**	**1698**	**1708**	**1718**
Energy Intensity										
Million Btu Consumed per Household										
Delivered Energy Consumption	106.10	104.36	103.78	103.19	102.82	102.06	101.50	102.22	101.19	100.33
Electricity Related Losses	79.94	77.96	77.43	76.88	78.02	76.80	76.06	76.56	75.20	74.94
Total Energy Consumption	186.03	182.31	181.21	180.07	180.84	178.86	177.57	178.78	176.39	175.27
Thousand Btu Consumed per Square Foot										
Delivered Energy Consumption	64.57	62.23	61.65	61.05	60.90	60.16	59.53	60.21	59.26	58.40
Electricity Related Losses	48.65	46.49	46.00	45.49	46.21	45.27	44.61	45.10	44.04	43.63
Total Energy Consumption	113.22	108.71	107.64	106.54	107.12	105.43	104.14	105.30	103.29	102.03
Delivered Energy Consumption by Fuel										
Distillate										
Space Heating	0.76	0.68	0.69	0.69	0.64	0.65	0.67	0.62	0.63	0.65
Water Heating	0.09	0.10	0.10	0.10	0.09	0.10	0.10	0.09	0.10	0.10
Other Uses[1]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	**0.85**	**0.78**	**0.78**	**0.79**	**0.74**	**0.75**	**0.77**	**0.72**	**0.73**	**0.75**
Liquefied Petroleum Gas										
Space Heating	0.30	0.31	0.32	0.33	0.30	0.32	0.34	0.30	0.32	0.34
Water Heating	0.06	0.08	0.08	0.09	0.08	0.09	0.09	0.09	0.09	0.10
Cooking[2]	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	**0.40**	**0.43**	**0.44**	**0.46**	**0.42**	**0.45**	**0.47**	**0.42**	**0.46**	**0.49**
Natural Gas										
Space Heating	3.48	3.71	3.79	3.87	3.75	3.88	4.02	3.79	3.96	4.13
Space Cooling	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.03
Water Heating	1.25	1.30	1.34	1.37	1.33	1.39	1.44	1.37	1.45	1.52
Cooking[2]	0.15	0.13	0.14	0.14	0.13	0.14	0.15	0.13	0.14	0.15
Clothes Dryers	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Other Uses[3]	0.09	0.10	0.10	0.10	0.10	0.10	0.11	0.10	0.11	0.11
Delivered Energy	**5.01**	**5.30**	**5.43**	**5.55**	**5.37**	**5.57**	**5.79**	**5.46**	**5.73**	**6.00**
Electricity										
Space Heating	0.43	0.46	0.47	0.49	0.46	0.48	0.50	0.47	0.49	0.52
Space Cooling	0.48	0.47	0.48	0.50	0.47	0.49	0.51	0.48	0.51	0.54
Water Heating	0.35	0.36	0.37	0.37	0.36	0.38	0.39	0.37	0.39	0.41
Refrigeration	0.40	0.32	0.33	0.33	0.30	0.31	0.32	0.29	0.31	0.33
Cooking	0.12	0.13	0.13	0.14	0.13	0.14	0.14	0.13	0.14	0.15
Clothes Dryers	0.18	0.19	0.20	0.20	0.20	0.21	0.22	0.20	0.22	0.23
Freezers	0.13	0.09	0.09	0.09	0.08	0.08	0.08	0.07	0.08	0.08
Lighting	0.32	0.33	0.34	0.36	0.34	0.35	0.37	0.34	0.36	0.39
Other Uses[4]	1.15	1.68	1.73	1.79	1.93	2.02	2.11	2.21	2.35	2.49
Delivered Energy	**3.56**	**4.02**	**4.14**	**4.27**	**4.27**	**4.46**	**4.66**	**4.57**	**4.85**	**5.13**

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

Key Indicators and Consumption	1995	Projections								
		2005			2010			2015		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Marketed Renewables										
Wood[5]	0.57	0.55	0.56	0.57	0.53	0.55	0.56	0.52	0.54	0.56
Delivered Energy	0.57	0.55	0.56	0.57	0.53	0.55	0.56	0.52	0.54	0.56
Other Fuels[6]	0.13	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.10	0.11
Delivered Energy Consumption by End-Use										
Space Heating	5.65	5.82	5.94	6.07	5.80	5.99	6.20	5.80	6.05	6.32
Space Cooling	0.48	0.48	0.49	0.51	0.49	0.51	0.53	0.50	0.53	0.56
Water Heating	1.75	1.84	1.88	1.93	1.87	1.95	2.02	1.92	2.03	2.13
Refrigeration	0.40	0.32	0.33	0.33	0.30	0.31	0.32	0.29	0.31	0.33
Cooking	0.30	0.29	0.30	0.31	0.29	0.30	0.32	0.29	0.31	0.34
Clothes Dryers	0.23	0.24	0.24	0.25	0.24	0.26	0.27	0.25	0.27	0.28
Freezers	0.13	0.09	0.09	0.09	0.08	0.08	0.08	0.07	0.08	0.08
Lighting	0.32	0.33	0.34	0.36	0.34	0.35	0.37	0.34	0.36	0.39
Other Uses[7]	1.24	1.79	1.84	1.90	2.04	2.14	2.23	2.32	2.47	2.62
Delivered Energy	10.51	11.18	11.46	11.75	11.44	11.89	12.36	11.79	12.41	13.04
Electricity Related Losses by End-Use										
Space Heating	0.95	0.95	0.97	1.00	0.94	0.96	1.00	0.90	0.94	0.99
Space Cooling	1.07	0.97	0.99	1.02	0.96	0.99	1.02	0.93	0.97	1.02
Water Heating	0.78	0.74	0.76	0.77	0.74	0.76	0.78	0.72	0.74	0.77
Refrigeration	0.90	0.66	0.67	0.69	0.60	0.62	0.65	0.56	0.59	0.62
Cooking	0.27	0.27	0.27	0.28	0.27	0.28	0.29	0.26	0.27	0.29
Clothes Dryers	0.40	0.40	0.41	0.42	0.40	0.42	0.43	0.40	0.41	0.44
Freezers	0.29	0.18	0.19	0.19	0.16	0.16	0.17	0.14	0.15	0.16
Lighting	0.70	0.69	0.71	0.73	0.68	0.71	0.74	0.65	0.69	0.73
Other Uses[7]	2.55	3.49	3.58	3.67	3.92	4.05	4.20	4.27	4.47	4.72
Total Electricity Related Losses	7.92	8.35	8.55	8.76	8.68	8.95	9.26	8.83	9.22	9.74
Total Energy Consumption by End-Use										
Space Heating	6.61	6.77	6.91	7.06	6.74	6.96	7.20	6.70	6.99	7.31
Space Cooling	1.56	1.45	1.49	1.53	1.44	1.49	1.56	1.43	1.50	1.58
Water Heating	2.53	2.58	2.64	2.70	2.62	2.71	2.80	2.64	2.77	2.90
Refrigeration	1.30	0.97	1.00	1.02	0.90	0.93	0.97	0.85	0.89	0.95
Cooking	0.58	0.55	0.57	0.59	0.55	0.58	0.60	0.55	0.59	0.62
Clothes Dryers	0.63	0.63	0.65	0.67	0.65	0.67	0.70	0.65	0.68	0.72
Freezers	0.42	0.27	0.28	0.28	0.24	0.24	0.25	0.22	0.23	0.24
Lighting	1.02	1.02	1.05	1.09	1.02	1.06	1.11	0.99	1.05	1.12
Other Uses[7]	3.79	5.28	5.43	5.57	5.97	6.19	6.43	6.60	6.94	7.34
Total	18.43	19.54	20.02	20.51	20.12	20.83	21.62	20.63	21.63	22.78
Non-Marketed Renewables										
Geothermal[8]	0.01	0.04	0.04	0.04	0.05	0.05	0.05	0.07	0.07	0.08
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	0.05	0.05	0.05	0.06	0.06	0.07	0.08	0.08	0.09

[1]Includes such appliances as swimming pool and hot tub heaters.
[2]Does not include outdoor grills.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as microwave ovens, television sets, and dishwashers.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1993*.
[6]Includes kerosene and coal.
[7]Includes such appliances as swimming pool heaters, hot tub heaters, outdoor grills, outdoor lighting (natural gas), microwave ovens, television sets, and dishwashers.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B5. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections								
		2005			2010			2015		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Key Indicators										
Total Floor Space (billion square feet)										
Surviving	68.9	75.5	76.0	77.8	78.3	79.1	82.1	81.2	82.5	86.7
New Additions	1.7	1.5	1.5	1.7	1.5	1.6	1.8	1.7	1.8	2.0
Total	**70.7**	**76.9**	**77.5**	**79.6**	**79.8**	**80.7**	**83.9**	**82.8**	**84.2**	**88.7**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	101.2	101.5	101.1	100.8	101.3	100.7	100.6	101.6	100.9	100.8
Electricity Related Losses	101.6	99.9	99.0	98.3	99.3	97.3	96.4	96.3	93.9	93.9
Total Energy Consumption	202.8	201.4	200.1	199.1	200.6	198.0	197.0	197.9	194.8	194.7
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.11	0.12	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.14
Space Cooling	0.58	0.52	0.52	0.53	0.52	0.52	0.55	0.53	0.53	0.57
Water Heating	0.17	0.15	0.15	0.15	0.14	0.14	0.14	0.13	0.13	0.13
Ventilation	0.17	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20	0.21
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Lighting	1.21	1.32	1.32	1.34	1.33	1.32	1.35	1.36	1.36	1.40
Refrigeration	0.14	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17	0.19
Office Equipment (PC)	0.07	0.09	0.09	0.10	0.10	0.10	0.11	0.10	0.10	0.11
Office Equipment (non-PC)	0.18	0.22	0.22	0.23	0.24	0.25	0.26	0.27	0.27	0.29
Other Uses[1]	0.56	0.91	0.92	0.95	1.07	1.08	1.14	1.21	1.24	1.33
Delivered Energy	**3.23**	**3.70**	**3.71**	**3.81**	**3.90**	**3.91**	**4.07**	**4.13**	**4.16**	**4.39**
Natural Gas[2]										
Space Heating	1.30	1.34	1.34	1.37	1.35	1.36	1.40	1.37	1.38	1.43
Space Cooling	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04
Water Heating	0.48	0.50	0.50	0.51	0.52	0.52	0.54	0.54	0.55	0.58
Cooking	0.18	0.21	0.21	0.22	0.23	0.23	0.24	0.25	0.25	0.26
Other Uses[3]	1.17	1.35	1.36	1.39	1.39	1.40	1.45	1.43	1.45	1.52
Delivered Energy	**3.16**	**3.43**	**3.44**	**3.52**	**3.51**	**3.54**	**3.67**	**3.61**	**3.65**	**3.83**
Distillate										
Space Heating	0.20	0.17	0.17	0.17	0.16	0.16	0.16	0.15	0.15	0.16
Water Heating	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.05
Other Uses[4]	0.15	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.15
Delivered Energy	**0.41**	**0.36**	**0.36**	**0.36**	**0.35**	**0.35**	**0.36**	**0.34**	**0.34**	**0.35**
Other Fuels[5]	**0.35**	**0.32**	**0.32**	**0.33**	**0.33**	**0.33**	**0.35**	**0.34**	**0.34**	**0.36**
Marketed Renewable Fuels										
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Delivered Energy Consumption by End-Use										
Space Heating	1.61	1.63	1.63	1.66	1.63	1.64	1.69	1.65	1.66	1.72
Space Cooling	0.61	0.55	0.55	0.57	0.55	0.55	0.58	0.56	0.56	0.60
Water Heating	0.70	0.69	0.70	0.71	0.70	0.70	0.73	0.71	0.72	0.76
Ventilation	0.17	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20	0.21
Cooking	0.22	0.24	0.24	0.25	0.25	0.26	0.27	0.27	0.27	0.29
Lighting	1.21	1.32	1.32	1.34	1.33	1.32	1.35	1.36	1.36	1.40
Refrigeration	0.14	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17	0.19
Office Equipment (PC)	0.07	0.09	0.09	0.10	0.10	0.10	0.11	0.10	0.10	0.11
Office Equipment (non-PC)	0.18	0.22	0.22	0.23	0.24	0.25	0.26	0.27	0.27	0.29
Other Uses[6]	2.24	2.73	2.75	2.82	2.92	2.96	3.09	3.12	3.18	3.36
Delivered Energy	**7.15**	**7.81**	**7.84**	**8.02**	**8.08**	**8.13**	**8.44**	**8.41**	**8.50**	**8.94**

Table B5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections 2005 Low Economic Growth	2005 Reference	2005 High Economic Growth	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2015 Low Economic Growth	2015 Reference	2015 High Economic Growth
Electricity Related Losses by End-Use										
Space Heating	0.25	0.25	0.25	0.25	0.25	0.25	0.26	0.25	0.25	0.26
Space Cooling	1.29	1.08	1.07	1.10	1.06	1.05	1.09	1.02	1.01	1.08
Water Heating	0.38	0.31	0.31	0.32	0.28	0.28	0.28	0.25	0.24	0.25
Ventilation	0.38	0.38	0.37	0.38	0.38	0.38	0.39	0.38	0.37	0.40
Cooking	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05
Lighting	2.68	2.74	2.72	2.75	2.70	2.65	2.68	2.64	2.58	2.65
Refrigeration	0.31	0.32	0.32	0.33	0.33	0.33	0.34	0.33	0.33	0.35
Office Equipment (PC)	0.16	0.19	0.19	0.20	0.20	0.20	0.21	0.20	0.20	0.21
Office Equipment (non-PC)	0.40	0.46	0.46	0.47	0.49	0.49	0.52	0.52	0.52	0.56
Other Uses[6]	1.25	1.90	1.91	1.96	2.17	2.17	2.27	2.34	2.35	2.52
Total Electricity Related Losses	7.18	7.69	7.67	7.82	7.92	7.85	8.09	7.98	7.91	8.33
Total Energy Consumption by End-Use										
Space Heating	1.87	1.88	1.88	1.92	1.89	1.89	1.95	1.90	1.91	1.99
Space Cooling	1.89	1.62	1.62	1.66	1.61	1.60	1.67	1.58	1.58	1.68
Water Heating	1.09	1.01	1.01	1.03	0.98	0.98	1.02	0.96	0.96	1.01
Ventilation	0.55	0.56	0.55	0.57	0.57	0.56	0.59	0.57	0.57	0.61
Cooking	0.29	0.30	0.30	0.31	0.31	0.31	0.32	0.32	0.32	0.34
Lighting	3.89	4.06	4.04	4.09	4.03	3.97	4.04	4.00	3.94	4.05
Refrigeration	0.46	0.47	0.47	0.49	0.49	0.49	0.51	0.50	0.50	0.54
Office Equipment (PC)	0.23	0.29	0.29	0.30	0.30	0.30	0.31	0.30	0.30	0.33
Office Equipment (non-PC)	0.59	0.68	0.68	0.70	0.74	0.74	0.78	0.79	0.79	0.85
Other Uses[6]	3.49	4.63	4.66	4.77	5.10	5.14	5.35	5.46	5.53	5.88
Total	14.33	15.50	15.51	15.84	16.00	15.98	16.53	16.39	16.40	17.27
Non-Marketed Renewable Fuels										
Solar[7]	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04
Total	0.01	0.03	0.03	0.03	0.03	0.03	0.03	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, lighting, emergency electric generators, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, district services, and emergency electric generators.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes primary energy displaced by solar thermal water heaters.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections								
		2005			2010			2015		
		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	2907	3519	3709	3902	3806	4117	4437	3986	4441	4905
Nonmanufacturing	765	864	917	972	901	978	1056	925	1028	1135
Total	3672	4383	4626	4874	4707	5095	5494	4911	5469	6039
Energy Prices (1995 dollars per million Btu)										
Electricity	14.54	12.93	13.46	13.82	12.53	13.13	13.52	11.75	12.56	13.20
Natural Gas	2.28	2.37	2.54	2.77	2.39	2.61	2.85	2.41	2.74	3.11
Steam Coal	1.48	1.41	1.44	1.47	1.34	1.37	1.39	1.25	1.30	1.33
Residual Oil	2.55	2.80	2.92	3.05	2.85	3.03	3.19	2.82	3.01	3.27
Distillate Oil	4.61	5.04	5.21	5.40	5.14	5.38	5.58	5.02	5.29	5.66
Liquefied Petroleum Gas	6.53	5.75	6.00	6.29	5.94	6.28	6.33	5.51	5.95	6.33
Motor Gasoline	9.18	8.44	8.63	8.89	8.50	8.85	9.11	8.28	8.65	9.06
Metallurgical Coal	1.75	1.69	1.72	1.75	1.54	1.58	1.60	1.43	1.48	1.52
Energy Consumption										
Consumption[1] (quadrillion Btu per year)										
Purchased Electricity	3.46	3.93	4.16	4.44	4.03	4.40	4.81	4.09	4.62	5.21
Natural Gas[2]	9.74	10.74	11.04	11.34	10.92	11.42	11.99	10.97	11.63	12.33
Steam Coal	1.59	1.70	1.82	1.99	1.70	1.89	2.12	1.68	1.97	2.30
Metallurgical Coal and Coke[3]	0.91	0.76	0.80	0.83	0.70	0.75	0.79	0.64	0.70	0.75
Residual Fuel	0.34	0.30	0.31	0.33	0.32	0.33	0.33	0.31	0.35	0.35
Distillate	1.15	1.32	1.39	1.46	1.37	1.47	1.58	1.41	1.55	1.69
Liquefied Petroleum Gas	2.01	2.11	2.20	2.29	2.14	2.28	2.43	2.16	2.35	2.55
Petrochemical Feedstocks	1.16	1.25	1.30	1.35	1.27	1.35	1.43	1.29	1.40	1.51
Other Petroleum[4]	4.03	4.36	4.57	4.70	4.44	4.69	4.90	4.47	4.75	4.99
Renewables[5]	1.74	2.02	2.12	2.21	2.12	2.28	2.43	2.17	2.40	2.62
Delivered Energy	26.12	28.49	29.70	30.93	29.01	30.87	32.81	29.17	31.73	34.30
Electricity Related Losses	7.69	8.17	8.59	9.11	8.20	8.82	9.56	7.90	8.79	9.89
Total	33.81	36.66	38.28	40.04	37.20	39.69	42.37	37.07	40.51	44.19
Consumption per Unit of Output[1] (thousand Btu per 1987 dollar)										
Purchased Electricity	0.94	0.90	0.90	0.91	0.86	0.86	0.88	0.83	0.84	0.86
Natural Gas[2]	2.65	2.45	2.39	2.33	2.32	2.24	2.18	2.23	2.13	2.04
Steam Coal	0.43	0.39	0.39	0.41	0.36	0.37	0.39	0.34	0.36	0.38
Metallurgical Coal and Coke[3]	0.25	0.17	0.17	0.17	0.15	0.15	0.14	0.13	0.13	0.12
Residual Fuel	0.09	0.07	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06
Distillate	0.31	0.30	0.30	0.30	0.29	0.29	0.29	0.29	0.28	0.28
Liquefied Petroleum Gas	0.55	0.48	0.48	0.47	0.46	0.45	0.44	0.44	0.43	0.42
Petrochemical Feedstocks	0.32	0.28	0.28	0.28	0.27	0.27	0.26	0.26	0.26	0.25
Other Petroleum[4]	1.10	0.99	0.99	0.96	0.94	0.92	0.89	0.91	0.87	0.83
Renewables[5]	0.47	0.46	0.46	0.45	0.45	0.45	0.44	0.44	0.44	0.43
Delivered Energy	7.11	6.50	6.42	6.35	6.16	6.06	5.97	5.94	5.80	5.68
Electricity Related Losses	2.09	1.86	1.86	1.87	1.74	1.73	1.74	1.61	1.61	1.64
Total	9.21	8.36	8.28	8.22	7.90	7.79	7.71	7.55	7.41	7.32

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net coke coal imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995 prices for gasoline and distillate are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(95/3-96/4) (Washington, DC, 1995 - 1996). 1995 coal prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(96/08) (Washington, DC, August 1996). 1995 electricity prices: EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A. 1995 prices derived from EIA, *State Energy Data Report 1993*, DOE/EIA-0214(93) (Washington, DC, July 1995). Other 1995 values: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	1995	Projections								
		2005			2010			2015		
		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 (vehicle miles traveled)	2209	2510	2574	2634	2663	2767	2867	2769	2924	3069
Freight Trucks (vehicle miles traveled)	166	208	219	230	220	237	254	226	250	274
Air (seat miles available)	927	1419	1493	1568	1590	1729	1865	1706	1923	2134
Rail (ton miles traveled)	1181	1313	1368	1431	1370	1459	1560	1410	1535	1672
Marine (ton miles traveled)	871	951	989	1035	986	1047	1120	1015	1099	1196
Energy Efficiency Indicators										
New Car (miles per gallon)[1]	27.5	29.7	29.8	29.9	31.4	31.5	31.6	32.6	32.6	32.5
New Light Truck (miles per gallon)[1]	20.5	21.5	21.6	21.6	22.9	22.9	22.9	24.2	24.2	24.2
Light-Duty Fleet (miles per gallon)[2]	19.7	19.8	19.8	19.8	20.3	20.4	20.4	21.3	21.3	21.3
Aircraft Efficiency (seat miles per gallon)	50.8	55.6	55.8	56.0	57.9	58.2	58.5	60.2	60.6	61.0
Freight Truck Efficiency (miles per gallon)	5.5	5.8	5.9	5.9	5.9	6.0	6.0	6.0	6.1	6.1
Rail Efficiency (ton miles per thousand Btu)	2.6	2.9	2.9	2.9	3.0	3.0	3.0	3.2	3.2	3.2
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.7	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0
Energy Use by Mode (quadrillion Btu per year)										
Light-Duty Vehicles	14.20	16.13	16.52	16.90	16.64	17.26	17.87	16.53	17.43	18.28
Freight Trucks	5.43	6.23	6.47	6.70	6.45	6.80	7.16	6.58	7.07	7.56
Air	3.18	4.11	4.30	4.48	4.38	4.71	5.04	4.50	5.00	5.48
Rail	0.48	0.48	0.50	0.52	0.48	0.51	0.54	0.47	0.51	0.55
Marine	1.63	2.03	2.09	2.16	2.19	2.30	2.41	2.31	2.46	2.62
Pipeline Fuel	0.72	0.82	0.84	0.86	0.84	0.88	0.94	0.88	0.93	1.00
Other[3]	0.21	0.26	0.27	0.28	0.27	0.29	0.31	0.26	0.30	0.33
Total	24.31	28.47	29.38	30.28	29.61	31.11	32.60	29.84	31.99	34.09

[1]Environmental Protection Agency rated miles per gallon.
[2]Combined car and light truck "on-the-road" estimate.
[3]Includes lubricants and aviation gasoline.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995: Federal Aviation Administration (FAA), *FAA Aviation Forecasts Fiscal Years 1993-2004*, (Washington, DC, February 1994); Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996); EIA, *Fuel Oil and Kerosene Sales 1995*, DOE/EIA-0535(95) (Washington, DC, September 1996); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B8. Electricity Supply, Disposition, and Prices
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1995	Projections								
		2005			2010			2015		
		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	1671	1801	1854	1946	1881	1942	2058	1948	2052	2287
Petroleum	64	55	58	63	56	58	60	59	64	73
Natural Gas	322	652	705	766	775	892	1008	1042	1184	1267
Nuclear Power	673	654	654	654	614	614	614	448	448	448
Pumped Storage	-2	-3	-3	-3	-3	-3	-3	-3	-3	-3
Renewable Sources[2]	354	359	361	363	367	371	378	380	394	410
Total	3083	3518	3629	3789	3690	3874	4114	3874	4139	4482
Non-Utility Generation for Own Use	22	22	22	22	22	22	22	22	22	22
Cogenerators[3]										
Coal	43	47	48	49	48	50	51	49	51	53
Petroleum	5	5	5	6	5	6	6	5	6	6
Natural Gas	180	202	205	208	208	214	220	212	221	230
Other Gaseous Fuels[4]	7	8	8	8	8	8	8	8	8	8
Renewable Sources[2]	42	48	49	51	49	53	56	50	55	60
Other[5]	3	3	4	4	3	4	4	3	4	4
Total	279	313	319	324	322	333	345	327	344	361
Sales to Utilities	148	157	158	160	158	161	164	159	163	168
Generation for Own Use	132	156	161	165	164	172	181	168	181	194
Net Imports	38	35	35	35	31	31	31	27	27	27
Electricity Sales by Sector										
Residential	1043	1179	1214	1250	1251	1307	1366	1339	1421	1504
Commercial	946	1085	1089	1116	1142	1147	1193	1209	1219	1287
Industrial	1013	1153	1218	1301	1181	1289	1409	1198	1354	1527
Transportation	6	23	24	25	39	41	42	47	50	53
Total	3008	3440	3545	3693	3611	3784	4011	3793	4044	4371
End-Use Prices (1995 cents per kilowatthour)[6]										
Residential	8.4	7.7	8.0	8.1	7.5	7.8	8.0	7.2	7.6	7.8
Commercial	7.9	7.0	7.3	7.5	6.8	7.2	7.4	6.5	6.9	7.2
Industrial	5.0	4.4	4.6	4.7	4.3	4.5	4.6	4.0	4.3	4.5
Transportation	5.2	4.8	4.9	5.0	4.7	4.9	4.9	4.6	4.7	4.8
All Sectors Average	7.1	6.4	6.6	6.7	6.2	6.4	6.6	6.0	6.3	6.5
Price Components (1995 cents per kilowatthour)										
Capital Component	2.6	2.4	2.5	2.5	2.2	2.3	2.4	2.1	2.2	2.3
Fuel Component	1.1	1.0	1.1	1.1	1.0	1.0	1.0	0.9	0.9	0.9
Operation and Maintenance Component	3.0	2.5	2.5	2.5	2.5	2.5	2.5	2.3	2.3	2.3
Wholesale Power Cost	0.4	0.5	0.6	0.7	0.5	0.7	0.8	0.6	0.8	0.9
Total	7.1	6.4	6.6	6.7	6.2	6.4	6.6	6.0	6.3	6.5

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers, exempt wholesale generators, and generators at industrial and commercial facilities which provide electricity for on-site use and for sales to utilities.
[2]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar, and wind power.
[3]Includes cogeneration at facilities whose primary function is not electricity production. 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]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995 commercial and transportation sales derived from: Total transportation plus commercial sales come from Energy Information Administration (EIA), *State Energy Data Report 1993*, DOE/EIA-0214(93) (Washington, DC, July 1995), 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 15* (May 1995) which indicates the transportation value should be higher. 1995 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). 1995 residential electricity prices derived from EIA, *Short Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **1995 electricity prices for commercial, industrial, and transportation; price components; and projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	1995	Projections								
		2005			2010			2015		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Electric Generators[2]										
Capability										
Coal Steam	304.9	294.5	298.2	306.8	298.4	304.0	317.5	303.8	315.4	349.2
Other Fossil Steam[3]	139.6	102.6	102.6	102.6	99.9	99.9	99.9	96.1	96.1	96.1
Combined Cycle	14.7	66.0	73.5	88.8	87.2	107.5	126.0	125.0	153.0	166.4
Combustion Turbine/Diesel	56.0	126.3	134.5	151.0	143.0	153.1	164.8	157.2	168.3	183.6
Nuclear Power	99.2	94.7	94.7	94.7	88.9	88.9	88.9	62.7	62.7	62.7
Pumped Storage	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
Fuel Cells	0.0	0.6	2.0	2.2	2.1	2.1	2.8	2.2	2.1	2.9
Renewable Sources[4]	88.0	91.5	92.2	92.5	93.5	94.1	95.2	96.5	98.3	101.2
Total	**722.2**	**796.1**	**817.5**	**858.4**	**832.9**	**869.4**	**914.9**	**863.4**	**915.8**	**982.0**
Cumulative Planned Additions[5]										
Coal Steam	1.4	3.7	3.7	3.7	5.3	5.3	5.3	5.3	5.3	5.3
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	1.4	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Combustion Turbine/Diesel	3.2	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Nuclear Power	0.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Pumped Storage	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
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]	0.7	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Total	**8.0**	**15.5**	**15.5**	**15.5**	**17.1**	**17.1**	**17.1**	**17.1**	**17.1**	**17.1**
Cumulative Unplanned Additions[5]										
Coal Steam	0.0	5.8	9.5	18.1	10.7	16.4	29.8	20.0	31.6	65.4
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	50.5	58.0	73.3	71.7	91.9	110.5	109.5	137.5	150.9
Combustion Turbine/Diesel	0.1	70.0	78.2	94.7	87.1	97.1	108.8	102.3	113.5	128.7
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.6	2.0	2.2	2.1	2.1	2.8	2.2	2.1	2.9
Renewable Sources[3]	0.0	1.1	1.8	2.1	3.3	3.9	5.0	6.6	8.4	11.3
Total	**0.1**	**128.0**	**149.5**	**190.3**	**174.9**	**211.4**	**256.9**	**240.6**	**293.1**	**359.2**
Cumulative Total Additions	**8.2**	**143.5**	**165.0**	**205.9**	**192.0**	**228.5**	**274.0**	**257.7**	**310.2**	**376.3**
Cumulative Retirements[6]	**11.9**	**72.1**	**72.1**	**72.1**	**83.9**	**83.9**	**83.9**	**119.1**	**119.1**	**119.1**

Table B9. Electricity Generating Capability (Continued)
(Thousand Megawatts)

Net Summer Capability[1]	1995	Projections								
		2005			2010			2015		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Cogenerators[7]										
Capacity										
Coal	8.2	8.8	9.0	9.1	9.0	9.3	9.5	9.1	9.5	9.9
Petroleum	0.9	0.9	0.9	0.9	0.9	1.0	1.0	0.9	1.0	1.0
Natural Gas	28.9	31.6	32.1	32.5	32.5	33.3	34.2	32.9	34.2	35.5
Other Gaseous Fuels	1.0	0.9	0.9	1.0	0.9	0.9	1.0	0.9	0.9	1.0
Renewable Sources[4]	6.2	7.1	7.3	7.5	7.3	7.8	8.3	7.5	8.2	8.9
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	45.1	49.4	50.2	51.1	50.7	52.3	53.9	51.4	53.8	56.3
Cumulative Additions[5]	10.2	14.4	15.3	16.1	15.7	17.3	18.9	16.4	18.8	21.3

[1]Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.

[2]Includes grid-connected utilities and nonutilities except for cogenerators. Includes small power producers, exempt wholesale generators, and generators at industrial and commercial facilities which produce electricity for on-site use and sales to utilities.

[3]Includes oil-, gas-, and dual-fired capability.

[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power.

[5]Cumulative additions after December 31, 1994.

[6]Cumulative total retirements from 1990.

