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Annual Energy Outlook 2004

With Projections to 2025

January 2004

For Further Information . . .

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AEO2004 will be available on the EIA web site at www.eia.doe.gov/oiaf/aeo/ in early January 2004. Assumptions underlying the projections and tables of regional and other detailed results will also be available in early January 2004, at web sites www.eia.doe.gov/oiaf/assumption/ and /supplement/. Model documentation reports for the National Energy Modeling System (NEMS) and the report *NEMS: An Overview* are available at web site www.eia.doe.gov/bookshelf/docs.html and will be updated for *AEO2004* in the first few months of 2004.

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Preface

The *Annual Energy Outlook 2004* (*AEO2004*) presents midterm forecasts of energy supply, demand, and prices through 2025 prepared by the Energy Information Administration (EIA). The projections are based on results from EIA's National Energy Modeling System (NEMS).

The report begins with an "Overview" summarizing the *AEO2004* reference case. The next section, "Legislation and Regulations," discusses evolving legislation and regulatory issues. "Issues in Focus" includes discussions of future labor productivity growth; lower 48 natural gas depletion and productive capacity; natural gas supply options, with a focus on liquefied natural gas; natural gas demand for Canadian oil sands production; National Petroleum Council forecasts for natural gas; natural gas consumption in the industrial and electric power sectors; nuclear power plant construction costs; renewable electricity tax credits; and U.S. greenhouse gas intensity. It is followed by a discussion of "Energy Market Trends."

The analysis in *AEO2004* focuses primarily on a reference case and four other cases that assume higher and lower economic growth and higher and lower world oil prices. Forecast tables for those cases are provided in Appendixes A through C. Appendix D provides a summary of key projections in oil equivalent units. Appendix E summarizes projected household expenditures for each fuel by region and household income quintiles. The major results for the alternative cases, which explore the impacts of varying key assumptions in NEMS (such as technology penetration rates), are summarized in Appendix F. Appendix G briefly describes NEMS, the *AEO2004* assumptions, and the alternative cases.

The *AEO2004* projections are based on Federal, State, and local laws and regulations in effect on September 1, 2003. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation requiring funds that have not been appropriated) are not reflected in the projections. For example, *AEO2004* does not include the potential impact of the pending Energy Policy Act of 2003. In general, the historical data used for *AEO2004* projections are based on EIA's *Annual Energy Review 2003*, published in October 2003; however, data are taken from multiple sources. In some cases, only partial or preliminary 2002 data were available. Historical data are presented in this report for comparative purposes; documents referenced in the source notes should be consulted for official data values. The projections for 2003 and 2004 incorporate short-term projections from EIA's September 2003 *Short-Term Energy Outlook*.

Federal, State, and local governments, trade associations, and other planners and decisionmakers in the public and private sectors use the *AEO2004* projections. They are published in accordance with Section 205c of the Department of Energy Organization Act of 1977 (Public Law 95-91), which requires the EIA Administrator to prepare annual reports on trends and projections for energy use and supply.

The projections in *AEO2004* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. Thus, they provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as currently enacted; however, the impacts of emerging regulatory changes, when defined, are reflected.

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

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated, including severe weather, political disruptions, strikes, and technological breakthroughs. In addition, future developments in technologies, demographics, and resources cannot be foreseen with any degree of precision. Many key uncertainties in the *AEO2004* projections are addressed through alternative cases.

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

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Key Energy Issues to 2025

For almost 4 years, natural gas prices have remained at levels substantially higher than those of the 1990s. This has led to a reevaluation of expectations about future trends in natural gas markets, the economics of exploration and production, and the size of the natural gas resource. The *Annual Energy Outlook 2004* (*AEO2004*) forecast reflects such revised expectations, projecting greater dependence on more costly alternative supplies of natural gas, such as imports of liquefied natural gas (LNG), with expansion of existing terminals and development of new facilities, and remote resources from Alaska and from the Mackenzie Delta in Canada, with completion of the Alaska Natural Gas Transportation System and the Mackenzie Delta pipeline.

Crude oil prices rose from under $20 per barrel in the late 1990s to about $35 per barrel in early 2003, driven in part by concerns about the conflict in Iraq, the situation in Venezuela, greater adherence to export quotas by members of the Organization of Petroleum Exporting Countries (OPEC), and changing views regarding the economics of oil production. *AEO2004* reflects changes in expectations about the relative roles of various basins in providing future crude oil supplies.

Outside OPEC, the major sources of growth in crude oil production in the *AEO2004* forecast are Russia, the Caspian Basin, non-OPEC Africa, and South and Central America. U.S. dependence on imported oil has grown over the past decade, with declining domestic oil production and growing demand. This trend is expected to continue. Net imports, which accounted for 54 percent of total U.S. petroleum demand in 2002—up from 37 percent in 1980 and 42 percent in 1990—are expected to account for 70 percent of total U.S. petroleum demand in 2025 in the *AEO2004* forecast, higher than the *Annual Energy Outlook 2003* (*AEO2003*) projection of 68 percent.

The change in expectations for future natural gas prices, in combination with the substantial amount of new natural-gas-fired generating capacity recently completed or in the construction pipeline, has also led to a different view of future capacity additions. Although only a few years ago, natural gas was viewed as the fuel of choice for new generating plants, coal is now projected to play a more important role, particularly in the later years of the forecast. In the *AEO2004* forecast, beyond the completion of plants currently under construction, little new generating capacity is expected to be added before 2010. With a higher long-term forecast for natural gas prices, the competitive position of coal is expected to improve. As a result, cumulative additions of natural-gas-fired generating capacity between 2003 and 2025 are lower in the *AEO2004* forecast than they were in *AEO2003*, and more additions of coal and renewable generating capacity are projected.

Economic Growth

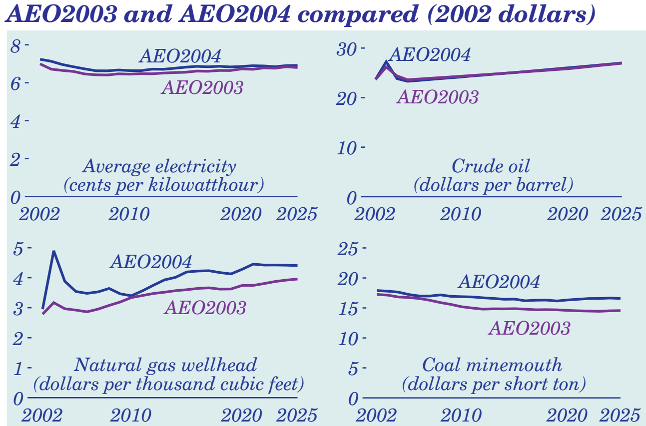
In the *AEO2004* reference case, the U.S. economy, as measured by gross domestic product (GDP), grows at an average annual rate of 3.0 percent from 2002 to 2025, slightly lower than the growth rate of 3.1 percent per year for the same period in *AEO2003*. Most of the determinants of economic growth in *AEO2004* are similar to those in *AEO2003*, but there are some important differences. For example, *AEO2004* starts with lower nominal interest rates than *AEO2003*; the rate of inflation is generally higher; and unemployment levels are higher. Consequently, differences between *AEO2004* and *AEO2003* cannot be explained simply by differences in GDP growth.

Energy Prices

In the *AEO2004* reference case, the average world oil price increases from $23.68 per barrel (2002 dollars) in 2002 to $27.25 per barrel in 2003 and then declines to $23.30 per barrel in 2005. It then rises slowly to $27.00 per barrel in 2025, about the same as the *AEO2003* projection of $26.94 per barrel in 2025 (Figure 1). Between 2002 and 2025, real world oil prices increase at an average rate of 0.6 percent per year in the *AEO2004* forecast. In nominal dollars, the average world oil price is about $29 per barrel in 2010 and about $52 per barrel in 2025.

World oil demand is projected to increase from 78 million barrels per day in 2002 to 118 million barrels per day in 2025, less than the *AEO2003* projection of 123 million barrels per day in 2025. In *AEO2004*,

Figure 1. Energy price projections, 2002-2025: AEO2003 and AEO2004 compared (2002 dollars)



projected demand for petroleum in the United States and Western Europe and, particularly, in China, India, and other developing nations in the Middle East, Africa, and South and Central America is lower than was projected in *AEO2003*. Growth in oil production in both OPEC and non-OPEC nations leads to relatively slow growth in prices through 2025. OPEC oil production is expected to reach 54 million barrels per day in 2025, almost 80 percent higher than the 30 million barrels per day produced in 2002. The forecast assumes that sufficient capital will be available to expand production capacity.

Non-OPEC oil production is expected to increase from 44.7 to 63.9 million barrels per day between 2002 and 2025. Production in the industrialized nations (United States, Canada, Mexico, Western Europe, and Australia) remains roughly constant at 24.2 million barrels per day in 2025, compared with 23.4 million barrels per day in 2002. In the forecast, increased nonconventional oil production, predominantly from oil sands in Canada, more than offsets a decline in conventional production in the industrialized nations.

The largest share of the projected increase in non-OPEC oil production is expected in Russia, the Caspian Basin, Non-OPEC Africa, and South and Central America (in particular, Brazil). Russian oil production is expected to continue to recover from the lows of the 1990s and to reach 10.9 million barrels per day in 2025, 43 percent above 2002 levels. Production from the Caspian Basin is expected to exceed 6.0 million barrels per day by 2025, compared with 1.7 million barrels per day in 2002. In 2025, projected production from South and Central America reaches 7.8 million barrels per day, up from 4.3 million barrels per day in 2002. A large portion of the increase in South and Central American production, 0.9 million barrels per day, is expected to come from nonconventional oil production in Venezuela. Non-OPEC African production is projected to grow from 3.1 million barrels per day in 2002 to 6.7 million barrels per day in 2025.

Average wellhead prices for natural gas (including both spot purchases and contracts) are projected to increase from $2.95 per thousand cubic feet (2002 dollars) in 2002 to $4.90 per thousand cubic feet in 2003, declining to $3.40 per thousand cubic feet in 2010 as the initial availability of new import sources (such as LNG) and increased drilling in response to the higher prices increase supplies. With the exception of a temporary decline in natural gas wellhead prices just before 2020, when an Alaska pipeline is expected to be completed, wellhead prices are projected to increase gradually after 2010, reaching $4.40 per thousand cubic feet in 2025 (equivalent to about $8.50 per thousand cubic feet in nominal dollars). LNG imports, Alaskan production, and lower 48 production from nonconventional sources are not expected to increase sufficiently to offset the impacts of resource depletion and increased demand. At $4.40 per thousand cubic feet, the 2025 wellhead natural gas price in *AEO2004* is 44 cents higher than the *AEO2003* projection. The higher price projection results from reduced expectations for onshore and offshore production of nonassociated gas, based on recent data indicating lower discoveries per well and higher costs for drilling in the lower 48 States.

In *AEO2004*, the average minemouth price of coal is projected to decline from $17.90 (2002 dollars) in 2002 to a low of $16.19 per short ton in 2016. Prices decline in the forecast because of increased mine productivity, a shift to western production, declines in rail transportation costs, and competitive pressures on labor costs. After 2016, however, average minemouth coal prices are projected to rise as productivity improvements slow and the industry faces increasing costs to open new mining areas to meet rising demand. In 2025, the average minemouth price is projected to be $16.57 per short ton, still lower than the real price in 2002 but considerably higher than the *AEO2003* projection of $14.56 per short ton. In nominal dollars, projected minemouth coal prices in *AEO2004* are equivalent to $32 per short ton in 2025.

Average delivered electricity prices are projected to decline from 7.2 cents per kilowatthour in 2002 to a low of 6.6 cents (2002 dollars) in 2007 as a result of cost reductions in an increasingly competitive market—where excess generating capacity has resulted from the recent boom in construction—and continued declines in coal prices. In markets where electricity industry restructuring is still ongoing, it contributes to the projected price decline through reductions in operating and maintenance costs, administrative costs, and other miscellaneous costs. After 2007, average real electricity prices are projected to increase, reaching 6.9 cents per kilowatthour in 2025 (equivalent to 13.2 cents per kilowatthour in nominal dollars). In *AEO2003*, real electricity prices followed a similar pattern but were projected to be slightly lower in 2025, at 6.8 cents per kilowatthour. The higher price projection in *AEO2004* results primarily from higher expected costs for both generation and transmission of electricity. Higher generation costs reflect the higher projections for natural gas and coal prices in *AEO2004*, particularly in the later years of the forecast.

Overview

Energy Consumption

Total primary energy consumption in *AEO2004* is projected to increase from 97.7 quadrillion British thermal units (Btu) in 2002 to 136.5 quadrillion Btu in 2025 (an average annual increase of 1.5 percent). *AEO2003* projected total primary energy consumption at 139.1 quadrillion Btu in 2025. The *AEO2004* projections for total petroleum and natural gas consumption in 2025 are lower than those in *AEO2003*, and the projections for coal, nuclear, and renewable energy consumption are higher. Higher natural gas prices in the *AEO2004* forecast, and the effects of higher corporate average fuel economy (CAFE) standards for light trucks in the transportation sector, are among the most important factors accounting for the differences between the two forecasts.

Delivered residential energy consumption, excluding losses attributable to electricity generation, is projected to grow at an average rate of 1.0 percent per year between 2002 and 2025 (1.4 percent per year between 2002 and 2010, slowing to 0.8 percent per year between 2010 and 2025). The most rapid growth is expected in demand for electricity used to power computers, electronic equipment, and appliances. *AEO2004* projects residential energy demand totaling 14.2 quadrillion Btu in 2025 (slightly higher than the 14.1 quadrillion Btu projected in *AEO2003*). The *AEO2004* forecast includes more rapid growth in the total number of U.S. households than was projected in *AEO2003*; however, fewer new single-family homes are projected to be built than in the *AEO2003* forecast, because the mix of single- and multi-family units has been revised, based on preliminary data on housing characteristics from the Energy Information Administration's 2001 Residential Energy Consumption Survey. Multi-family units tend to be smaller and use less energy per household, offsetting some of the increase in projected energy demand due to the increase in the number of U.S. households.

Delivered commercial energy consumption is projected to grow at an average annual rate of 1.7 percent between 2002 and 2025, reaching 12.2 quadrillion Btu in 2025 (slightly less than the 12.3 quadrillion Btu projected in *AEO2003*). The most rapid increase in energy demand is projected for electricity used for computers, office equipment, telecommunications, and miscellaneous small appliances. Commercial floorspace is projected to grow by an average of 1.5 percent per year between 2002 and 2025, identical to the rate of growth in *AEO2003* for the same period.

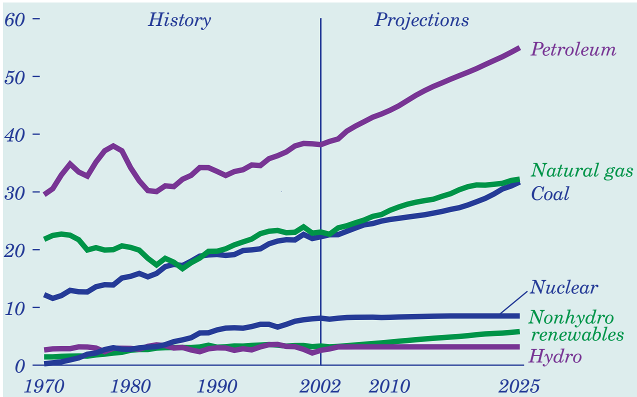
Delivered industrial energy consumption in *AEO2004* is projected to increase at an average rate of 1.3 percent per year between 2002 and 2025, reaching 33.4 quadrillion Btu in 2025 (lower than the *AEO2003* forecast of 34.8 quadrillion Btu). The *AEO2004* forecast includes slower projected growth in the dollar value of industrial product shipments and higher energy prices (particularly natural gas) than in *AEO2003*; however, those effects are offset in part by more rapid projected growth in the energy-intensive industries.

Delivered energy consumption in the transportation sector is projected to grow at an average annual rate of 1.9 percent between 2002 and 2025 in the *AEO2004* forecast, reaching 41.2 quadrillion Btu in 2025 (2.5 quadrillion Btu lower than the *AEO2003* projection). Two factors account for the reduction in projected transportation energy use from *AEO2003* to *AEO2004*. First is the adoption of new Federal CAFE standards for light trucks—including sport utility vehicles. The new CAFE standards require that the light trucks sold by a manufacturer have a minimum average fuel economy of 21.0 miles per gallon for model year 2005, 21.6 miles per gallon for model year 2006, and 22.2 miles per gallon for model years 2007 and beyond. (The old standard was 20.7 miles per gallon in all years.) As a result, the average fuel economy for all new light-duty vehicles is projected to increase to 26.9 miles per gallon in 2025 in *AEO2004*, as compared with 26.1 miles per gallon in *AEO2003*. Second is the lower forecast for industrial product shipments in *AEO2004*, leading to a projection for freight truck travel in 2025 that is 7 percent lower than the *AEO2003* projection.

Total electricity consumption, including both purchases from electric power producers and on-site generation, is projected to grow from 3,675 billion kilowatthours in 2002 to 5,485 billion kilowatthours in 2025, increasing at an average rate of 1.8 percent per year (slightly below the 1.9-percent average annual increase projected in *AEO2003*). Rapid growth in electricity use for computers, office equipment, and a variety of electrical appliances in the residential and commercial sectors is partially offset in the *AEO2004* forecast by improved efficiency in these and other, more traditional electrical applications, by the effects of demand-side management programs, and by slower growth in electricity demand for some applications, such as air conditioning, which have reached near-maximum penetration levels in regional markets.

Total demand for natural gas is projected to increase at an average annual rate of 1.4 percent from 2002 to 2025. From 22.8 trillion cubic feet in 2002, natural gas consumption increases to 31.4 trillion cubic feet in 2025 (Figure 2), primarily as a result of increasing use for electricity generation and

Figure 2. Energy consumption by fuel, 1970-2025 (quadrillion Btu)



industrial applications, which together account for almost 70 percent of the projected growth in natural gas demand from 2002 to 2025. The annual rate of increase in natural gas demand varies over the projection period. In particular, the growth in demand for natural gas slows in the later years of the forecast (growing by 0.6 percent per year from 2020 to 2025, as compared with 1.6 percent per year from 2002 to 2020), as rising prices for natural gas make it less competitive for electricity generation. The *AEO2004* projection for total consumption of natural gas in 2025 is 3.5 trillion cubic feet lower than in *AEO2003*.