[7]Nameplate capacity is reported for nonutilities on Form EIA-867, "Annual Power Producer Report." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO97. Net summer capacity is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recent data available as of August 15, 1996. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: 1995 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 1995 and planned additions estimated based on EIA, Form EIA-867, "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1995	Projections								
		2005			2010			2015		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Interregional Electricity Trade										
Gross Domestic Firm Power Sales	155.0	139.2	139.2	139.2	139.2	139.2	139.2	139.2	139.2	139.2
Gross Domestic Economy Sales	81.6	64.9	61.3	69.4	66.8	77.6	85.2	74.4	79.4	78.1
Gross Domestic Trade	236.6	204.1	200.5	208.7	206.0	216.8	224.4	213.6	218.6	217.3
Gross Domestic Firm Power Sales (million 1995 dollars)	7023.5	6309.0	6309.0	6309.0	6309.0	6309.0	6309.0	6309.0	6309.0	6309.0
Gross Domestic Economy Sales (million 1995 dollars)	1958.3	1467.0	1420.8	1696.9	1450.1	1753.8	2111.5	1627.0	1831.4	2086.9
Gross Domestic Sales (million 1995 dollars)	8981.7	7776.0	7729.8	8005.9	7759.1	8062.8	8420.5	7936.0	8140.4	8395.9
International Electricity Trade										
Firm Power Imports From Canada and Mexico	30.2	19.7	19.7	19.7	18.6	18.6	18.6	18.6	18.6	18.6
Economy Imports From Canada and Mexico	18.0	35.2	35.2	35.2	33.6	33.6	33.6	29.2	29.2	29.2
Gross Imports From Canada and Mexico	48.3	54.9	54.8	54.8	52.2	52.2	52.2	47.9	47.9	47.9
Firm Power Exports To Canada and Mexico	3.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
Economy Exports To Canada and Mexico	7.2	7.0	7.0	7.0	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	10.6	20.3	20.3	20.3	21.0	21.0	21.0	21.0	21.0	21.0

Note: Totals may not equal sum of components due to independent rounding. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 1995 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1995 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." Firm/economy share: National Energy Board, *Annual Report 1993*. Planned interregional and international firm power sales: DOE Form IE-411, "Coordinated Bulk Power Supply Program Report" (April 1995). **Projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1995	Projections								
		2005			2010			2015		
		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]	6.56	5.42	5.49	5.56	5.28	5.39	5.50	5.10	5.23	5.36
Alaska	1.48	0.94	0.94	0.94	0.77	0.77	0.77	0.63	0.63	0.64
Lower 48 States	5.08	4.47	4.55	4.61	4.51	4.62	4.72	4.47	4.60	4.73
Net Imports	7.14	9.29	9.49	9.68	9.65	9.76	10.19	9.85	10.24	10.64
Other Crude Supply[2]	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	13.97	14.70	14.98	15.24	14.93	15.15	15.69	14.96	15.47	16.00
Natural Gas Plant Liquids	1.76	2.07	2.14	2.22	2.14	2.28	2.44	2.27	2.44	2.61
Other Inputs[3]	0.46	0.24	0.24	0.24	0.19	0.19	0.21	0.18	0.19	0.21
Refinery Processing Gain[4]	0.77	0.76	0.80	0.84	0.78	0.82	0.87	0.73	0.77	0.82
Net Product Imports[5]	0.75	2.21	2.51	2.80	2.49	3.14	3.41	2.46	3.22	3.92
Total Primary Supply[6]	17.73	19.98	20.67	21.34	20.53	21.58	22.62	20.60	22.10	23.56
Refined Petroleum Products Supplied										
Motor Gasoline[7]	7.81	8.69	8.90	9.10	8.84	9.17	9.49	8.73	9.19	9.63
Jet Fuel[8]	1.51	1.97	2.06	2.15	2.09	2.25	2.41	2.15	2.39	2.63
Distillate Fuel[9]	3.25	3.66	3.81	3.97	3.76	3.99	4.24	3.81	4.12	4.46
Residual Fuel	0.85	1.00	1.04	1.08	1.07	1.11	1.15	1.10	1.20	1.29
Other[10]	4.32	4.67	4.87	5.04	4.78	5.07	5.34	4.83	5.21	5.56
Total	17.73	19.98	20.68	21.34	20.54	21.60	22.63	20.62	22.12	23.57
Refined Petroleum Products Supplied										
Residential and Commercial	1.07	1.01	1.03	1.05	0.99	1.02	1.05	0.98	1.01	1.06
Industrial[11]	4.58	4.91	5.13	5.33	5.01	5.33	5.62	5.06	5.48	5.86
Transportation	11.79	13.82	14.26	14.69	14.29	15.00	15.70	14.33	15.35	16.33
Electric Generators[12]	0.30	0.24	0.26	0.28	0.25	0.26	0.27	0.26	0.28	0.32
Total	17.73	19.98	20.68	21.34	20.54	21.60	22.63	20.62	22.12	23.57
Discrepancy[13]	-0.01	-0.01	-0.01	0.00	-0.01	-0.02	-0.01	-0.02	-0.02	-0.01
World Oil Price (1995 dollars per barrel)[14]	17.26	18.93	19.72	20.54	19.43	20.41	21.37	19.78	20.98	22.21
Import Share of Product Supplied	0.44	0.58	0.58	0.59	0.59	0.60	0.60	0.60	0.61	0.62
Expenditures for Imported Crude Oil and Petroleum Products (billion 1995 dollars)	49.39	77.98	85.05	92.73	84.96	95.44	105.63	86.65	101.18	116.22
Domestic Refinery Distillation Capacity	15.4	15.6	16.0	16.3	15.9	16.2	16.8	16.1	16.5	17.1
Capacity Utilization Rate (percent)	92.0	94.1	94.1	94.0	94.1	94.0	94.0	93.3	94.0	94.0

[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]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net petroleum imports.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes naphtha and kerosene types.
[9]Includes distillate and kerosene.
[10]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.
[11]Includes consumption by cogenerators.
[12]Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[13]Balancing item. Includes unaccounted for supply, losses and gains.
[14]Average refiner acquisition cost for imported crude oil.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995 expenditures for imported crude oil and petroleum products based on internal calculations. Other 1995 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1995*, DOE/EIA-0340(95) (Washington, DC, May 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B12. Petroleum Product Prices
(1995 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	1995	Projections								
		2005			2010			2015		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
World Oil Price (dollars per barrel)	17.26	18.93	19.72	20.54	19.43	20.41	21.37	19.78	20.98	22.21
Delivered Sector Product Prices										
Residential										
Distillate Fuel	86.5	98.7	100.9	103.4	99.9	103.3	105.8	98.3	101.7	106.5
Liquefied Petroleum Gas	88.8	96.2	98.4	100.9	99.0	102.3	103.3	96.4	99.9	103.2
Commercial										
Distillate Fuel	60.8	70.9	73.3	75.8	71.9	75.4	78.0	70.2	73.7	78.6
Residual Fuel	44.7	41.0	42.9	44.9	42.2	44.6	47.7	42.4	45.3	48.4
Residual Fuel (dollars per barrel)	18.78	17.21	18.02	18.86	17.71	18.73	20.02	17.82	19.02	20.33
Industrial [1]										
Distillate Fuel	63.9	69.8	72.3	74.9	71.2	74.6	77.4	69.6	73.3	78.5
Liquefied Petroleum Gas	56.4	49.6	51.8	54.3	51.3	54.2	54.7	47.5	51.4	54.7
Residual Fuel	38.2	42.0	43.7	45.7	42.7	45.3	47.8	42.1	45.1	49.0
Residual Fuel (dollars per barrel)	16.06	17.62	18.36	19.18	17.93	19.04	20.07	17.70	18.95	20.57
Transportation										
Distillate Fuel [2]	111.4	115.5	120.6	125.1	113.3	120.4	125.6	108.1	116.2	124.0
Jet Fuel [3]	52.0	69.4	73.7	77.8	70.1	76.3	80.4	67.2	73.5	79.8
Motor Gasoline [4]	114.8	116.7	121.2	125.6	114.7	121.8	126.6	110.0	117.4	124.4
Residual Fuel	36.5	41.3	43.4	45.8	44.2	47.3	50.6	42.7	46.0	49.7
Residual Fuel (dollars per barrel)	15.32	17.37	18.24	19.24	18.58	19.86	21.24	17.94	19.33	20.88
Electric Generators [5]										
Distillate Fuel	54.7	63.7	66.1	68.4	64.6	68.3	70.9	63.0	67.0	72.0
Residual Fuel	39.2	42.8	44.4	46.3	44.5	47.2	49.9	43.9	46.5	50.0
Residual Fuel (dollars per barrel)	16.45	17.96	18.66	19.43	18.70	19.82	20.97	18.44	19.54	20.99
Refined Petroleum Product Prices [6]										
Distillate Fuel [2]	96.8	103.3	107.5	111.4	102.3	108.2	112.7	98.1	104.9	111.9
Jet Fuel [3]	52.0	69.4	73.7	77.8	70.1	76.3	80.4	67.2	73.5	79.8
Liquefied Petroleum Gas	62.2	60.0	62.2	64.7	62.5	65.6	66.3	59.3	63.2	66.5
Motor Gasoline [4]	114.8	116.5	120.9	125.3	114.6	121.6	126.4	109.8	117.2	124.2
Residual Fuel	38.1	41.7	43.6	45.8	44.0	46.9	50.0	42.8	46.0	49.6
Residual Fuel (dollars per barrel)	16.01	17.50	18.32	19.25	18.47	19.69	20.99	17.99	19.31	20.83
Average	92.4	95.6	99.4	103.0	94.7	100.4	104.1	90.4	96.4	102.2

[1]Includes cogenerators.
[2]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[3]Kerosene-type jet fuel.
[4]Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[5]Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Sources: 1995 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(95/3-96/4) (Washington, DC, 1995-1996). 1995 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1993*, DOE/EIA-0376(93) (Washington, DC, December 1995). **Projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	1995	Projections								
		2005			2010			2015		
		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]	18.49	21.85	22.66	23.53	22.75	24.25	26.00	24.29	26.10	27.89
Supplemental Natural Gas[2]	0.13	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	2.68	3.69	3.69	3.69	3.92	3.92	3.92	4.23	4.23	4.23
Canada	2.79	3.52	3.52	3.52	3.74	3.74	3.74	4.06	4.06	4.06
Mexico	-0.05	-0.11	-0.11	-0.11	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12
Liquefied Natural Gas	-0.05	0.27	0.27	0.27	0.29	0.29	0.29	0.29	0.29	0.29
Total Supply	21.30	25.60	26.41	27.28	26.73	28.23	29.98	28.58	30.39	32.19
Consumption by Sector										
Residential	4.87	5.15	5.27	5.40	5.22	5.42	5.62	5.31	5.57	5.83
Commercial	3.07	3.33	3.34	3.42	3.41	3.44	3.56	3.51	3.55	3.73
Industrial[3]	8.33	9.03	9.27	9.52	9.14	9.56	10.02	9.10	9.65	10.23
Electric Generators[4]	3.46	5.52	5.88	6.21	6.23	6.94	7.72	7.74	8.52	9.11
Lease and Plant Fuel[5]	1.14	1.41	1.45	1.50	1.47	1.55	1.64	1.56	1.65	1.75
Pipeline Fuel	0.70	0.80	0.82	0.83	0.82	0.86	0.92	0.85	0.91	0.97
Transportation[6]	0.01	0.17	0.18	0.18	0.24	0.25	0.27	0.27	0.30	0.33
Total	21.58	25.41	26.22	27.06	26.52	28.01	29.75	28.35	30.16	31.95
Discrepancy[7]	-0.28	0.19	0.19	0.21	0.20	0.22	0.23	0.23	0.23	0.23

[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 as a by product of other processes.
[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, 1995 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors.
Sources: 1995 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). 1995 imports and dry gas production derived from: EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). 1995 transportation sector consumption: EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A. Other 1995 consumption: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A. **Projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B14. Natural Gas Prices, Margins, and Revenues
(1995 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1995	Projections								
		2005			2010			2015		
		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]	1.61	1.79	1.94	2.15	1.81	2.01	2.23	1.83	2.13	2.49
Average Import Price	1.49	1.73	1.85	2.12	1.77	1.94	2.23	1.78	2.06	2.43
Average[2]	1.59	1.78	1.93	2.15	1.81	2.00	2.23	1.82	2.12	2.48
Delivered Prices										
Residential	6.18	5.53	5.65	5.85	5.25	5.43	5.62	5.05	5.33	5.64
Commercial	5.10	4.63	4.79	5.00	4.42	4.64	4.86	4.27	4.61	4.95
Industrial[3]	2.35	2.44	2.61	2.85	2.46	2.69	2.93	2.48	2.82	3.20
Electric Generators[4]	2.06	2.18	2.33	2.53	2.17	2.38	2.62	2.19	2.52	2.88
Transportation[5]	5.94	6.22	6.38	6.62	6.71	6.93	7.17	6.95	7.27	7.63
Average[6]	3.67	3.41	3.55	3.75	3.31	3.49	3.70	3.21	3.52	3.87
Transmission and Distribution Margins[7]										
Residential	4.59	3.75	3.73	3.70	3.45	3.43	3.39	3.23	3.21	3.16
Commercial	3.51	2.85	2.86	2.85	2.62	2.64	2.63	2.45	2.49	2.47
Industrial[3]	0.76	0.66	0.68	0.70	0.65	0.69	0.70	0.66	0.70	0.72
Electric Generators[4]	0.47	0.40	0.41	0.38	0.37	0.38	0.39	0.37	0.40	0.40
Transportation[5]	4.35	4.44	4.45	4.47	4.90	4.93	4.94	5.13	5.15	5.15
Average[6]	2.08	1.63	1.62	1.60	1.50	1.49	1.47	1.39	1.40	1.38
Transmission and Distribution Revenue (billion 1995 dollars)										
Residential	22.35	19.31	19.66	19.99	17.99	18.56	19.06	17.15	17.91	18.44
Commercial	10.79	9.48	9.56	9.74	8.92	9.08	9.37	8.60	8.85	9.18
Industrial[3]	6.31	5.95	6.32	6.63	5.98	6.57	7.00	5.99	6.72	7.33
Electric Generators[4]	1.61	2.21	2.40	2.38	2.29	2.61	3.02	2.88	3.42	3.62
Transportation[5]	0.04	0.76	0.79	0.83	1.16	1.25	1.33	1.41	1.56	1.69
Total	41.11	37.71	38.73	39.58	36.34	38.08	39.78	36.02	38.45	40.27

[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 as a by product of other processes.
[5]Compressed natural gas used as a vehicle fuel.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

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

Sources: 1995 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1991*. 1995 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). **Other 1995 values, and projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B15. Oil and Gas Supply

Production and Supply	1995	Projections								
		2005			2010			2015		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Crude Oil										
Lower 48 Average Wellhead Price[1] (1995 dollars per barrel)	15.58	18.61	19.36	20.23	19.09	20.02	20.97	18.68	19.85	21.06
Production (million barrels per day)[2]										
U.S. Total	6.56	5.42	5.49	5.56	5.28	5.39	5.50	5.10	5.23	5.36
Lower 48 Onshore	3.82	2.98	3.04	3.11	2.96	3.04	3.14	2.96	3.07	3.19
Conventional	3.24	2.40	2.44	2.49	2.30	2.36	2.41	2.26	2.33	2.38
Enhanced Oil Recovery	0.58	0.58	0.60	0.62	0.66	0.69	0.73	0.70	0.75	0.81
Lower 48 Offshore	1.26	1.49	1.50	1.51	1.56	1.57	1.58	1.51	1.53	1.54
Alaska	1.48	0.94	0.94	0.94	0.77	0.77	0.77	0.63	0.63	0.64
Lower 48 End of Year Reserves (billion barrels)	17.18	14.99	15.26	15.51	15.14	15.51	15.92	15.12	15.61	16.14
Natural Gas										
Lower 48 Average Wellhead Price[1] (1995 dollars per thousand cubic feet)	1.61	1.79	1.94	2.15	1.81	2.01	2.23	1.83	2.13	2.49
Production (trillion cubic feet)[3]										
U.S. Total	18.48	21.85	22.66	23.53	22.75	24.25	26.00	24.29	26.10	27.89
Lower 48 Onshore	13.00	15.03	15.75	16.59	15.93	17.19	18.61	16.97	18.59	20.13
Associated-Dissolved[4]	1.85	1.27	1.28	1.30	1.20	1.21	1.23	1.17	1.18	1.20
Non-Associated	11.15	13.77	14.47	15.29	14.74	15.98	17.38	15.81	17.40	18.93
Conventional	7.92	10.65	11.21	11.84	11.35	12.33	13.54	12.20	13.28	14.30
Unconventional	3.24	3.12	3.26	3.45	3.39	3.66	3.84	3.61	4.13	4.63
Lower 48 Offshore	5.05	6.30	6.39	6.42	6.27	6.51	6.83	6.74	6.94	7.18
Associated-Dissolved[4]	0.71	0.78	0.78	0.78	0.80	0.81	0.81	0.79	0.80	0.80
Non-Associated	4.34	5.52	5.61	5.64	5.47	5.70	6.03	5.95	6.14	6.38
Alaska	0.42	0.52	0.52	0.53	0.55	0.55	0.56	0.57	0.58	0.59
U.S. End of Year Reserves (trillion cubic feet)	155.03	169.88	174.73	184.20	178.44	187.05	197.89	178.91	188.42	196.73
Supplemental Gas Supplies (trillion cubic feet)[5]	0.13	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Total Lower 48 Wells Completed (thousands)	18.52	31.61	34.33	37.82	34.41	37.60	40.95	36.79	41.75	47.64

[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.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors.
Sources: 1995 crude oil lower 48 average wellhead price: Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting. 1995 total wells completed: EIA, Office of Integrated Analysis and Forecasting. 1995 lower 48 onshore, lower 48 offshore, Alaska crude oil production: EIA, *Petroleum Supply Annual 1995*, DOE/EIA-0340(95) (Washington, DC, May 1996). 1995 natural gas lower 48 average wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/06) (Washington, DC, June 1996). 1995 total natural gas production derived from: EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). Other 1995 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1995	Projections								
		2005			2010			2015		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production[1]										
Appalachia	435	442	441	454	468	479	502	482	494	544
Interior	169	154	157	162	160	165	173	154	160	195
West	429	522	548	583	532	557	600	561	614	660
East of the Mississippi	544	536	538	554	564	579	604	572	586	649
West of the Mississippi	489	582	608	645	597	622	671	625	682	750
Total	1033	1118	1146	1199	1161	1201	1275	1197	1268	1399
Net Imports										
Imports	7	8	8	8	9	9	9	9	9	9
Exports	89	102	102	102	111	111	111	121	121	121
Total	-81	-94	-94	-94	-103	-103	-103	-112	-112	-112
Total Supply[2]	951	1024	1052	1105	1058	1098	1172	1085	1156	1287
Consumption by Sector										
Residential and Commercial	6	6	6	6	6	6	6	6	6	6
Industrial[3]	73	78	84	91	78	87	97	78	91	106
Coke Plants	33	26	26	26	23	23	23	20	20	20
Electric Generators[4]	847	912	938	986	953	983	1046	987	1039	1155
Total	959	1022	1054	1109	1060	1099	1172	1091	1156	1288
Discrepancy and Stock Change[5]	-8	1	-2	-3	-2	-1	0	-6	-1	0
Average Minemouth Price										
(1995 dollars per short ton)	18.83	17.19	17.47	17.78	16.80	16.92	16.64	15.32	15.46	15.90
(1995 dollars per million Btu)	0.88	0.82	0.83	0.85	0.80	0.81	0.80	0.73	0.74	0.77
Delivered Prices (1995 dollars per short ton)[6]										
Industrial	32.30	30.64	31.18	31.87	29.09	29.72	30.15	27.19	28.12	29.01
Coke Plants	46.94	45.22	46.03	46.99	41.37	42.32	42.98	38.39	39.79	40.74
Electric Generators										
(1995 dollars per short ton)	27.01	24.65	24.97	25.38	23.89	24.23	24.19	21.92	22.47	23.08
(1995 dollars per million Btu)	1.32	1.22	1.24	1.26	1.18	1.20	1.20	1.08	1.11	1.15
Average	28.11	25.63	25.99	26.42	24.65	25.05	25.06	22.61	23.23	23.85
Exports[7]	39.51	37.30	37.96	38.75	34.92	35.47	35.72	31.90	32.91	33.76

[1]Includes anthracite, bituminous coal, and lignite.
[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 as a by-product of other processes.
[5]Balancing item: the sum of production, net imports, and net storage minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995 data derived from: Energy Information Administration (EIA), *Coal Industry Annual 1994*, DOE/EIA-0584(94) (Washington, DC, October 1995). **Projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B17. Renewable Energy Generating Capacity and Generation
(Thousand Megawatts, Unless Otherwise Noted)

Capacity and Generation	1995	Projections								
		2005			2010			2015		
		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)										
Capability										
Conventional Hydropower	78.48	80.33	80.33	80.33	80.38	80.38	80.38	80.38	80.38	80.38
Geothermal[2]	2.97	2.93	3.04	3.24	2.95	3.19	3.32	2.99	3.46	3.82
Municipal Solid Waste	2.43	3.29	3.34	3.39	3.76	3.89	4.01	3.99	4.19	4.37
Wood and Other Biomass[3]	1.86	1.99	2.00	1.99	2.04	2.21	2.66	2.46	3.92	5.25
Solar Thermal	0.36	0.42	0.42	0.42	0.50	0.50	0.50	0.63	0.63	0.63
Solar Photovoltaic	0.01	0.08	0.08	0.08	0.19	0.19	0.19	0.35	0.35	0.35
Wind	1.83	2.47	2.97	3.06	3.69	3.78	4.12	5.75	5.39	6.41
Total	87.95	91.49	92.17	92.51	93.52	94.14	95.19	96.54	98.32	101.23
Generation (billion kilowatthours)										
Conventional Hydropower	309.82	303.54	303.59	303.65	304.04	304.11	304.21	304.11	304.21	304.36
Geothermal[2]	14.66	17.16	17.94	19.40	17.77	19.46	20.39	18.67	22.04	24.59
Municipal Solid Waste	18.69	21.98	22.33	22.68	25.21	26.12	27.02	26.83	28.18	29.51
Wood and Other Biomass[3]	7.12	9.15	9.24	9.15	9.55	10.73	13.89	12.46	22.72	32.02
Solar Thermal	0.82	1.10	1.10	1.10	1.38	1.38	1.38	1.78	1.78	1.78
Solar Photovoltaic	0.00	0.22	0.22	0.22	0.48	0.48	0.48	0.87	0.87	0.87
Wind	3.17	5.47	6.80	7.12	9.03	9.15	10.19	14.83	13.80	16.72
Total	354.28	358.63	361.21	363.33	367.45	371.43	377.55	379.56	393.62	409.86
Cogenerators[4]										
Capability										
Municipal Solid Waste	0.41	0.43	0.43	0.44	0.43	0.44	0.45	0.44	0.45	0.47
Biomass	5.79	6.65	6.88	7.11	6.91	7.38	7.83	7.03	7.75	8.48
Total	6.19	7.07	7.31	7.54	7.34	7.82	8.28	7.47	8.21	8.95
Generation (billion kilowatthours)										
Municipal Solid Waste	1.97	2.05	2.08	2.10	2.09	2.13	2.17	2.11	2.17	2.23
Biomass	39.58	45.49	47.05	48.56	47.25	50.37	53.41	48.07	52.90	57.76
Total	41.55	47.54	49.12	50.66	49.34	52.50	55.58	50.18	55.07	59.99

[1]Includes grid-connected utilities and nonutilities other than cogenerators. These nonutility facilities include small power producers, exempt wholesale generators and generators at industrial and commercial facilities which do not produce steam for other uses.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes projections for energy crops after 2010.
[4]Cogenerators are facilities whose primary function is not electricity production.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO97. Net summer capability is used to be consistent with electric utility capacity estimates. Data for electric utility capacity data are the most recently available data as of August 15, 1996. Additional retirements are also determined on the basis of the size and age of the units. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: 1995 electric utility capability: Energy Information Administration (EIA), Form EIA-860 "Annual Electric Utility Report." 1995 nonutility and cogenerator capability: Form EIA-867, "Annual Nonutility Power Producer Report." 1995 generation: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B18. Renewable Energy, Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1995	Projections								
		2005			2010			2015		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Marketed Renewable Energy[2]										
Residential	0.57	0.55	0.56	0.57	0.53	0.55	0.56	0.52	0.54	0.56
Wood	0.57	0.55	0.56	0.57	0.53	0.55	0.56	0.52	0.54	0.56
Commercial[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[4]	1.74	2.02	2.12	2.21	2.12	2.28	2.43	2.17	2.40	2.62
Conventional Hydroelectric	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Municipal Solid Waste	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biomass	1.70	1.98	2.08	2.17	2.08	2.24	2.39	2.13	2.36	2.58
Transportation	0.08	0.10	0.10	0.10	0.10	0.10	0.14	0.13	0.15	0.20
Ethanol used in E85[5]	0.00	0.02	0.02	0.02	0.06	0.06	0.06	0.08	0.09	0.09
Ethanol used in Gasoline Blending	0.08	0.08	0.08	0.08	0.05	0.04	0.07	0.05	0.07	0.11
Electric Generators[6]	3.99	4.14	4.18	4.24	4.28	4.36	4.45	4.45	4.68	4.90
Conventional Hydroelectric	3.18	3.12	3.12	3.12	3.13	3.13	3.13	3.13	3.13	3.13
Geothermal	0.39	0.49	0.52	0.56	0.53	0.58	0.61	0.58	0.69	0.76
Municipal Solid Waste	0.31	0.36	0.37	0.37	0.41	0.43	0.44	0.44	0.46	0.48
Biomass	0.07	0.09	0.10	0.09	0.10	0.11	0.14	0.13	0.23	0.33
Solar Thermal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Wind	0.03	0.06	0.07	0.07	0.09	0.09	0.10	0.15	0.14	0.17
Total Marketed Renewable Energy	6.37	6.81	6.96	7.12	7.04	7.29	7.58	7.28	7.77	8.28
Non-Marketed Renewable Energy[7] Selected Consumption										
Residential	0.02	0.05	0.05	0.05	0.06	0.06	0.07	0.08	0.08	0.09
Solar Hot Water Heating	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Geothermal Heat Pumps	0.01	0.04	0.04	0.04	0.05	0.05	0.05	0.07	0.07	0.08
Commercial	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04
Solar Thermal	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid.
[3]Value is less than 0.005 quadrillion Btu per year and rounds to zero.
[4]Includes all electricity production by industrial and other cogenerators for the grid and for own use.
[5]Excludes motor gasoline component of E85.
[6]Includes renewable energy delivered to the grid from electric utilities and nonutilities. Renewable energy used in generating electricity for own use is included in the individual sectoral electricity energy consumption values.
[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
Btu = British thermal unit.
Notes: Totals may not equal sum of components due to independent rounding.
Sources: 1995 electric generators: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Utility Report," and EIA, Form EIA-867, "Annual Nonutility Power Producer Report." 1995 ethanol: EIA, *Petroleum Supply Annual 1995*, DOE/EIA-0340(95/1) (Washington, DC, May 1996). Other 1995: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B19. Carbon Emissions by Sector and Source
(Million Metric Tons per Year)

Sector and Source	1995	Projections								
		2005			2010			2015		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential										
Petroleum	25.0	23.9	24.3	24.8	23.0	23.7	24.5	22.5	23.4	24.4
Natural Gas	72.1	76.3	78.1	80.0	77.3	80.3	83.3	78.6	82.5	86.4
Coal	1.4	1.2	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.0
Electricity	175.6	194.6	201.0	209.0	207.9	216.4	227.7	225.9	238.3	257.2
Total	274.0	295.9	304.6	314.9	309.3	321.4	336.7	328.1	345.3	369.0
Commercial										
Petroleum	13.4	11.8	11.8	12.1	11.7	11.7	12.1	11.6	11.7	12.2
Natural Gas	45.6	49.3	49.5	50.6	50.5	50.9	52.8	52.0	52.6	55.2
Coal	2.0	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.5
Electricity	159.3	179.1	180.2	186.5	189.7	189.9	199.0	204.0	204.4	219.9
Total	220.3	242.3	243.8	251.4	254.1	254.7	266.2	269.8	271.0	289.8
Industrial [1]										
Petroleum	92.4	99.9	104.9	108.7	102.5	108.9	114.4	103.3	111.9	118.9
Natural Gas[2]	138.6	152.9	157.1	161.4	155.4	162.7	170.8	156.2	165.6	175.5
Coal	62.8	60.5	63.6	67.8	58.5	63.5	69.2	56.5	63.8	72.2
Electricity	170.5	190.2	201.7	217.5	196.2	213.4	235.1	202.0	227.1	261.1
Total	464.3	503.6	527.3	555.3	512.7	548.5	589.5	517.8	568.4	627.7
Transportation										
Petroleum	453.5	527.1	544.1	560.9	545.8	573.4	599.8	547.3	586.7	624.1
Natural Gas[3]	10.5	14.4	14.8	15.1	15.6	16.5	17.6	16.7	17.9	19.2
Other[4]	0.0	0.4	0.5	0.5	1.1	1.2	1.2	1.5	1.6	1.8
Electricity	1.0	3.8	3.9	4.1	6.4	6.7	7.1	7.9	8.4	9.0
Total	465.1	545.7	563.3	580.6	568.9	597.7	625.7	573.4	614.5	654.1
Total Carbon Emissions[5]										
Petroleum	584.4	662.6	685.1	706.4	683.0	717.7	750.8	684.6	733.6	779.5
Natural Gas	266.7	292.8	299.6	307.1	298.8	310.3	324.5	303.5	318.7	336.4
Coal	66.2	63.8	67.0	71.2	61.9	66.9	72.6	59.8	67.2	75.7
Other[4]	0.0	0.4	0.5	0.5	1.1	1.2	1.2	1.5	1.6	1.8
Electricity	506.3	567.7	586.9	617.1	600.2	626.4	668.9	639.7	678.1	747.2
Total	1423.7	1587.5	1638.9	1702.2	1645.0	1722.4	1818.1	1689.1	1799.3	1940.6
Electric Generators[6]										
Petroleum	14.4	11.5	12.2	13.0	11.7	12.0	12.5	12.1	13.2	15.2
Natural Gas	50.9	81.3	86.5	91.4	91.7	102.1	113.6	114.0	125.4	134.1
Coal	441.1	474.9	488.2	512.6	496.8	512.3	542.8	513.6	539.5	597.8
Total	506.3	567.7	586.9	617.1	600.2	626.4	668.9	639.7	678.1	747.2
Total Carbon Emissions[7]										
Petroleum	598.7	674.2	697.2	719.4	694.7	729.7	763.3	696.8	746.9	794.8
Natural Gas	317.6	374.1	386.1	398.5	390.6	412.4	438.2	417.5	444.1	470.5
Coal	507.3	538.7	555.2	583.8	558.7	579.2	615.4	573.4	606.7	673.5
Other[4]	0.0	0.4	0.5	0.5	1.1	1.2	1.2	1.5	1.6	1.8
Total	1423.7	1587.5	1638.9	1702.2	1645.0	1722.4	1818.1	1689.1	1799.3	1940.6
Carbon Emissions (tons per person)	5.4	5.7	5.7	5.8	5.7	5.8	5.9	5.7	5.8	6.0

[1]Includes consumption by cogenerators.
[2]Includes lease and plant fuel.
[3]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[4]"Other" includes methanol and liquid hydrogen.
[5]Measured for delivered energy consumption.
[6]Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[7]Measured for total energy consumption, with emissions for electric power generators distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Utility coal carbon emissions from Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States, 1987-1992,* DOE/EIA-0573 (Washington, DC, November 1994). Carbon coefficients from EIA, *Emissions of Greenhouse Gases in the United States 1995,* DOE/EIA-0573(95) (Washington, DC, October 1996). 1995 consumption estimates based on: EIA, *Short Term Energy Outlook,* DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B20. Macroeconomic Indicators
(Billion 1992 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	1995	Projections								
		2005			2010			2015		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
GDP Implicit Price Deflator										
(Index 1992=1.000)	1.076	1.653	1.411	1.314	2.136	1.667	1.479	2.779	1.986	1.675
Real Gross Domestic Product	6739	8013	8390	8767	8562	9185	9797	8982	9880	10766
Real Consumption	4579	5483	5673	5861	5873	6220	6551	6188	6708	7208
Real Investment	1011	1226	1366	1502	1292	1487	1676	1333	1592	1846
Real Government Spending	1261	1320	1364	1409	1367	1440	1512	1395	1499	1600
Real Exports	775	1308	1395	1484	1560	1723	1884	1779	2037	2290
Real Imports	889	1315	1395	1472	1519	1661	1796	1700	1921	2130
Real Gross Domestic Product										
(1987 fixed-weighted dollars)	5677	6968	7317	7662	7553	8145	8719	7951	8817	9657
Real Disposable Personal Income										
(1987 fixed-weighted dollars)	4047	4947	5113	5280	5332	5644	5950	5614	6109	6585
Index of Manufacturing Gross Output										
(Index 1987=1.000)	1.246	1.508	1.590	1.673	1.631	1.765	1.902	1.709	1.904	2.102
AA Utility Bond Rate (percent)	7.76	8.40	6.27	4.71	8.25	6.11	4.56	8.31	6.16	4.56
90-Day U.S. Government Treasury Bill Rate										
(percent)	5.49	5.77	4.31	3.23	5.64	4.15	3.01	5.56	4.04	2.82
Real Yield on Government 10 Year Bonds										
(percent)	5.22	2.07	2.07	1.68	1.46	1.35	0.96	1.45	1.24	0.85
Real 90-Day U.S. Government Treasury Bill Rate										
(percent)	2.94	0.66	1.10	0.97	0.33	0.71	0.60	0.05	0.35	0.21
Real Utility Bond Rate (percent)	5.21	3.28	3.06	2.45	2.93	2.67	2.15	2.80	2.46	1.96
Delivered Energy Intensity										
(thousand Btu per 1992 dollar of GDP)										
Delivered Energy	10.11	9.49	9.35	9.25	9.14	8.94	8.81	8.83	8.58	8.40
Total Energy	13.50	12.53	12.33	12.20	12.07	11.76	11.59	11.62	11.23	11.03
Consumer Price Index (1982-84=1.00)	1.52	2.43	2.08	1.94	3.19	2.49	2.21	4.20	3.01	2.54
Employment Cost Index (June 1989=1.00)	1.22	1.95	1.66	1.56	2.51	1.99	1.81	3.24	2.39	2.09
Unemployment Rate (percent)	5.59	5.71	5.64	5.57	5.74	5.70	5.75	5.70	5.67	5.71
Million Units										
Truck Deliveries, Light-Duty	6.10	6.75	7.03	7.29	6.80	7.32	7.78	6.96	7.73	8.45
Unit Sales of Automobiles	8.67	9.49	10.14	10.72	8.99	10.07	11.05	8.40	9.89	11.26
Millions of People										
Population with Armed Forces Overseas	263.6	279.9	287.1	293.8	288.3	298.9	308.7	297.0	311.2	324.3
Population (aged 16 and over)	202.1	218.4	223.8	228.6	227.7	235.4	242.5	235.4	245.8	255.4
Employment, Non-Agriculture	116.1	134.4	138.6	142.4	143.4	149.9	155.7	149.6	158.6	166.8
Employment, Manufacturing	18.2	17.5	18.1	18.8	17.0	18.0	18.8	16.2	17.4	18.5
Labor Force	132.3	145.9	149.7	153.5	151.8	157.3	162.8	153.6	161.1	168.6

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 1995: Data Resources Incorporated (DRI), DRI Trend0296. **Projections:** Energy Information Administration, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Table B21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1995	Projections								
		2005			2010			2015		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
World Oil Price (1995 dollars per barrel)[1]	17.26	18.93	19.72	20.54	19.43	20.41	21.37	19.78	20.98	22.21
Production[2]										
OECD										
U.S. (50 states)	9.29	8.47	8.67	8.86	8.45	8.75	9.09	8.40	8.76	9.13
Canada	2.44	2.46	2.46	2.47	2.34	2.35	2.35	2.23	2.24	2.24
Mexico	3.09	3.12	3.13	3.14	3.05	3.07	3.08	2.98	3.00	3.01
OECD Europe[3]	6.55	6.04	6.05	6.05	5.19	5.20	5.21	4.24	4.25	4.26
Other OECD	0.74	0.70	0.71	0.71	0.65	0.65	0.65	0.59	0.60	0.60
Total OECD	22.11	20.80	21.01	21.22	19.69	20.02	20.38	18.44	18.84	19.24
Developing Countries										
Other South & Central America	3.06	4.17	4.18	4.20	3.98	3.99	4.01	3.79	3.81	3.83
Pacific Rim	2.04	2.25	2.26	2.26	2.16	2.17	2.18	2.01	2.02	2.03
OPEC	28.07	42.02	42.10	42.17	50.61	50.64	50.67	60.20	60.35	60.49
Other Developing Countries	4.05	5.06	5.07	5.08	4.70	4.72	4.73	4.25	4.28	4.30
Total Developing Countries	37.21	53.50	53.61	53.71	61.44	61.51	61.58	70.25	70.45	70.63
Eurasia										
Former Soviet Union	6.96	8.32	8.34	8.36	9.39	9.43	9.46	10.04	10.09	10.14
Eastern Europe	0.31	0.23	0.23	0.23	0.21	0.21	0.21	0.18	0.18	0.18
China	3.02	3.04	3.04	3.05	2.99	3.00	3.01	2.93	2.94	2.96
Total Eurasia	10.29	11.59	11.62	11.65	12.59	12.64	12.69	13.15	13.21	13.28
Total Production	69.62	85.88	86.24	86.58	93.71	94.17	94.65	101.84	102.50	103.15
Consumption										
OECD										
U.S. (50 states)	17.73	19.99	20.68	21.35	20.55	21.60	22.64	20.62	22.12	23.57
U.S. Territories	0.26	0.35	0.35	0.34	0.39	0.38	0.37	0.43	0.42	0.41
Canada	1.76	2.03	2.01	1.99	2.18	2.14	2.11	2.34	2.29	2.25
Mexico	1.96	2.40	2.39	2.37	2.72	2.69	2.66	3.07	3.02	2.98
Japan	5.73	6.92	6.85	6.78	7.45	7.31	7.18	7.99	7.78	7.58
Australia and New Zealand	0.96	1.10	1.10	1.09	1.18	1.17	1.16	1.25	1.24	1.23
OECD Europe[3]	13.88	14.88	14.80	14.73	15.22	15.12	15.01	15.55	15.41	15.29
Total OECD	42.28	47.67	48.18	48.66	49.68	50.41	51.14	51.24	52.28	53.31
Developing Countries										
Other South and Central America	3.58	4.32	4.31	4.30	4.64	4.62	4.60	4.94	4.92	4.89
Pacific Rim	4.87	7.75	7.72	7.70	9.12	9.07	9.03	10.80	10.73	10.67
OPEC	4.94	6.30	6.30	6.30	7.06	7.06	7.06	7.91	7.91	7.91
Other Developing Countries	4.79	7.24	7.20	7.16	8.04	7.95	7.87	8.89	8.75	8.62
Total Developing Countries	18.19	25.61	25.53	25.45	28.85	28.70	28.56	32.53	32.31	32.09

Table B21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1995	Projections								
		2005			2010			2015		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Eurasia										
Former Soviet Union	4.75	5.82	5.80	5.78	6.78	6.74	6.70	7.71	7.65	7.60
Eastern Europe	1.39	1.52	1.51	1.51	1.73	1.72	1.72	1.97	1.96	1.96
China	3.31	5.56	5.52	5.48	6.96	6.89	6.83	8.70	8.59	8.49
Total Eurasia	9.46	12.90	12.84	12.77	15.47	15.36	15.25	18.37	18.21	18.05
Total Consumption	69.92	86.18	86.54	86.88	94.01	94.47	94.95	102.14	102.80	103.45
Non-OPEC Production	41.55	43.87	44.14	44.41	43.10	43.53	43.98	41.64	42.15	42.67
Net Eurasia Exports	0.83	-1.31	-1.22	-1.12	-2.88	-2.72	-2.56	-5.23	-4.99	-4.77
OPEC Market Share	0.40	0.49	0.49	0.49	0.54	0.54	0.54	0.59	0.59	0.59

[1]Average refiner acquisition cost of imported crude oil.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol, liquids produced from coal and other sources, and refinery gains.
[3]OECD Europe includes the unified Germany.
OECD = Organization for Economic Cooperation and Development - Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States (including territories).
Pacific Rim = Hong Kong, Malaysia, Philippines, Singapore, South Korea, Taiwan, and Thailand.
OPEC = Organization of Petroleum Exporting Countries - Algeria, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
Eurasia = Albania, Bulgaria, China, Czech Republic, Hungary, Poland, Romania, Slovak Republic, the Former Soviet Union, and the Former Yugoslavia.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs LMAC97.D100396A, AEO97B.D100296K, and HMAC97.D100296A.

Appendix C

Oil Price Case Comparisons

Table C1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1995	Projections								
		2005			2010			2015		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Production										
Crude Oil and Lease Condensate	13.89	9.36	11.62	13.56	8.62	11.41	13.82	8.40	11.08	14.59
Natural Gas Plant Liquids	2.37	2.90	3.01	3.06	3.12	3.04	3.30	3.34	3.47	3.57
Dry Natural Gas	19.01	22.46	23.30	23.75	24.12	24.93	25.61	25.92	26.83	27.68
Coal	21.98	24.11	23.99	24.17	25.07	25.16	25.30	26.18	26.46	26.60
Nuclear Power	7.19	6.98	6.98	6.98	6.55	6.55	6.55	4.79	4.79	4.79
Renewable Energy[1]	6.29	6.88	6.88	6.87	7.20	7.25	7.25	7.56	7.71	7.78
Other[2]	1.34	0.40	0.42	0.43	0.41	0.39	0.44	0.43	0.42	0.48
Total	**72.08**	**73.10**	**76.19**	**78.82**	**75.10**	**78.73**	**82.28**	**76.62**	**80.75**	**85.49**
Imports										
Crude Oil[3]	15.69	24.46	20.72	19.20	25.35	21.19	19.39	25.61	22.23	19.26
Petroleum Products[4]	3.19	7.44	6.79	5.62	9.46	8.23	6.55	10.77	8.35	6.31
Natural Gas	2.90	3.98	3.98	3.98	4.23	4.23	4.23	4.55	4.55	4.55
Other Imports[5]	0.60	0.65	0.67	0.65	0.67	0.67	0.67	0.64	0.64	0.64
Total	**22.38**	**36.53**	**32.16**	**29.45**	**39.71**	**34.31**	**30.83**	**41.57**	**35.77**	**30.76**
Exports										
Petroleum[6]	2.02	2.22	1.92	2.11	2.29	1.94	2.23	2.22	1.97	2.25
Natural Gas	0.16	0.21	0.21	0.21	0.22	0.22	0.22	0.22	0.22	0.22
Coal	2.27	2.60	2.59	2.59	2.86	2.82	2.82	3.04	3.04	3.04
Total	**4.45**	**5.03**	**4.73**	**4.92**	**5.38**	**4.98**	**5.27**	**5.49**	**5.24**	**5.51**
Discrepancy[7]	**0.91**	**-0.51**	**-0.26**	**-0.25**	**-0.59**	**-0.17**	**-0.39**	**-0.77**	**-0.40**	**-0.40**
Consumption										
Petroleum Products[8]	34.92	41.94	40.46	39.58	44.19	42.24	40.98	45.66	43.26	41.65
Natural Gas	22.18	26.09	26.94	27.39	27.92	28.77	29.46	30.04	30.97	31.84
Coal	19.95	21.82	21.72	21.93	22.57	22.68	22.81	23.51	23.76	23.92
Nuclear Power	7.19	6.98	6.98	6.98	6.55	6.55	6.55	4.79	4.79	4.79
Renewable Energy[1]	6.30	6.89	6.88	6.88	7.21	7.25	7.26	7.56	7.71	7.78
Other[9]	0.39	0.36	0.38	0.36	0.39	0.39	0.39	0.37	0.37	0.37
Total	**90.93**	**104.09**	**103.36**	**103.11**	**108.84**	**107.89**	**107.44**	**111.93**	**110.87**	**110.35**
Net Imports - Petroleum	**16.87**	**29.68**	**25.59**	**22.70**	**32.52**	**27.48**	**23.70**	**34.16**	**28.60**	**23.33**
Prices (1995 dollars per unit)										
World Oil Price (dollars per barrel)[10]	17.26	14.08	19.72	24.13	14.03	20.41	26.44	13.99	20.98	28.23
Gas Wellhead Price (dollars per Mcf)[11]	1.61	1.86	1.94	2.02	1.92	2.01	2.07	2.12	2.13	2.16
Coal Minemouth Price (dollars per ton)	18.83	16.94	17.47	17.98	16.15	16.92	17.48	14.82	15.46	16.24

[1]Includes utility and nonutility grid-connected electricity from hydroelectric, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes nonmarketed renewable energy. 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.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors.

Sources: 1995 natural gas price: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). 1995 natural gas supply derived from: EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC November 1996). 1995 coal minemouth price, coal production, and exports derived from: EIA, *Monthly Energy Review*, DOE/EIA-0035(96/08) (Washington, DC, August 1996). Other 1995 values: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Table C2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1995	Projections								
		2005			2010			2015		
		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	0.85	0.81	0.78	0.76	0.78	0.75	0.72	0.76	0.73	0.70
Kerosene	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.07	0.06	0.06
Liquefied Petroleum Gas	0.40	0.45	0.44	0.43	0.46	0.45	0.44	0.46	0.46	0.44
Petroleum Subtotal	1.32	1.33	1.29	1.26	1.30	1.26	1.22	1.29	1.25	1.20
Natural Gas	5.01	5.46	5.43	5.41	5.61	5.57	5.55	5.75	5.73	5.72
Coal	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04
Renewable Energy[1]	0.57	0.56	0.56	0.56	0.55	0.55	0.55	0.54	0.54	0.54
Electricity	3.56	4.15	4.14	4.14	4.46	4.46	4.46	4.86	4.85	4.84
Delivered Energy	**10.51**	**11.54**	**11.46**	**11.41**	**11.97**	**11.89**	**11.82**	**12.48**	**12.41**	**12.34**
Electricity Related Losses	7.92	8.74	8.55	8.53	9.17	8.95	8.93	9.44	9.22	9.22
Total	**18.43**	**20.27**	**20.02**	**19.94**	**21.14**	**20.83**	**20.75**	**21.92**	**21.63**	**21.56**
Commercial										
Distillate Fuel	0.41	0.38	0.36	0.35	0.38	0.35	0.34	0.38	0.34	0.33
Residual Fuel	0.17	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.14
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02
Petroleum Subtotal	0.67	0.62	0.60	0.59	0.62	0.59	0.58	0.63	0.59	0.58
Natural Gas	3.16	3.43	3.44	3.44	3.52	3.54	3.53	3.62	3.65	3.65
Coal	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.09
Renewable Energy[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	3.23	3.72	3.71	3.71	3.92	3.91	3.91	4.17	4.16	4.15
Delivered Energy	**7.15**	**7.86**	**7.84**	**7.82**	**8.16**	**8.13**	**8.11**	**8.52**	**8.50**	**8.48**
Electricity Related Losses	7.18	7.84	7.67	7.64	8.05	7.85	7.83	8.11	7.91	7.90
Total	**14.33**	**15.70**	**15.51**	**15.47**	**16.21**	**15.98**	**15.94**	**16.62**	**16.40**	**16.39**
Industrial[4]										
Distillate Fuel	1.15	1.39	1.39	1.38	1.48	1.47	1.47	1.56	1.55	1.55
Liquefied Petroleum Gas	2.01	2.30	2.20	2.11	2.41	2.28	2.16	2.52	2.35	2.20
Petrochemical Feedstocks	1.16	1.36	1.30	1.24	1.43	1.35	1.27	1.50	1.40	1.29
Residual Fuel	0.34	0.43	0.31	0.27	0.48	0.33	0.26	0.51	0.35	0.25
Motor Gasoline[2]	0.20	0.24	0.24	0.24	0.26	0.26	0.26	0.27	0.27	0.27
Other Petroleum[5]	3.83	4.66	4.33	3.98	4.78	4.43	3.97	4.93	4.48	3.93
Petroleum Subtotal	8.68	10.37	9.77	9.22	10.85	10.13	9.39	11.30	10.41	9.50
Natural Gas[6]	9.74	10.56	11.04	11.45	10.84	11.42	12.00	10.89	11.63	12.33
Metallurgical Coal	0.88	0.69	0.69	0.69	0.62	0.62	0.62	0.55	0.55	0.55
Steam Coal	1.59	1.75	1.82	1.87	1.81	1.89	1.93	1.89	1.97	2.01
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.13	0.13	0.13	0.15	0.15	0.15
Coal Subtotal	2.51	2.55	2.62	2.67	2.56	2.64	2.67	2.59	2.67	2.70
Renewable Energy[7]	1.74	2.13	2.12	2.11	2.29	2.28	2.26	2.41	2.40	2.38
Electricity	3.46	4.08	4.16	4.21	4.30	4.40	4.46	4.53	4.62	4.69
Delivered Energy	**26.12**	**29.68**	**29.70**	**29.67**	**30.84**	**30.87**	**30.78**	**31.72**	**31.73**	**31.60**
Electricity Related Losses	7.69	8.60	8.59	8.69	8.83	8.82	8.93	8.82	8.79	8.92
Total	**33.81**	**38.28**	**38.28**	**38.35**	**39.66**	**39.69**	**39.71**	**40.54**	**40.51**	**40.52**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1995	Projections								
		2005			2010			2015		
		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	4.42	5.47	5.46	5.45	5.80	5.78	5.76	6.03	6.00	5.97
Jet Fuel [8]	3.13	4.30	4.26	4.23	4.72	4.67	4.62	5.00	4.95	4.89
Motor Gasoline[2]	14.65	16.85	16.61	16.44	17.44	17.09	16.82	17.52	17.11	16.75
Residual Fuel	1.08	1.47	1.47	1.47	1.65	1.64	1.64	1.79	1.78	1.78
Liquefied Petroleum Gas	0.03	0.11	0.11	0.11	0.18	0.18	0.17	0.22	0.21	0.21
Other Petroleum[9]	0.26	0.31	0.31	0.31	0.33	0.33	0.33	0.34	0.34	0.34
Petroleum Subtotal	23.56	28.52	28.22	28.01	30.12	29.69	29.34	30.90	30.39	29.93
Pipeline Fuel Natural Gas	0.72	0.83	0.84	0.85	0.88	0.88	0.89	0.93	0.93	0.96
Compressed Natural Gas	0.01	0.19	0.18	0.18	0.26	0.26	0.26	0.31	0.31	0.31
Renewable Energy (E85)[10]	0.00	0.02	0.02	0.02	0.07	0.07	0.07	0.11	0.10	0.10
Methanol [11]	0.00	0.03	0.03	0.03	0.07	0.07	0.06	0.10	0.09	0.09
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.08	0.08	0.08	0.14	0.14	0.14	0.17	0.17	0.17
Delivered Energy	**24.31**	**29.66**	**29.38**	**29.18**	**31.54**	**31.11**	**30.76**	**32.52**	**31.99**	**31.56**
Electricity Related Losses	0.04	0.17	0.17	0.17	0.29	0.28	0.28	0.33	0.32	0.32
Total	**24.36**	**29.84**	**29.55**	**29.35**	**31.83**	**31.39**	**31.03**	**32.85**	**32.32**	**31.88**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	6.82	8.05	7.98	7.95	8.44	8.35	8.29	8.74	8.62	8.55
Kerosene	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.11	0.11	0.10
Jet Fuel [8]	3.13	4.30	4.26	4.23	4.72	4.67	4.62	5.00	4.95	4.89
Liquefied Petroleum Gas	2.49	2.92	2.81	2.71	3.11	2.97	2.83	3.27	3.09	2.92
Motor Gasoline[2]	14.87	17.11	16.88	16.71	17.72	17.38	17.11	17.82	17.40	17.04
Petrochemical Feedstocks	1.16	1.36	1.30	1.24	1.43	1.35	1.27	1.50	1.40	1.29
Residual Fuel	1.58	2.04	1.92	1.87	2.27	2.11	2.04	2.44	2.27	2.17
Other Petroleum[12]	4.07	4.95	4.62	4.28	5.09	4.74	4.28	5.25	4.80	4.24
Petroleum Subtotal	34.24	40.84	39.88	39.09	42.89	41.67	40.54	44.12	42.63	41.21
Natural Gas[6]	18.64	20.46	20.93	21.33	21.12	21.68	22.23	21.51	22.26	22.97
Metallurgical Coal	0.88	0.69	0.69	0.69	0.62	0.62	0.62	0.55	0.55	0.55
Steam Coal	1.73	1.88	1.95	2.00	1.95	2.02	2.06	2.02	2.10	2.14
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.13	0.13	0.13	0.15	0.15	0.15
Coal Subtotal	2.64	2.68	2.75	2.80	2.69	2.77	2.80	2.72	2.80	2.84
Renewable Energy[13]	2.31	2.71	2.70	2.69	2.91	2.90	2.88	3.05	3.04	3.02
Methanol [11]	0.00	0.03	0.03	0.03	0.07	0.07	0.06	0.10	0.09	0.09
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	10.26	12.03	12.09	12.14	12.82	12.91	12.96	13.73	13.80	13.85
Delivered Energy	**68.10**	**78.74**	**78.38**	**78.08**	**82.51**	**81.99**	**81.47**	**85.23**	**84.62**	**83.98**
Electricity Related Losses	22.83	25.35	24.98	25.03	26.33	25.90	25.97	26.70	26.24	26.37
Total	**90.93**	**104.09**	**103.36**	**103.11**	**108.84**	**107.89**	**107.44**	**111.93**	**110.87**	**110.35**
Electric Generators[14]										
Distillate Fuel	0.08	0.14	0.12	0.13	0.18	0.14	0.14	0.22	0.15	0.16
Residual Fuel	0.60	0.97	0.46	0.36	1.13	0.43	0.30	1.32	0.48	0.28
Petroleum Subtotal	0.68	1.10	0.58	0.49	1.30	0.57	0.44	1.54	0.63	0.44
Natural Gas	3.54	5.63	6.01	6.05	6.80	7.09	7.23	8.53	8.71	8.86
Steam Coal	17.31	19.15	18.97	19.13	19.88	19.91	20.01	20.79	20.96	21.08
Nuclear Power	7.19	6.98	6.98	6.98	6.55	6.55	6.55	4.79	4.79	4.79
Renewable Energy[15]	3.99	4.18	4.18	4.19	4.30	4.36	4.37	4.51	4.67	4.76
Electricity Imports	0.39	0.34	0.36	0.34	0.32	0.32	0.32	0.28	0.28	0.28
Total	**33.10**	**37.37**	**37.07**	**37.18**	**39.15**	**38.81**	**38.92**	**40.43**	**40.04**	**40.22**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1995	Projections								
		2005			2010			2015		
		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	6.90	8.19	8.11	8.07	8.62	8.49	8.43	8.96	8.77	8.71
Kerosene	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.11	0.11	0.10
Jet Fuel [8]	3.13	4.30	4.26	4.23	4.72	4.67	4.62	5.00	4.95	4.89
Liquefied Petroleum Gas	2.49	2.92	2.81	2.71	3.11	2.97	2.83	3.27	3.09	2.92
Motor Gasoline[2]	14.87	17.11	16.88	16.71	17.72	17.38	17.11	17.82	17.40	17.04
Petrochemical Feedstocks	1.16	1.36	1.30	1.24	1.43	1.35	1.27	1.50	1.40	1.29
Residual Fuel	2.18	3.00	2.38	2.23	3.39	2.54	2.34	3.76	2.75	2.45
Other Petroleum[12]	4.07	4.95	4.62	4.28	5.09	4.74	4.28	5.25	4.80	4.24
Petroleum Subtotal	34.92	41.94	40.46	39.58	44.19	42.24	40.98	45.66	43.26	41.65
Natural Gas	22.18	26.09	26.94	27.39	27.92	28.77	29.46	30.04	30.97	31.84
Metallurgical Coal	0.88	0.69	0.69	0.69	0.62	0.62	0.62	0.55	0.55	0.55
Steam Coal	19.04	21.02	20.92	21.13	21.82	21.94	22.06	22.81	23.06	23.22
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.13	0.13	0.13	0.15	0.15	0.15
Coal Subtotal	19.95	21.82	21.72	21.93	22.57	22.68	22.81	23.51	23.76	23.92
Nuclear Power	7.19	6.98	6.98	6.98	6.55	6.55	6.55	4.79	4.79	4.79
Renewable Energy[16]	6.30	6.89	6.88	6.88	7.21	7.25	7.26	7.56	7.71	7.78
Methanol [11]	0.00	0.03	0.03	0.03	0.07	0.07	0.06	0.10	0.09	0.09
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.39	0.34	0.36	0.34	0.32	0.32	0.32	0.28	0.28	0.28
Total	90.93	104.09	103.36	103.11	108.84	107.89	107.44	111.93	110.87	110.35
Energy Use and Related Statistics										
Delivered Energy Use	68.10	78.74	78.38	78.08	82.51	81.99	81.47	85.23	84.62	83.98
Total Energy Use	90.93	104.08	103.35	103.10	108.82	107.87	107.42	111.90	110.83	110.31
Population (millions)	263.58	287.12	287.12	287.12	298.92	298.92	298.92	311.19	311.19	311.19
Gross Domestic Product (billion 1992 dollars)	6738.95	8418.14	8389.54	8368.88	9215.68	9185.32	9150.11	9919.12	9879.75	9835.54

[1]Includes wood used for residential heating. See Table C18 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps and solar thermal hot water heating.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector electricity cogenerated by using wood and wood waste, municipal solid waste, and other biomass. See Table C18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating.
[4]Fuel consumption includes consumption for cogeneration.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]*Includes lease and plant fuel.*
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[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]Only M85 (85 percent methanol).
[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 electric utilities and for self use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps and solar thermal hot water heaters.
[14]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity as a by-product of other processes.
[15]*Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, E85, wind, photovoltaic and solar thermal sources.*
[16]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 nonmarketed renewable energy consumption for geothermal heat pumps and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1995 natural gas lease, plant, and pipeline fuel values: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). 1995 transportation sector compressed natural gas consumption: EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B. 1995 electric utility fuel consumption: EIA, *Electric Power Annual, Volume I*, DOE/EIA-0348(95)/1 (Washington, DC, July 1996). 1995 nonutility consumption estimates: EIA Form 867, "Annual Nonutility Power Producer Report." Other 1995 values: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** *EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.*

Table C3. Energy Prices by Sector and Source
(1995 Dollars per Million Btu)

Sector and Source	1995	Projections								
		2005			2010			2015		
		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	12.87	12.40	12.70	12.92	12.29	12.61	12.89	12.30	12.55	12.81
Primary Energy	6.28	5.81	6.09	6.31	5.63	5.95	6.19	5.61	5.83	6.07
Petroleum Products	7.51	7.85	8.75	9.55	8.02	9.08	10.07	7.90	8.95	10.22
Distillate Fuel	6.24	6.29	7.28	7.99	6.39	7.45	8.37	6.21	7.33	8.50
Liquefied Petroleum Gas	10.29	10.72	11.40	12.33	10.87	11.85	12.95	10.74	11.57	13.00
Natural Gas	6.01	5.35	5.49	5.59	5.11	5.27	5.37	5.12	5.18	5.23
Electricity	24.67	23.26	23.49	23.65	22.67	22.88	23.15	22.06	22.28	22.51
Commercial	13.12	12.36	12.60	12.81	12.20	12.48	12.72	12.06	12.28	12.51
Primary Energy	4.82	4.44	4.69	4.87	4.32	4.59	4.79	4.35	4.54	4.74
Petroleum Products	4.58	4.41	5.34	6.07	4.48	5.52	6.47	4.31	5.42	6.60
Distillate Fuel	4.39	4.28	5.28	6.00	4.35	5.44	6.37	4.15	5.32	6.49
Residual Fuel	2.99	2.06	2.87	3.51	2.07	2.98	3.88	2.00	3.03	4.11
Natural Gas[1]	4.96	4.52	4.65	4.74	4.36	4.51	4.60	4.44	4.48	4.53
Electricity	23.19	21.18	21.38	21.63	20.71	20.98	21.26	20.09	20.35	20.60
Industrial[2]	5.02	4.55	4.96	5.28	4.57	5.05	5.43	4.54	4.99	5.44
Primary Energy	3.36	2.93	3.34	3.66	2.99	3.47	3.86	3.00	3.47	3.93
Petroleum Products	4.92	3.68	4.60	5.39	3.74	4.80	5.83	3.59	4.68	5.93
Distillate Fuel	4.61	4.22	5.21	5.93	4.32	5.38	6.33	4.15	5.29	6.45
Liquefied Petroleum Gas	6.53	5.35	6.00	6.84	5.43	6.28	7.38	5.23	5.95	7.30
Residual Fuel	2.55	1.96	2.92	3.56	1.95	3.03	3.88	1.83	3.01	4.10
Natural Gas[3]	2.28	2.46	2.54	2.60	2.53	2.61	2.66	2.73	2.74	2.76
Metallurgical Coal	1.75	1.66	1.72	1.75	1.52	1.58	1.62	1.44	1.48	1.53
Steam Coal	1.48	1.39	1.44	1.47	1.31	1.37	1.41	1.25	1.30	1.34
Electricity	14.54	13.30	13.46	13.63	12.92	13.13	13.31	12.35	12.56	12.73
Transportation	7.92	7.43	8.51	9.28	7.34	8.55	9.61	6.96	8.21	9.49
Primary Energy	7.92	7.41	8.49	9.26	7.30	8.53	9.59	6.93	8.18	9.47
Petroleum Products	7.92	7.42	8.51	9.28	7.31	8.54	9.61	6.93	8.19	9.49
Distillate Fuel[4]	8.03	7.73	8.70	9.37	7.59	8.68	9.63	7.23	8.38	9.58
Jet Fuel[5]	3.85	4.34	5.46	6.12	4.42	5.65	6.75	4.17	5.45	6.74
Motor Gasoline[6]	9.23	8.64	9.79	10.64	8.53	9.85	10.98	8.14	9.49	10.87
Residual Fuel	2.44	2.03	2.90	3.57	2.13	3.16	4.14	1.98	3.08	4.19
Natural Gas[7]	5.77	6.00	6.20	6.29	6.39	6.73	6.83	6.75	7.07	7.18
Electricity	15.14	14.42	14.45	14.52	14.16	14.25	14.36	13.68	13.85	13.92
Total End-Use Energy	8.22	7.68	8.31	8.78	7.62	8.34	8.96	7.47	8.18	8.90
Primary Energy	7.82	7.29	7.98	8.49	7.22	8.01	8.69	7.03	7.82	8.63
Electricity	20.77	19.18	19.33	19.50	18.71	18.89	19.10	18.15	18.34	18.52
Electric Generators[8]										
Fossil Fuel Average	1.48	1.47	1.53	1.58	1.48	1.54	1.59	1.52	1.55	1.61
Petroleum Products	2.78	2.19	3.35	4.12	2.29	3.59	4.69	2.24	3.52	4.94
Distillate Fuel	3.94	3.78	4.77	5.48	3.85	4.92	5.86	3.68	4.83	5.99
Residual Fuel	2.62	1.97	2.97	3.64	2.05	3.15	4.14	2.00	3.11	4.33
Natural Gas	2.01	2.22	2.28	2.35	2.26	2.32	2.41	2.47	2.47	2.52
Steam Coal	1.32	1.20	1.24	1.27	1.15	1.20	1.23	1.08	1.11	1.15

Table C3. Energy Prices by Sector and Source (Continued)
(1995 Dollars per Million Btu)

Sector and Source	1995	Projections								
		2005			2010			2015		
		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[9]										
Petroleum Products	7.07	6.40	7.52	8.34	6.34	7.62	8.72	6.01	7.33	8.67
Distillate Fuel[4]	6.98	6.76	7.75	8.44	6.70	7.80	8.75	6.39	7.56	8.75
Jet Fuel	3.85	4.34	5.46	6.12	4.42	5.65	6.75	4.17	5.45	6.74
Liquefied Petroleum Gas	7.20	6.52	7.20	8.09	6.69	7.61	8.74	6.52	7.32	8.72
Motor Gasoline[6]	9.23	8.63	9.77	10.62	8.52	9.83	10.96	8.13	9.47	10.85
Residual Fuel	2.55	2.00	2.91	3.58	2.07	3.13	4.10	1.97	3.07	4.19
Natural Gas	3.57	3.39	3.45	3.51	3.32	3.39	3.45	3.42	3.42	3.44
Coal	1.35	1.22	1.25	1.29	1.17	1.21	1.25	1.09	1.13	1.17
Electricity	20.77	19.18	19.33	19.50	18.71	18.89	19.10	18.15	18.34	18.52

[1]Excludes independent power producers.
[2]Includes cogenerators.
[3]Excludes uses for lease and plant fuel.
[4]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[5]Kerosene-type jet fuel.
[6]Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[7]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[8]Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[9]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: 1995 figures may differ from published data due to internal rounding.