In *AEO2004*, total coal consumption is projected to increase from 1,066 million short tons (22.2 quadrillion Btu) in 2002 to 1,567 million short tons (31.7 quadrillion Btu) in 2025. From 2002 to 2025, coal use (based on tonnage) is projected to grow by 1.7 percent per year on average, compared with the *AEO2003* projection of 1.4 percent per year. From 2002 to 2025, on a Btu basis, coal use is projected to grow by 1.6 percent per year. (Because of differences in the Btu content of coal across the Nation and changes in the regional mix of coal supply over time, the rate of growth varies, depending on whether it is measured in short tons or Btu.) The primary reason for the change in the rate of growth is higher natural gas prices in the *AEO2004* forecast. In *AEO2004*, total coal consumption for electricity generation is projected to increase by an average of 1.8 percent per year (1.7 percent per year on a Btu basis), from 976 million short tons in 2002 to 1,477 million short tons in 2025, compared with the *AEO2003* projection of 1,350 million short tons in 2025.

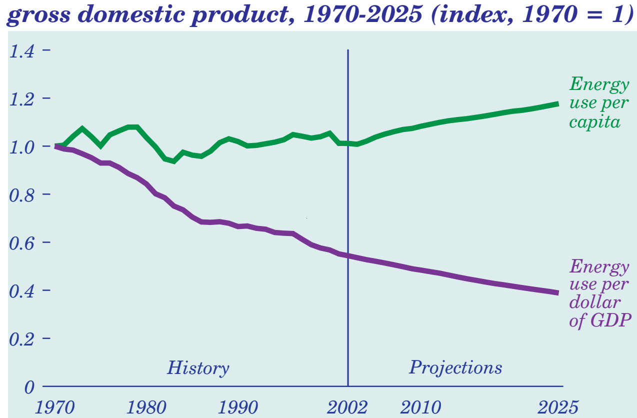
Total petroleum demand is projected to grow at an average annual rate of 1.6 percent in the *AEO2004* forecast, from 19.6 million barrels per day in 2002 to 28.3 million barrels per day in 2025. *AEO2003* projected a 1.8-percent annual average growth rate over the same period. The largest share of the difference between the two forecasts is attributable to the transportation sector. In 2025, total petroleum demand for transportation is 1.2 million barrels per day lower in *AEO2004* than it was in *AEO2003*.

Total renewable fuel consumption, including ethanol for gasoline blending, is projected to grow by 1.9 percent per year on average, from 5.8 quadrillion Btu in 2002 to 9.0 quadrillion Btu in 2025, as a result of State mandates for renewable electricity generation, higher natural gas prices, and the effect of production tax credits. About 60 percent of the projected demand for renewables in 2025 is for grid-related electricity generation (including combined heat and power), and the rest is for dispersed heating and cooling, industrial uses, and fuel blending. Projected demand for renewables in 2025 in *AEO2004* is 0.2 quadrillion Btu higher than in *AEO2003*, with more wind and geothermal energy consumption and less biomass fuel consumption expected in the *AEO2004* forecast.

Energy Intensity

Energy intensity, as measured by energy use per dollar of GDP, is projected to decline at an average annual rate of 1.5 percent in the *AEO2004* forecast, with efficiency gains and structural shifts in the economy offsetting growth in demand for energy services (Figure 3). This rate of improvement, the same as projected in *AEO2003*, is generally consistent with recent historical experience. With energy prices increasing between 1970 and 1986, energy intensity declined at an average annual rate of 2.3 percent, as the economy shifted to less energy-intensive industries, product mix changed, and more efficient technologies were adopted. Between 1986 and 1992, however, when energy prices were generally falling, energy intensity declined at an average rate of only 0.7 percent a year. Since 1992, it has declined on average by 1.9 percent a year.

Figure 3. Energy use per capita and per dollar of gross domestic product, 1970-2025 (index, 1970 = 1)



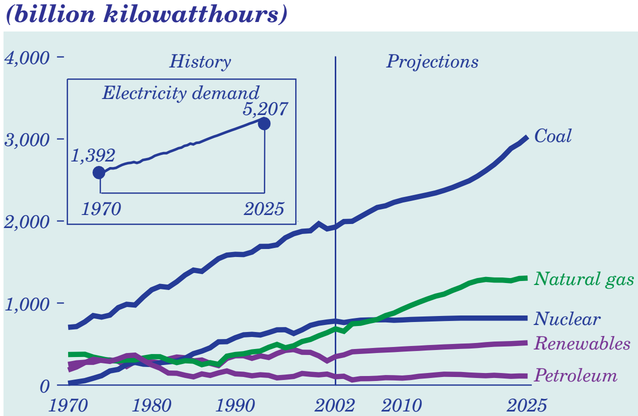
Energy use per person generally declined from 1970 through the mid-1980s but began to increase as energy prices declined in the late 1980s and 1990s. Per capita energy use is projected to increase in the forecast, with growth in demand for energy services only partially offset by efficiency gains. Per capita energy use increases by an average of 0.7 percent per year between 2002 and 2025 in *AEO2004*, the same as in *AEO2003*.

The potential for more energy conservation has received increased attention recently as a potential contributor to the balancing of energy supply and demand as energy supplies become tighter and prices rise. *AEO2004* does not assume policy-induced conservation measures beyond those in existing legislation and regulation or behavioral changes that could result in greater energy conservation.

Electricity Generation

In the *AEO2004* forecast, the projected average price for natural gas delivered to electricity generators is 25 cents per million Btu higher in 2025 than was projected in *AEO2003*. As a result, cumulative additions of natural-gas-fired generating capacity between 2003 and 2025 are lower than projected in *AEO2003*, generation from gas-fired plants in 2025 is lower, and generation from coal, petroleum, nuclear, and renewable fuels is higher. Cumulative natural gas capacity additions between 2003 and 2025 are 219 gigawatts in *AEO2004*, compared with 292 gigawatts in *AEO2003*. The *AEO2004* projection of 1,304 billion kilowatthours of electricity generation from natural gas in 2025 is still nearly double the 2002 level of 682 billion kilowatthours (Figure 4), reflecting utilization of the new capacity added over the past few years and the construction of new natural-gas-fired capacity later in the forecast period to meet increasing demand and replace capacity that is expected to be retired. Less new gas-fired capacity is added in the later years of the forecast because of the projected rise in prices for natural gas and the current surplus of capacity in many regions of the country. In *AEO2003*, 1,678 billion kilowatthours of electricity was projected to be generated from natural gas in 2025.

Figure 4. Electricity generation by fuel, 1970-2025 (billion kilowatthours)



The natural gas share of electricity generation (including generation in the end-use sectors) is projected to increase from 18 percent in 2002 to 22 percent in 2025 (as compared with 29 percent in the *AEO2003* forecast). The share from coal is projected to increase from 50 percent in 2002 to 52 percent in 2025 as rising natural gas prices improve the cost competitiveness of coal-fired technologies. *AEO2004* projects that 112 gigawatts of new coal-fired generating capacity will be constructed between 2003 and 2025 (compared with 74 gigawatts in *AEO2003*).

Nuclear generating capacity in the *AEO2004* forecast is projected to increase from 98.7 gigawatts in 2002 to 102.6 gigawatts in 2025, including uprates of existing plants equivalent to 3.9 gigawatts of new capacity between 2002 and 2025. In *AEO2003*, total nuclear capacity reached a peak of 100.4 gigawatts in 2006 before declining to 99.6 gigawatts in 2025. In a departure from *AEO2003*, no existing U.S. nuclear units are retired in the *AEO2004* reference case. Like *AEO2003*, *AEO2004* assumes that the Browns Ferry nuclear plant will begin operation in 2007 but projects that no new nuclear facilities will be built before 2025, based on the relative economics of competing technologies.

Renewable technologies are projected to grow slowly because of the relatively low costs of fossil-fired generation and because competitive electricity markets favor less capital-intensive technologies in the competition for new capacity. Where enacted, State renewable portfolio standards, which specify a minimum share of generation or sales from renewable sources, are included in the forecast. The production tax credit for wind and biomass is assumed to end on December 31, 2003, its statutory expiration date at the time *AEO2004* was prepared.

Total renewable generation, including combined heat and power generation, is projected to increase from 339 billion kilowatthours in 2002 to 518 billion kilowatthours in 2025, at an average annual growth rate of 1.9 percent. *AEO2003* projected slower growth in renewable generation, averaging 1.4 percent per year from 2002 to 2025.

Energy Production and Imports

Total energy consumption is expected to increase more rapidly than domestic energy supply through 2025. As a result, net imports of energy are projected to meet a growing share of energy demand (Figure 5). Net imports are expected to constitute 36 percent of total U.S. energy consumption in 2025, up from 26 percent in 2002.

Projected U.S. crude oil production increases from 5.6 million barrels per day in 2002 to a peak of 6.1 million barrels per day in 2008 as a result of increased production offshore, predominantly from the deep waters of the Gulf of Mexico. Beginning in 2009, U.S. crude oil production begins a gradual decline, falling to 4.6 million barrels per day in 2025—an average annual decline of 0.9 percent between 2002 and 2025. The *AEO2004* projection for U.S. crude oil production in 2025 is 0.7 million barrels per day lower than was projected in *AEO2003*. The projections for Alaskan production and offshore production in 2025 both are lower than in *AEO2003* (by 660,000 and 120,000 barrels per day, respectively), based on revised expectations about the discovery of new speculative fields in Alaska and on an update of the cost of offshore production.

Total domestic petroleum supply (crude oil, natural gas plant liquids, refinery processing gains, and other refinery inputs) follows the same pattern as crude oil production in the *AEO2004* forecast, increasing from 9.2 million barrels per day in 2002 to a peak of 9.7 million barrels per day in 2008, then declining to 8.6 million barrels per day in 2025 (Figure 6). The projected drop in total domestic petroleum supply would be greater without a projected increase of 590,000 barrels per day in the production of natural gas plant liquids (a rate of increase that is consistent with the projected growth in domestic natural gas production).

In 2025, net petroleum imports, including both crude oil and refined products (on the basis of barrels per day), are expected to account for 70 percent of demand, up from 54 percent in 2002. Despite an expected increase in domestic refinery distillation capacity of 5 million barrels per day, net refined petroleum product imports account for a growing portion of total net imports, increasing from 13 percent in 2002 to 20 percent in 2025 (as compared with 34 percent in *AEO2003*).

The most significant change made in the *AEO2004* energy supply projections is in the outlook for natural gas. Total natural gas supply is projected to increase at an average annual rate of 1.4 percent in *AEO2004*, from 22.6 trillion cubic feet in 2002 to 31.3 trillion cubic feet in 2025, which is 3.3 trillion cubic feet less than the 2025 projection in *AEO2003*. Domestic natural gas production increases from 19.1 trillion cubic feet in 2002 to 24.1 trillion cubic feet in 2025 in the *AEO2004* forecast, an average increase of 1.0 percent per year. *AEO2003* projected 26.8 trillion cubic feet of domestic natural gas production in 2025.

The projection for conventional onshore production of natural gas is lower in *AEO2004* than it was in *AEO2003*, because slower reserve growth, fewer new discoveries, and higher exploration and development costs are expected. In particular, reserves added per well drilled in the Midcontinent and Southwest regions are projected to be about 30 percent lower than projected in *AEO2003*. Offshore natural gas production is also lower in *AEO2004* than in *AEO2003* because of the tendency to find more oil than natural gas in the offshore and at higher costs than previously anticipated. Recent data from the Minerals Management Service show that about three-quarters of the hydrocarbons discovered in deepwater fields are oil, compared with 50 percent assumed in *AEO2003*. Conventional production of associated-dissolved and nonassociated natural gas in the onshore and offshore remains important, meeting 39 percent of total U.S. supply requirements in 2025, down from 56 percent in 2002.

Figure 5. Total energy production and consumption, 1970-2025 (quadrillion Btu)

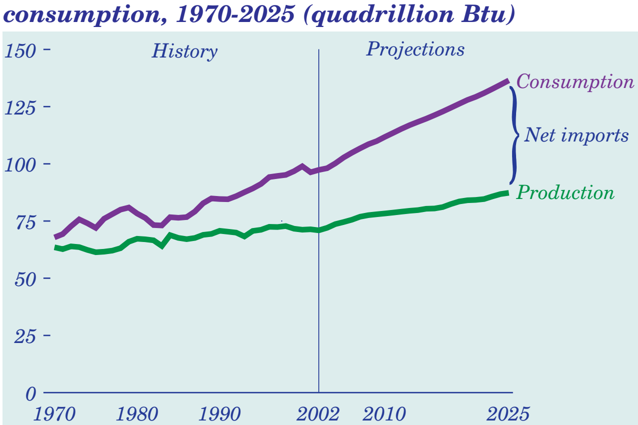
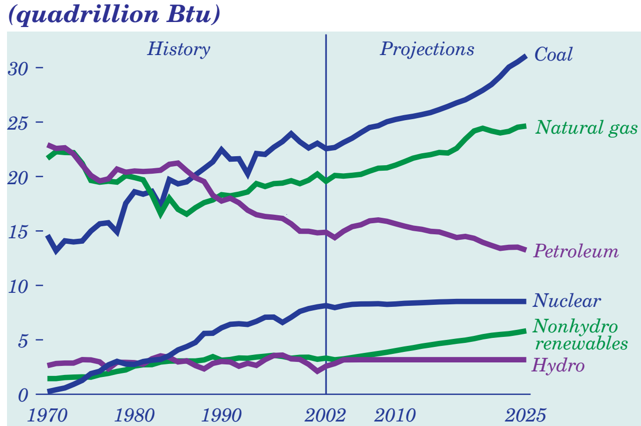


Figure 6. Energy production by fuel, 1970-2025 (quadrillion Btu)



Canadian imports are also projected to be sharply lower in *AEO2004* than in *AEO2003*. Net imports of natural gas from Canada are projected to remain at about the 2002 level of 3.6 trillion cubic feet through 2010 and then decline to 2.6 trillion cubic feet in 2025 (compared with the *AEO2003* projection of 4.8 trillion cubic feet in 2025). The lower forecast in *AEO2004* reflects revised expectations about Canadian natural gas production, particularly coalbed methane and conventional production in Alberta, based on data and projections from the Canadian National Energy Board and other sources.

Growth in U.S. natural gas supplies will be dependent on unconventional domestic production, natural gas from Alaska, and imports of LNG. Total nonassociated unconventional natural gas production is projected to grow from 5.9 trillion cubic feet in 2002 to 9.2 trillion cubic feet in 2025. With completion of an Alaskan natural gas pipeline in 2018, total Alaskan production is projected to increase from 0.4 trillion cubic feet in 2002 to 2.7 trillion cubic feet in 2025. The four existing U.S. LNG terminals (Everett, Massachusetts; Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana) all are expected to expand by 2007, and additional facilities are expected to be built in the lower 48 States, serving the Gulf, Mid-Atlantic, and South Atlantic States, with a new small facility in New England and a new facility in the Bahamas serving Florida via a pipeline. Another facility is projected to be built in Baja California, Mexico, serving the California market. Total net LNG imports are projected to increase from 0.2 trillion cubic feet in 2002 to 4.8 trillion cubic feet in 2025, more than double the *AEO2003* projection of 2.1 trillion cubic feet.

As domestic coal demand grows in *AEO2004*, U.S. coal production is projected to increase at an average rate of 1.5 percent per year, from 1,105 million short tons in 2002 to 1,543 million short tons in 2025. Projected production in 2025 is 103 million short tons higher than in *AEO2003* because of a substantial increase in projected coal demand for electricity generation resulting from higher natural gas prices. Production from mines west of the Mississippi River is expected to provide the largest share of the incremental production. In 2025, nearly two-thirds of coal production is projected to originate from the western States.

Renewable energy production is projected to increase from 5.8 quadrillion Btu in 2002 to 9.0 quadrillion Btu in 2025, with growth in industrial biomass, ethanol for gasoline blending, and most sources of renewable electricity generation (including conventional hydroelectric, geothermal, biomass, and wind). The *AEO2004* projection for renewable energy production in 2025 is 0.2 quadrillion Btu higher than was projected in *AEO2003* as a result of higher projections for electricity generation from geothermal and wind energy.

Carbon Dioxide Emissions

Carbon dioxide emissions from energy use are projected to increase from 5,729 million metric tons in 2002 to 8,142 million metric tons in 2025 in *AEO2004*, an average annual increase of 1.5 percent (Figure 7). This is slightly less than the projected rate of increase over the same period in *AEO2003*, 1.6 percent per year.

By sector, projected carbon dioxide emissions from residential, commercial, and electric power sector sources are higher in *AEO2004* than they were in *AEO2003* because of an updated estimate of 2002 emissions and higher projected energy consumption in each of the three sectors—particularly, coal consumption for electricity generation in the electric power sector. Projected carbon dioxide emissions from the industrial and transportation sectors are lower in the *AEO2004* forecast, because of lower projections for industrial natural gas consumption and the new CAFE standards for light trucks as well as other changes in the transportation sector that lead to lower petroleum consumption. The *AEO* projections do not include future policy actions or agreements that might be taken to reduce carbon dioxide emissions.

Figure 7. Projected U.S. carbon dioxide emissions by sector and fuel, 1990-2025 (million metric tons)

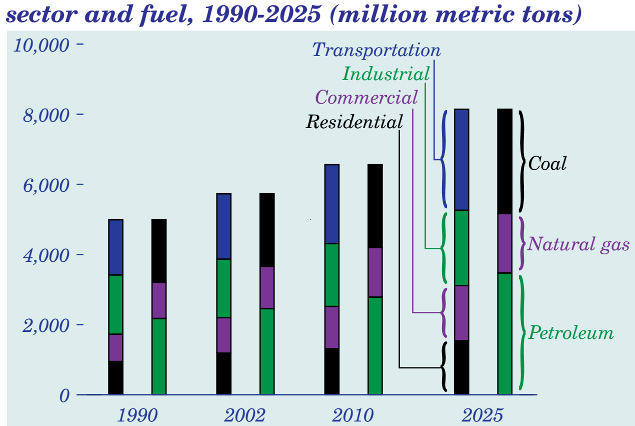


Table 1. Total energy supply and disposition in the *AEO2004* reference case: summary, 2001-2025