Sources: 1995 prices for gasoline, distillate, and jet fuel are based on prices in various 1995 issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly,* DOE/EIA-0380(95/1-12) (Washington, DC, 1995). 1995 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1993,* DOE/EIA-0376(93) (Washington, DC, December 1995). 1995 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1991.* 1995 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly,* DOE/EIA-0130(96/6) (Washington, DC, June 1996). Other 1995 natural gas delivered prices: EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B. Values for 1995 coal prices have been estimated from EIA, *State Energy Price and Expenditure Report 1993,* DOE/EIA-0376(93) (Washington, DC, December 1995) by use of consumption quantities aggregated from EIA, *State Energy Data Report 1993, Consumption Estimates,* DOE/EIA-0214(93) (Washington, DC, July 1995). 1995 electricity prices for commercial, industrial, and transportation: EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B. **Projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Table C4. Residential Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections								
		2005			2010			2015		
		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
Household Characteristics										
Households (millions)										
Single-Family	68.66	76.88	76.85	76.84	80.95	80.93	80.90	85.09	85.07	85.05
Multifamily	24.56	27.02	26.98	26.95	28.70	28.67	28.63	30.49	30.45	30.41
Mobile Homes	5.83	6.64	6.64	6.64	6.89	6.89	6.89	7.12	7.12	7.13
Total	99.06	110.53	110.47	110.43	116.54	116.49	116.43	122.70	122.65	122.58
Housing Starts (millions)										
Single-Family	1.08	1.08	1.08	1.08	1.03	1.03	1.03	1.09	1.09	1.09
Multifamily	0.28	0.43	0.42	0.42	0.48	0.48	0.48	0.48	0.48	0.48
Mobile Homes	0.34	0.29	0.29	0.29	0.28	0.28	0.28	0.29	0.29	0.29
Total	1.70	1.80	1.80	1.80	1.79	1.79	1.79	1.86	1.86	1.86
Average House Square Footage	1643	1683	1683	1683	1696	1696	1697	1708	1708	1708
Energy Intensity										
Million Btu Consumed per Household										
Delivered Energy Consumption	106.10	104.38	103.78	103.32	102.74	102.06	101.55	101.68	101.19	100.71
Electricity Related Losses	79.94	79.04	77.43	77.28	78.65	76.80	76.70	76.97	75.20	75.21
Total Energy Consumption	186.03	183.41	181.21	180.60	181.38	178.86	178.24	178.65	176.39	175.92
Thousand Btu Consumed per Square Foot										
Delivered Energy Consumption	64.57	62.01	61.65	61.37	60.57	60.16	59.86	59.55	59.26	58.97
Electricity Related Losses	48.65	46.95	46.00	45.91	46.36	45.27	45.21	45.08	44.04	44.04
Total Energy Consumption	113.22	108.96	107.64	107.28	106.93	105.43	105.07	104.63	103.29	103.01
Delivered Energy Consumption by Fuel										
Distillate										
Space Heating	0.76	0.71	0.69	0.66	0.68	0.65	0.62	0.67	0.63	0.60
Water Heating	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Other Uses[1]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	0.85	0.81	0.78	0.76	0.78	0.75	0.72	0.76	0.73	0.70
Liquefied Petroleum Gas										
Space Heating	0.30	0.33	0.32	0.31	0.33	0.32	0.31	0.33	0.32	0.31
Water Heating	0.06	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.09	0.09
Cooking[2]	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	0.40	0.45	0.44	0.43	0.46	0.45	0.44	0.46	0.46	0.44
Natural Gas										
Space Heating	3.48	3.83	3.79	3.78	3.92	3.88	3.86	3.98	3.96	3.96
Space Cooling	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
Water Heating	1.25	1.34	1.34	1.34	1.39	1.39	1.39	1.45	1.45	1.45
Cooking[2]	0.15	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Clothes Dryers	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Other Uses[3]	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.11	0.11
Delivered Energy	5.01	5.46	5.43	5.41	5.61	5.57	5.55	5.75	5.73	5.72
Electricity										
Space Heating	0.43	0.47	0.47	0.47	0.48	0.48	0.48	0.49	0.49	0.49
Space Cooling	0.48	0.48	0.48	0.48	0.49	0.49	0.49	0.51	0.51	0.51
Water Heating	0.35	0.37	0.37	0.37	0.38	0.38	0.38	0.39	0.39	0.39
Refrigeration	0.40	0.33	0.33	0.33	0.31	0.31	0.31	0.31	0.31	0.31
Cooking	0.12	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.14
Clothes Dryers	0.18	0.20	0.20	0.20	0.21	0.21	0.21	0.22	0.22	0.22
Freezers	0.13	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.08
Lighting	0.32	0.34	0.34	0.34	0.35	0.35	0.35	0.36	0.36	0.36
Other Uses[4]	1.15	1.74	1.73	1.73	2.02	2.02	2.02	2.35	2.35	2.35
Delivered Energy	3.56	4.15	4.14	4.14	4.46	4.46	4.46	4.86	4.85	4.84

Table C4. Residential Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections								
		2005			2010			2015		
		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 Renewables										
Wood[5]	0.57	0.56	0.56	0.56	0.55	0.55	0.55	0.54	0.54	0.54
Delivered Energy	0.57	0.56	0.56	0.56	0.55	0.55	0.55	0.54	0.54	0.54
Other Fuels[6]	0.13	0.12	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.10
Delivered Energy Consumption by End-Use										
Space Heating	5.65	6.01	5.94	5.89	6.07	5.99	5.93	6.11	6.05	5.99
Space Cooling	0.48	0.49	0.49	0.49	0.51	0.51	0.51	0.53	0.53	0.53
Water Heating	1.75	1.88	1.88	1.88	1.95	1.95	1.95	2.03	2.03	2.02
Refrigeration	0.40	0.33	0.33	0.33	0.31	0.31	0.31	0.31	0.31	0.31
Cooking	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.31	0.31	0.31
Clothes Dryers	0.23	0.24	0.24	0.24	0.26	0.26	0.26	0.27	0.27	0.27
Freezers	0.13	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.08
Lighting	0.32	0.34	0.34	0.34	0.35	0.35	0.35	0.36	0.36	0.36
Other Uses[7]	1.24	1.85	1.84	1.84	2.14	2.14	2.13	2.47	2.47	2.47
Delivered Energy	10.51	11.54	11.46	11.41	11.97	11.89	11.82	12.48	12.41	12.34
Electricity Related Losses by End-Use										
Space Heating	0.95	0.99	0.97	0.97	0.99	0.96	0.96	0.96	0.94	0.93
Space Cooling	1.07	1.02	0.99	0.99	1.01	0.99	0.98	0.99	0.97	0.96
Water Heating	0.78	0.77	0.76	0.76	0.78	0.76	0.76	0.76	0.74	0.74
Refrigeration	0.90	0.69	0.67	0.67	0.64	0.62	0.62	0.60	0.59	0.59
Cooking	0.27	0.28	0.27	0.27	0.28	0.28	0.28	0.28	0.27	0.27
Clothes Dryers	0.40	0.42	0.41	0.41	0.43	0.42	0.41	0.42	0.41	0.42
Freezers	0.29	0.19	0.19	0.19	0.17	0.16	0.16	0.15	0.15	0.15
Lighting	0.70	0.73	0.71	0.71	0.73	0.71	0.71	0.70	0.69	0.69
Other Uses[7]	2.55	3.66	3.58	3.57	4.15	4.05	4.05	4.57	4.47	4.47
Total Electricity Related Losses	7.92	8.74	8.55	8.53	9.17	8.95	8.93	9.44	9.22	9.22
Total Energy Consumption by End-Use										
Space Heating	6.61	7.00	6.91	6.86	7.06	6.96	6.89	7.07	6.99	6.93
Space Cooling	1.56	1.51	1.49	1.48	1.52	1.49	1.49	1.53	1.50	1.49
Water Heating	2.53	2.66	2.64	2.64	2.73	2.71	2.70	2.79	2.77	2.77
Refrigeration	1.30	1.01	1.00	1.00	0.95	0.93	0.93	0.91	0.89	0.89
Cooking	0.58	0.58	0.57	0.57	0.58	0.58	0.58	0.59	0.59	0.59
Clothes Dryers	0.63	0.66	0.65	0.65	0.68	0.67	0.67	0.69	0.68	0.68
Freezers	0.42	0.28	0.28	0.28	0.25	0.24	0.24	0.23	0.23	0.23
Lighting	1.02	1.07	1.05	1.05	1.08	1.06	1.06	1.07	1.05	1.05
Other Uses[7]	3.79	5.50	5.43	5.42	6.29	6.19	6.18	7.04	6.94	6.94
Total	18.43	20.27	20.02	19.94	21.14	20.83	20.75	21.92	21.63	21.56
Non-Marketed Renewables										
Geothermal[8]	0.01	0.04	0.04	0.04	0.05	0.05	0.05	0.07	0.07	0.07
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	0.05	0.05	0.05	0.06	0.06	0.06	0.08	0.08	0.08

[1]Includes such appliances as swimming pool and hot tub heaters.
[2]Does not include outdoor grills.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as microwave ovens, television sets, and dishwashers.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1993*.
[6]Includes kerosene and coal.
[7]Includes such appliances as swimming pool heaters, hot tub heaters, outdoor grills, outdoor lighting (natural gas), microwave ovens, television sets, and dishwashers.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Table C5. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections								
		2005			2010			2015		
		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	68.9	76.0	76.0	76.0	79.1	79.1	79.1	82.5	82.5	82.5
New Additions	1.7	1.5	1.5	1.5	1.6	1.6	1.6	1.8	1.8	1.8
Total	70.7	77.5	77.5	77.5	80.7	80.7	80.7	84.2	84.2	84.2
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	101.2	101.4	101.1	100.9	101.0	100.7	100.5	101.1	100.9	100.7
Electricity Related Losses	101.6	101.1	99.0	98.6	99.7	97.3	97.0	96.3	93.9	93.9
Total Energy Consumption	202.8	202.5	200.1	199.6	200.8	198.0	197.5	197.4	194.8	194.6
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.13	0.13	0.13
Space Cooling	0.58	0.52	0.52	0.52	0.52	0.52	0.52	0.53	0.53	0.53
Water Heating	0.17	0.15	0.15	0.15	0.14	0.14	0.14	0.13	0.13	0.13
Ventilation	0.17	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Lighting	1.21	1.32	1.32	1.31	1.33	1.32	1.32	1.36	1.36	1.35
Refrigeration	0.14	0.15	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17
Office Equipment (PC)	0.07	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10
Office Equipment (non-PC)	0.18	0.22	0.22	0.22	0.25	0.25	0.25	0.27	0.27	0.27
Other Uses[1]	0.56	0.92	0.92	0.92	1.08	1.08	1.08	1.24	1.24	1.24
Delivered Energy	3.23	3.72	3.71	3.71	3.92	3.91	3.91	4.17	4.16	4.15
Natural Gas[2]										
Space Heating	1.30	1.33	1.34	1.34	1.34	1.36	1.36	1.34	1.38	1.38
Space Cooling	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Water Heating	0.48	0.50	0.50	0.50	0.52	0.52	0.52	0.55	0.55	0.55
Cooking	0.18	0.21	0.21	0.21	0.23	0.23	0.23	0.25	0.25	0.25
Other Uses[3]	1.17	1.36	1.36	1.36	1.40	1.40	1.40	1.45	1.45	1.45
Delivered Energy	3.16	3.43	3.44	3.44	3.52	3.54	3.53	3.62	3.65	3.65
Distillate										
Space Heating	0.20	0.20	0.17	0.16	0.19	0.16	0.15	0.20	0.15	0.14
Water Heating	0.06	0.05	0.05	0.05	0.05	0.05	0.04	0.05	0.04	0.04
Other Uses[4]	0.15	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Delivered Energy	0.41	0.38	0.36	0.35	0.38	0.35	0.34	0.38	0.34	0.33
Other Fuels[5]	0.35	0.32	0.32	0.32	0.33	0.33	0.33	0.34	0.34	0.34
Marketed Renewable Fuels										
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy Consumption by End-Use										
Space Heating	1.61	1.64	1.63	1.62	1.65	1.64	1.63	1.67	1.66	1.65
Space Cooling	0.61	0.55	0.55	0.55	0.55	0.55	0.55	0.57	0.56	0.56
Water Heating	0.70	0.70	0.70	0.69	0.71	0.70	0.70	0.72	0.72	0.72
Ventilation	0.17	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20
Cooking	0.22	0.24	0.24	0.24	0.26	0.26	0.26	0.27	0.27	0.27
Lighting	1.21	1.32	1.32	1.31	1.33	1.32	1.32	1.36	1.36	1.35
Refrigeration	0.14	0.15	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17
Office Equipment (PC)	0.07	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10
Office Equipment (non-PC)	0.18	0.22	0.22	0.22	0.25	0.25	0.25	0.27	0.27	0.27
Other Uses[6]	2.24	2.75	2.75	2.75	2.96	2.96	2.97	3.17	3.18	3.18
Delivered Energy	7.15	7.86	7.84	7.82	8.16	8.13	8.11	8.52	8.50	8.48

Table C5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections								
		2005			2010			2015		
		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 by End-Use										
Space Heating	0.25	0.25	0.25	0.25	0.26	0.25	0.25	0.25	0.25	0.25
Space Cooling	1.29	1.10	1.07	1.07	1.07	1.05	1.05	1.04	1.01	1.01
Water Heating	0.38	0.32	0.31	0.31	0.28	0.28	0.28	0.25	0.24	0.24
Ventilation	0.38	0.38	0.37	0.37	0.39	0.38	0.37	0.38	0.37	0.37
Cooking	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05
Lighting	2.68	2.79	2.72	2.71	2.73	2.65	2.64	2.65	2.58	2.58
Refrigeration	0.31	0.33	0.32	0.32	0.33	0.33	0.33	0.34	0.33	0.33
Office Equipment (PC)	0.16	0.20	0.19	0.19	0.20	0.20	0.20	0.20	0.20	0.20
Office Equipment (non-PC)	0.40	0.47	0.46	0.46	0.50	0.49	0.49	0.53	0.52	0.52
Other Uses[6]	1.25	1.95	1.91	1.91	2.23	2.17	2.17	2.41	2.35	2.36
Total Electricity Related Losses	**7.18**	**7.84**	**7.67**	**7.64**	**8.05**	**7.85**	**7.83**	**8.11**	**7.91**	**7.90**
Total Energy Consumption by End-Use										
Space Heating	1.87	1.90	1.88	1.87	1.91	1.89	1.88	1.92	1.91	1.90
Space Cooling	1.89	1.64	1.62	1.62	1.63	1.60	1.60	1.60	1.58	1.58
Water Heating	1.09	1.02	1.01	1.00	0.99	0.98	0.98	0.97	0.96	0.96
Ventilation	0.55	0.56	0.55	0.55	0.57	0.56	0.56	0.58	0.57	0.57
Cooking	0.29	0.30	0.30	0.30	0.31	0.31	0.31	0.33	0.32	0.32
Lighting	3.89	4.11	4.04	4.02	4.06	3.97	3.95	4.02	3.94	3.93
Refrigeration	0.46	0.48	0.47	0.47	0.50	0.49	0.49	0.51	0.50	0.50
Office Equipment (PC)	0.23	0.29	0.29	0.29	0.30	0.30	0.30	0.31	0.30	0.30
Office Equipment (non-PC)	0.59	0.69	0.68	0.68	0.75	0.74	0.74	0.80	0.79	0.79
Other Uses[6]	3.49	4.69	4.66	4.66	5.19	5.14	5.14	5.58	5.53	5.54
Total	**14.33**	**15.70**	**15.51**	**15.47**	**16.21**	**15.98**	**15.94**	**16.62**	**16.40**	**16.39**
Non-Marketed Renewable Fuels										
Solar[7]	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04
Total	**0.01**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**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, lighting, emergency electric generators, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, district services, and emergency electric generators.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes primary energy displaced by solar thermal water heaters.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995: Energy Information Administration (EIA), *Short-Term Energy Outlook,* DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Table C6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections								
		2005			2010			2015		
		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	2907	3727	3709	3695	4138	4117	4096	4463	4441	4416
Nonmanufacturing	765	911	917	922	971	978	982	1020	1028	1037
Total	3672	4638	4626	4618	5109	5095	5078	5483	5469	5453
Energy Prices (1995 dollars per million Btu)										
Electricity	14.54	13.30	13.46	13.63	12.92	13.13	13.31	12.35	12.56	12.73
Natural Gas	2.28	2.46	2.54	2.60	2.53	2.61	2.66	2.73	2.74	2.76
Steam Coal	1.48	1.39	1.44	1.47	1.31	1.37	1.41	1.25	1.30	1.34
Residual Oil	2.55	1.96	2.92	3.56	1.95	3.03	3.88	1.83	3.01	4.10
Distillate Oil	4.61	4.22	5.21	5.93	4.32	5.38	6.33	4.15	5.29	6.45
Liquefied Petroleum Gas	6.53	5.35	6.00	6.84	5.43	6.28	7.38	5.23	5.95	7.30
Motor Gasoline	9.18	7.51	8.63	9.49	7.56	8.85	9.96	7.33	8.65	10.00
Metallurgical Coal	1.75	1.66	1.72	1.75	1.52	1.58	1.62	1.44	1.48	1.53
Energy Consumption										
Consumption[1] (quadrillion Btu per year)										
Purchased Electricity	3.46	4.08	4.16	4.21	4.30	4.40	4.46	4.53	4.62	4.69
Natural Gas[2]	9.74	10.56	11.04	11.45	10.84	11.42	12.00	10.89	11.63	12.33
Steam Coal	1.59	1.75	1.82	1.87	1.81	1.89	1.93	1.89	1.97	2.01
Metallurgical Coal and Coke[3]	0.91	0.80	0.80	0.80	0.75	0.75	0.75	0.70	0.70	0.70
Residual Fuel	0.34	0.43	0.31	0.27	0.48	0.33	0.26	0.51	0.35	0.25
Distillate	1.15	1.39	1.39	1.38	1.48	1.47	1.47	1.56	1.55	1.55
Liquefied Petroleum Gas	2.01	2.30	2.20	2.11	2.41	2.28	2.16	2.52	2.35	2.20
Petrochemical Feedstocks	1.16	1.36	1.30	1.24	1.43	1.35	1.27	1.50	1.40	1.29
Other Petroleum[4]	4.03	4.90	4.57	4.23	5.03	4.69	4.23	5.20	4.75	4.20
Renewables[5]	1.74	2.13	2.12	2.11	2.29	2.28	2.26	2.41	2.40	2.38
Delivered Energy	26.12	29.68	29.70	29.67	30.84	30.87	30.78	31.72	31.73	31.60
Electricity Related Losses	7.69	8.60	8.59	8.69	8.83	8.82	8.93	8.82	8.79	8.92
Total	33.81	38.28	38.28	38.35	39.66	39.69	39.71	40.54	40.51	40.52
Consumption per Unit of Output[1] (thousand Btu per 1987 dollar)										
Purchased Electricity	0.94	0.88	0.90	0.91	0.84	0.86	0.88	0.83	0.84	0.86
Natural Gas[2]	2.65	2.28	2.39	2.48	2.12	2.24	2.36	1.99	2.13	2.26
Steam Coal	0.43	0.38	0.39	0.41	0.35	0.37	0.38	0.34	0.36	0.37
Metallurgical Coal and Coke[3]	0.25	0.17	0.17	0.17	0.15	0.15	0.15	0.13	0.13	0.13
Residual Fuel	0.09	0.09	0.07	0.06	0.09	0.06	0.05	0.09	0.06	0.05
Distillate	0.31	0.30	0.30	0.30	0.29	0.29	0.29	0.29	0.28	0.28
Liquefied Petroleum Gas	0.55	0.50	0.48	0.46	0.47	0.45	0.43	0.46	0.43	0.40
Petrochemical Feedstocks	0.32	0.29	0.28	0.27	0.28	0.27	0.25	0.27	0.26	0.24
Other Petroleum[4]	1.10	1.06	0.99	0.92	0.99	0.92	0.83	0.95	0.87	0.77
Renewables[5]	0.47	0.46	0.46	0.46	0.45	0.45	0.45	0.44	0.44	0.44
Delivered Energy	7.11	6.40	6.42	6.42	6.04	6.06	6.06	5.78	5.80	5.79
Electricity Related Losses	2.09	1.85	1.86	1.88	1.73	1.73	1.76	1.61	1.61	1.64
Total	9.21	8.25	8.28	8.31	7.76	7.79	7.82	7.39	7.41	7.43

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net coke coal imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995 prices for gasoline and distillate are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(95/3-96/4) (Washington, DC, 1995 - 1996). 1995 coal prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(96/08) (Washington, DC, August 1996). 1995 electricity prices: EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B. 1995 prices derived from EIA, *State Energy Data Report 1993*, DOE/EIA-0214(93) (Washington, DC, July 1995). Other 1995 values: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Table C7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	1995	Projections								
		2005			2010			2015		
		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 (vehicle miles traveled)	2209	2591	2574	2561	2787	2767	2750	2944	2924	2903
Freight Trucks (vehicle miles traveled)	166	219	219	218	238	237	236	251	250	249
Air (seat miles available)	927	1512	1493	1480	1751	1729	1707	1947	1923	1897
Rail (ton miles traveled)	1181	1343	1368	1388	1429	1459	1485	1503	1535	1572
Marine (ton miles traveled)	871	962	989	1011	1015	1047	1075	1065	1099	1139
Energy Efficiency Indicators										
New Car (miles per gallon)[1]	27.5	29.2	29.8	30.3	30.6	31.5	32.3	31.6	32.6	33.5
New Light Truck (miles per gallon)[1]	20.5	21.3	21.6	21.7	22.6	22.9	23.2	23.8	24.2	24.7
Light-Duty Fleet (miles per gallon)[2]	19.7	19.7	19.8	19.9	20.1	20.4	20.6	20.9	21.3	21.6
Aircraft Efficiency (seat miles per gallon)	50.8	55.8	55.8	55.8	58.3	58.2	58.2	60.7	60.6	60.6
Freight Truck Efficiency (miles per gallon)	5.5	5.8	5.9	5.9	5.9	6.0	6.0	6.0	6.1	6.1
Rail Efficiency (ton miles per thousand Btu)	2.6	2.9	2.9	2.9	3.0	3.0	3.0	3.2	3.2	3.2
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.7	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0
Energy Use by Mode (quadrillion Btu per year)										
Light-Duty Vehicles	14.20	16.76	16.52	16.35	17.62	17.26	16.98	17.86	17.43	17.05
Freight Trucks	5.43	6.49	6.47	6.45	6.84	6.80	6.77	7.11	7.07	7.03
Air	3.18	4.34	4.30	4.27	4.76	4.71	4.66	5.05	5.00	4.94
Rail	0.48	0.49	0.50	0.51	0.50	0.51	0.52	0.50	0.51	0.52
Marine	1.63	2.09	2.09	2.10	2.30	2.30	2.30	2.46	2.46	2.47
Pipeline Fuel	0.72	0.83	0.84	0.85	0.88	0.88	0.89	0.93	0.93	0.96
Other[3]	0.21	0.27	0.27	0.27	0.29	0.29	0.29	0.30	0.30	0.29
Total	24.31	29.66	29.38	29.18	31.54	31.11	30.76	32.52	31.99	31.56

[1]Environmental Protection Agency rated miles per gallon.
[2]Combined car and light truck "on-the-road" estimate.
[3]Includes lubricants and aviation gasoline.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995: Federal Aviation Administration (FAA), *FAA Aviation Forecasts Fiscal Years 1993-2004*, (Washington, DC, February 1994); Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996); EIA, *Fuel Oil and Kerosene Sales 1995*, DOE/EIA-0535(95) (Washington, DC, September 1996); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Table C8. Electricity Supply, Disposition, and Prices
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1995	Projections								
		2005			2010			2015		
		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	1671	1867	1854	1871	1936	1942	1952	2031	2052	2066
Petroleum	64	109	58	49	128	58	44	151	64	45
Natural Gas	322	623	705	713	808	892	907	1109	1184	1194
Nuclear Power	673	654	654	654	614	614	614	448	448	448
Pumped Storage	-2	-3	-3	-3	-3	-3	-3	-3	-3	-3
Renewable Sources[2]	354	360	361	361	369	371	372	383	394	402
Total	3083	3610	3629	3645	3851	3874	3886	4120	4139	4152
Non-Utility Generation for Own Use	22	22	22	22	22	22	22	22	22	22
Cogenerators[3]										
Coal	43	48	48	48	50	50	50	51	51	51
Petroleum	5	6	5	5	6	6	6	6	6	6
Natural Gas	180	195	205	212	199	214	224	204	221	230
Other Gaseous Fuels[4]	7	8	8	8	8	8	8	8	8	8
Renewable Sources[2]	42	49	49	49	53	53	52	55	55	55
Other[5]	3	4	4	3	4	4	4	4	4	4
Total	279	309	319	326	319	333	343	328	344	353
Sales to Utilities	148	157	158	159	159	161	162	161	163	164
Generation for Own Use	132	152	161	167	160	172	181	166	181	188
Net Imports	38	33	35	33	31	31	31	27	27	27
Electricity Sales by Sector										
Residential	1043	1215	1214	1213	1308	1307	1306	1423	1421	1419
Commercial	946	1090	1089	1087	1149	1147	1145	1221	1219	1217
Industrial	1013	1196	1218	1235	1260	1289	1306	1329	1354	1374
Transportation	6	24	24	24	41	41	40	50	50	49
Total	3008	3525	3545	3558	3758	3784	3797	4024	4044	4059
End-Use Prices (1995 cents per kilowatthour)[6]										
Residential	8.4	7.9	8.0	8.1	7.7	7.8	7.9	7.5	7.6	7.7
Commercial	7.9	7.2	7.3	7.4	7.1	7.2	7.3	6.9	6.9	7.0
Industrial	5.0	4.5	4.6	4.6	4.4	4.5	4.5	4.2	4.3	4.3
Transportation	5.2	4.9	4.9	5.0	4.8	4.9	4.9	4.7	4.7	4.7
All Sectors Average	7.1	6.5	6.6	6.7	6.4	6.4	6.5	6.2	6.3	6.3
Price Components (1995 cents per kilowatthour)										
Capital Component	2.6	2.5	2.5	2.5	2.3	2.3	2.4	2.2	2.2	2.3
Fuel Component	1.1	1.1	1.1	1.1	1.0	1.0	1.0	0.9	0.9	0.9
Operation and Maintenance Component	3.0	2.5	2.5	2.5	2.5	2.5	2.5	2.3	2.3	2.3
Wholesale Power Cost	0.4	0.5	0.6	0.6	0.6	0.7	0.7	0.8	0.8	0.8
Total	7.1	6.5	6.6	6.7	6.4	6.4	6.5	6.2	6.3	6.3

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers, exempt wholesale generators, and generators at industrial and commercial facilities which provide electricity for on-site use and for sales to utilities.
[2]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar, and wind power.
[3]Includes cogeneration at facilities whose primary function is not electricity production. 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]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995 commercial and transportation sales derived from: Total transportation plus commercial sales come from Energy Information Administration (EIA), *State Energy Data Report 1993*, DOE/EIA-0214(93) (Washington, DC, July 1995), 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 15* (May 1995) which indicates the transportation value should be higher. 1995 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). 1995 residential electricity prices derived from EIA, *Short Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **1995 electricity prices for commercial, industrial, and transportation; price components; and projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Table C9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	1995	Projections								
		2005			2010			2015		
		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	304.9	298.5	298.2	300.9	303.2	304.0	305.4	311.7	315.4	318.3
Other Fossil Steam[3]	139.6	102.6	102.6	102.6	99.9	99.9	99.9	96.1	96.1	96.1
Combined Cycle	14.7	50.6	73.5	75.4	77.4	107.5	107.3	120.8	153.0	149.4
Combustion Turbine/Diesel	56.0	150.7	134.5	134.6	174.8	153.1	151.6	198.2	168.3	168.3
Nuclear Power	99.2	94.7	94.7	94.7	88.9	88.9	88.9	62.7	62.7	62.7
Pumped Storage	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
Fuel Cells	0.0	1.7	2.0	2.2	1.8	2.1	3.2	1.9	2.1	3.3
Renewable Sources[4]	88.0	91.8	92.2	91.9	93.6	94.1	94.2	97.0	98.3	100.5
Total	**722.2**	**810.4**	**817.5**	**822.1**	**859.5**	**869.4**	**870.4**	**908.4**	**915.8**	**918.6**
Cumulative Planned Additions[5]										
Coal Steam	1.4	3.7	3.7	3.7	5.3	5.3	5.3	5.3	5.3	5.3
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	1.4	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Combustion Turbine/Diesel	3.2	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Nuclear Power	0.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Pumped Storage	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
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]	0.7	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Total	**8.0**	**15.5**	**15.5**	**15.5**	**17.1**	**17.1**	**17.1**	**17.1**	**17.1**	**17.1**
Cumulative Unplanned Additions[5]										
Coal Steam	0.0	9.7	9.5	12.2	15.6	16.4	17.8	27.9	31.6	34.5
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	35.1	58.0	59.9	61.9	91.9	91.8	105.3	137.5	133.9
Combustion Turbine/Diesel	0.1	94.4	78.2	78.3	118.9	97.1	95.7	143.4	113.5	113.5
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	1.7	2.0	2.2	1.8	2.1	3.2	1.9	2.1	3.3
Renewable Sources[3]	0.0	1.4	1.8	1.6	3.4	3.9	4.0	7.1	8.4	10.6
Total	**0.1**	**142.4**	**149.5**	**154.0**	**201.5**	**211.4**	**212.4**	**285.6**	**293.1**	**295.8**
Cumulative Total Additions	8.2	157.9	165.0	169.5	218.6	228.5	229.5	302.7	310.2	312.9
Cumulative Retirements[6]	11.9	72.1	72.1	72.1	83.9	83.9	83.9	119.1	119.1	119.1

Table C9. Electricity Generating Capability (Continued)
(Thousand Megawatts)

Net Summer Capability[1]	1995	Projections								
		2005			2010			2015		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Cogenerators[7]										
Capacity										
Coal	8.2	9.0	9.0	8.9	9.3	9.3	9.2	9.5	9.5	9.4
Petroleum	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0
Natural Gas	28.9	30.9	32.1	33.0	31.5	33.3	34.6	32.1	34.2	35.3
Other Gaseous Fuels	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Renewable Sources[4]	6.2	7.3	7.3	7.3	7.8	7.8	7.8	8.2	8.2	8.2
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	45.1	49.0	50.2	51.1	50.5	52.3	53.5	51.8	53.8	54.8
Cumulative Additions[5]	10.2	14.1	15.3	16.2	15.6	17.3	18.5	16.8	18.8	19.9

[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, exempt wholesale generators, and generators at industrial and commercial facilities which produce electricity for on-site use and sales to utilities.
[3]Includes oil-, gas-, and dual-fired capability.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power.
[5]Cumulative additions after December 31, 1994.
[6]Cumulative total retirements from 1990.
[7]Nameplate capacity is reported for nonutilities on Form EIA-867, "Annual Power Producer Report." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO97. Net summer capacity is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recent data available as of August 15, 1996. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: 1995 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 1995 and planned additions estimated based on EIA, Form EIA-867, "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Table C10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1995	Projections								
		2005			2010			2015		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Interregional Electricity Trade										
Gross Domestic Firm Power Sales	155.0	139.2	139.2	139.2	139.2	139.2	139.2	139.2	139.2	139.2
Gross Domestic Economy Sales	81.6	66.5	61.3	69.6	68.1	77.6	83.2	69.5	79.4	79.6
Gross Domestic Trade	**236.6**	**205.7**	**200.5**	**208.9**	**207.3**	**216.8**	**222.4**	**208.7**	**218.6**	**218.8**
Gross Domestic Firm Power Sales (million 1995 dollars)	7023.5	6309.0	6309.0	6309.0	6309.0	6309.0	6309.0	6309.0	6309.0	6309.0
Gross Domestic Economy Sales (million 1995 dollars)	1958.3	1439.9	1420.8	1743.5	1452.4	1753.8	2014.1	1598.1	1831.4	2020.9
Gross Domestic Sales (million 1995 dollars)	**8981.7**	**7748.9**	**7729.8**	**8052.5**	**7761.4**	**8062.8**	**8323.1**	**7907.1**	**8140.4**	**8329.9**
International Electricity Trade										
Firm Power Imports From Canada and Mexico	30.2	17.8	19.7	17.8	18.6	18.6	18.6	18.6	18.6	18.6
Economy Imports From Canada and Mexico	18.0	35.2	35.2	35.2	33.6	33.6	33.6	29.2	29.2	29.2
Gross Imports From Canada and Mexico	**48.3**	**52.9**	**54.8**	**52.9**	**52.2**	**52.2**	**52.2**	**47.9**	**47.9**	**47.9**
Firm Power Exports To Canada and Mexico	3.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
Economy Exports To Canada and Mexico	7.2	7.0	7.0	7.0	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**10.6**	**20.3**	**20.3**	**20.3**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**	**21.0**

Note: Totals may not equal sum of components due to independent rounding. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 1995 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1995 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." Firm/economy share: National Energy Board, *Annual Report 1993*. Planned interregional and international firm power sales: DOE Form IE-411, "Coordinated Bulk Power Supply Program Report" (April 1995). **Projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Table C11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1995	Projections								
		2005			2010			2015		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Crude Oil										
Domestic Crude Production[1]	6.56	4.42	5.49	6.41	4.07	5.39	6.53	3.97	5.23	6.89
Alaska	1.48	0.91	0.94	0.99	0.73	0.77	0.94	0.59	0.63	1.05
Lower 48 States	5.08	3.51	4.55	5.41	3.34	4.62	5.58	3.38	4.60	5.84
Net Imports	7.14	11.27	9.49	8.69	11.68	9.76	8.78	11.80	10.24	8.72
Other Crude Supply[2]	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	13.97	15.69	14.98	15.10	15.75	15.15	15.31	15.77	15.47	15.62
Natural Gas Plant Liquids	1.76	2.07	2.14	2.18	2.21	2.28	2.34	2.36	2.44	2.52
Other Inputs[3]	0.46	0.21	0.24	0.25	0.20	0.19	0.22	0.19	0.19	0.23
Refinery Processing Gain[4]	0.77	0.84	0.80	0.84	0.85	0.82	0.87	0.81	0.77	0.84
Net Product Imports[5]	0.75	2.56	2.51	1.86	3.50	3.14	2.23	4.14	3.22	2.11
Total Primary Supply[6]	17.73	21.37	20.67	20.24	22.51	21.58	20.97	23.26	22.10	21.31
Refined Petroleum Products Supplied										
Motor Gasoline[7]	7.81	9.03	8.90	8.81	9.36	9.17	9.03	9.42	9.19	9.00
Jet Fuel[8]	1.51	2.08	2.06	2.04	2.28	2.25	2.23	2.42	2.39	2.36
Distillate Fuel[9]	3.25	3.85	3.81	3.80	4.05	3.99	3.97	4.21	4.12	4.10
Residual Fuel	0.85	1.31	1.04	0.97	1.48	1.11	1.02	1.64	1.20	1.07
Other[10]	4.32	5.13	4.87	4.61	5.37	5.07	4.72	5.59	5.21	4.78
Total	17.73	21.40	20.68	20.23	22.55	21.60	20.96	23.28	22.12	21.30
Refined Petroleum Products Supplied										
Residential and Commercial	1.07	1.06	1.03	1.01	1.05	1.02	0.99	1.06	1.01	0.98
Industrial[11]	4.58	5.44	5.13	4.86	5.69	5.33	4.95	5.93	5.48	5.02
Transportation	11.79	14.42	14.26	14.15	15.23	15.00	14.82	15.62	15.35	15.11
Electric Generators[12]	0.30	0.49	0.26	0.22	0.57	0.26	0.20	0.68	0.28	0.20
Total	17.73	21.40	20.68	20.23	22.55	21.60	20.96	23.28	22.12	21.30
Discrepancy[13]	-0.01	-0.03	-0.01	0.00	-0.04	-0.02	0.00	-0.02	-0.02	0.01
World Oil Price (1995 dollars per barrel)[14]	17.26	14.08	19.72	24.13	14.03	20.41	26.44	13.99	20.98	28.23
Import Share of Product Supplied	0.44	0.65	0.58	0.52	0.67	0.60	0.53	0.68	0.61	0.51
Expenditures for Imported Crude Oil and Petroleum Products (billion 1995 dollars)	49.39	70.59	85.05	91.94	77.97	95.44	105.73	80.12	101.18	110.39
Domestic Refinery Distillation Capacity	15.4	16.8	16.0	16.1	16.9	16.2	16.4	16.9	16.5	16.7
Capacity Utilization Rate (percent)	92.0	93.8	94.1	94.0	94.0	94.0	93.6	93.7	94.0	94.0

[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]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net petroleum imports.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes naphtha and kerosene types.
[9]Includes distillate and kerosene.
[10]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.
[11]Includes consumption by cogenerators.
[12]Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[13]Balancing item. Includes unaccounted for supply, losses and gains.
[14]Average refiner acquisition cost for imported crude oil.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995 expenditures for imported crude oil and petroleum products based on internal calculations. Other 1995 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1995*, DOE/EIA-0340(95) (Washington, DC, May 1996). Projections: EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Table C12. Petroleum Product Prices
(1995 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	1995	Projections								
		2005			2010			2015		
		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 (dollars per barrel)	17.26	14.08	19.72	24.13	14.03	20.41	26.44	13.99	20.98	28.23
Delivered Sector Product Prices										
Residential										
Distillate Fuel	86.5	87.2	100.9	110.8	88.6	103.3	116.0	86.1	101.7	117.9
Liquefied Petroleum Gas	88.8	92.5	98.4	106.5	93.8	102.3	111.8	92.7	99.9	112.2
Commercial										
Distillate Fuel	60.8	59.3	73.3	83.2	60.4	75.4	88.4	57.6	73.7	90.0
Residual Fuel	44.7	30.8	42.9	52.6	31.0	44.6	58.0	30.0	45.3	61.5
Residual Fuel (dollars per barrel)	18.78	12.94	18.02	22.08	13.00	18.73	24.38	12.58	19.02	25.82
Industrial [1]										
Distillate Fuel	63.9	58.5	72.3	82.2	59.9	74.6	87.8	57.5	73.3	89.5
Liquefied Petroleum Gas	56.4	46.2	51.8	59.1	46.9	54.2	63.7	45.1	51.4	63.0
Residual Fuel	38.2	29.4	43.7	53.3	29.2	45.3	58.1	27.3	45.1	61.4
Residual Fuel (dollars per barrel)	16.06	12.34	18.36	22.39	12.27	19.04	24.40	11.48	18.95	25.78
Transportation										
Distillate Fuel [2]	111.4	107.2	120.6	130.0	105.3	120.4	133.5	100.3	116.2	132.8
Jet Fuel [3]	52.0	58.6	73.7	82.6	59.7	76.3	91.2	56.3	73.5	91.0
Motor Gasoline [4]	114.8	106.9	121.2	131.7	105.4	121.8	135.8	100.6	117.4	134.5
Residual Fuel	36.5	30.4	43.4	53.4	31.9	47.3	62.0	29.7	46.0	62.7
Residual Fuel (dollars per barrel)	15.32	12.78	18.24	22.45	13.38	19.86	26.02	12.46	19.33	26.32
Electric Generators [5]										
Distillate Fuel	54.7	52.4	66.1	76.0	53.4	68.3	81.2	51.0	67.0	83.1
Residual Fuel	39.2	29.5	44.4	54.5	30.6	47.2	61.9	29.9	46.5	64.9
Residual Fuel (dollars per barrel)	16.45	12.38	18.66	22.90	12.86	19.82	26.01	12.56	19.54	27.25
Refined Petroleum Product Prices [6]										
Distillate Fuel [2]	96.8	93.8	107.5	117.1	92.9	108.2	121.3	88.6	104.9	121.4
Jet Fuel [3]	52.0	58.6	73.7	82.6	59.7	76.3	91.2	56.3	73.5	91.0
Liquefied Petroleum Gas	62.2	56.3	62.2	69.8	57.7	65.6	75.4	56.3	63.2	75.3
Motor Gasoline [4]	114.8	106.7	120.9	131.5	105.3	121.6	135.6	100.5	117.2	134.3
Residual Fuel	38.1	30.0	43.6	53.5	31.0	46.9	61.3	29.4	46.0	62.7
Residual Fuel (dollars per barrel)	16.01	12.59	18.32	22.49	13.03	19.69	25.75	12.36	19.31	26.34
Average	92.4	85.3	99.4	109.5	84.2	100.4	114.2	79.8	96.4	113.2

[1] Includes cogenerators.
[2] Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[3] Kerosene-type jet fuel.
[4] Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[5] Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[6] Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Sources: 1995 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(95/3-96/4) (Washington, DC, 1995-1996). 1995 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1993,* DOE/EIA-0376(93) (Washington, DC, December 1995). **Projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Oil Price Case Comparisons

Table C13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	1995	Projections								
		2005			2010			2015		
		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]	18.49	21.85	22.66	23.10	23.46	24.25	24.92	25.22	26.10	26.93
Supplemental Natural Gas[2]	0.13	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	2.68	3.69	3.69	3.69	3.92	3.92	3.92	4.23	4.23	4.23
Canada	2.79	3.52	3.52	3.52	3.74	3.74	3.74	4.06	4.06	4.06
Mexico	-0.05	-0.11	-0.11	-0.11	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12
Liquefied Natural Gas	-0.05	0.27	0.27	0.27	0.29	0.29	0.29	0.29	0.29	0.29
Total Supply	21.30	25.60	26.41	26.85	27.44	28.23	28.89	29.51	30.39	31.22
Consumption by Sector										
Residential	4.87	5.31	5.27	5.26	5.45	5.42	5.40	5.58	5.57	5.56
Commercial	3.07	3.33	3.34	3.34	3.42	3.44	3.43	3.52	3.55	3.55
Industrial[3]	8.33	8.85	9.27	9.65	9.03	9.56	10.08	8.98	9.65	10.28
Electric Generators[4]	3.46	5.51	5.88	5.92	6.65	6.94	7.07	8.34	8.52	8.67
Lease and Plant Fuel[5]	1.14	1.41	1.45	1.48	1.51	1.55	1.58	1.61	1.65	1.70
Pipeline Fuel	0.70	0.80	0.82	0.83	0.86	0.86	0.86	0.91	0.91	0.93
Transportation[6]	0.01	0.18	0.18	0.18	0.26	0.25	0.25	0.31	0.30	0.30
Total	21.58	25.39	26.22	26.66	27.18	28.01	28.68	29.25	30.16	31.00
Discrepancy[7]	-0.28	0.21	0.19	0.19	0.26	0.22	0.21	0.26	0.23	0.22

[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 as a by product of other processes.
[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, 1995 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors.
Sources: 1995 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). 1995 imports and dry gas production derived from: EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). 1995 transportation sector consumption: EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B. Other 1995 consumption: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B. **Projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Table C14. Natural Gas Prices, Margins, and Revenues
(1995 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1995	Projections								
		2005			2010			2015		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Source Price										
Average Lower 48 Wellhead Price[1]	1.61	1.86	1.94	2.02	1.92	2.01	2.07	2.12	2.13	2.16
Average Import Price	1.49	1.77	1.85	1.93	1.86	1.94	2.07	2.10	2.06	2.13
Average[2]	1.59	1.85	1.93	2.00	1.91	2.00	2.07	2.12	2.12	2.16
Delivered Prices										
Residential	6.18	5.50	5.65	5.75	5.26	5.43	5.52	5.27	5.33	5.38
Commercial	5.10	4.65	4.79	4.88	4.49	4.64	4.73	4.57	4.61	4.66
Industrial[3]	2.35	2.53	2.61	2.67	2.60	2.69	2.74	2.81	2.82	2.84
Electric Generators[4]	2.06	2.27	2.33	2.40	2.31	2.38	2.46	2.52	2.52	2.57
Transportation[5]	5.94	6.17	6.38	6.47	6.57	6.93	7.03	6.94	7.27	7.39
Average[6]	3.67	3.48	3.55	3.60	3.41	3.49	3.54	3.52	3.52	3.53
Transmission and Distribution Margins[7]										
Residential	4.59	3.65	3.73	3.75	3.34	3.43	3.45	3.15	3.21	3.22
Commercial	3.51	2.80	2.86	2.87	2.58	2.64	2.67	2.45	2.49	2.50
Industrial[3]	0.76	0.68	0.68	0.67	0.69	0.69	0.67	0.69	0.70	0.68
Electric Generators[4]	0.47	0.42	0.41	0.39	0.40	0.38	0.39	0.41	0.40	0.41
Transportation[5]	4.35	4.32	4.45	4.47	4.66	4.93	4.96	4.83	5.15	5.23
Average[6]	2.08	1.63	1.62	1.60	1.50	1.49	1.47	1.40	1.40	1.38
Transmission and Distribution Revenue (billion 1995 dollars)										
Residential	22.35	19.38	19.66	19.70	18.24	18.56	18.64	17.61	17.91	17.92
Commercial	10.79	9.32	9.56	9.60	8.82	9.08	9.15	8.62	8.85	8.88
Industrial[3]	6.31	6.00	6.32	6.46	6.21	6.57	6.77	6.22	6.72	6.95
Electric Generators[4]	1.61	2.30	2.40	2.33	2.63	2.61	2.79	3.40	3.42	3.59
Transportation[5]	0.04	0.78	0.79	0.79	1.19	1.25	1.25	1.47	1.56	1.57
Total	41.11	37.78	38.73	38.88	37.10	38.08	38.60	37.32	38.45	38.92

[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 as a by product of other processes.
[5]Compressed natural gas used as a vehicle fuel.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

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

Sources: 1995 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1991*. 1995 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). Other 1995 values, and **projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Oil Price Case Comparisons

Table C15. Oil and Gas Supply

Production and Supply	1995	Projections								
		2005			2010			2015		
		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] (1995 dollars per barrel)	15.58	13.95	19.36	23.63	14.01	20.02	25.85	13.35	19.85	26.82
Production (million barrels per day)[2]										
U.S. Total	6.56	4.42	5.49	6.41	4.07	5.39	6.53	3.97	5.23	6.89
Lower 48 Onshore	3.82	2.30	3.04	3.60	2.09	3.04	3.74	2.13	3.07	3.82
Conventional	3.24	1.89	2.44	2.83	1.70	2.36	2.77	1.73	2.33	2.74
Enhanced Oil Recovery	0.58	0.41	0.60	0.76	0.40	0.69	0.97	0.39	0.75	1.09
Lower 48 Offshore	1.26	1.21	1.50	1.82	1.25	1.57	1.84	1.25	1.53	2.02
Alaska	1.48	0.91	0.94	0.99	0.73	0.77	0.94	0.59	0.63	1.05
Lower 48 End of Year Reserves (billion barrels)	17.18	11.55	15.26	18.39	11.24	15.51	19.33	11.21	15.61	20.39
Natural Gas										
Lower 48 Average Wellhead Price[1] (1995 dollars per thousand cubic feet)	1.61	1.86	1.94	2.02	1.92	2.01	2.07	2.12	2.13	2.16
Production (trillion cubic feet)[3]										
U.S. Total	18.48	21.85	22.66	23.10	23.46	24.25	24.92	25.22	26.10	26.93
Lower 48 Onshore	13.00	14.97	15.75	16.31	16.35	17.19	18.12	17.74	18.59	19.48
Associated-Dissolved[4]	1.85	1.15	1.28	1.39	1.05	1.21	1.31	1.03	1.18	1.27
Non-Associated	11.15	13.81	14.47	14.92	15.30	15.98	16.82	16.71	17.40	18.20
Conventional	7.92	10.86	11.21	11.57	12.08	12.33	12.81	13.02	13.28	13.58
Unconventional	3.24	2.95	3.26	3.35	3.23	3.66	4.01	3.69	4.13	4.63
Lower 48 Offshore	5.05	6.36	6.39	6.27	6.56	6.51	6.24	6.91	6.94	6.88
Associated-Dissolved[4]	0.71	0.72	0.78	0.84	0.73	0.81	0.85	0.74	0.80	0.88
Non-Associated	4.34	5.64	5.61	5.43	5.83	5.70	5.39	6.17	6.14	5.99
Alaska	0.42	0.52	0.52	0.52	0.55	0.55	0.55	0.58	0.58	0.58
U.S. End of Year Reserves (trillion cubic feet)	155.03	169.02	174.73	181.77	177.70	187.05	196.18	178.46	188.42	197.90
Supplemental Gas Supplies (trillion cubic feet)[5]	0.13	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Total Lower 48 Wells Completed (thousands)	18.52	27.43	34.33	39.71	31.45	37.60	43.54	36.90	41.75	47.16

[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.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors.
Sources: 1995 crude oil lower 48 average wellhead price: Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting. 1995 total wells completed: EIA, Office of Integrated Analysis and Forecasting. 1995 lower 48 onshore, lower 48 offshore, Alaska crude oil production: EIA, *Petroleum Supply Annual 1995*, DOE/EIA-0340(95) (Washington, DC, May 1996). 1995 natural gas lower 48 average wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/06) (Washington, DC, June 1996). 1995 total natural gas production derived from: EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). Other 1995 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Table C16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1995	Projections								
		2005			2010			2015		
		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	435	441	441	444	478	479	484	482	494	509
Interior	169	165	157	158	169	165	169	167	160	170
West	429	546	548	553	550	557	556	607	614	594
East of the Mississippi	544	544	538	542	576	579	586	575	586	607
West of the Mississippi	489	608	608	613	620	622	622	680	682	666
Total	1033	1151	1146	1155	1196	1201	1208	1255	1268	1273
Net Imports										
Imports	7	8	8	8	9	9	9	9	9	9
Exports	89	102	102	102	113	111	111	121	121	121
Total	-81	-94	-94	-94	-105	-103	-103	-112	-112	-112
Total Supply[2]	951	1057	1052	1061	1092	1098	1105	1143	1156	1161
Consumption by Sector										
Residential and Commercial	6	6	6	6	6	6	6	6	6	6
Industrial[3]	73	80	84	86	84	87	89	87	91	92
Coke Plants	33	26	26	26	23	23	23	20	20	20
Electric Generators[4]	847	947	938	947	981	983	989	1032	1039	1044
Total	959	1059	1054	1065	1094	1099	1106	1145	1156	1162
Discrepancy and Stock Change[5]	-8	-1	-2	-3	-2	-1	-1	-2	-1	-1
Average Minemouth Price										
(1995 dollars per short ton)	18.83	16.94	17.47	17.98	16.15	16.92	17.48	14.82	15.46	16.24
(1995 dollars per million Btu)	0.88	0.81	0.83	0.86	0.77	0.81	0.83	0.71	0.74	0.78
Delivered Prices (1995 dollars per short ton)[6]										
Industrial	32.30	30.22	31.18	31.90	28.43	29.72	30.65	27.07	28.12	29.06
Coke Plants	46.94	44.51	46.03	46.95	40.68	42.32	43.51	38.66	39.79	40.93
Electric Generators										
(1995 dollars per short ton)	27.01	24.36	24.97	25.65	23.35	24.23	24.91	21.71	22.47	23.29
(1995 dollars per million Btu)	1.32	1.20	1.24	1.27	1.15	1.20	1.23	1.08	1.11	1.15
Average	28.11	25.30	25.99	26.67	24.11	25.05	25.76	22.42	23.23	24.07
Exports[7]	39.51	36.82	37.96	38.73	34.08	35.47	36.40	31.86	32.91	33.78

[1]Includes anthracite, bituminous coal, and lignite.
[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 as a by-product of other processes.
[5]Balancing item: the sum of production, net imports, and net storage minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995 data derived from: Energy Information Administration (EIA), *Coal Industry Annual 1994*, DOE/EIA-0584(94) (Washington, DC, October 1995). **Projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Table C17. Renewable Energy Generating Capacity and Generation
(Thousand Megawatts, Unless Otherwise Noted)

Capacity and Generation	1995	Projections								
		2005			2010			2015		
		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)										
Capability										
Conventional Hydropower	78.48	80.33	80.33	80.33	80.38	80.38	80.38	80.38	80.38	80.38
Geothermal [2]	2.97	3.08	3.04	3.10	3.00	3.19	3.21	3.14	3.46	3.49
Municipal Solid Waste	2.43	3.34	3.34	3.33	3.89	3.89	3.88	4.19	4.19	4.17
Wood and Other Biomass[3]	1.86	1.99	2.00	2.01	2.05	2.21	2.36	2.62	3.92	4.46
Solar Thermal	0.36	0.42	0.42	0.42	0.50	0.50	0.50	0.63	0.63	0.63
Solar Photovoltaic	0.01	0.08	0.08	0.08	0.19	0.19	0.19	0.35	0.35	0.35
Wind	1.83	2.58	2.97	2.68	3.61	3.78	3.70	5.71	5.39	7.01
Total	87.95	91.80	92.17	91.95	93.63	94.14	94.23	97.02	98.32	100.49
Generation (billion kilowatthours)										
Conventional Hydropower	309.82	303.58	303.59	303.59	304.10	304.11	304.11	304.21	304.21	304.22
Geothermal [2]	14.66	18.21	17.94	18.41	18.16	19.46	19.64	19.77	22.04	22.20
Municipal Solid Waste	18.69	22.36	22.33	22.30	26.15	26.12	26.08	28.24	28.18	28.11
Wood and Other Biomass[3]	7.12	9.15	9.24	9.31	9.63	10.73	11.76	13.56	22.72	26.47
Solar Thermal	0.82	1.10	1.10	1.10	1.38	1.38	1.38	1.78	1.78	1.78
Solar Photovoltaic	0.00	0.22	0.22	0.22	0.48	0.48	0.48	0.87	0.87	0.87
Wind	3.17	5.72	6.80	6.05	8.75	9.15	8.97	14.96	13.80	18.04
Total	354.28	360.34	361.21	360.98	368.64	371.43	372.41	383.38	393.62	401.70
Cogenerators[4]										
Capability										
Municipal Solid Waste	0.41	0.43	0.43	0.43	0.44	0.44	0.44	0.45	0.45	0.45
Biomass	5.79	6.89	6.88	6.87	7.40	7.38	7.35	7.78	7.75	7.72
Total	6.19	7.32	7.31	7.30	7.84	7.82	7.80	8.24	8.21	8.17
Generation (billion kilowatthours)										
Municipal Solid Waste	1.97	2.08	2.08	2.08	2.13	2.13	2.13	2.17	2.17	2.17
Biomass	39.58	47.12	47.05	46.96	50.50	50.37	50.21	53.10	52.90	52.67
Total	41.55	49.19	49.12	49.03	52.64	52.50	52.34	55.27	55.07	54.84

[1]Includes grid-connected utilities and nonutilities other than cogenerators. These nonutility facilities include small power producers, exempt wholesale generators and generators at industrial and commercial facilities which do not produce steam for other uses.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes projections for energy crops after 2010.
[4]Cogenerators are facilities whose primary function is not electricity production.
Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO97. Net summer capability is used to be consistent with electric utility capacity estimates. Data for electric utility capacity data are the most recently available data as of August 15, 1996. Additional retirements are also determined on the basis of the size and age of the units. Therefore, capacity estimates may differ from other Energy Information Administration sources.
Sources: 1995 electric utility capability: Energy Information Administration (EIA), Form EIA-860 "Annual Electric Utility Report." 1995 nonutility and cogenerator capability: Form EIA-867, "Annual Nonutility Power Producer Report." 1995 generation: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Table C18. Renewable Energy, Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1995	2005 Low World Oil Price	2005 Reference	2005 High World Oil Price	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2015 Low World Oil Price	2015 Reference	2015 High World Oil Price
Marketed Renewable Energy[2]										
Residential	0.57	0.56	0.56	0.56	0.55	0.55	0.55	0.54	0.54	0.54
Wood	0.57	0.56	0.56	0.56	0.55	0.55	0.55	0.54	0.54	0.54
Commercial[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[4]	1.74	2.13	2.12	2.11	2.29	2.28	2.26	2.41	2.40	2.38
Conventional Hydroelectric	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Municipal Solid Waste	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biomass	1.70	2.09	2.08	2.07	2.25	2.24	2.23	2.37	2.36	2.34
Transportation	0.08	0.07	0.10	0.10	0.10	0.10	0.12	0.15	0.15	0.20
Ethanol used in E85[5]	0.00	0.02	0.02	0.02	0.06	0.06	0.06	0.09	0.09	0.08
Ethanol used in Gasoline Blending	0.08	0.04	0.08	0.08	0.04	0.04	0.06	0.06	0.07	0.11
Electric Generators[6]	3.99	4.18	4.18	4.19	4.30	4.36	4.38	4.52	4.68	4.77
Conventional Hydroelectric	3.18	3.12	3.12	3.12	3.13	3.13	3.13	3.13	3.13	3.13
Geothermal	0.39	0.52	0.52	0.53	0.54	0.58	0.59	0.61	0.69	0.70
Municipal Solid Waste	0.31	0.37	0.37	0.37	0.43	0.43	0.43	0.46	0.46	0.46
Biomass	0.07	0.09	0.10	0.10	0.10	0.11	0.12	0.14	0.23	0.27
Solar Thermal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Wind	0.03	0.06	0.07	0.06	0.09	0.09	0.09	0.15	0.14	0.19
Total Marketed Renewable Energy	6.37	6.93	6.96	6.96	7.24	7.29	7.31	7.62	7.77	7.89
Non-Marketed Renewable Energy[7] Selected Consumption										
Residential	0.02	0.05	0.05	0.05	0.06	0.06	0.06	0.08	0.08	0.08
Solar Hot Water Heating	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Geothermal Heat Pumps	0.01	0.04	0.04	0.04	0.05	0.05	0.05	0.07	0.07	0.07
Commercial	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04
Solar Thermal	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid.
[3]Value is less than 0.005 quadrillion Btu per year and rounds to zero.
[4]Includes all electricity production by industrial and other cogenerators for the grid and for own use.
[5]Excludes motor gasoline component of E85.
[6]Includes renewable energy delivered to the grid from electric utilities and nonutilities. Renewable energy used in generating electricity for own use is included in the individual sectoral electricity energy consumption values.
[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
Btu = British thermal unit.
Notes: Totals may not equal sum of components due to independent rounding.
Sources: 1995 electric generators: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Utility Report," and EIA, Form EIA-867, "Annual Nonutility Power Producer Report." 1995 ethanol: EIA, *Petroleum Supply Annual 1995*, DOE/EIA-0340(95/1) (Washington, DC, May 1996). Other 1995: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Table C19. Carbon Emissions by Sector and Source
(Million Metric Tons per Year)

Sector and Source	1995	Projections								
		2005			2010			2015		
		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	25.0	24.9	24.3	23.7	24.4	23.7	22.9	24.2	23.4	22.5
Natural Gas	72.1	78.6	78.1	77.9	80.8	80.3	80.0	82.7	82.5	82.4
Coal	1.4	1.2	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.0
Electricity	175.6	205.8	201.0	201.0	221.7	216.4	216.0	244.1	238.3	237.6
Total	**274.0**	**310.5**	**304.6**	**303.8**	**328.1**	**321.4**	**320.0**	**352.2**	**345.3**	**343.5**
Commercial										
Petroleum	13.4	12.3	11.8	11.7	12.3	11.7	11.6	12.5	11.7	11.5
Natural Gas	45.6	49.4	49.5	49.5	50.7	50.9	50.9	52.2	52.6	52.6
Coal	2.0	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.3
Electricity	159.3	184.6	180.2	180.1	194.7	189.9	189.3	209.5	204.4	203.7
Total	**220.3**	**248.5**	**243.8**	**243.5**	**260.0**	**254.7**	**254.0**	**276.6**	**271.0**	**270.1**
Industrial [1]										
Petroleum	92.4	112.8	104.9	98.4	117.4	108.9	100.2	122.3	111.9	101.2
Natural Gas[2]	138.6	150.2	157.1	163.0	154.3	162.7	170.8	155.0	165.6	175.5
Coal	62.8	61.7	63.6	64.8	61.5	63.5	64.3	61.7	63.8	64.7
Electricity	170.5	202.5	201.7	204.7	213.5	213.4	216.1	228.0	227.1	229.9
Total	**464.3**	**527.2**	**527.3**	**530.9**	**546.7**	**548.5**	**551.4**	**567.0**	**568.4**	**571.3**
Transportation										
Petroleum	453.5	550.5	544.1	540.0	581.6	573.4	566.3	596.5	586.7	577.0
Natural Gas[3]	10.5	14.6	14.8	14.9	16.5	16.5	16.5	18.0	17.9	18.3
Other[4]	0.0	0.5	0.5	0.5	1.2	1.2	1.1	1.7	1.6	1.6
Electricity	1.0	4.1	3.9	3.9	6.9	6.7	6.7	8.7	8.4	8.2
Total	**465.1**	**569.6**	**563.3**	**559.3**	**606.2**	**597.7**	**590.6**	**624.8**	**614.5**	**605.1**
Total Carbon Emissions[5]										
Petroleum	584.4	700.5	685.1	673.8	735.8	717.7	701.0	755.5	733.6	712.1
Natural Gas	266.7	292.8	299.6	305.3	302.3	310.3	318.2	307.9	318.7	328.8
Coal	66.2	65.0	67.0	68.2	64.9	66.9	67.7	65.1	67.2	68.1
Other[4]	0.0	0.5	0.5	0.5	1.2	1.2	1.1	1.7	1.6	1.6
Electricity	506.3	597.0	586.9	589.8	636.7	626.4	628.0	690.3	678.1	679.4
Total	**1423.7**	**1655.9**	**1638.9**	**1637.5**	**1741.0**	**1722.4**	**1715.9**	**1820.6**	**1799.3**	**1790.0**
Electric Generators[6]										
Petroleum	14.4	23.3	12.2	10.1	27.5	12.0	9.2	32.4	13.2	9.2
Natural Gas	50.9	81.0	86.5	87.2	97.9	102.1	104.1	122.8	125.4	127.7
Coal	441.1	492.7	488.2	492.5	511.3	512.3	514.8	535.1	539.5	542.6
Total	**506.3**	**597.0**	**586.9**	**589.8**	**636.7**	**626.4**	**628.0**	**690.3**	**678.1**	**679.4**
Total Carbon Emissions[7]										
Petroleum	598.7	723.8	697.2	683.9	763.3	729.7	710.1	788.0	746.9	721.3
Natural Gas	317.6	373.9	386.1	392.5	400.3	412.4	422.3	430.7	444.1	456.5
Coal	507.3	557.7	555.2	560.7	576.2	579.2	582.4	600.2	606.7	610.7
Other[4]	0.0	0.5	0.5	0.5	1.2	1.2	1.1	1.7	1.6	1.6
Total	**1423.7**	**1655.9**	**1638.9**	**1637.5**	**1741.0**	**1722.4**	**1715.9**	**1820.6**	**1799.3**	**1790.0**
Carbon Emissions (tons per person)	5.4	5.8	5.7	5.7	5.8	5.8	5.7	5.9	5.8	5.8

[1]Includes consumption by cogenerators.
[2]Includes lease and plant fuel.
[3]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[4]"Other" includes methanol and liquid hydrogen.
[5]Measured for delivered energy consumption.
[6]Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[7]Measured for total energy consumption, with emissions for electric power generators distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Utility coal carbon emissions from Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States, 1987-1992*, DOE/EIA-0573 (Washington, DC, November 1994). Carbon coefficients from EIA, *Emissions of Greenhouse Gases in the United States 1995*, DOE/EIA-0573(95) (Washington, DC, October 1996). 1995 consumption estimates based on: EIA, *Short Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Table C20. Macroeconomic Indicators
(Billion 1992 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	1995	Projections								
		2005			2010			2015		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
GDP Implicit Price Deflator (Index 1992=1.000)	1.076	1.406	1.411	1.415	1.661	1.667	1.672	1.983	1.986	1.991
Real Gross Domestic Product	6739	8418	8390	8369	9216	9185	9150	9919	9880	9836
Real Consumption	4579	5695	5673	5656	6244	6220	6192	6737	6708	6674
Real Investment	1011	1371	1366	1362	1498	1487	1475	1599	1592	1583
Real Government Spending	1261	1368	1364	1361	1445	1440	1435	1504	1499	1492
Real Exports	775	1403	1395	1390	1733	1723	1713	2050	2037	2023
Real Imports	889	1411	1395	1382	1682	1661	1640	1946	1921	1893
Real Gross Domestic Product (1987 fixed-weighted dollars)	5677	7340	7317	7301	8173	8145	8114	8847	8817	8782
Real Disposable Personal Income (1987 fixed-weighted dollars)	4047	5137	5113	5095	5670	5644	5617	6137	6109	6075
Index of Manufacturing Gross Output (Index 1987=1.000)	1.246	1.598	1.590	1.584	1.774	1.765	1.755	1.913	1.904	1.893
AA Utility Bond Rate (percent)	7.76	6.16	6.27	6.35	6.01	6.11	6.21	6.07	6.16	6.27
90-Day U.S. Government Treasury Bill Rate (percent)	5.49	4.36	4.31	4.29	4.22	4.15	4.10	4.12	4.04	3.98
Real Yield on Government 10 Year Bonds (percent)	5.22	1.97	2.07	2.16	1.25	1.35	1.42	1.14	1.24	1.33
Real 90-Day U.S. Government Treasury Bill Rate (percent)	2.94	1.16	1.10	1.06	0.76	0.71	0.67	0.37	0.35	0.32
Real Utility Bond Rate (percent)	5.21	2.96	3.06	3.12	2.56	2.67	2.78	2.31	2.46	2.62
Delivered Energy Intensity (thousand Btu per 1992 dollar of GDP)										
Delivered Energy	10.11	9.36	9.35	9.34	8.96	8.94	8.91	8.60	8.58	8.55
Total Energy	13.50	12.37	12.33	12.33	11.82	11.76	11.75	11.30	11.23	11.23
Consumer Price Index (1982-84=1.00)	1.52	2.07	2.08	2.09	2.48	2.49	2.51	2.99	3.01	3.03
Employment Cost Index (June 1989=1.00)	1.22	1.66	1.66	1.66	1.99	1.99	1.99	2.40	2.39	2.39
Unemployment Rate (percent)	5.59	5.59	5.64	5.65	5.63	5.70	5.82	5.60	5.67	5.75
Million Units										
Truck Deliveries, Light-Duty	6.10	7.10	7.03	6.97	7.39	7.32	7.25	7.78	7.73	7.65
Unit Sales of Automobiles	8.67	10.14	10.14	10.13	10.07	10.07	10.06	9.88	9.89	9.89
Millions of People										
Population with Armed Forces Overseas	263.6	287.1	287.1	287.1	298.9	298.9	298.9	311.2	311.2	311.2
Population (aged 16 and over)	202.1	223.8	223.8	223.8	235.4	235.4	235.4	245.8	245.8	245.8
Employment, Non-Agriculture	116.1	139.1	138.6	138.3	150.4	149.9	149.4	159.2	158.6	158.0
Employment, Manufacturing	18.2	18.2	18.1	18.1	18.1	18.0	17.9	17.5	17.4	17.3
Labor Force	132.3	149.8	149.7	149.7	157.4	157.3	157.3	161.2	161.1	161.0

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 1995: Data Resources Incorporated (DRI), DRI Trend0296. **Projections:** Energy Information Administration, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Table C21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1995	Projections								
		2005			2010			2015		
		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 (1995 dollars per barrel)[1]	17.26	14.08	19.72	24.13	14.03	20.41	26.44	13.99	20.98	28.23
Production[2]										
OECD										
U.S. (50 states)	9.29	7.52	8.67	9.69	7.39	8.75	10.01	7.45	8.76	10.59
Canada	2.44	2.43	2.46	2.49	2.30	2.35	2.38	2.18	2.24	2.27
Mexico	3.09	3.05	3.13	3.18	2.97	3.07	3.13	2.89	3.00	3.08
OECD Europe[3]	6.55	5.97	6.05	6.09	5.12	5.20	5.26	4.17	4.25	4.30
Other OECD	0.74	0.69	0.71	0.72	0.62	0.65	0.67	0.57	0.60	0.62
Total OECD	22.11	19.66	21.01	22.16	18.40	20.02	21.44	17.25	18.84	20.87
Developing Countries										
Other South & Central America	3.06	4.08	4.18	4.25	3.86	3.99	4.08	3.67	3.81	3.91
Pacific Rim	2.04	2.20	2.26	2.29	2.10	2.17	2.21	1.94	2.02	2.07
OPEC	28.07	48.17	42.10	38.17	59.08	50.64	44.98	70.71	60.35	52.61
Other Developing Countries	4.05	4.94	5.07	5.15	4.56	4.72	4.82	4.12	4.28	4.39
Total Developing Countries	37.21	59.40	53.61	49.86	69.61	61.51	56.09	80.44	70.45	62.98
Eurasia										
Former Soviet Union	6.96	8.13	8.34	8.47	9.12	9.43	9.63	9.72	10.09	10.36
Eastern Europe	0.31	0.23	0.23	0.24	0.20	0.21	0.22	0.17	0.18	0.19
China	3.02	2.97	3.04	3.09	2.90	3.00	3.06	2.84	2.94	3.02
Total Eurasia	10.29	11.33	11.62	11.80	12.23	12.64	12.91	12.73	13.21	13.57
Total Production	69.62	90.38	86.24	83.82	100.24	94.17	90.45	110.42	102.50	97.41
Consumption										
OECD										
U.S. (50 states)	17.73	21.41	20.68	20.24	22.55	21.60	20.96	23.29	22.12	21.31
U.S. Territories	0.26	0.39	0.35	0.32	0.44	0.38	0.35	0.49	0.42	0.37
Canada	1.76	2.22	2.01	1.89	2.43	2.14	1.97	2.64	2.29	2.07
Mexico	1.96	2.55	2.39	2.29	2.95	2.69	2.53	3.38	3.02	2.79
Japan	5.73	7.65	6.85	6.40	8.63	7.31	6.57	9.60	7.78	6.73
Australia and New Zealand	0.96	1.14	1.10	1.07	1.23	1.17	1.13	1.31	1.24	1.20
OECD Europe[3]	13.88	15.51	14.80	14.39	16.01	15.12	14.56	16.43	15.41	14.73
Total OECD	42.28	50.87	48.18	46.60	54.24	50.41	48.07	57.14	52.28	49.20
Developing Countries										
Other South and Central America	3.58	4.43	4.31	4.24	4.78	4.62	4.52	5.10	4.92	4.79
Pacific Rim	4.87	7.97	7.72	7.58	9.43	9.07	8.84	11.21	10.73	10.40
OPEC	4.94	6.30	6.30	6.30	7.06	7.06	7.06	7.91	7.91	7.91
Other Developing Countries	4.79	7.65	7.20	6.93	8.75	7.95	7.48	9.91	8.75	8.04
Total Developing Countries	18.19	26.35	25.53	25.04	30.02	28.70	27.90	34.13	32.31	31.14

Table C21. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1995	Projections								
		2005			2010			2015		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Eurasia										
Former Soviet Union	4.75	6.02	5.80	5.67	7.05	6.74	6.54	8.05	7.65	7.38
Eastern Europe	1.39	1.55	1.51	1.49	1.77	1.72	1.69	2.03	1.96	1.92
China	3.31	5.89	5.52	5.31	7.46	6.89	6.55	9.37	8.59	8.07
Total Eurasia	9.46	13.46	12.84	12.47	16.28	15.36	14.78	19.45	18.21	17.38
Total Consumption	69.92	90.68	86.54	84.12	100.54	94.47	90.75	110.72	102.80	97.71
Non-OPEC Production	41.55	42.21	44.14	45.65	41.15	43.53	45.46	39.71	42.15	44.80
Net Eurasia Exports	0.83	-2.13	-1.22	-0.67	-4.05	-2.72	-1.87	-6.72	-4.99	-3.81
OPEC Market Share	0.40	0.53	0.49	0.46	0.59	0.54	0.50	0.64	0.59	0.54

[1]Average refiner acquisition cost of imported crude oil.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol, liquids produced from coal and other sources, and refinery gains.
[3]OECD Europe includes the unified Germany.
OECD = Organization for Economic Cooperation and Development - Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States (including territories).
Pacific Rim = Hong Kong, Malaysia, Philippines, Singapore, South Korea, Taiwan, and Thailand.
OPEC = Organization of Petroleum Exporting Countries - Algeria, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
Eurasia = Albania, Bulgaria, China, Czech Republic, Hungary, Poland, Romania, Slovak Republic, the Former Soviet Union, and the Former Yugoslavia.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs LWOP97.D100696A, AEO97B.D100296K, and HWOP97.D100296B.