Energy and economic factors	2001	2002	2010	2015	2020	2025	Average annual change, 2002-2025
Primary energy production (quadrillion Btu)							
Petroleum	14.70	14.47	15.66	14.91	13.95	13.24	-0.4%
Dry natural gas	20.23	19.56	21.05	22.20	24.43	24.64	1.0%
Coal	23.97	22.70	25.25	26.14	27.92	31.10	1.4%
Nuclear power	8.03	8.15	8.29	8.48	8.53	8.53	0.2%
Renewable energy	5.25	5.84	7.18	7.84	8.45	9.00	1.9%
Other	0.53	1.13	0.88	0.79	0.81	0.84	-1.3%
Total	**72.72**	**71.85**	**78.30**	**80.36**	**84.09**	**87.33**	**0.9%**
Net imports (quadrillion Btu)							
Petroleum	23.29	22.56	28.13	33.20	37.25	41.69	2.7%
Natural gas	3.69	3.58	5.63	6.39	6.63	7.41	3.2%
Coal/other (- indicates export)	-0.67	-0.51	0.06	0.26	0.43	0.61	NA
Total	**26.31**	**25.63**	**33.82**	**39.84**	**44.31**	**49.71**	**2.9%**
Consumption (quadrillion Btu)							
Petroleum products	38.49	38.11	44.15	48.26	51.35	54.99	1.6%
Natural gas	23.05	23.37	26.82	28.74	31.21	32.21	1.4%
Coal	22.04	22.18	25.23	26.32	28.30	31.73	1.6%
Nuclear power	8.03	8.15	8.29	8.48	8.53	8.53	0.2%
Renewable energy	5.25	5.84	7.18	7.84	8.46	9.00	1.9%
Other	0.08	0.07	0.11	0.11	0.07	0.03	-4.6%
Total	**96.94**	**97.72**	**111.77**	**119.75**	**127.92**	**136.48**	**1.5%**
Petroleum (million barrels per day)							
Domestic crude production	5.74	5.62	5.93	5.53	4.95	4.61	-0.9%
Other domestic production	3.11	3.60	3.59	3.72	3.94	3.98	0.4%
Net imports	10.90	10.54	13.17	15.52	17.48	19.67	2.7%
Consumption	19.71	19.61	22.71	24.80	26.41	28.30	1.6%
Natural gas (trillion cubic feet)							
Production	19.79	19.13	20.59	21.72	23.89	24.08	1.0%
Net imports	3.60	3.49	5.50	6.24	6.47	7.24	3.2%
Consumption	22.48	22.78	26.15	28.03	30.44	31.41	1.4%
Coal (million short tons)							
Production	1,138	1,105	1,230	1,285	1,377	1,543	1.5%
Net imports	-29	-23	-2	6	14	23	NA
Consumption	1,060	1,066	1,229	1,291	1,391	1,567	1.7%
Prices (2002 dollars)							
World oil price (dollars per barrel)	22.25	23.68	24.17	25.07	26.02	27.00	0.6%
Domestic natural gas at wellhead (dollars per thousand cubic feet)	4.14	2.95	3.40	4.19	4.28	4.40	1.8%
Domestic coal at minemouth (dollars per short ton)	17.79	17.90	16.88	16.47	16.32	16.57	-0.3%
Average electricity price (cents per kilowatthour)	7.4	7.2	6.6	6.8	6.9	6.9	-0.2%
Economic indicators							
Real gross domestic product (billion 1996 dollars)	9,215	9,440	12,190	14,101	16,188	18,520	3.0%
GDP chain-type price index (index, 1996=1.000)	1.094	1.107	1.301	1.503	1.774	2.121	2.9%
Real disposable personal income (billion 1996 dollars)	6,748	7,032	8,894	10,330	11,864	13,826	3.0%
Value of manufacturing shipments (billion 1996 dollars)	5,368	5,285	6,439	7,345	8,344	9,491	2.6%
Energy intensity (thousand Btu per 1996 dollar of GDP)	**10.53**	**10.36**	**9.17**	**8.50**	**7.91**	**7.37**	**-1.5%**
Carbon dioxide emissions (million metric tons)	**5,691.7**	**5,729.3**	**6,558.8**	**7,028.4**	**7,535.6**	**8,142.0**	**1.5%**

Notes: Quantities are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, supplemental natural gas, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Some refinery inputs appear as petroleum product consumption. Other consumption includes net electricity imports, liquid hydrogen, and methanol.
Sources: Tables A1, A19, and A20.

Legislation and Regulations

Legislation and Regulations

Introduction

Because analyses by the Energy Information Administration (EIA) are required to be policy-neutral, the projections in this *Annual Energy Outlook 2004* (*AEO2004*) are based on Federal and State laws and regulations in effect on September 1, 2003. The potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require funds or implementing regulations that have not been provided or specified—are not reflected in the projections.

Examples of Federal and State legislation incorporated in the projections include the following:

- The Energy Policy Conservation Act of 1975
- The National Appliance Energy Conservation Act of 1987
- The Clean Air Act Amendments of 1990 (CAAA90), which include new standards for motor gasoline and diesel fuel and for heavy-duty vehicle emissions
- The Energy Policy Act of 1992 (EPACT)
- The Omnibus Budget Reconciliation Act of 1993, which added 4.3 cents per gallon to the Federal tax on highway fuels
- The Outer Continental Shelf Deep Water Royalty Relief Act of 1995 and subsequent provisions on royalty relief for new leases issued after November 2000 on a lease-by-lease basis
- The Federal Highway Bill of 1998, which included an extension of the ethanol tax incentive
- The Maritime Security Act of 2002, which amended the Deepwater Port Act of 1974 to include offshore natural gas facilities
- State of Alaska's Right-Of-Way Leasing Act Amendments of 2001, which prohibit leases across State land for a "northern" or "over-the-top" natural gas pipeline route running east from the North Slope to Canada's MacKenzie River Valley
- State renewable portfolio standards, including the California renewable portfolio standards passed on September 12, 2002
- State programs for restructuring of the electricity industry.

AEO2004 assumes that State taxes on gasoline, diesel, jet fuel, and E85 (fuel containing a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume) will increase with inflation, and that Federal taxes on those fuels will continue at 2002 levels in nominal terms. *AEO2004* also assumes the continuation of the ethanol tax incentive through 2025. Although these tax and tax incentive provisions include "sunset" clauses that limit their duration, they have been extended historically, and *AEO2004* assumes their continuation throughout the forecast.

Examples of Federal and State regulations incorporated in *AEO2004* include the following:

- Standards for energy-consuming equipment that have been announced
- The new corporate average fuel economy (CAFE) standards for light trucks published by the National Highway Traffic Safety Administration (NHTSA) in 2003
- Federal Energy Regulatory Commission (FERC), Orders 888 and 889, which provide open access to interstate transmission lines in electricity markets
- The December 2002 Hackberry Decision, which terminated open access requirements for new onshore liquefied natural gas (LNG) terminals.

AEO2004 includes the CAAA90 requirement of a phased in reduction in vehicle emissions of regulated pollutants. In addition, AEO2004 incorporates the CAAA90 requirement of a phased in reduction in annual emissions of sulfur dioxide by electricity generators, which in general are capped at 8.95 million tons per year in 2010 and thereafter, although "banking" of allowances from earlier years is permitted. *AEO2004* also incorporates nitrogen oxide (NO_x) boiler standards issued by the U.S. Environmental Protection Agency (EPA) under CAAA90. The 19-State NO_x cap and trade program in the Northeast and Midwest is also represented. Limits on emissions of mercury, which have not yet been promulgated, are not represented.

AEO2004 reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements finalized by the EPA in February 2000. The Tier 2 standards for reformulated gasoline (RFG) will be required by 2004 but will not be fully realized in conventional gasoline until 2008 due to allowances for small refineries. *AEO2004* also incorporates the "ultra-low-sulfur diesel" (ULSD) regulation finalized by the EPA in December 2000, which requires the production of at least 80 percent ULSD (15 parts sulfur per million) highway diesel between June 2006 and June 2010 and a 100-percent requirement for ULSD thereafter (see Appendix G for more detail).

Because the new rules for nonroad diesel have not yet been finalized, they are not reflected in the *AEO2004* projections. The *AEO2004* projections reflect legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in the next several years in 17 States and assumes that the Federal oxygen requirement for RFG in Federal nonattainment areas will remain intact.

The provisions of EPACT focus primarily on reducing energy demand. They require minimum building efficiency standards for Federal buildings and other new buildings that receive Federally backed mortgages. Efficiency standards for electric motors, lights, and other equipment are required, and Federal, State, and utility vehicle fleets are required to phase in vehicles that do not rely on petroleum products. The *AEO2004* projections include only those equipment standards for which final actions have been taken and for which specific efficiency levels are provided.

The *AEO2004* reference case projections include impacts of the programs in the Climate Change Action Plan (CCAP)—44 actions developed by the Clinton Administration in 1993 to achieve the stabilization of greenhouse gas emissions (carbon dioxide, methane, nitrous oxide, and others) in the United States at 1990 levels by 2000. Of the 44 CCAP actions, 13 are not related either to energy combustion or to carbon dioxide and, consequently, are not incorporated in the *AEO2004* projections. Although CCAP no longer exists as a unified program, most of the individual programs, which generally are voluntary, remain.

The projections do not include carbon dioxide mitigation actions that may be enacted as a result of the Kyoto Protocol, which was agreed to on December 11, 1997, but has not been ratified or submitted to the U.S. Senate for ratification.

More detailed information on recent legislative and regulatory developments is provided below.

Corporate Average Fuel Economy Standards for Light Trucks

The regulation of fuel economy for new light vehicles was established through the enactment of the Energy Policy Conservation Act of 1975. The regulation of light truck fuel economy was implemented in model year 1979. Increases in light truck CAFE standards continued to be made through the 1980s and 1990s, reaching 20.7 miles per gallon for model year 1996. Thereafter, Congress prohibited any further increases in fuel economy standards.

Congress lifted the prohibition on new CAFE standards on December 18, 2001. On April 1, 2003, NHTSA published a final rule for increasing CAFE standards for light trucks (all pickup trucks, vans, and sport utility vehicles with gross vehicle weight rating less than 8,500 pounds). The new CAFE standard requires that the light trucks sold by a manufacturer have a minimum average fuel economy of 21.0 miles per gallon for model year 2005, 21.6 miles per gallon for model year 2006, and 22.2 miles per gallon for model year 2007. The new light truck CAFE standards are incorporated in *AEO2004*.