Appendix D

Crude Oil Equivalency Summary

Table D1. Total Energy Supply and Disposition Crude Oil Equivalency Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case						Annual Growth 1995-2015 (percent)
	1994	1995	2000	2005	2010	2015	
Production							
Crude Oil and Lease Condensate	6.66	6.56	5.87	5.49	5.39	5.23	-1.1%
Natural Gas Plant Liquids	1.17	1.12	1.28	1.42	1.44	1.64	1.9%
Dry Natural Gas	9.10	8.98	9.95	11.00	11.78	12.67	1.7%
Coal	10.43	10.38	10.99	11.33	11.88	12.50	0.9%
Nuclear Power	3.23	3.40	3.45	3.30	3.10	2.26	-2.0%
Renewable Energy[1]	2.75	2.97	3.08	3.25	3.42	3.64	1.0%
Other[2]	0.46	0.64	0.21	0.20	0.19	0.20	-5.7%
Total	33.80	34.05	34.83	35.99	37.19	38.14	0.6%
Imports							
Crude Oil[3]	7.07	7.23	8.85	9.54	9.76	10.24	1.8%
Petroleum Products[4]	1.86	1.51	2.35	3.21	3.89	3.94	4.9%
Natural Gas	1.27	1.37	1.76	1.88	2.00	2.15	2.3%
Other Imports[5]	0.32	0.28	0.32	0.32	0.32	0.30	0.4%
Total	10.51	10.39	13.29	14.95	15.96	16.63	2.4%
Exports							
Petroleum[6]	0.94	0.95	0.85	0.91	0.92	0.93	-0.1%
Natural Gas	0.08	0.08	0.10	0.10	0.10	0.11	1.7%
Coal	0.89	1.07	1.15	1.23	1.33	1.44	1.5%
Total	1.91	2.10	2.09	2.23	2.35	2.48	0.8%
Discrepancy[7]	-0.49	0.60	0.04	0.07	0.11	0.00	N/A
Consumption							
Petroleum Products[8]	16.42	16.50	17.86	19.11	19.95	20.44	1.1%
Natural Gas	10.08	10.48	11.55	12.72	13.59	14.63	1.7%
Coal	9.20	9.41	9.92	10.21	10.65	11.15	0.9%
Nuclear Power	3.23	3.40	3.45	3.30	3.10	2.26	-2.0%
Renewable Energy[1]	2.75	2.97	3.08	3.25	3.43	3.64	1.0%
Other[9]	0.22	0.18	0.20	0.18	0.18	0.17	-0.3%
Total	41.91	42.94	46.06	48.77	50.90	52.30	1.0%
Net Imports - Petroleum	7.98	7.78	10.36	11.84	12.73	13.25	2.7%
Prices (1995 dollars per unit)							
World Oil Price (dollars per barrel)[10]	15.94	17.26	18.20	19.72	20.41	20.98	1.0%
Gas Wellhead Price (dollars per Mcf)[11]	1.97	1.61	1.82	1.94	2.01	2.13	1.4%
Coal Minemouth Price (dollars per ton)	19.89	18.83	18.38	17.47	16.92	15.46	-1.0%

[1]Includes utility and nonutility grid connected electricity from hydroelectric, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes nonmarketed renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdraws.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Mcf = Thousand cubic feet.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1994 and 1995 may differ from published data due to internal conversion factors.
Sources: 1994 natural gas values: Energy Information Administration (EIA), *Natural Gas Annual 1994*, DOE/EIA-0131(94) (Washington, DC, November 1995). 1994 coal minemouth prices: EIA, *Coal Industry Annual 1994*, DOE/EIA-0584(94) (Washington, DC, October 1995). Other 1994 values: EIA, *Annual Energy Review 1994*, DOE/EIA-0384(94) (Washington, DC, July 1995). 1995 natural gas price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). 1995 natural gas supply derived from: EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95)/1 (Washington, DC October 1996). 1995 coal minemouth price, coal production, and exports derived from: EIA, *Monthly Energy Review*, DOE/EIA-0035(96/08) (Washington, DC, August 1996). Other 1995 values: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996).
Projections: EIA, AEO97 National Energy Modeling System run AEO97B.D100296K.

Table E1. 1995 Average Household Expenditures for Energy by Household Characteristic (1995 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	2211.73	1231.75	857.62	313.37	60.75	979.98
Households by Income Quintile						
1st	1402.00	939.63	628.07	269.18	42.38	462.37
2nd	1832.94	1088.47	739.92	297.89	50.66	744.47
3rd	2336.18	1230.24	888.46	277.89	63.89	1105.93
4th	2489.71	1331.92	946.26	316.87	68.79	1157.79
5th	3027.07	1572.56	1093.96	399.68	78.92	1454.52
Households by Census Division						
New England	2364.46	1324.20	689.90	313.79	320.50	1040.27
Middle Atlantic	2272.40	1469.17	773.32	500.78	195.07	803.23
South Atlantic	2219.49	1203.89	721.52	458.39	23.98	1015.59
East North Central	2173.44	1155.00	802.11	308.70	44.19	1018.43
East South Central	2154.66	1267.28	1078.75	156.73	31.81	887.38
West North Central	2599.37	1432.34	1234.36	191.46	6.51	1167.03
West South Central	2311.19	1248.97	975.21	273.77	0.00	1062.21
Mountain	2125.14	1029.51	738.87	285.46	5.18	1095.63
Pacific	1977.62	971.73	711.06	249.57	11.09	1005.89

Source: Energy Information Administration, AEO97 National Energy Modeling System, run AEO97B.D100296K.

Table E2. 2000 Average Household Expenditures for Energy by Household Characteristic (1995 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	2263.39	1220.18	862.12	295.04	63.02	1043.21
Households by Income Quintile						
1st	1424.67	927.98	632.79	251.13	44.06	496.69
2nd	1872.46	1080.37	747.74	280.64	52.00	792.09
3rd	2398.42	1219.81	890.84	263.52	65.45	1178.60
4th	2552.35	1320.69	950.92	298.54	71.24	1231.66
5th	3100.80	1556.81	1097.03	376.67	83.11	1543.99
Households by Census Division						
New England	2493.56	1336.68	662.58	303.02	371.08	1156.87
Middle Atlantic	2344.84	1478.38	825.04	442.68	210.65	866.46
South Atlantic	2243.43	1200.29	741.14	437.49	21.66	1043.14
East North Central	2255.05	1139.04	790.77	310.66	37.61	1116.01
East South Central	2185.96	1245.03	1059.41	153.94	31.69	940.93
West North Central	2572.65	1347.45	1147.96	193.82	5.67	1225.20
West South Central	2377.83	1203.00	941.22	261.78	0.00	1174.83
Mountain	2193.98	1041.43	748.94	286.81	5.67	1152.55
Pacific	2044.12	993.68	746.27	236.26	11.15	1050.43

Source: Energy Information Administration, AEO97 National Energy Modeling System, run AEO97B.D100296K.

Table E3. 2005 Average Household Expenditures for Energy by Household Characteristic (1995 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2240.21**	**1186.20**	**849.77**	**278.08**	**58.35**	**1054.01**
Households by Income Quintile						
1st	1400.84	898.99	622.90	235.48	40.61	501.85
2nd	1849.71	1051.47	738.99	264.32	48.16	798.23
3rd	2375.94	1186.13	876.38	249.16	60.60	1189.81
4th	2532.90	1286.31	938.35	281.92	66.04	1246.59
5th	3076.84	1514.25	1081.69	355.44	77.11	1562.59
Households by Census Division						
New England	2518.75	1323.19	676.72	283.59	362.88	1195.57
Middle Atlantic	2342.88	1453.04	839.12	413.43	200.48	889.84
South Atlantic	2221.93	1173.36	741.08	412.05	20.23	1048.57
East North Central	2249.88	1118.18	784.97	298.81	34.40	1131.70
East South Central	2119.18	1188.12	1013.34	146.93	27.84	931.06
West North Central	2480.27	1274.83	1081.01	188.24	5.59	1205.43
West South Central	2343.38	1170.88	916.24	254.65	0.00	1172.49
Mountain	2179.96	1039.65	755.72	278.54	5.39	1140.31
Pacific	2074.66	973.91	738.58	224.33	11.01	1100.75

Source: Energy Information Administration, AEO97 National Energy Modeling System, run AEO97B.D100296K.

Table E4. 2010 Average Household Expenditures for Energy by Household Characteristic (1995 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2192.34**	**1158.35**	**844.41**	**259.78**	**54.16**	**1033.99**
Households by Income Quintile						
1st	1366.97	875.29	618.82	219.00	37.47	491.67
2nd	1809.16	1026.86	735.36	246.85	44.66	782.30
3rd	2326.40	1159.32	869.46	233.56	56.30	1167.07
4th	2484.33	1259.23	933.94	263.87	61.42	1225.09
5th	3014.94	1479.39	1075.32	332.29	71.79	1535.55
Households by Census Division						
New England	2496.76	1300.84	687.41	262.37	351.05	1195.92
Middle Atlantic	2325.11	1437.53	862.46	383.59	191.47	887.59
South Atlantic	2177.96	1145.22	735.13	390.86	19.23	1032.74
East North Central	2220.28	1104.32	788.38	284.29	31.64	1115.97
East South Central	2057.01	1151.67	988.14	138.97	24.56	905.34
West North Central	2383.06	1226.08	1039.67	180.84	5.57	1156.98
West South Central	2297.44	1154.53	913.62	240.92	0.00	1142.91
Mountain	2122.25	1018.68	748.38	265.08	5.22	1103.57
Pacific	2032.77	947.52	729.81	207.08	10.63	1085.24

Source: Energy Information Administration, AEO97 National Energy Modeling System, run AEO97B.D100296K.

Table E5. 2015 Average Household Expenditures for Energy by Household Characteristic
(1995 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	2092.96	1146.33	847.70	249.36	49.28	946.63
Households by Income Quintile						
1st	1313.77	864.30	620.85	209.58	33.87	449.47
2nd	1731.18	1015.70	738.42	236.73	40.55	715.49
3rd	2215.53	1147.15	871.07	224.88	51.19	1068.38
4th	2372.11	1248.46	938.75	253.73	55.99	1123.65
5th	2874.72	1466.38	1081.64	319.08	65.66	1408.34
Households by Census Division						
New England	2408.58	1289.31	704.96	250.31	334.04	1119.27
Middle Atlantic	2265.50	1441.07	894.59	367.50	178.97	824.43
South Atlantic	2073.69	1125.08	725.67	381.77	17.64	948.61
East North Central	2138.96	1115.45	809.79	277.79	27.87	1023.51
East South Central	1955.94	1131.06	973.98	135.70	21.38	824.88
West North Central	2237.13	1199.36	1015.45	178.51	5.40	1037.77
West South Central	2169.83	1128.38	896.47	231.91	0.00	1041.45
Mountain	1989.12	992.22	732.20	255.12	4.91	996.90
Pacific	1962.62	966.15	761.41	194.88	9.85	996.48

Source: Energy Information Administration, AEO97 National Energy Modeling System, run AEO97B.D100296K.

Results from Side Cases

Table F1. Key Results for Residential Sector Technology Cases

Energy Consumption	1995	Projections 2000: 1997 Technology	2000: Reference Case	2000: Advanced Technology Cost Reduction	2000: High Technology	2005: 1997 Technology	2005: Reference Case	2005: Advanced Technology Cost Reduction	2005: High Technology
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.85	0.84	0.83	0.82	0.81	0.82	0.78	0.78	0.75
Kerosene	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.06
Liquefied Petroleum Gas	0.40	0.44	0.43	0.43	0.42	0.46	0.44	0.43	0.42
Petroleum Subtotal	1.32	1.35	1.33	1.32	1.30	1.35	1.29	1.28	1.23
Natural Gas	5.01	5.35	5.33	5.24	5.24	5.57	5.43	5.29	5.18
Coal	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04
Renewable Energy	0.57	0.57	0.57	0.56	0.56	0.57	0.56	0.54	0.54
Electricity	3.56	3.90	3.88	3.85	3.77	4.20	4.14	4.08	3.87
Delivered Energy	**10.51**	**11.23**	**11.16**	**11.01**	**10.92**	**11.74**	**11.46**	**11.23**	**10.88**
Electricity Related Losses	7.92	8.31	8.25	8.20	8.03	8.68	8.55	8.43	8.00
Total	**18.43**	**19.53**	**19.41**	**19.21**	**18.95**	**20.42**	**20.02**	**19.65**	**18.88**
Delivered Energy Consumption per Household (million Btu per year)	**106.10**	**107.49**	**106.81**	**105.41**	**104.54**	**106.29**	**103.78**	**101.63**	**98.46**

Table F2. Key Results for Commercial Sector Technology Cases

Energy Consumption	1995	Projections 2000: 1997 Technology	2000: Reference Case	2000: Advanced Technology Cost Reduction	2000: High Technology	2005: 1997 Technology	2005: Reference Case	2005: Advanced Technology Cost Reduction	2005: High Technology
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.41	0.37	0.37	0.37	0.37	0.36	0.36	0.36	0.35
Residual Fuel	0.17	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Motor Gasoline	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.67	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.59
Natural Gas	3.16	3.37	3.36	3.35	3.31	3.46	3.44	3.43	3.32
Coal	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Renewable Energy	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	3.23	3.50	3.50	3.50	3.34	3.76	3.71	3.69	3.43
Delivered Energy	**7.15**	**7.56**	**7.54**	**7.54**	**7.33**	**7.91**	**7.84**	**7.81**	**7.43**
Electricity Related Losses	7.18	7.46	7.44	7.44	7.12	7.77	7.67	7.63	7.08
Total	**14.33**	**15.01**	**14.98**	**14.98**	**14.45**	**15.68**	**15.51**	**15.44**	**14.51**
Delivered Energy Consumption per Square Foot (thousand Btu per year)	**101.17**	**101.72**	**101.49**	**101.45**	**98.72**	**102.04**	**101.13**	**100.72**	**95.81**

Table F1. Key Results for Residential Sector Technology Cases (Continued)

Projections: 2010				2015				Annual Growth 1995-2015 (percent)			
1997 Technology	Reference Case	Advanced Technology Cost Reduction	High Technology	1997 Technology	Reference Case	Advanced Technology Cost Reduction	High Technology	1997 Technology	Reference Case	Advanced Technology Cost Reduction	High Technology
0.80	0.75	0.74	0.70	0.80	0.73	0.71	0.67	-0.3%	-0.8%	-0.9%	-1.2%
0.07	0.07	0.06	0.06	0.07	0.06	0.06	0.06	-0.2%	-0.6%	-0.8%	-1.2%
0.48	0.45	0.44	0.41	0.51	0.46	0.44	0.40	1.2%	0.7%	0.5%	0.0%
1.36	1.26	1.24	1.17	1.38	1.25	1.22	1.12	0.2%	-0.3%	-0.4%	-0.8%
5.85	5.57	5.37	5.03	6.17	5.73	5.47	4.93	1.0%	0.7%	0.4%	-0.1%
0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	-0.9%	-1.3%	-1.6%	-1.7%
0.57	0.55	0.52	0.52	0.58	0.54	0.50	0.51	0.1%	-0.3%	-0.6%	-0.6%
4.58	4.46	4.33	4.04	5.05	4.85	4.64	4.30	1.8%	1.6%	1.3%	0.9%
12.41	11.89	11.50	10.80	13.22	12.41	11.87	10.90	1.2%	0.8%	0.6%	0.2%
9.20	8.95	8.68	8.10	9.60	9.22	8.83	8.17	1.0%	0.8%	0.5%	0.2%
21.61	20.83	20.18	18.90	22.81	21.63	20.70	19.07	1.1%	0.8%	0.6%	0.2%
106.57	102.06	98.75	92.72	107.77	101.19	96.80	88.83	0.1%	-0.2%	-0.5%	-0.9%

Btu = British thermal unit.
Note: Side cases were run without the fully integrated modeling system, so not all feedbacks are captured.
Source: AEO97 National Energy Modeling System runs RSFRZN.D100896A, AEO97B.D100296K, BLGATCR.D100396E, and RSBEST.D100896A.

Table F2. Key Results for Commercial Sector Technology Cases (Continued)

Projections: 2010				2015				Annual Growth 1995-2015 (percent)			
1997 Technology	Reference Case	Advanced Technology Cost Reduction	High Technology	1997 Technology	Reference Case	Advanced Technology Cost Reduction	High Technology	1997 Technology	Reference Case	Advanced Technology Cost Reduction	High Technology
0.35	0.35	0.34	0.34	0.35	0.34	0.34	0.33	-0.8%	-0.9%	-0.9%	-1.0%
0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	-0.9%	-0.9%	-0.9%	-0.9%
0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.4%	0.4%	0.4%	0.4%
0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.9%	0.9%	0.9%	0.9%
0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	-0.3%	-0.3%	-0.3%	-0.3%
0.60	0.59	0.59	0.59	0.60	0.59	0.59	0.59	-0.6%	-0.7%	-0.7%	-0.7%
3.58	3.54	3.52	3.34	3.72	3.65	3.63	3.40	0.8%	0.7%	0.7%	0.4%
0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.6%	0.6%	0.6%	0.6%
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.8%	0.8%	0.8%	0.8%
4.00	3.91	3.87	3.54	4.27	4.16	4.09	3.72	1.4%	1.3%	1.2%	0.7%
8.27	8.13	8.07	7.56	8.68	8.50	8.40	7.81	1.0%	0.9%	0.8%	0.4%
8.02	7.85	7.76	7.10	8.13	7.91	7.79	7.08	0.6%	0.5%	0.4%	-0.1%
16.29	15.98	15.82	14.66	16.81	16.40	16.19	14.89	0.8%	0.7%	0.6%	0.2%
102.40	100.72	99.93	93.65	103.08	100.88	99.80	92.68	0.1%	0.0%	-0.1%	-0.4%

Btu = British thermal unit.
Note: Side cases were run without the fully integrated modeling system, so not all feedbacks are captured.
Source: AEO97 National Energy Modeling System runs TK1997.D101696A, AEO97B.D100296K, BLDGATCR.D100396E, and COMHGH.D100396A.

Table F3. Key Results for Industrial Sector Technology Cases

Energy Consumption	1995	Projections								
		2000			2010			2015		
		1997 Technology	Reference Case	High Technology	1997 Technology	Reference Case	High Technology	1997 Technology	Reference Case	High Technology
Energy Consumption (quadrillion Btu)										
Distillate Fuel	1.15	1.27	1.26	1.25	1.48	1.47	1.41	1.56	1.55	1.45
Liquefied Petroleum Gas	2.01	2.12	2.08	2.03	2.38	2.28	2.14	2.47	2.35	2.17
Petrochemical Feedstocks	1.16	1.27	1.25	1.21	1.42	1.35	1.26	1.48	1.40	1.28
Residual Fuel	0.34	0.28	0.28	0.26	0.33	0.33	0.27	0.37	0.35	0.29
Motor Gasoline	0.20	0.22	0.22	0.22	0.26	0.26	0.24	0.27	0.27	0.25
Other Petroleum	3.83	4.25	4.19	4.12	4.68	4.43	4.28	4.79	4.48	4.28
Petroleum Subtotal	8.68	9.41	9.28	9.09	10.54	10.13	9.60	10.93	10.41	9.73
Natural Gas	9.74	10.75	10.62	10.34	11.74	11.42	10.82	12.01	11.63	10.93
Metallurgical Coal	0.88	0.79	0.79	0.79	0.62	0.62	0.62	0.55	0.55	0.55
Steam Coal	1.59	1.74	1.72	1.62	1.97	1.89	1.66	2.07	1.97	1.66
Net Coal Coke Imports	0.03	0.08	0.08	0.08	0.14	0.13	0.13	0.15	0.15	0.15
Coal Subtotal	2.51	2.61	2.58	2.49	2.72	2.64	2.40	2.77	2.67	2.36
Renewable Energy	1.74	1.91	1.91	1.90	2.29	2.28	2.26	2.42	2.40	2.37
Electricity	3.46	3.87	3.83	3.72	4.50	4.40	4.12	4.76	4.62	4.25
Delivered Energy	26.12	28.56	28.22	27.55	31.79	30.87	29.20	32.88	31.73	29.64
Electricity Related Losses	7.69	8.23	8.15	7.93	9.03	8.82	8.26	9.05	8.79	8.09
Total	33.81	36.79	36.37	35.47	40.82	39.69	37.46	41.94	40.51	37.73
Energy Use per Dollar of Output (thousand Btu per 1987 dollar)										
Delivered Energy	7.11	6.92	6.84	6.67	6.24	6.06	5.73	6.01	5.80	5.42
Total Energy	9.21	8.91	8.81	8.60	8.01	7.79	7.35	7.67	7.41	6.90

Btu = British thermal unit.
Note: Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured.
Source: AEO97 National Energy Modeling System runs FRZTECH.D102396A, AEO97B.D100296K, and HITECH.D101896B.

Table F4. Key Results for Transportation Sector Technology Cases

Energy Consumption	1995	Projections								
		2000			2010			2015		
		1997 Technology	Reference Case	Rapid Technology	1997 Technology	Reference Case	Rapid Technology	1997 Technology	Reference Case	Rapid Technology
Energy Consumption (quadrillion Btu)										
Distillate Fuel	4.42	4.96	4.96	4.88	5.78	5.78	5.32	6.00	6.00	5.35
Jet Fuel	3.13	3.83	3.83	3.83	4.66	4.67	4.59	4.95	4.95	4.81
Motor Gasoline	14.65	15.76	15.76	15.74	17.25	17.09	16.15	17.72	17.11	15.62
Residual Fuel	1.08	1.29	1.29	1.29	1.64	1.64	1.64	1.78	1.78	1.78
Liquefied Petroleum Gas	0.03	0.04	0.04	0.04	0.18	0.18	0.16	0.22	0.21	0.19
Other Petroleum	0.26	0.29	0.29	0.29	0.33	0.33	0.33	0.34	0.34	0.34
Pipeline Fuel Natural Gas	0.72	0.77	0.77	0.77	0.88	0.88	0.88	0.94	0.93	0.94
Compressed Natural Gas	0.01	0.06	0.06	0.06	0.26	0.26	0.24	0.32	0.31	0.28
Renewables (Ethanol)	0.00	0.00	0.00	0.00	0.07	0.07	0.07	0.11	0.1	0.09
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Methanol	0.00	0.00	0.00	0.00	0.07	0.07	0.06	0.1	0.09	0.09
Electricity	0.02	0.02	0.02	0.02	0.14	0.14	0.13	0.17	0.17	0.16
Total	24.31	27.04	27.04	26.93	31.27	31.11	29.58	32.66	31.99	29.66
Light-Duty Fleet (miles per gallon)	19.7	19.6	19.6	19.7	20.2	20.4	21.5	20.6	21.3	23.3

Btu = British thermal unit.
Note: Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured.
Source: AEO97 National Energy Modeling System runs FRZNEFF.D100896A, AEO97B.D100296K, and HITECH.D100896H.

Table F5. Key Results for Nuclear Retirement Cases
(Thousand Megawatts)

Net Summer Capability	1995	Projections								
		2005			2010			2015		
		Low Nuclear	Reference Case	High Nuclear	Low Nuclear	Reference Case	High Nuclear	Low Nuclear	Reference Case	High Nuclear
Electric Generators										
Capability										
Coal Steam	304.9	303.6	298.2	297.5	310.8	304.0	303.2	328.2	315.4	310.3
Other Fossil Steam	139.6	102.6	102.6	102.6	99.9	99.9	99.9	96.1	96.1	96.1
Combined Cycle	14.7	89.3	73.5	70.5	132.9	107.5	99.5	169.1	153.0	131.2
Combustion Turbine/Diesel	56.0	145.8	134.5	133.9	160.0	153.1	153.1	171.2	168.3	163.3
Nuclear Power	99.2	62.7	94.7	100.4	48.9	88.9	99.1	22.1	62.7	94.7
Pumped Storage	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
Fuel Cells	0.0	2.6	2.0	1.7	3.1	2.1	2.0	3.1	2.1	2.0
Renewable Sources	88.0	92.4	92.2	92.0	94.6	94.1	94.4	100.0	98.3	98.2
Total	722.2	818.7	817.5	818.4	870.1	869.4	871.2	909.6	915.8	915.7
Cumulative Planned Additions										
Coal Steam	1.4	3.7	3.7	3.7	5.3	5.3	5.3	5.3	5.3	5.3
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	1.4	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Combustion Turbine/Diesel	3.2	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Nuclear Power	0.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Pumped Storage	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.7	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Total	8.0	15.5	15.5	15.5	17.1	17.1	17.1	17.1	17.1	17.1
Cumulative Unplanned Additions										
Coal Steam	0.0	14.8	9.5	8.7	23.1	16.4	15.6	44.4	31.6	26.5
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	73.7	58.0	55.0	117.4	91.9	84.0	153.6	137.5	115.7
Combustion Turbine/Diesel	0.1	89.5	78.2	77.6	104.0	97.1	97.2	116.3	113.5	108.5
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	2.5	2.0	1.7	3.1	2.1	2.0	3.1	2.1	2.0
Renewable Sources	0.0	2.0	1.8	1.6	4.4	3.9	4.2	10.1	8.4	8.3
Total	0.1	182.6	149.5	144.7	252.0	211.4	203.0	327.5	293.1	260.9
Cumulative Total Additions	8.2	198.1	165.0	160.2	269.2	228.5	220.1	344.7	310.2	278.1
Cumulative Retirements	11.9	104.9	72.1	67.3	124.6	83.9	74.5	159.7	119.1	87.1
Cogenerators										
Capacity										
Coal	8.2	9.0	9.0	9.0	9.3	9.3	9.3	9.5	9.5	9.5
Petroleum	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0
Natural Gas	28.9	32.1	32.1	32.1	33.3	33.3	33.3	34.2	34.2	34.2
Other Gaseous Fuels	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Renewable Sources	6.2	7.3	7.3	7.3	7.8	7.8	7.8	8.2	8.2	8.2
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	45.1	50.2	50.2	50.2	52.3	52.3	52.2	53.8	53.8	53.8
Cumulative Additions	10.2	15.3	15.3	15.3	17.3	17.3	17.3	18.8	18.8	18.8

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO97. Net summer capacity is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recent data available as of August 15, 1996. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Source: Energy Information Administration, AEO97 National Energy Modeling System runs LNUC97.D100796B, AEO97B.D100296K, and HNUC97.D100796B.

Table F6. Key Results for Electricity Demand Cases

Electricity Supply and Demand	1995	Projections: 2000 Reference Case	2000 High Demand	2010 Reference Case	2010 High Demand	2015 Reference Case	2015 High Demand	Annual Growth 1995-2015 (percent) Reference Case	Annual Growth 1995-2015 (percent) High Demand
Electricity Sales (billion kilowatthours)	3008	3290	3543	3784	4228	4044	4474	1.50%	2.00%
Net Imports (billion kilowatthours)	38	40	40	31	39	27	33	-1.70%	-0.60%
Electricity Prices (1995 cents per kilowatthour)	7.1	6.9	7.3	6.4	7.1	6.3	6.8	-0.60%	-0.20%
Generation by Fuel (billion kilowatthours)									
Coal	1714	1843	1926	1992	2195	2103	2412	13.01%	12.08%
Natural Gas	502	672	815	1106	1333	1405	1508	11.81%	9.65%
Renewables	396	397	397	424	436	449	472	7.63%	4.68%
Other	750	753	795	685	710	526	541	3.55%	3.70%
Total	3362	3665	3933	4207	4674	4483	4933	1.38%	1.42%
Generating Capacity (gigawatts)									
Coal	304.9	298.7	301.1	304.0	329.7	315.4	362.1	0.20%	0.90%
Combined-Cycle/Combustion Turbine	70.7	153.6	167.4	260.6	334.3	321.3	369.3	8.11%	5.70%
Renewables	88.0	90.5	90.6	94.1	96.6	98.3	103.1	0.60%	0.80%
Nuclear Power	99.2	99.1	99.1	88.9	88.9	62.7	62.7	-2.30%	-2.30%
Cogenerators	45.1	47.6	47.6	52.3	52.3	53.8	53.8	0.90%	0.90%
Other	159.4	140.0	140.1	121.8	124.3	118.1	119.5	3.00%	3.54%
Total	767.3	829.5	845.9	921.7	1026.1	969.6	1070.5	1.12%	1.22%
Energy Production									
Coal (million short tons)	1031	1105	1144	1201	1306	1268	1410	1.00%	1.60%
Natural Gas (trillion cubic feet)	18.48	20.54	22.00	24.25	25.98	26.10	27.12	1.70%	1.90%
Carbon Emissions (million metric tons)	1423.7	1543.1	1599.1	1722.4	1805.7	1799.3	1892.7	1.20%	1.40%
Prices to Utilities (1995 dollars per million Btu)									
Coal	1.34	1.29	1.34	1.20	1.21	1.11	1.15	-0.90%	-0.80%
Natural Gas	2.01	2.19	2.57	2.32	2.60	2.47	2.54	1.00%	1.20%

Btu = British thermal unit.
Note: Other includes non-coal fossil steam, pumped storage, methane, propane, and blast furnace gas.
Source: AEO97 National Energy Modeling System runs HIDEMD.D100596A and AEO97B.D100296K.

Table F7. Key Results for Electricity Generation Sector Technology Cases
(Thousand Megawatts)

Net Summer Capability	1995	Projections								
		2005			2010			2015		
		Low Technology	Reference Case	High Technology	Low Technology	Reference Case	High Technology	Low Technology	Reference Case	High Technology
Electric Generators										
Capability										
Coal Steam	304.9	301.9	298.2	297.0	317.8	304.0	303.0	353.0	315.4	317.1
Other Fossil Steam	139.6	102.6	102.6	102.6	99.9	99.9	99.9	96.1	96.1	96.1
Combined Cycle	14.7	70.4	73.5	73.7	91.7	107.5	105.7	107.6	153.0	143.6
Combustion Turbine/Diesel	56.0	135.8	134.5	136.5	153.3	153.1	153.5	178.5	168.3	174.0
Nuclear Power	99.2	94.7	94.7	94.7	88.9	88.9	88.9	62.7	62.7	62.7
Pumped Storage	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
Fuel Cells	0.0	0.0	2.0	1.4	0.0	2.1	2.4	0.0	2.1	2.7
Renewable Sources	88.0	91.8	92.2	92.8	92.9	94.1	96.1	95.0	98.3	103.0
Total	**722.2**	**817.0**	**817.5**	**818.5**	**864.4**	**869.4**	**869.3**	**912.8**	**915.8**	**919.2**
Cumulative Planned Additions										
Coal Steam	1.4	3.7	3.7	3.7	5.3	5.3	5.3	5.3	5.3	5.3
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	1.4	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Combustion Turbine/Diesel	3.2	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Nuclear Power	0.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Pumped Storage	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.7	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Total	**8.0**	**15.5**	**15.5**	**15.5**	**17.1**	**17.1**	**17.1**	**17.1**	**17.1**	**17.1**
Cumulative Unplanned Additions										
Coal Steam	0.0	13.2	9.5	8.3	30.2	16.4	15.4	69.2	31.6	33.3
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	54.9	58.0	58.1	76.2	91.9	90.1	92.0	137.5	128.1
Combustion Turbine/Diesel	0.1	79.5	78.2	80.2	97.3	97.1	97.6	123.7	113.5	119.2
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	2.0	1.4	0.0	2.1	2.4	0.0	2.1	2.7
Renewable Sources	0.0	1.4	1.8	2.5	2.7	3.9	5.8	5.0	8.4	13.1
Total	**0.1**	**149.0**	**149.5**	**150.5**	**206.4**	**211.4**	**211.3**	**290.0**	**293.1**	**296.4**
Cumulative Total Additions	**8.2**	**164.5**	**165.0**	**166.0**	**223.5**	**228.5**	**228.4**	**307.1**	**310.2**	**313.5**
Cumulative Retirements	**11.9**	**72.1**	**72.1**	**72.1**	**83.9**	**83.9**	**83.9**	**119.1**	**119.1**	**119.1**
Cogenerators										
Capacity										
Coal	8.2	9.0	9.0	9.0	9.3	9.3	9.3	9.5	9.5	9.5
Petroleum	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0
Natural Gas	28.9	32.1	32.1	32.1	33.3	33.3	33.3	34.2	34.2	34.2
Other Gaseous Fuels	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Renewable Sources	6.2	7.3	7.3	7.3	7.8	7.8	7.8	8.2	8.2	8.2
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**45.1**	**50.2**	**50.2**	**50.2**	**52.3**	**52.3**	**52.3**	**53.8**	**53.8**	**53.8**
Cumulative Additions	**10.2**	**15.3**	**15.3**	**15.3**	**17.3**	**17.3**	**17.3**	**18.8**	**18.8**	**18.8**

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO97. Net summer capacity is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recent data available as of August 15, 1996. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Source: Energy Information Administration, AEO97 National Energy Modeling System runs LTECEL.D100896A, AEO97B.D100296K, and HTECEL.D100896A.

Table F8. Key Results for Oil and Gas Technological Progress Cases Including Market Feedback
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1995	2005 Slow Technology Progress	2005 Reference Case	2005 Rapid Technology Progress	2010 Slow Technology Progress	2010 Reference Case	2010 Rapid Technology Progress	2015 Slow Technology Progress	2015 Reference Case	2015 Rapid Technology Progress
Total Energy Supply and Disposition Summary										
Production										
Crude Oil and Lease Condensate	13.89	11.08	11.62	12.21	10.29	11.41	12.66	9.56	11.08	13.05
Natural Gas Plant Liquids	2.37	2.95	3.01	3.05	2.90	3.04	3.12	3.18	3.47	3.68
Dry Natural Gas	19.01	22.84	23.30	23.67	23.81	24.93	25.67	24.56	26.83	28.60
Coal	21.98	24.67	23.99	23.75	26.67	25.16	24.54	29.48	26.46	24.78
Nuclear Power	7.19	6.98	6.98	6.98	6.55	6.55	6.55	4.79	4.79	4.79
Renewable Energy	6.29	6.88	6.88	6.89	7.27	7.25	7.29	7.82	7.71	7.63
Other	1.34	0.42	0.42	0.41	0.40	0.39	0.39	0.43	0.42	0.41
Total	72.08	75.82	76.19	76.97	77.89	78.73	80.22	79.82	80.75	82.93
Imports										
Crude Oil	15.69	21.27	20.72	20.11	22.35	21.19	20.07	23.92	22.23	20.26
Petroleum Products	3.19	6.87	6.79	6.75	8.44	8.23	8.07	8.75	8.35	8.05
Natural Gas	2.90	3.97	3.98	3.99	4.12	4.23	4.28	4.37	4.55	4.64
Other Imports	0.60	0.65	0.67	0.67	0.67	0.67	0.67	0.64	0.64	0.64
Total	22.38	32.77	32.16	31.53	35.58	34.31	33.09	37.69	35.77	33.59
Exports										
Petroleum	2.02	1.92	1.92	1.92	1.92	1.94	2.10	2.10	1.97	2.08
Natural Gas	0.16	0.21	0.21	0.21	0.22	0.22	0.22	0.22	0.22	0.22
Coal	2.27	2.59	2.59	2.60	2.82	2.82	2.85	2.98	3.04	3.04
Total	4.45	4.73	4.73	4.73	4.96	4.98	5.17	5.30	5.24	5.35
Discrepancy	0.91	-0.30	-0.26	-0.24	-0.23	-0.17	-0.19	-0.45	-0.40	-0.33
Consumption										
Petroleum Products	34.92	40.50	40.46	40.46	42.36	42.24	42.14	43.38	43.26	43.09
Natural Gas	22.18	26.46	26.94	27.32	27.55	28.77	29.57	28.54	30.97	32.84
Coal	19.95	22.39	21.72	21.49	24.15	22.68	22.00	26.86	23.76	22.11
Nuclear Power	7.19	6.98	6.98	6.98	6.55	6.55	6.55	4.79	4.79	4.79
Renewable Energy	6.30	6.88	6.88	6.89	7.28	7.25	7.29	7.83	7.71	7.64
Other	0.39	0.36	0.38	0.38	0.39	0.39	0.39	0.37	0.37	0.37
Total	90.93	103.57	103.36	103.53	108.28	107.89	107.95	111.76	110.87	110.85
Net Imports - Petroleum	16.87	26.22	25.59	24.95	28.87	27.48	26.05	30.58	28.60	26.23
Prices (1995 dollars per unit)										
World Oil Price (dollars per barrel)	17.26	20.14	19.72	19.32	21.37	20.41	19.47	22.24	20.98	19.65
Gas Wellhead Price (dollars per Mcf)	1.61	2.05	1.94	1.86	2.37	2.01	1.70	2.77	2.13	1.55
Coal Minemouth Price (dollars per ton)	18.98	17.69	17.47	17.33	17.00	16.92	16.49	16.33	15.46	14.51
Natural Gas Supply, Disposition, and Delivered Prices										
Production (trillion cubic feet)										
Dry Gas Production	18.49	22.22	22.66	23.02	23.16	24.25	24.97	23.89	26.10	27.82
Supplemental Natural Gas	0.13	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports (trillion cubic feet)	2.68	3.68	3.69	3.69	3.82	3.92	3.97	4.06	4.23	4.32
Canada	2.79	3.51	3.52	3.53	3.64	3.74	3.79	3.88	4.06	4.15
Mexico	-0.05	-0.11	-0.11	-0.11	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12
Liquefied Natural Gas	-0.05	0.27	0.27	0.27	0.29	0.29	0.29	0.29	0.29	0.29
Total Supply (trillion cubic feet)	21.30	25.96	26.41	26.78	27.04	28.23	29.00	28.01	30.39	32.20
Consumption by Sector (trillion cubic feet)										
Residential	4.87	5.25	5.27	5.29	5.34	5.42	5.46	5.44	5.57	5.69
Commercial	3.07	3.33	3.34	3.35	3.41	3.44	3.45	3.50	3.55	3.59
Industrial	8.33	9.19	9.27	9.36	9.27	9.56	9.90	9.20	9.65	10.28
Electric Generators	3.46	5.58	5.88	6.10	6.25	6.94	7.25	6.96	8.52	9.38
Lease and Plant Fuel	1.14	1.43	1.45	1.47	1.49	1.55	1.58	1.54	1.65	1.74
Pipeline Fuel	0.70	0.79	0.82	0.85	0.81	0.86	0.89	0.83	0.91	0.99
Transportation	0.01	0.18	0.18	0.18	0.25	0.25	0.25	0.30	0.30	0.30
Total	21.58	25.75	26.22	26.60	26.81	28.01	28.79	27.78	30.16	31.99

Table F8. Key Results for Oil and Gas Technological Progress Cases Including Market Feedback (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1995	Projections								
		2005			2010			2015		
		Slow Technology Progress	Reference Case	Rapid Technology Progress	Slow Technology Progress	Reference Case	Rapid Technology Progress	Slow Technology Progress	Reference Case	Rapid Technology Progress
Natural Gas Supply, Disposition, and Delivered Prices (Continued)										
Discrepancy (trillion cubic feet)	-0.28	0.20	0.19	0.18	0.22	0.22	0.21	0.23	0.23	0.22
Delivered Prices (1995 dollars per thousand cubic feet)										
Residential	6.18	5.81	5.65	5.60	5.85	5.43	5.17	6.02	5.33	4.77
Commercial	5.10	4.94	4.79	4.73	5.05	4.64	4.39	5.28	4.61	4.08
Industrial	2.35	2.74	2.61	2.52	3.06	2.69	2.35	3.47	2.82	2.20
Electric Generators	2.06	2.46	2.33	2.27	2.76	2.38	2.09	3.15	2.52	2.05
Transportation	5.94	6.52	6.38	6.33	7.30	6.93	6.68	7.85	7.27	6.83
Average	3.67	3.70	3.55	3.46	3.92	3.49	3.18	4.23	3.52	2.93
Crude Oil Supply										
Lower 48 Average Wellhead Price (1995 dollars per barrel)	15.58	19.87	19.36	18.87	21.10	20.02	18.88	21.39	19.85	18.49
Production (million barrels per day)										
U.S. Total	6.56	5.23	5.49	5.77	4.86	5.39	5.98	4.52	5.23	6.16
Lower 48 Onshore	3.82	2.91	3.04	3.17	2.79	3.04	3.32	2.70	3.07	3.50
Conventional	3.24	2.34	2.44	2.54	2.13	2.36	2.59	1.98	2.33	2.72
Enhanced Oil Recovery	0.58	0.57	0.60	0.63	0.66	0.69	0.73	0.72	0.75	0.79
Lower 48 Offshore	1.26	1.38	1.50	1.65	1.30	1.57	1.89	1.18	1.53	2.03
Alaska	1.48	0.94	0.94	0.94	0.77	0.77	0.77	0.64	0.63	0.63
Lower 48 End of Year Reserves (billion barrels)	17.18	14.24	15.26	16.40	13.71	15.51	17.54	13.24	15.61	18.69
Natural Gas Supply										
Lower 48 Average Wellhead Price (1995 dollars per thousand cubic feet)	1.61	2.05	1.94	1.86	2.37	2.01	1.70	2.77	2.13	1.55
Production (trillion cubic feet)										
U.S. Total	18.48	22.22	22.66	23.02	23.16	24.25	24.97	23.89	26.10	27.82
Lower 48 Onshore	13.00	16.08	15.75	15.31	17.58	17.19	16.25	18.48	18.59	17.69
Associated-Dissolved	1.85	1.26	1.28	1.30	1.16	1.21	1.27	1.11	1.18	1.27
Non-Associated	11.15	14.83	14.47	14.01	16.42	15.98	14.98	17.37	17.40	16.42
Conventional	7.92	11.38	11.21	10.92	12.63	12.33	11.66	13.13	13.28	12.72
Unconventional	3.24	3.45	3.26	3.09	3.79	3.66	3.32	4.25	4.13	3.70
Lower 48 Offshore	5.05	5.62	6.39	7.19	5.02	6.51	8.17	4.84	6.94	9.55
Associated-Dissolved	0.71	0.76	0.78	0.80	0.75	0.81	0.86	0.72	0.80	0.88
Non-Associated	4.34	4.86	5.61	6.38	4.27	5.70	7.31	4.11	6.14	8.67
Alaska	0.42	0.52	0.52	0.52	0.55	0.55	0.55	0.58	0.58	0.58
U.S. End of Year Reserves (trillion cubic feet)	155.03	168.12	174.73	181.92	176.31	187.05	201.69	173.97	188.42	201.03
Supplemental Gas Supplies (trillion cubic feet)	0.13	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Total Lower 48 Wells Completed (thousands)	18.52	34.61	34.33	34.17	39.72	37.60	35.28	45.96	41.75	36.74

Btu = British thermal unit.
Mcf = Thousand cubic feet.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors.
Source: Energy Information Administration, AEO97 National Energy Modeling System runs LTECOGI.D100896A, AEO97B.D100296K, and HTECOGI.D100896A.

Table F9. Key Results for Oil and Gas Technological Progress Cases Assuming No Market Feedback

Production and Supply	1995	Projections								
		2005			2010			2015		
		Slow Technology Progress	Reference Case	Rapid Technology Progress	Slow Technology Progress	Reference Case	Rapid Technology Progress	Slow Technology Progress	Reference Case	Rapid Technology Progress
Crude Oil Supply										
Lower 48 Average Wellhead Price (1995 dollars per barrel)	15.58	19.45	19.36	19.27	20.13	20.02	19.81	20.16	19.85	19.83
Production (million barrels per day)										
U.S. Total	6.56	5.20	5.49	5.80	4.75	5.39	6.11	4.32	5.23	6.38
Lower 48 Onshore	3.82	2.89	3.04	3.20	2.72	3.04	3.40	2.58	3.07	3.64
Conventional	3.24	2.33	2.44	2.56	2.08	2.36	2.65	1.91	2.33	2.82
Enhanced Oil Recovery	0.58	0.56	0.60	0.64	0.63	0.69	0.76	0.67	0.75	0.82
Lower 48 Offshore	1.26	1.36	1.50	1.66	1.26	1.57	1.94	1.10	1.53	2.11
Alaska	1.48	0.94	0.94	0.94	0.77	0.77	0.77	0.63	0.63	0.63
Lower 48 End of Year Reserves (billion barrels)	17.18	14.09	15.26	16.54	13.28	15.51	18.07	12.52	15.61	19.52
Natural Gas Supply										
Lower 48 Average Wellhead Price (1995 dollars per thousand cubic feet)	1.61	2.14	1.94	1.85	2.62	2.01	1.58	3.48	2.13	1.37
Production (trillion cubic feet)										
U.S. Total	18.48	22.71	22.66	22.74	24.26	24.25	24.31	26.09	26.10	26.15
Lower 48 Onshore	13.00	16.50	15.75	15.20	18.54	17.19	15.88	20.41	18.59	16.54
Associated-Dissolved	1.85	1.25	1.28	1.31	1.15	1.21	1.28	1.09	1.18	1.29
Non-Associated	11.15	15.25	14.47	13.89	17.39	15.98	14.59	19.32	17.40	15.25
Conventional	7.92	11.67	11.21	10.74	13.47	12.33	11.25	14.64	13.28	11.58
Unconventional	3.24	3.58	3.26	3.16	3.92	3.66	3.34	4.68	4.13	3.67
Lower 48 Offshore	5.05	5.69	6.39	7.02	5.17	6.51	7.88	5.10	6.94	9.03
Associated-Dissolved	0.71	0.76	0.78	0.80	0.75	0.81	0.87	0.71	0.80	0.90
Non-Associated	4.34	4.93	5.61	6.21	4.42	5.70	7.02	4.39	6.14	8.14
Alaska	0.42	0.52	0.52	0.52	0.55	0.55	0.55	0.58	0.58	0.58
U.S. End of Year Reserves (trillion cubic feet)	155.03	171.42	174.73	183.72	181.90	187.05	198.48	181.36	188.42	194.65
Supplemental Gas Supplies (trillion cubic feet)	0.13	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.06	0.06
Total Lower 48 Wells Completed (thousands)	18.52	35.23	34.33	34.56	41.88	37.60	34.47	54.03	41.75	35.37

Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors. For natural gas production and consumption, the slight difference between the slow and rapid technological progress cases without market feedback and the reference case (with market feedback) are artifacts of the modeling methodology that are considered insignificant.

Source: Energy Information Administration, AEO97 National Energy Modeling System runs LTECOGS.D100896A, AEO97B.D100296K, and HTECOGS.D100896A.

Table F10. Key Results for Coal Labor Productivity Cases

Prices and Labor Productivity	1995	Projections								
		2000			2010			2015		
		Low Productivity	Reference Case	High Productivity	Low Productivity	Reference Case	High Productivity	Low Productivity	Reference Case	High Productivity
Minemouth Price (1995 dollars per short ton)	18.83	19.06	18.38	18.20	18.87	16.92	15.22	18.26	15.46	14.41
Delivered Price to Electric Generators (1995 dollars per million Btu)	1.32	1.32	1.29	1.28	1.30	1.20	1.12	1.26	1.11	1.05
Labor Productivity (short tons per miner per hour) ...	5.38	6.28	7.01	7.86	5.88	9.37	15.30	5.27	10.27	19.69
Labor Productivity (average annual growth from 1995)	N/A	3.1	5.4	7.9	0.6	3.8	7.2	-0.1	3.3	6.7

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.
Source: Energy Information Administration, AEO97 National Energy Modeling System runs LPROD.D100496B, AEO97B.D100296K, and HPROD.D100496B.

Table F11. Key Results for Coal Miner Wage Cases

Prices and Miner Wages	1995	Projections								
		2000			2010			2015		
		Low Wage	Reference Case	High Wage	Low Wage	Reference Case	High Wage	Low Wage	Reference Case	High Wage
Minemouth Price (1995 dollars per short ton)	18.83	18.32	18.38	18.96	15.44	16.92	17.45	14.55	15.46	16.44
Delivered Price to Electric Generators (1995 dollars per million Btu)	1.32	1.29	1.29	1.32	1.13	1.20	1.22	1.07	1.11	1.16
Average Coal Miner Wage (short tons per miner per hour)	18.44	17.98	18.44	18.91	17.10	18.44	19.87	16.68	18.44	20.37
Average Coal Miner Wage (average annual growth from 1995)	N/A	-0.5	0.0	0.5	-0.5	0.0	0.5	-0.5	0.0	0.5

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.
Source: Energy Information Administration, AEO97 National Energy Modeling System runs LWAG.D100396A, AEO97B.D100296K, and HWAG.D100396A.

Major Assumptions for the Forecasts

The National Energy Modeling System

The projections in the *Annual Energy Outlook 1997 (AEO97)* are generated with the National Energy Modeling System (NEMS), developed and maintained by the Office of Integrated Analysis and Forecasting of the Energy Information Administration (EIA). In addition to its use in the development of the *AEO* projections, NEMS is also used in analytical studies for the U.S. Congress and other offices within the Department of Energy. The *AEO* forecasts are also used by analysts and planners in other government agencies and outside organizations.

The projections in NEMS are developed with the use of a market-based approach to energy analysis. For each fuel and consuming sector, NEMS balances the energy supply and demand, accounting for the economic competition between the various energy fuels and sources. The time horizon of NEMS is the midterm period, 20 years in the future. In order to represent the regional differences in energy markets, the component models of NEMS function at the regional level: the 9 Census divisions for the end-use demand models; production regions specific to oil, gas, and coal supply and distribution; the North American Electric Reliability Council regions and subregions for electricity; and the Petroleum Administration for Defense Districts for refineries.

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

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

Each NEMS component also represents the impact and cost of legislation and environmental regulations that affect that sector and reports key emissions. NEMS represents all current legislation and environmental regulations, such as the Clean Air Act Amendments of 1990 (CAAA90) and the costs of compliance with other regulations.

In general, the *AEO97* projections were prepared by using the most current data available as of July 31, 1996. At that time, most 1995 data were available, but only partial 1996 data were available. Carbon emissions were calculated by using carbon coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 1995*, published in October 1996 [*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 *AEO97* 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 *AEO97* includes cogeneration in the industrial sector and other nonutility generators in the electricity sector. Footnotes in the appendix tables of this report indicate the definitions and sources of all historical data.

The *AEO97* projections for 1996 and 1997 incorporate the short-term projections from EIA's *Short-Term Energy Outlook* (*STEO*), Fourth Quarter 1996 [2], published in October 1996. For short-term energy projections, readers are referred to that *STEO* or later editions, which are available quarterly.

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, macroeconomic feedback mechanism within NEMS, and a mechanism to evaluate detailed macroeconomic and interindustry impacts associated with energy events. 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 response surface representation of the Data Resources, Inc., Quarterly Model of the U.S. Economy.

International Module

The International Module represents the world oil markets, calculating the average world oil price and computing supply curves for 5 categories of imported crude oil for the Petroleum Market Module of NEMS, in response to changes in U.S. import requirements. International petroleum product supply curves, including curves for oxygenates, are also calculated.

Household Expenditures Module

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

Residential and Commercial Demand Modules

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

Industrial Demand Module

The Industrial Demand Module forecasts the consumption of energy for heat and power and for feedstocks and raw materials in each of 16 industry groups, subject to the delivered prices of energy and macroeconomic variables representing employment and the value of output for each industry. The industries are classified into three groups—energy-intensive, non-energy-intensive, and nonmanufacturing. Of the 8 energy-intensive industries, 7 are modeled in the Industrial Demand Module with components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. A representation of cogeneration and a recycling component are also included. The use of energy for petroleum refining is modeled in the Petroleum Market Module, and the projected consumption is included in the industrial totals.

Transportation Demand Module

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

Electricity Market Module

The Electricity Market Module represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, and natural gas; costs of generation by centralized renewables; macroeconomic variables for costs of capital and domestic investment; and electricity load shapes and demand. There are four primary submodules—capacity planning, fuel dispatching, finance and pricing, and load and demand-side management. 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. Both new generating technologies and renewable technologies compete directly in these decisions. In addition, several options for wholesale pricing are included.

Renewable Fuels Module

The Renewable Fuels Module includes submodules that provide explicit representation of the supply of wood, municipal solid waste, wind energy, solar thermal electric and photovoltaic energy, and geothermal energy. It provides cost and performance criteria to the Electricity Market Module. The Electricity Market Module represents market penetration of renewable technologies used for centralized electricity generation, and the end-use demand modules incorporate market penetration of selected off-grid electric and nonmarketed nonelectric renewables.

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships between the various sources of supply: onshore, offshore, and Alaska by both conventional and nonconventional techniques, including enhanced oil recovery and unconventional gas recovery from tight gas formations, Devonian 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. The crude oil supply curves are input to the Petroleum Market Module in NEMS for conversion and blending into refined petroleum products. The supply curves for natural gas are input to the Natural Gas Transmission and Distribution Module.

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 capacity expansion requirements. Core and noncore markets are explicitly represented for natural gas transmission. 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 the 5 Petroleum Administration for Defense Districts, using the same crude oil types as the International Module. It explicitly models the requirements of CAAA90 and the costs of new automotive fuels, such as oxygenated and reformulated gasoline, and includes oxygenate production and blending for reformulated gasoline. Costs include capacity expansion for refinery processing units. End-use prices are based on the marginal costs of production, plus markups representing product distribution costs, State and Federal taxes, and environmental costs.

Coal Market Module

The Coal Market Module simulates mining, transportation, and pricing of coal, subject to the end-use demand for coal differentiated by physical characteristics, such as the heat and sulfur content. The coal supply curves include a response to capacity utilization and fuel costs, as well as reserve depletion, labor productivity, and factor input costs. Thirteen coal types are represented, differentiated by coal rank, sulfur content, and mining process. Production and distribution are computed for 11 supply and 13 demand regions, using imputed coal transportation costs and trends in factor input costs. The Coal Market Module also forecasts the requirements for U.S. coal exports and imports. The international coal market component of the module computes trade in 4 types of coal for 16 export and 20 import regions. Both the domestic and international coal markets are simulated in a linear program.

Major assumptions for the *Annual Energy Outlook 1997*

Table G1 provides a summary of the cases used to derive the *AEO97* forecasts. For each case, the table gives the name used in this report, a brief description of the major assumptions underlying the projections, a designation of the mode in which the case was run in the NEMS model (either fully integrated, partially integrated, or standalone), and a reference to the pages in the body of the report and in this appendix where the case is discussed.

Assumptions on world oil markets and domestic macroeconomic activity are primary drivers to the forecasts presented in *AEO97*. These assumptions are presented in the "Market Trends" section. The following section describes the key regulatory, programmatic, and resource assumptions that factor into the projections. More detailed assumptions for each sector will be available via the EIA Home Page on the Internet and on the EIA CD-ROM, along with regional results and other details of the projections.

Building sector assumptions

The buildings sector includes both residential and commercial structures. Both the National Appliance Energy Conservation Act of 1987 (NAECA), the Energy Policy Act of 1992 (EPACT), and the Climate Change Action Plan (CCAP) contain provisions which impact future buildings sector energy use. The provisions with the most significant effect are minimum equipment efficiency standards. These standards require that new heating, cooling, and other specified energy-using equipment meet minimum energy efficiency levels which change over time. The manufacture of equipment that does not meet the standards is prohibited.

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

- Heat pumps—a 10.0 minimum seasonal energy efficiency ratio for 1992
- Room air conditioners—an 8.6 energy efficiency ratio in 1990
- 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
- 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

Table G1. Summary of the *AEO97* 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 1.4 percent, compared to the reference case growth of 1.9 percent.	Fully integrated	p. 33	
High Economic Growth	Gross domestic product grows at an average annual rate of 2.4 percent, compared to the reference case growth of 1.9 percent.	Fully integrated	p. 33	
Low World Oil Price	World oil prices are $14 per barrel in 2015, compared to $21 per barrel in the reference case.	Fully integrated	p. 34	
High World Oil Price	World oil prices are $28 per barrel in 2015, compared to $21 per barrel in the reference case.	Fully integrated	p. 34	
Residential: 1997 Technology	Future equipment purchases based on equipment available in 1997. Building shell efficiencies fixed at 1997 levels.	Standalone	p. 45	p. 199
Residential: Advanced Technology Cost Reduction	Cost of best technologies reduced by 35 percent. Building shell efficiencies increase by 50 percent from reference values by 2015.	Standalone	p. 45	p. 200
Residential: High Technology	Future equipment purchases based on most efficient technologies available. Building shell efficiencies increase by 50 percent from reference values by 2015.	Standalone	p. 45	p: 200
Commercial: 1997 Technology	Future equipment purchases based on equipment available in 1997. Building shell efficiencies fixed at 1997 levels.	Standalone	p. 46	p. 200
Commercial: Advanced Technology Cost Reduction	Cost of best technologies reduced by 35 percent. Building shell efficiencies increase by 50 percent from reference values by 2015.	Standalone	p. 46	p. 200
Commercial: High Technology	Future equipment purchases based on most efficient technologies available. Building shell efficiencies increase by 50 percent from reference values by 2015.	Standalone	p. 46	p. 200
Industrial: 1997 Technology	Efficiency of plant and equipment fixed at 1997 levels.	Standalone	p. 47	p. 201
Industrial: High Technology	Energy intensity declines at an annual rate of 1.4 percent, compared to 0.9 percent in the reference case.	Standalone	p. 47	p. 201
Transportation: 1997 Technology	Menu of fuel saving technologies fixed at 1997 availability.	Standalone	p. 47	p. 202
Transportation: Rapid Technology	Efficiency improvements from new technology are 33 percent higher at 50 percent lower cost from reference values.	Standalone	p. 47	p. 202
Electricity: Low Nuclear	All reactors retire 10 years earlier than in the reference case.	Fully integrated	p. 52	p. 203
Electricity: High Nuclear	All reactors operate 10 years longer than in the reference case.	Fully integrated	p. 52	p. 203

Table G1. Summary of the *AEO97* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix G
Electricity: High Demand	Electricity demand increases at an annual rate of 2.0 percent, compared to 1.5 in the reference case.	Partially integrated	p. 53	p. 204
Electricity: Low Technology	Menu of technologies fixed at the 1996 availability.	Partially integrated	p. 54	p. 205
Electricity: High Technology	Advanced generating technologies reach full commercialization cost earlier than in the reference case.	Partially integrated	p. 54	p. 205
Oil and Gas: Slow Technology, Integrated	Cost, finding rate, and resource base growth parameters adjusted for slower improvement.	Fully integrated	p. 26 p. 62	p. 206
Oil and Gas: Rapid Technology, Integrated	Cost, finding rate, and resource base growth parameters adjusted for more rapid improvement.	Fully integrated	p. 26 p. 62	p. 206
Oil and Gas: Slow Technology, Standalone	Cost, finding rate, and resource base growth parameters adjusted for slower improvement.	Standalone	p. 22	p. 206
Oil and Gas: Rapid Technology, Standalone	Cost, finding rate, and resource base growth parameters adjusted for more rapid improvement.	Standalone	p. 26	p. 206
Coal: Low Productivity	Productivity declines at an annual rate of 0.1 percent, compared to the reference case growth of 3.3 percent.	Standalone	p. 68	p. 208
Coal: High Productivity	Productivity grows at an annual rate of 6.7 percent, compared to the reference case growth of 3.3 percent.	Standalone	p. 68	p. 208
Coal: Low Wage	Labor wage rates decline by 0.5 percent annually.	Standalone	p. 68	p. 208
Coal: High Wage	Labor wage rates increase by 0.5 percent annually.	Standalone	p. 68	p. 208

and cooling. For space heating, existing and new shells improve by 11 percent and 29 percent, respectively, by 2015 relative to the 1993 stock average. For space cooling, the corresponding increases are 10 percent and 24 percent for existing and new buildings. Building codes relevant to CCAP are represented by an increase in the shell integrity of new construction over time.

Other CCAP programs which could have a major impact on residential energy consumption are the Environmental Protection Agency's (EPA) Green Programs. These programs, which are cooperative efforts between the EPA and home builders and energy appliance manufacturers, encourage the development and production of highly energy-efficient housing and equipment. One of the best known examples of these programs is the "golden carrot refrigerator," a very efficient design that is projected to be widely available by 1998 and to consume less than two-thirds of the energy specified in the 1993 NAECA standard. At fully funded levels, residential CCAP programs are estimated by program sponsors to reduce carbon emissions by nearly 9 million metric tons by the year 2000. For the reference case, carbon reductions are estimated to be 4.3 million metric tons, primarily because of differences in the estimated penetration of energy-saving technologies.

In addition to the *AEO97* 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 *1997 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 1997. Building shell efficiencies are assumed to be fixed at 1997 levels.

- The *high 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. Building shell efficiencies are assumed to increase by 50 percent over the reference case level by 2015.
- The *advanced technology cost reduction case* assumes that the best technology within a given end use and fuel combination will experience a 35-percent reduction in purchase costs. Most of the decline will occur within the 10-year period following a technology's introduction. Building shells will be at high technology case levels.

Commercial assumptions. Minimum equipment efficiency standards for the commercial sector are mandated in the EPACT legislation [*4*]. 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 5 percent and 8 percent, respectively, by 2015 relative to the 1992 averages.

The CCAP programs recognized in the *AEO97* reference case include the expansion of the EPA Green Lights and Energy Star Buildings programs and improvements to building shells from advanced insulation methods and technologies. The EPA green programs are designed to facilitate cost-effective retrofitting of equipment by providing participants with information and analysis as well as participation recognition. Retrofitting behavior is captured in the commercial module via discount parameters for controlling cost-based equipment retrofit decisions for various market segments. To model programs such as Green Lights, which target particular end uses, the *AEO97* 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 nearly 6 million metric tons by the year 2000. For the reference case, carbon reductions are estimated to be just over 4.1 million metric tons in 2000, primarily because of differences in the estimated penetration of energy-saving technologies.

In addition to the *AEO97* 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 *1997 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 1997. Building shell efficiencies are assumed to be fixed at 1997 levels.
- The *high 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. Building shell efficiencies are assumed to increase by 50 percent over the reference case level by 2015.
- The *advanced technology cost reduction case* assumes that the two best technologies within a given end use and fuel combination will experience a 35-percent reduction in purchase costs. Most of the decline will occur within the 10-year period following a technology's introduction. Building shells will be at high technology case levels.

Industrial sector assumptions

Compared to the building sector, there are relatively few regulations which target industrial sector energy use. The electric motor standards in EPACT require a 10-percent increase in efficiency above 1992 efficiency levels for motors sold after 1997 [*5*]. These standards have been incorporated into the Industrial Demand Module through the analysis of process efficiencies for new industrial processes. These standards are expected to lead to significant improvements in efficiency since it has been estimated that electric motors account for about 60 percent of industrial process electricity use.

Climate Change Action Plan. Several programs included in the CCAP target the industrial sector. Note that the potential impacts of the Climate Wise Program are also included in the CCAP impacts. The intent of these programs is to reduce greenhouse gas emissions by lowering industrial energy consumption. The program offices estimated that full implementation of these programs would reduce industrial electricity consumption by 29 billion kilowatthours and non-electric consumption by 383 trillion Btu by 2000. However, since the energy savings associated with the voluntary programs in the CCAP are, to a large extent, already contained in the *AEO97* baseline, total CCAP energy savings were reduced. Consequently, CCAP reduces electricity consumption by 16 billion kilowatthours and non-electric energy consumption by 90 trillion Btu. The non-electric energy is assumed to be steam coal.