California Low Emission Vehicle Program

The Low Emission Vehicle Program (LEVP) was originally passed into legislation in 1990 in the State of California. It began as the implementation of a voluntary opt-in pilot program under the purview of CAAA90, which included a provision that other States could “opt in” to the California program to achieve lower emissions levels than would otherwise be achieved through CAAA90.

The 1990 LEVP was an emissions-based policy, setting sales mandates for three categories of vehicles: low-emission vehicles (LEVs), ultra-low-emission vehicles (ULEVs), and zero-emission vehicles (ZEVs). The mandate required that ZEVs make up 2 percent of new vehicle sales in California by 1998, 5 percent by 2001, and 10 percent by 2003. At that time, the only vehicles certified as ZEVs by the California Air Resources Board (CARB) were battery-powered electric vehicles [*1*].

The LEVP program incorporates the ZEV mandate, which has been revised and delayed several times. In December 2001, the CARB amended the LEVP to include ZEV credits for partial zero-emission vehicles (PZEVs) and advanced technology partial zero-emission vehicles (AT-PZEVs), phase-in credits for pure ZEVs, and additional credits for vehicles with high fuel economy. The ZEV sales mandates were also modified, increasing the ZEV sales requirement from 10 percent in 2003 to 16 percent in 2018. Auto manufacturers in 2002 filed Federal suits in both California and New York, arguing that the CARB revisions to the ZEV program were preempted by the Federal authority over vehicle fuel economy standards. In June 2002, a Federal judge granted a preliminary injunction that prevented the CARB from enforcing the ZEV regulations for model year 2003 and 2004 vehicles.

In April 2003, the CARB proposed further amendments (Resolution 03-4) to the ZEV mandates in response to the suit filed by auto manufacturers, and the manufacturers agreed to settle their litigation with the State of California. The proposed mandate places a greater emphasis on emissions reductions from PZEVs and AT-PZEVs and requires that manufacturers produce a minimum number of fuel cell and electric vehicles. The mandate now requires that ZEVs make up 10 percent of new vehicles sales in 2005, increasing to 16 percent in 2018 and thereafter. The amendment also includes phase-in multipliers for pure ZEVs and allows 20 percent of the sales requirement to be met with AT-PZEVs and 60 percent with PZEVs. AT-ZEVs and PZEVs are allowed 0.2 credit per vehicle. Given the acquiescence of auto manufacturers to the proposed amendments, they are incorporated in the *AEO2004* forecast.

California Carbon Standard For Light-Duty Vehicles

In July 2002, California Assembly Bill 1493 (A.B. 1493) was signed into law. The bill requires the CARB to develop and adopt, by January 1, 2005, a maximum feasible carbon dioxide pollution standard for light-duty vehicles. In estimating the feasibility of the standard, the CARB is required to consider cost-effectiveness, technological capability, economic impacts, and flexibility for manufacturers in meeting the requirement. The standard will apply to light-duty noncommercial passenger vehicles manufactured for model year 2009 and beyond. The bill does not mandate the sale of any specific technology but prohibits the use of the following as options for carbon dioxide reduction: mandatory trip reduction; land use restrictions; additional fees and/or taxes on any motor vehicle, fuel, or vehicles miles traveled; a ban on any vehicle category; a reduction in vehicle weight; or a limitation or reduction of the speed limit on any street or highway in the State. Consequently, A.B. 1493 will rely heavily on vehicle efficiency improvements or a switch to low-carbon fuels to achieve the carbon dioxide emission standard.

If it is determined that low-carbon alternatives are not a feasible solution, A.B. 1493 is likely to face considerable opposition from the auto industry, as evidenced by suits filed in 2002 against California's LEVP. Given that California has not yet set a specific carbon dioxide standard, and given the uncertainty surrounding the possible outcome of future standards, A.B. 1493 is not represented in *AEO2004.*

Regulation of Mercury and Fine Particulate Emissions

The EPA is currently developing regulations to reduce emissions of fine particulates and mercury from electric power plants. Efforts to reduce emissions of particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) began with the issuance of National Ambient Air Quality Standards (NAAQS) on July 16, 1997. Before then, only coarse particle emissions (10 microns and larger) were regulated.

The EPA and the States are now measuring fine particulate concentrations throughout the country to determine which areas are not in compliance with the $PM_{2.5}$, as required by the NAAQS. The EPA plans to make final designations identifying attainment and nonattainment areas by December 15, 2004 [*2*]. Following the EPA designations, States will have 3 years, until December 2007, to prepare State Implementation Plans (SIPs) identifying the steps they will take to bring nonattainment areas into compliance. The SIPs are likely to include plans to reduce emissions from power plants, cars, trucks, and various industrial sources. The States will generally have until 2009, 5 years from their designation, to bring nonattainment areas into compliance, but the deadline could be extended by 5 years under some circumstances. Until the final regulations and SIPs are in place, however, the full impacts on electricity generators will not be known.

On December 14, 2000, the EPA announced that regulating mercury emissions from oil- and coal-fired power plants as a hazardous air pollutant (HAP) under Section (112)(n)(1)(A) of CAAA90 is warranted. The EPA, which has been meeting with various stakeholder groups and reviewing the latest available data on mercury emissions control to develop emissions standards, plans to issue proposed standards on December 15, 2003, and final standards by December 14, 2004 [*3*]. Thereafter, electricity generators will have 3 years, until December 15, 2007, to comply. Although the new regulations are certain to have an impact, particularly on coal-fired plants, because SIPs have not been proposed, their effects are not known and are not reflected in *AEO2004*.

Extension of Deep Shelf Royalty Relief to Existing Leases

The Minerals Management Service (MMS) of the U.S. Department of the Interior [*4*] in March 2003 proposed a new rule that would extend to existing leases the same royalty relief that currently is provided for newly acquired leases, for natural gas production from wells drilled to deep vertical depth (below the "mudline") in the Outer Continental Shelf. Since March 2001, the MMS has provided royalty relief for production from wells drilled to 15,000 feet total vertical depth in newly acquired leases in the shallow waters (less than 200 meters of water depth) of the shelf. Royalty payments to the Federal Government are suspended for the first 20 billion cubic feet of such “deep shelf” production from wells beginning production within the first 5 years of a lease. The purpose of the new rule is to encourage more exploration in the deep shelf play [*5*], which has significant potential but presents substantial technical difficulties. Of the 10.5 trillion cubic feet of undiscovered resources in the deep shelf (as estimated by the MMS), about 6.3 trillion cubic feet is under existing leases. The proposed new rule would have granted relief for wells drilled after March 26, 2003. Leases currently eligible for royalty relief under the old rule may substitute the deep gas incentive of the new rule.

The proposed rule includes various levels of royalty relief. The first level covers wells drilled to at least 15,000 feet depth, providing relief on a minimum of 15 billion cubic feet of gas. A second level covers wells more than 18,000 feet deep, which would receive royalty relief on a minimum of 25 billion cubic feet. In addition, until a successful well is drilled, unsuccessful wells drilled to a depth of at least 15,000 feet would receive a royalty “credit” for 5 billion cubic feet of gas. Credits could be received for up to two wells. Thus, if two dry holes were drilled, the operator would accrue credits for 10 billion cubic feet, which could be added to the royalty relief for 15 billion cubic feet from a future, successful well drilled on the same lease. As of December 1, 2003, this proposal was still under review at the MMS. It is not included in *AEO2004*.

The Maritime Security Act of 2002 Amendments to the Deepwater Port Act

The Maritime Security Act of 2002, signed into law in November 2002, amended the Deepwater Port Act of 1974 to include offshore natural gas facilities. The legislation transferred jurisdiction for offshore natural gas facilities from the FERC to the Maritime Administration and the U.S. Coast Guard, both of which were at that time under the U.S. Department of Transportation. (The Coast Guard has since been moved to the Department of Homeland Security.)

The amendments in the Maritime Security Act of 2002 lowered the regulatory hurdles faced by potential developers of offshore LNG receiving terminals. Placing them under Coast Guard jurisdiction both streamlined the permitting process and relaxed regulatory requirements. Owners of offshore LNG terminals are allowed proprietary access to their own terminal capacity, removing what had once been a major stumbling block for potential developers of new LNG facilities. The Hackberry Decision, discussed below, has the same impact on onshore LNG facilities under FERC jurisdiction.

The streamlined application process under the new amendments promises a decision within 365 days of receipt of an application for construction of an offshore LNG terminal. Once the final public hearing on an application has been held, it must be either approved or denied within 90 days. The Maritime Administration will be responsible for reviewing the commercial aspects of the proposal, and the Coast Guard will consider safety, security, and environmental aspects.

Shortly after these changes went into effect, ChevronTexaco filed a preliminary application with the Coast Guard for its Port Pelican project, which was later approved. Plans for the project call for an LNG facility in 90 feet of water, with a baseload capacity of 800 million cubic feet per day. Subsequently, El Paso Natural Gas Company filed an application for its Energy Bridge project, which would use specialized tankers with on-board regasification equipment to offload regasified LNG through a submerged docking buoy into a pipeline to the mainland. AEO2004 incorporates the Deepwater Port Act amendments through reduced permitting costs and associated delays in such projects.

The Hackberry Decision

In December 2002, the FERC terminated open access requirements for new onshore LNG terminals in the United States, placing them on an equal footing with offshore terminals regulated under provisions of the Maritime Security Act of 2002. The FERC ruling, which granted preliminary approval to the proposed Dynergy/Sempra LNG terminal in Hackberry, Louisiana, is referred to as the Hackberry Decision. It authorized Hackberry LNG (now Cameron LNG) to provide services to its affiliates under rates and terms mutually agreed upon (i.e., market-based), rather than under regulated cost-of-service rates, and exempted the company from having to provide open access service. In essence, from a regulatory perspective, LNG import facilities will be treated as supply sources rather than as part of the transportation chain.