For 2010, the program offices estimated electricity savings of 81 billion kilowatthours and fossil fuel savings of 650 trillion Btu. For the reason cited above, these estimates were revised to 47 billion kilowatthours for electricity and 190 trillion Btu for fossil fuels. In this situation, carbon emissions would be reduced by about 10 million metric tons (2 percent) in 2010.

High technology and 1997 technology cases. From 1960 to 1994, the decline in the 10-year moving average for aggregate industrial energy intensity was 1.2 percent, with a standard deviation of 1.1 percent. Thus, a change of 1 standard deviation would approximately double the decline in intensity. The *high technology case* emulates this result by approximately doubling the projected rates of decline in energy intensity for the energy-intensive industries. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changing composition of industrial output. Since the composition of industrial output remains the same as in the reference case, aggregate intensity falls by only 1.4 percent annually.

The *1997 technology case* holds the energy efficiency of plant and equipment constant at the 1997 level over the forecast.

Both cases were run with only the Industrial Demand Module rather than as a fully integrated NEMS run. Consequently, no potential feedback effects from energy market interactions were captured.

Transportation sector assumptions

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

EPACT requires that centrally-fueled automobile fleet operators—Federal, State, and local governments, and fuel providers (e.g., gas and electric utilities)—purchase a minimum fraction of alternative-fuel vehicles [6]. Federal fleet purchases of alternative-fuel vehicles must reach 50 percent of their total vehicle purchases by 1998 and 75 percent by 1999. Purchases of alternative-fuel vehicles by State governments must realize 25 percent of total purchases by 1998 and 75 percent by 2000. Private fuel-provider companies are required to purchase 50 percent alternative-fuel vehicles in 1997, increasing to 90 percent by 1999. Fuel provider exemptions for electric utilities are assumed to follow the electric utility provisions beginning in 1998 at 30 percent and reaching 90 percent by 2001. It is assumed that the municipal and private business fleet mandates begin in 2002 at 20 percent and scale up to 70 percent by 2005.

In addition to these requirements, the State of California has delayed the Low Emission Vehicle Program, which now requires that 10 percent of all new vehicles sold by 2003 meet the "zero emissions requirements." At present, only electric-dedicated vehicles meet these requirements. Originally, Massachusetts and New York adopted this program. The projections currently assume that only California and Massachusetts have formally delayed the Low Emission Vehicle Program.

The projections assume that these regulations represent minimum requirements for alternative-fuel-vehicle sales; consumers are allowed to purchase more of these vehicles, should vehicle cost, fuel efficiency, range, and performance characteristics make them desirable. In fact, the projections indicate that more than the minimum will be purchased, as shown in Figure 48.

Projections for both vehicle-miles traveled [7] and ton-miles traveled [8] are calculated endogenously and are based on the assumption that modal shares, for example, personal automobile travel versus mass transit, remain stable over the forecast and track recent historical patterns. Other important factors affecting the forecast of vehicle-miles traveled are personal disposable income per capita; the ratio of miles driven by females to males in the total driving population, which increases from 56 percent in 1990 to 80 percent by 2015; and the aging of the largest segment of the age distribution of the population, which will slow the growth in vehicle-miles traveled.

Climate Change Action Plan. There are four CCAP programs that focus on transportation energy use: (1) reform Federal subsidy for employer-provided parking; (2) adopt a transportation system efficiency strategy; (3) promote telecommuting; and (4) develop fuel economy labels for tires. The combined assumed effect of the Federal subsidy, system efficiency, and telecommuting policies in the *AEO97* reference case is a 1.1-percent reduction in vehicle-miles traveled (194 trillion Btu). The fuel economy tire labeling program improved new fuel efficiency by 4 percent among vehicles that switched to low rolling resistance tires, and resulted in a reduction in fuel consumption of 40 trillion Btu.

Rapid technology and 1997 technology cases. In the *rapid technology case*, fuel efficiency improvements from new technology over the forecast were set at 33-percent higher incremental technology fuel efficiency improvement levels and at 50 percent of the reference case technology cost levels for light-duty vehicles. Similar fuel saving technology efficiency improvements and cost reductions were applied to both air and freight truck sectors. The *1997 technology case* assumes that the list of available fuel saving technologies is held constant throughout the forecast at the 1997 level of availability for light-duty vehicles, air, and freight truck modes. The 1997 technology case and the reference case result in similar consumption levels for both the air and freight truck modes because of the lack of low-cost technology availability and the high capital cost for the available fuel-saving technologies in the air and freight truck modes.

Both cases were run with only the Transportation Demand Module rather than as a fully integrated NEMS run. Consequently, no potential macroeconomic feedback on travel demand was captured.

Electricity assumptions

Characteristics of generating technologies. The costs and performance of new generating technologies are important factors in determining the future mix of capacity. There are 26 fossil, renewable, and nuclear generating technologies included in these projections. Technologies represented include those currently available as well as those that are assumed to be commercially available within the horizon of the forecast. Capital cost estimates and operational characteristics, such as efficiency of electricity production, are used for decisionmaking where it is assumed that the selection of new plants to be built is based on least cost subject to environmental constraints. The levelized lifetime cost, including fuel costs, is evaluated and is 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 will be available via the EIA Home Page on the Internet and on the EIA CD-ROM.

Regulation of electricity markets. It is assumed that electricity producers comply with CAAA90, which mandates a limit of 8.95 million short tons of sulfur dioxide emissions by 2000. 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 $187 per kilowatt, in 1995 dollars, although the costs vary widely across the regions. It is also assumed that the market for trading emission allowances is allowed to operate without regulation and that the States do not further regulate the selection of coal to be used.

The provisions of EPACT include revised licensing procedures for nuclear plants and the creation of exempt wholesale generators [9]. These entities are included among nonutility producers and are assumed to have a capital structure which is highly leveraged, compared with that of investor-owned regulated utilities.

Prices for electricity are assumed to be regulated at the State level. Prices for the residential, commercial, industrial, and transportation sectors are developed by classifying costs into four categories: fuel (including wholesale power purchases), fixed operation and maintenance, variable operation and maintenance, and capital. These costs are allocated to each of the four customer classes by using the proportion of sales to the class and the contribution of each class to system peak load requirements. These allocated costs are divided by the sales to each sector to obtain electricity prices to the 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 $2.4 billion per year by 1999.

Representation of utility Climate Challenge participation agreements. As a result of the Climate Challenge Program, many utilities have announced efforts to voluntarily reduce their greenhouse gas emissions between now and 2000. These efforts cover a wide variety of programs, including increasing demand-side management (DSM) investments, repowering (fuel-switching) fossil plants, restarting nuclear plants that have been out-of-service, planting trees, and purchasing emission offsets from international sources. To the degree possible, each one of the participation agreements was examined to determine if the commitments made were addressed in the normal reference case assumptions or whether they were addressable in NEMS. Programs like tree planting and emission offset purchasing are not addressable in NEMS. With regard to the other programs, they are, for the most part, captured in NEMS. For example, utilities annually report to EIA their plans (over the next 10 years) to bring a plant back on line, repower a plant, life extend a plant, cancel a previously planned plant, build a new plant, or switch fuel at a plant. These data are inputs to NEMS. Thus, programs that would affect these areas are reflected in NEMS input data. However, because many of the agreements do not identify the specific plants where action is planned, it is not possible to determine which of the specified actions, together with their greenhouse gas emissions savings, should be attributed to the Climate Challenge Program and which are the result of normal business operations.

Nuclear power. One nuclear unit, Watts Bar 1, owned by the Tennessee Valley Authority, received its operating license in 1996. No additional units are actively under construction; therefore, no new planned units are assumed to come into service during the forecast.

In the reference case, nuclear units are assumed to operate until their license expiration dates, unless current operating costs exceed 4 cents per kilowatthour. Nuclear units with higher operating costs are assumed to be retired 10 years before their license expiration dates. Two standalone side cases were developed with alternate retirement dates for nuclear units. The *low nuclear case* assumes that all reactors retire 10 years earlier than the reference case retirement dates, while the *high nuclear case* assumes 10 additional years of operation.

The average nuclear capacity factor is currently 77 percent and is expected to remain between 76 and 79 percent throughout the forecast. Capacity factor assumptions are developed at the unit level, and improvements and losses are forecast based on the age of the reactor. Unit level projections are aggregated to the regional level for use in the model.

Fossil-steam retirement assumptions. Using current and historical data from FERC Form 1, existing plants whose combined operating and fuel costs exceed 4 cents per kilowatthour are identified for retirement. These plants are then retired annually in equal numbers between 1998 and 2003. After 2003, only units reported by utilities as candidates for retirement are retired. No nonutility or cogeneration plants are assumed to retire during the projection period.

High electricity demand case. The *high electricity demand case*, which is a standalone case, assumes that the demand for electricity grows by 2.0 percent annually between 1995 and 2015, compared with 1.5 percent in the reference case. No attempt was made to determine the changes necessary in the end-use sectors needed to result in the stronger demand growth. The high electricity demand case is a partially integrated run, i.e., the Macroeconomic Activity, Petroleum Marketing, International Energy, and end-use demand modules use the reference case values and are not effected by the higher electricity demand growth. Conversely, the Oil and Gas, Natural Gas Transmission and Distribution, Coal Market, and Renewable Fuels Modules are allowed to interact with the Electricity Market Module in the high electricity demand case.

High and low technology cases. The high technology case assumes that the advanced generating technologies will reach their full commercialization cost sooner than in the reference case. Input for each technology is an *n*th-of-a-kind cost, which occurs when plant cost estimates approach actual costs and the effects of "learning by doing" are no longer observed. To get the current overnight cost, the *n*th-of-a-kind cost is multiplied by an optimism factor and a learning factor.

The optimism factor is a measure of the project risk for the first commercialization of a new technology. In the reference case, this factor decreases linearly over the first four plants. For the high technology case, this factor is halved.

The learning factor captures the decrease in costs that occurs from "learning by doing." The learning function is a log-linear function which decreases the plant cost by a learning factor for each doubling of capacity. In the reference case, learning occurs for the first five units. In the high technology case, cost reductions due to learning increase by 50 percent relative to learning in the reference case. In the low technology case, only those technologies that are available in 1996 are considered as new capacity options for the entire projection period.

This is a partially integrated run of the Electricity Market, Oil and Gas Supply, Natural Gas Transmission and Distribution, Petroleum Market, and Coal Market Modules.

Renewable fuels assumptions

Energy Policy Act of 1992. The Renewable Fuels Module incorporates the provisions of EPACT that support the development of renewable energy forms. EPACT provides a renewable electricity production credit of 1.5 cents per kilowatthour for electricity produced by wind, applied to plants that become operational between January 1, 1994, and June 30, 1999 [*10*]. The credit extends for 10 years after the date of initial operation. EPACT also includes provisions that allow an investment tax credit of 10 percent for solar and geothermal technologies that generate electric power [*11*]. This credit is included as a 10-percent reduction to the capital costs.

Supplemental Additions. AEO97 includes 1,521 megawatts of assumed new generating capacity using renewable resources, including 946 megawatts of planned new capacity additions not reported among EIA data collections and 575 megawatts assumed by EIA to be built for reasons not incorporated in NEMS modeling (such as for testing, investment, and for distributed applications). Total supplementals include 110 megawatts of geothermal, 670 megawatts of wind, 41 megawatts of solar, and 125 megawatts of biomass. These supplementals include 536 megawatts of mandated new capacity, 525 of which are in Minnesota (400 megawatts of wind-powered capacity and 125 megawatts of biomass). Floors include 320 megawatts of new capacity using photovoltaics (PV) and 255 megawatts of solar thermal, representing central receiver, dish Stirling, and trough technologies.

Renewable resources. The major source of renewable energy for electricity generation is hydroelectric power. Environmental and other restrictions are assumed to limit the growth of hydroelectric power, which grows slightly. The total resources for most other renewables are theoretically large, for example, the amount of sunlight. However, total resources are not always the relevant measure. Regional characterization is required in order to properly represent the resource. For example, while the capability to produce solar thermal energy is present in all regions of the United States, it is assumed that solar thermal energy technologies will penetrate first in those regions where its economics are most favorable. Wind energy resource potential, while large, is constrained by land-use and environmental factors that result in the exclusion of some land area within suitable wind classes. The geographic distribution of available wind resources is based on a resource assessment study by the Pacific Northwest Laboratory as revised in 1992 [*12*]. 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 producible, since 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.

Non-electric renewable energy. The forecast for wood consumption in the residential sector is based on the Residential Energy Consumption Survey [*13*] (RECS) and data from the *Characteristics of New Housing: 1993*, published by the Bureau of the Census [*14*]. The RECS data provide a benchmark for Btu of wood use in 1993. The Census data are used to develop the forecasts of new housing units utilizing wood. Wood consumption is then computed by multiplying the number of homes that use wood for main and secondary space heating by the amount of wood used. Ground source (geothermal) heat pump consumption is also based on the latest RECS and Census data; however, the measure of geothermal energy consumption is represented by the amount of primary energy displaced by using a geothermal heat pump in place of an electric resistance furnace. Solar thermal consumption for water heating is also represented by displaced primary energy relative to an electric water heater.

Exogenous projections of active and passive solar technologies and geothermal heat pumps in the commercial sector are based on projections from the National Renewable Energy Laboratory [*15*]. Industrial use of renewable energy is primarily the use of wood and wood byproducts in the paper and lumber industries as well as a small amount of hydropower for electricity generation.

Oil and gas supply assumptions

Domestic oil and gas economically recoverable resources. The assumed resource levels are based on analyses of estimates of the economically recoverable resource base from the U.S. Geological Survey (USGS) and the Minerals Management Service (MMS) of the Department of the Interior and the National Petroleum Council (NPC) [*16*]. The values are given as beginning-of-the-year 1990, because that is the initial year of the model execution. They have been derived from estimates based in other years (USGS, 1/1/94; MMS, 1/1/95; NPC, 1/1/91) by adjusting for reserve additions in the intervening years.

Economically recoverable resources are those volumes considered to be of sufficient size and quality for their production to be commercially profitable by current conventional or nonconventional techniques, under specified economic conditions. Estimates were developed on a regional basis. Total lower 48 unproved oil resources are assumed to be 96 billion barrels with 1990 technology and 119 billion barrels with 2015 technology. Total lower 48 unproved gas resources are assumed to be 936 trillion cubic feet with 1990 technology and 1,322 trillion cubic feet with 2015 technology. Unproved resources comprise inferred reserves and undiscovered resources. Inferred reserves are that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves. Undiscovered resources are located outside oil and gas fields in which the presence of resources has been confirmed by exploratory drilling.

The assumed lower 48 unproved resource levels with 2015 technology in *AEO97* are somewhat lower than in *AEO96*—approximately 16 percent and 19 percent lower for oil and gas, respectively. This is largely due to a reassessment of the limits of technological expansion. In addition, the assumed unproved oil resources with 1990 technology are lower in *AEO97* (by approximately 10 percent) than in *AEO96*. This is due primarily to the incorporation of undiscovered economically recoverable resource estimates from the U.S. Geological Survey, which for oil are significantly lower than assumed in *AEO96*.

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 *AEO97* assumption is that it reaches a maximum annual production level of 19.1 billion cubic feet by 2000.

Technological improvements affecting recovery and costs. Productivity improvements are simulated by assuming that the undiscovered recoverable resource target will expand and the effective cost of supply activities will be reduced. The total volumes of undiscovered economically recoverable domestic oil and natural gas resources are assumed to increase over the 1990-2015 period in response to technological innovation, as indicated by the volumes cited above. The increase is due to the development and deployment of new technologies, such as three-dimensional seismology and horizontal drilling and completion techniques. Drilling, operating, and lease equipment costs are expected to decline due to technological progress, at econometrically estimated rates that vary somewhat by cost and fuel categories, ranging from roughly 1 to 4 percent, most of them generally near 2 percent. These technological impacts work against increases in costs associated with drilling to greater depths and higher drilling activity levels.

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, oil and natural gas reference case parameters for the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and growth in the undiscovered economic resource base were adjusted. The two cases were created by varying parameters that represent the effects of technological progress on U.S. drilling lease equipment and operating costs from their statistically estimated values by one standard deviation (based on the standard error associated with each estimated parameter).

Statistically estimated values for U.S. finding rates were similarly varied (although additional transformations of these statistically estimated values, based on analyst judgment, were subsequently required prior to their use as parameters within the *AEO97* analytic framework). Parameters for growth in the U.S. undiscovered economic resource base (which are not statistically derived) were also varied, in proportion to the changes in the technological progress parameters affecting finding rates (reserves found per well).

Assumptions relating to natural gas trade with Canada were also adjusted. Similar to the United States, adjustments were made to costs, resources, and finding rates used in deriving the Canadian natural gas supply curves to reflect different rates of technological progress. Additionally, exogenously determined pipeline capacities at the U.S.-Canada border were adjusted to allow import volumes to change across the cases. Upper bounds on capacities were changed to give import volumes the same market share they achieved in the reference case.

All other parameters in the model were kept at their reference case values, including success rates, technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of liquefied natural gas (LNG) and natural gas trade between the United States and Mexico. Specific detail by region and resource category is presented in the supplementary tables to the *Annual Energy Outlook 1997*, which will be available in January 1997 on the EIA FTP site (ftp://ftp.eia.doe.gov/pub/forecasting/aeo97/tables).

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 $3.74, in 1995 dollars per thousand cubic feet. The liquefied natural gas facilities at Everett, Massachusetts, and Lake Charles, Louisiana (the only ones currently in operation) have an operating capacity of 311 billion cubic feet. The facilities at Cove Point, Maryland, and Elba Island, Georgia, are assumed to reopen when economically justified, but not before 1998. Should these facilities reopen, total liquefied natural gas operating capacity would increase to 794 billion cubic feet.

Natural gas transmission and distribution assumptions. Consistent with industry restructuring, the methodology employed in solving for the market equilibrium assumes that marginal costs are the basis for determining market-clearing prices for noncore markets. Core market prices are based on average cost of service rates minus a credit (to account for capacity release) that credits a share of the revenue from interruptible and release capacity services to holders of firm capacity should those revenues exceed costs.

Firm transportation rates for pipeline services are calculated with the assumption that the costs of new pipeline capacity will be rolled into the existing rate base (the test for determining whether or not to build new capacity is based on incremental rates, however). Although distribution markups to firm service customers are based on historical data, they also respond to changes in consumption levels, cost of capital, and assumed industry efficiency improvements. It is assumed that, independent of changes in costs related to the cost of capital and consumption levels, distributor costs for firm service customers will decline by 1 percent per year.

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 and/or replacement of existing pipe.) Reductions in operations and maintenance costs and total administrative and general costs as a result of efficiency improvements are accounted for on the basis of historical trends.

The vehicle natural gas (VNG) sector is divided into fleet and non-fleet vehicles. The end-use price of natural gas to fleet vehicles is based on EIA's *Natural Gas Annual* historical tariffs 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 of $0.50 (1994 dollars) per thousand cubic feet plus corresponding State taxes are levied starting in 1994.

CCAP initiatives to increase the natural gas share of total energy use through Federal regulatory reform (Action 23) are reflected in the new methodology for the pricing of pipeline services. This methodology is consistent with recent signals from FERC that show receptivity to alternative ratemaking and a desire to provide an atmosphere that fosters efficient capacity release. Provisions of the CCAP to expand the Natural Gas Star program (Action 32) are assumed to recover 35 billion cubic feet of natural gas per year by the year 2000 that otherwise might be lost to fugitive emissions. This is phased in by recovering an additional 7 billion cubic feet per year from 1996 through 2000, and by recovering the full 35 billion cubic feet from 2000 through the end of the forecast period.

Petroleum market assumptions

The petroleum refining and marketing industry is assumed to incur large environmental costs to comply with CAAA90 and other regulations. Investments related to reducing emissions at refineries are represented as an average annualized expenditure. Costs identified by the National Petroleum Council [*17*] are allocated among the prices of liquefied petroleum gases, gasoline, distillate, and jet fuel, assuming they are recovered in the prices of light products. The lighter products, such as gasoline and distillate, are assumed to bear a greater amount of these costs because demand for these products is less price-responsive than for the heavier products.

Petroleum product prices also include additional costs resulting from requirements for new fuels, including oxygenated and reformulated gasolines and low-sulfur diesel. These additional costs are determined in the representation of refinery operations by incorporating specifications and demands for these fuels. Demands for traditional, reformulated, and oxygenated gasolines are disaggregated from composite gasoline consumption based on market share assumptions for each Census Division. The expected oxygenated gasoline market shares assume wintertime participation of carbon monoxide non-attainment areas and year-round participation of Minnesota beginning in 1995.

Starting in 1995, reformulated gasoline is assumed to be consumed in the nine serious ozone nonattainment areas required by CAAA90 and in areas in 12 States and the District of Columbia that voluntarily opted into the program [*18*]. The reformulated gasoline is assumed to account for about 36 percent of annual gasoline sales throughout the *AEO97* forecast

Reformulated gasoline reflects the "Complex Model" definition as required by the EPA. *AEO97* projections also reflect California's statewide requirement for severely reformulated gasoline beginning in 1996. Throughout the forecast, traditional gasoline is blended according to 1990 baseline specifications, to reflect CAAA90 "antidumping" requirements aimed at preventing traditional gasoline from becoming more polluting.

AEO97 assumes that the 54 cent per gallon tax credit for gasoline blended with ethanol will not expire in 2000 and will remain at 54 cents per gallon throughout the forecast.

AEO97 assumes that State taxes on gasoline, diesel, jet fuel, M85, and E85 increase with inflation, as they have tended to in the past. Federal taxes which have increased sporadically in the past are assumed to stay at 1996 nominal levels (a decline in real terms).

Coal market assumptions

Resource base. Estimates of recoverable coal reserves are based on the EIA Demonstrated Reserve Base (DRB) of in-ground coal resources of the United States. Resource estimates from the DRB are correlated with coal quality data from other sources to create a Coal Reserves Data Base. Estimates are developed on a regionally disaggregated basis.

In certain coal-producing regions, the DRB estimates have been augmented by a proration of inferred resources. The extent of augmentation varies by State and coal type, based on the currency of DRB estimates and the amount of inferred coal that meets criteria related to seam thickness, depth, and overburden. The purpose of this change is to represent expected additions to demonstrated reserves that would occur in later years of the forecast. The effect of the change is to reduce somewhat mine-mouth and delivered prices in that period.

Productivity. Technological advances in the coal industry, such as continuous mining, contribute to increases in productivity, as measured in average tons of coal per miner per hour. Productivity improvements are assumed to continue but to decline in magnitude over the forecast horizon. Different rates of improvement are assumed by region and by mine type, surface and deep. On a national basis, labor productivity is assumed to improve at a rate of 3.3 percent per year, declining from an annual rate of 8.0 percent in 1995 to approximately 2 percent over the 2010 to 2015 period. In the alternative cases that were run to examine the impacts of different labor productivity assumptions, the annual growth rates for productivity were increased and decreased by region and mine type, based on historical variations in labor productivity. The rapid and slow productivity cases were developed by adjusting the *AEO97* reference case productivity path by 2 standard deviations, although productivity growth rates were adjusted gradually with full variation from the reference case phased in by 2000. The resulting national average productivities attained in 2015 (in short tons per hour) were 19.69 in the *high productivity case* and 5.27 in the *low productivity case*, compared with 10.27 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 wage case* and *high wage case* that were run to examine the effects of different labor cost escalation rates, wages were assumed to decline and increase by 0.5 percent per year in real terms, respectively.

The productivity and wage cases were run without allowing demands to shift in response to changing prices. If demands had been allowed to shift, the price changes would be smaller, since minemouth prices vary with the levels of capacity utilization required to meet demand.

Notes

[*1*] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1995*, DOE/ EIA-0573(95) (Washington, DC, October 1996).

[*2*] Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996).

[*3*] Lawrence Berkeley Laboratory, *U.S. Residential Appliance Energy Efficiency: Present Status and Future Direction*.

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

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

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

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

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

[*9*] National Energy Policy Act of 1992, P.L. 102-486, Title VII, Subtitle A, Section 711, and Title XXVIII, Sections 2801 and 2802.

[*10*] National Energy Policy Act of 1992, P.L. 102-486, Title XIX, Section 1914.

[*11*] National Energy Policy Act of 1992, P.L. 102-486, Title XIX, Section 1916.

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

[*13*] Energy Information Administration, *Household Energy Consumption and Expenditures 1993*, DOE/ EIA-0321(93) (Washington, DC, 1995).

[*14*] U.S. Bureau of the Census, U.S. Department of Commerce, *Current Construction Reports, Series C25 Characteristics of New Housing: 1993* (Washington, DC, 1994).

[*15*] National Renewable Energy Laboratory, "Baseline Projections of Renewables Use in the Buildings Sector," prepared for the U.S. Department of Energy under Contract DE-AC02-83CH10093 (December 1992).

[*16*] Goutier, Donald L., et al., U.S. Department of the Interior, U.S. Geological Survey, *1995 National Assessment of the United States Oil and Gas Resources* (Washington, DC, 1995); U.S. Department of the Interior, Minerals Management Service, *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf*, OCS Report MMS 96-0034 (Washington, DC, June 1996); Cooke, Larry W., U.S. Department of the Interior, Minerals Management Service, *Estimates of Undiscovered, Economically Recoverable Oil and Gas Resources for the Outer Continental Shelf, Revised as of January 1990*, OCS Report MMS 91-0051 (July 1991); National Petroleum Council, Committee on Natural Gas, *The Potential for Natural Gas in the United States, Volume II, Source and Supply* (Washington, DC, December 1992).

[*17*] Estimated from National Petroleum Council, *U.S. Petroleum Refining—Meeting Requirements for Cleaner Fuels and Refineries*, Volume I (Washington, DC, August 1993). Excludes operation and maintenance base cost prior to 1996.

[*18*] 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, Maine, Massachusetts, Maryland, New Hampshire, New Jersey, New York, Rhode Island, Texas, Virginia, and the District of Columbia. Excludes areas that "opted-out" prior to June 1996.

Conversion Factors

Table H1. Heat Rates

Fuel	Units	Approximate Heat Content
Coal [1]		
Production	million Btu per short ton	21.352
Consumption	million Btu per short ton	21.010
Coke Plants	million Btu per short ton	26.800
Industrial	million Btu per short ton	22.068
Residential and Commercial	million Btu per short ton	23.112
Electric Utilities	million Btu per short ton	20.573
Imports	million Btu per short ton	25.000
Exports	million Btu per short ton	26.329
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	5.309
Motor Gasoline[2]	million Btu per barrel	5.199
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	5.420
Exports[2]	million Btu per barrel	5.640
Natural Gas Plant Liquids		
Production[2]	million Btu per barrel	3.794
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
Electricity Component		
Plant Generation Efficiency (heat rate)		
Fossil Fuel Steam	Btu per kilowatthour	10,280
Nuclear Energy	Btu per kilowatthour	10,678
Geothermal [3]	Btu per kilowatthour	32,391
Biomass[3]	Btu per kilowatthour	8,979
Municipal Solid Waste[3]	Btu per kilowatthour	16,377

[1]Conversion factors vary from year to year. 1994 values are reported.
[2]Conversion factors vary from year to year. 1998 values are reported.
[3]Conversion factors vary from year to year. Values shown are for units entering service in 2000.
Source: Energy Information Administration, AEO97 National Energy Modeling System, run AEO97B.D100296K.

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)
Distance				
Miles	X	1.609 344	=	kilometers (km)
Energy				
British thermal unit (Btu)[1]	X	1055.056	=	joules (J)
Kilowatthours	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)
Gallons (gal)	X	3.785 412	=	liters (L)
Area				
Square feet (ft^2)	X	0.092 903 04	=	square meters (m^2)

[1]The Btu used in this table is the International Table Btu adopted by the Fifth International Conference on Properties of Steam (London, UK, 1956).

Note: Spaces have been inserted after every third digit to the right of the decimal for ease of reading.

Source: Energy Information Administration, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington DC, July 1996), Table B1.

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 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996), Table B2, and EIA, Office of Statistical Standards.

Fax-On-Demand

Data tables for the reference case of *AEO97* are available via Fax-On-Demand, with data for 1994 to 2015. Supplementary tables providing regional and other detail from the *AEO97* reference case will be available by January 31, 1997. To obtain document numbers for supplementary tables, follow the directions below and request document 101.

To use the EIA's Fax-On-Demand system, dial (202) 586-3550. All international customers must phone in from a fax machine. A voice will guide you through the system. When prompted for a document number, enter the document number of the table you want.

Document Number	Description/Source	Pages
101	Directory of all EIA documents in the Fax-On-Demand System	multi
383001	Total Energy Supply and Distribution Summary from *AEO97*, Table A1	2
383002	Energy Consumption by Sector and Source from *AEO97*, Table A2	6
383003	Energy Prices by Sector and Source from *AEO97*, Table A3	4
383004	Residential Sector Key Indicators and Consumption from *AEO97*, Table A4	4
383005	Commercial Sector Key Indicators and Consumption from *AEO97*, Table A5	4
383006	Industrial Sector Key Indicators and Consumption from *AEO97*, Table A6	2
383007	Transportation Sector Key Indicators and Delivered Energy Consumption from *AEO97*, Table A7	2
383008	Electricity Supply, Disposition, and Prices from *AEO97*, Table A8	2
383009	Electricity Generating Capability from *AEO97*, Table A9	4
383010	Electricity Trade from *AEO97*, Table A10	2
383011	Petroleum Supply and Disposition Balance from *AEO97*, Table A11	2
383012	Petroleum Product Prices from *AEO97*, Table A12	2
383013	Natural Gas Supply and Disposition from *AEO97*, Table A13	2
383014	Natural Gas Prices, Margins, and Revenues from *AEO97*, Table A14	2
383015	Oil and Gas Supply from *AEO97*, Table A15	2
383016	Coal Supply, Disposition, and Prices from *AEO97*, Table A16	2
383017	Renewable Energy Generating Capacity and Generation from *AEO97*, Table A17	2
383018	Renewable Energy Consumption by Sector and Source from *AEO97*, Table A18	2
383019	Carbon Emissions by Sector and Source from *AEO97*, Table A19	2
383020	Macroeconomic Indicators from *AEO97*, Table A20	2
383021	International Petroleum Supply and Disposition Summary from *AEO97*, Table A21	4

A

B

C

N

O

The Energy Information Administration
National Energy Modeling System/Annual Energy Outlook
Conference

Crystal Gateway Marriott, Arlington, VA — *March 17, 1997*

8:30 a.m.	**Opening Remarks**	- *Jay E. Hakes, Administrator*, Energy Information Administration
8:45-9:15 a.m.	**Overview of the** ***Annual Energy Outlook 1997***	- *Mary J. Hutzler, Director*, Office of Integrated Analysis and Forecasting, Energy Information Administration
9:15-10:00 a.m.	**Keynote Address**	- *Larry E. Ruff, Managing Director*, Putnam, Hayes and Bartlett, Inc., speaking on electricity restructuring

Morning Sessions
10:15 a.m. - 12:00 p.m.

1. New Generating Technologies Penetration and Cost
2. Oil Import Dependence: U.S. Supply and Refining Capacity
3. Electricity Demand in Buildings and the Industrial Sector

Afternoon Sessions - A
1:15 p.m. - 3:00 p.m.

1. Electricity Restructuring: Competition in Current Markets
2. Natural Gas Supply
3. Transportation Demand and Fuel Efficiency

Afternoon Sessions - B
3:15 p.m. - 5:00 p.m.

1. Electricity Prices under a Competitive Environment
2. International: Demand in Developing Countries
3. Coal Supply and Distribution

5:00 p.m. Adjourn

Hotel

The conference will be held at the *Crystal Gateway Marriott*, not to be confused with the Crystal City Marriott.

The *Crystal Gateway Marriott* is located near the Crystal City Metro subway station at 1700 Jefferson Davis Highway, Arlington, VA 22202.

For room reservations, contact the *Crystal Gateway Marriott* directly by Telephone: (703) 920-3230 or Fax: (703) 979-6332.

Information

For further information, contact Susan H. Shaw, Energy Information Administration, at (202) 586-4838, sshaw@eia.doe.gov, or Sharon Wood, Decision Analysis Corporation of Virginia, at (703) 893-5087.

Conference Registration

Conference registration is free, but space is limited. Please register by March 5, 1997.

To register, mail this form to:

Decision Analysis Corporation of Virginia
1600 Spring Hill Road, Suite 230
Vienna, VA 22182
Phone: (703) 893-5087
Fax: (703) 893-7104

I plan to attend the following sessions:

Morning
____New Generating Technologies
____Oil Import Dependence
____Electricity Demand

Afternoon A
____Electricity Restructuring: Competition in Current Markets
____Natural Gas Supply
____Transportation Demand and Fuel Efficiency

Afternoon B
____Electricity Prices under a Competitive Environment
____International: Demand in Developing Countries
____Coal Supply and Distribution

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Street: ______________________________
City, State, Zip Code: ______________________________
Telephone: ______________________________
Fax: ______________________________