The LNG industry had been lobbying strongly for a relaxation of regulatory requirements, arguing that the FERC should focus on doing whatever it can to ensure that the United States has adequate natural gas supplies. Industry participants at a public conference hosted by the FERC in October 2002 on issues facing the natural gas industry maintained that the

Commission's open season [6] and open access requirements were a deterrent to the construction of new LNG terminals in the United States. They stressed that investors needed assurance that they would have access to terminal capacity, and that such assurance could not be given under the FERC's existing open season bidding requirements.

The FERC has specifically stated that it hopes the new policy will encourage the construction of new LNG facilities by removing some of the economic and regulatory barriers to investment. Existing terminals will continue to operate under open access and regulated rates, but FERC has indicated a willingness to allow them to modify their regulatory status as long as their existing customers are in agreement. AEO2004 incorporates the Hackberry Decision through reduced permitting costs and delays associated with LNG projects.

State Air Emission Regulations

Several States, primarily in the Northeast, have recently enacted air emission regulations that will affect the electricity generation sector. The regulations are intended to improve air quality in the States and assist them in complying with the revised 1997 National Ambient Air Quality Standards (NAAQS) for ground-level ozone and fine particulates. The affected States include Connecticut, North Carolina, Massachusetts, Maine, New Hampshire, New Jersey, New York, and Oregon. The regulations govern emissions of NO_x, sulfur dioxide (SO_2), carbon dioxide (CO_2), and mercury from power plants. Table 2 shows emissions of NO_x, SO_2, and CO_2 by electricity generators in the eight States and in the rest of the country. Comparable data on mercury emissions by State are not available.

Where firm compliance plans have been announced, State regulations are represented in *AEO2004*. For example, the SO_2 scrubbers, selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR) installations associated with the largest State program, North Carolina's "Clean Smokestacks Initiative," are included. As shown in Table 2, North Carolina accounts for nearly one-half of the emissions in the eight affected States. Overall, the *AEO2004* forecast includes 23 gigawatts of announced SO_2 scrubbers, 41.6 gigawatts of announced SCRs, and 4.5 gigawatts of announced SNCRs (both SCRs and SNCRs are NO_x removal technologies).

In addition to the existing regulations, Governor George Pataki of New York has announced proposed greenhouse gas reduction targets for the State of New York and he invited nine other States (Connecticut, Delaware, Maryland, Maine, New Hampshire, New Jersey, Pennsylvania, Rhode Island, and Vermont) to participate in a future "Northeast CO_2 cap and trade" program.

Table 3 summarizes current State regulatory initiatives on air emissions, and the following section gives brief descriptions of programs in the eight States that have enacted air emission regulations more stringent than Federal regulations. State-level initiatives to limit greenhouse gas emissions without directly regulating the electricity generation sector, which are not discussed here, include the following examples: California's CO_2 pollution standards for 2009 model vehicles and those sold later; Georgia's transportation initiative, focusing on expanding use of mass transit and other transportation sector measures; Minnesota's Releaf Program, which encourages tree planting as a way to reduce atmospheric CO_2 levels; Nebraska's carbon sequestration advisory committee, which proposes to sequester carbon through agricultural reform practices; North Carolina's program to develop new technologies for solid waste management practices that reduce emissions; Texas's renewable portfolio standard program; and Wisconsin's greenhouse gas emissions inventory.

Table 2. Emissions from electricity generators in selected States, 2002 (tons)

State	SO_2	NO_x	CO_2
Connecticut	10,814	5,100	7,827,884
Massachusetts	90,726	28,500	21,486,936
Maine	2,022	1,154	5,784,562
New Hampshire	43,946	6,826	5,556,992
New Jersey	48,268	27,581	12,440,663
New York	231,875	69,334	51,293,393
North Carolina	462,993	145,706	72,866,548
Oregon	12,280	8,840	7,607,557
Subtotal	902,925	293,039	184,864,534
Rest of country	9,287,292	4,068,670	2,240,690,001
Total	**10,190,216**	**4,361,709**	**2,425,554,535**
Percent of total for selected States	8.86%	6.72%	7.62%

Connecticut. The Connecticut "Abatement of Air Pollution" regulation was enacted in December 2000. It limits SO_2 and NO_x emissions from all NO_x budget program (NBP) sources that are more than 15 megawatts or require fuel input greater than 250 million Btu per hour [*7*]. The regulation applies to the electricity generation sector, the cogeneration sector, and industrial units. The NO_x limit is 0.15 pound per million Btu of heat input. The SO_2 limit is enforced in two phases. Under Phase I, the limit for all NBP sources is 0.5 percent sulfur in fuel or 0.55 pound per million Btu of heat input by January 2002. The Phase II limit applies to all NBP sources that are also Acid Rain Program Sources, and the limit is 0.3 percent sulfur in fuel and 0.33 pound per million Btu by January 2003.

In May 2003, the Connecticut State legislature passed legislation requiring coal-fired power plants to remove 90 percent of their mercury (or a maximum of 0.6 pound mercury emitted per trillion Btu input, which is equivalent to 0.005 to 0.007 pound per gigawatthour) by July 2008. The legislature has recommended that the State Department of Environmental Protection consider stricter limits by July 2012 [*8*].

Connecticut is developing a climate change action plan that is designed to help meet the New England

Table 3. Existing State air emissions legislation with potential impacts on the electricity generation sector

State	Activities	Emissions limits
Connecticut	"Abatement of Air Pollution" regulations for electric utility, industrial cogeneration, and industrial units	
	SO_2 emissions Phase I limit by 2002	0.55 pound per million Btu input
	SO_2 emissions Phase II limit by 2003	0.33 pound per million Btu input
	NO_x limit	0.15 pound per million Btu input
	Mercury limit by July 2008	90% removal (or maximum of 0.6 pound mercury emitted per trillion Btu input, equivalent to 0.005-0.007 pound mercury per gigawatthour)
Maine	"An Act to Provide Leadership in Addressing the Threat of Climate Change," regulation for greenhouse gas emissions reduction from all sectors	
	Greenhouse gas emissions by 2010	At 1990 levels
	Greenhouse gas emissions by 2020	10% below 1990 levels
	Greenhouse gas emissions in the "long term"	75% to 80% below 2003 levels
	Potential participant in Northeast CO_2 cap and trade program	
Massachusetts	"Emissions Standards for Power Plants," multi-pollutant cap for existing power plants	
	SO_2 emissions 1999: 6.7 pounds per megawatthour	
	SO_2 cap 2004 or 2006 (depending on compliance strategy)	6.0 pounds per megawatthour
	SO_2 cap 2006 or 2008 (depending on compliance strategy)	3.0 pounds per megawatthour
	NO_x emissions 1999: 2.4 pounds per megawatthour	
	NO_x cap 2004 or 2006 (depending on compliance strategy)	1.5 pounds per megawatthour
	CO_2 emissions (current): 2,200 pounds per megawatthour	
	CO_2 cap 2006 or 2008 (depending on compliance strategy)	1,800 pounds per megawatthour
New Hampshire	"Clean Power Act" for existing fossil-fuel power plants	
	SO_2 emissions 1999: 48,000 tons	
	SO_2 cap 2006	7,289 tons
	NO_x emissions 1999: 9,000 tons	
	NO_x cap 2006	3,644 tons
	CO_2 emissions 1990: 5,426 thousand tons	
	CO_2 emissions 1999: 5,594 thousand tons	
	CO_2 cap 2006	5,426 thousand tons
New Jersey	Greenhouse gas emissions 1990: 136 million metric tons carbon dioxide equivalent	
	Greenhouse gas emissions 2005	3.5% below 1990
New York	Title 6 NYCRR Parts 237 and 238 applicable to electric utilities, cogenerators, and industrial units	
	SO_2 Phase I limit January 2005, 25% below allocation	197,046 tons
	SO_2 Phase II limit January 2008, 50% below allocation	131,364 tons
	NO_x limit beginning in October 2004	39,908 tons
North Carolina	"Clean Smokestacks Act" for existing coal-fired plants only	
	SO_2 emissions 1999: 429,000 tons	
	SO_2 cap 2009	250,000 tons
	SO_2 cap 2013	130,000 tons
	NO_x emissions 1999: 178,000 tons	
	NO_x cap 2009	56,000 tons
Oregon	CO_2 for new or expanded power plants	675 pounds per megawatthour

Governors/Eastern Canadian Provinces goal for CO_2 reduction (stabilization of greenhouse gas emissions at 1990 levels by 2010, and a 10-percent reduction from 1990 levels by 2020). The State is also a potential participant in the Northeast CO_2 cap and trade program. Modifications are being made to the current NBP rules to provide incentives in the form of allowances for renewable energy and energy efficiency programs [*9*].

Maine. Maine enacted a climate change statute—"An Act to Provide Leadership in Addressing the Threat of Climate Change" (Public Law 2003, Chapter 237, H.P. 622-L.D. 845)—in May 2003. The statute requires the establishment of a greenhouse gas emissions inventory for State-owned facilities and State-funded programs and calls for a plan to reduce emissions to 1990 levels by 2010. The statute specifies that carbon emission reduction agreements must be signed with at least 50 businesses and nonprofit organizations by January 2006, and that Maine must participate in a regional greenhouse gas registry. The goals of the statute are a reduction of greenhouse gases to 1990 levels by January 2010, a reduction to 10 percent below 1990 levels by 2020, and a reduction to between 75 and 80 percent below 2003 levels "in the long term." It authorizes the Department of Environmental Quality to adopt a State climate action plan by July 2004 to meet the goals of the statute [*10*].

Massachusetts. The Massachusetts Department of Environmental Protection air pollution control regulations (310 CMR 7.29, "Emissions Standards for Power Plants") [*11*] apply to existing power plants in Massachusetts. They would affect six older power plants. There are two options for utilities to comply with the regulations: either "repower" (defined as replacing existing boilers with new ones that meet the environmental standards, switching fuel to low-sulfur coal, or switching from coal to natural gas); or choose a standard path that includes installing low-NO_x burners, installing SO_2 scrubbers, and installing SCR or SNCR equipment.

The rule offers an incentive for a fuel shift by delaying the compliance deadline to October 2008 for any facility choosing to repower. Plants using other techniques, such as pollution control equipment, must comply by October 2006. The SO_2 standard is 6.0 pounds per megawatthour by October 2004 (standard) or October 2006 (repowering) and 3.0 pounds per megawatthour by October 2006 (standard) or October 2008 (repowering). The NO_x standard is 1.5 pounds per megawatthour by October 2004 (standard) or October 2006 (repowering). The SO_2 and NO_x regulations are considered by the State to be more stringent than the Clean Air Act Amendments of 1990 would imply. Most of the facilities are choosing the repowering mode rather than the standard mode of compliance. Compliance plans have been submitted for the six power stations affected: Brayton Point, Salem Harbor, Somerset, Mount Tom, Canal, and Mystic [*12*].

The CO_2 standard annual facility cap is based on 3 years of data as of October 2004 (standard) or October 2006 (repowering) and an annual facility rate of 1,800 pounds CO_2 per megawatthour as of October 2006 (standard) or October 2008 (repowering). Credits for off-site reductions of CO_2 emissions can be obtained through carbon sequestration or renewable energy projects. The Massachusetts Department of Environmental Protection is developing regulations that would determine what projects could qualify as reductions. Greenhouse gas banking and trading regulations are also being developed. Plants that fail to achieve the reductions may purchase emissions credits. The governor of Massachusetts has sent a letter expressing interest in working with New York State to develop a cap and trade program for CO_2 emission reductions from power plants [*13*]. Data collection and feasibility assessment on mercury control are ongoing. Draft mercury regulations have been publicly released and are going through a comment period before consideration by the State legislature [*14*].

New Hampshire. New Hampshire has enacted legislation—the Clean Power Act (House Bill 284)—to reduce emissions of SO_2, NO_x, CO_2, and mercury from existing fossil-fuel-burning steam-electric power plants. Governor Jeanne Shaheen signed the Act into law in May 2002, and implementing regulations have been finalized [*15*]. The legislation applies to the State's three existing fossil-fuel power plants only and does not apply to new capacity. The plants must either reduce emissions, purchase emissions credits from other plants outside New Hampshire that have achieved such reductions, or use some combination of these strategies. Compliance plans submitted to the New Hampshire Department of Environmental Services (DES) are under review.

The SO_2 annual cap is 7,289 tons by 2006, which amounts to a 75-percent reduction from Phase II Acid Rain legislation requirements and an 85-percent reduction from 1999 emission levels (see Table 3). The NO_x annual cap is 3,644 tons by 2006, which amounts to a 60-percent reduction from 1999 emission levels. The CO_2 annual cap is 5,425,866 tons by

2006, which amounts to a 3-percent reduction from 1999 levels. The Governor of New Hampshire has sent a letter expressing interest in working with New York State to develop a cap and trade program for reducing CO_2 emissions from power plants.

The mercury cap is to be determined after the U.S. Environmental Protection Agency (EPA) establishes a Maximum Achievable Control Technology (MACT) standard for mercury control, but no later than March 31, 2004. Emissions allowances from Federal or regional trading and banking programs can be used to comply with the State cap. For CO_2 and mercury, early reductions can be banked for future use. NO_x allowances can be pooled but cannot be applied to emissions between May and September. SO_2 allowances obtained under the Federal acid rain program can be used against the cap. The statute includes incentives for investment in energy efficiency, new renewable energy projects, conservation, and load management. It does not apply to utilities that have installed "qualifying repowering technology" or replacement units meeting certain pollution control criteria [*16*].

New Jersey. New Jersey's goal is to reduce State-wide emissions of greenhouse gases from all sectors by 3.5 percent from 1990 levels by 2005. "Covenants" have been signed, pledging organizations to reduce their greenhouse gas emissions in accordance with the State goal [*17*]. In January 2002, the U.S. Department of Justice, the U.S. EPA, and the State of New Jersey obtained a Clean Air Act Consent Decree involving Public Service Enterprise Group Fossil, LLC (PSEG). In addition to a $1.4 million monetary penalty to be paid to the Federal Government [*18*], the settlement commits PSEG to reduce SO_2, NO_x, and particulate matter emissions on all its coal-fired units, to retire SO_2 and NO_x allowances, and to undertake other environmental projects. This is a part of the Prevention of Significant Deterioration/New Source Review (PSD/NSR) enforcement effort. The Governor of New Jersey has also sent a letter expressing interest in working with New York to develop a cap and trade program for CO_2 emission reductions from power plants.

New York. New York's "Acid Deposition Reduction Budget Trading Programs"—Title 6 NYCRR Parts 237 and 238—were approved by the State Environmental Board in March 2003 and became effective in May 2003 [*19*]. The NO_x regulations apply to electricity generators of 25 megawatts or greater, and the SO_2 regulations apply to all Title IV sources under the Clean Air Act [*20*], including electric utilities and other sources of SO_2 and NO_x, such as cogenerators and industrial facilities. NO_x emissions are limited to 39,908 tons beginning in October 2004. SO_2 emissions are limited in two phases: Phase I, beginning in January 2005, limits SO_2 emissions to 25 percent below Title IV allocations (197,046 tons), and Phase II, beginning in January 2008, increases the limits to 50 percent below Title IV allocations (131,364 tons) [*21*]. A governor's task force was established in June 2001 to recommend greenhouse gas limits. Further details on the recommendations of the Task Force are provided below.

North Carolina. The General Assembly of North Carolina has passed the Clean Smokestacks Act—officially called the Air Quality/Electric Utilities Act (S.B. 1078)—which requires emissions reductions from 14 coal-fired power plants in the State. Under the Act, North Carolina utilities must reduce NO_x emissions from 245,000 tons in 1998 to 56,000 tons by 2009 and SO_2 emissions from 489,000 tons in 1998 to 250,000 tons by 2009 and 130,000 tons by 2013. Progress Energy Carolinas, Inc., and Duke Power have submitted compliance plans to the North Carolina Department of Environment and Natural Resources and the North Carolina Utilities Commission. The utilities will comply with the Act by installing scrubbers and SNCR technology at their plants.

The Act requires the Department of Environment and Natural Resources to evaluate issues related to the control of mercury and CO_2 emissions and recommend the development of standards and plans to control them. In 2003, the Department of Air Quality has prepared a report on mercury [*22*] and CO_2 reductions for the State [*23*]. This is the first of three sets of reports submitted to the Environmental Management Commission and the Environmental Review Commission. The subsequent reports are due in September 2004 and September 2005. The objective of the 2003 report is to provide a general background on the topic of climate change and to define the scope of efforts needed to meet the legislative requirements. The 2004 and 2005 reports will build on this background, report on any developments in the Federal Government, and recommend courses of action that may follow. A proposed workshop being planned for spring 2004 will form the basis for the September 2004 report.

The Act also requires North Carolina to persuade other States and power companies to reduce their emissions to similar levels and on similar timetables. The Act specifically mentions that discussions should be held with the Tennessee Valley Authority (TVA) to determine its emission reduction policies. A meeting was held between the Department of Environment and Natural Resources/Department of Air Quality and TVA in August 2002 to discuss actions planned by TVA that would be comparable to the Clean Smokestacks Act. TVA presented its plans to add scrubbers to five additional power plants, primarily in the eastern portion of the TVA system, beginning with its Paradise plant in 2006. TVA plans to complete installation of the new scrubbers by 2010. TVA also plans to install the first 8 SCR systems for NO_x control and to have 25 boiler units controlled by 2005, which will reduce NO_x emissions during the ozone season by 75 percent. Duke Power and Progress Energy have reported compliance costs for SO_2 and NO_x control. For the North Carolina utilities, SNCR costs range from $4.93 to $63.70 per kilowatt, and scrubber costs range from $113 to $414 per kilowatt [*24*].

Oregon. Oregon has established its first formal State standards for CO_2 emissions from new electricity generating plants. The standards apply to power plants and non-generating facilities that emit CO_2. The Oregon Energy Facility Siting Council originally adopted the rules pursuant to House Bill 3283, which was passed by the Oregon legislature in June 1997, and has subsequently updated the rules, most recently in April 2002 [*25*]. For baseload natural gas plants and non-baseload plants, the standard is CO_2 emission rates of 675 pounds per megawatthour, 17 percent below the rate for the most efficient natural-gas-fired plants currently in operation in the United States. The Council has not set CO_2 emission standards for baseload power plants using other fossil fuels.

The Council's definition of a natural-gas-fired facility allows up to 10 percent of the expected annual energy to be provided by an alternative fuel, most likely distillate fuel. Proposed facilities may meet the requirement through cogeneration, using new technologies, or purchasing CO_2 offsets from carbon mitigation projects. It is possible to offset all excess CO_2 emissions through cogeneration offsets alone, and there are no limitations on the geographic locations or types of CO_2 offset projects. The Council has set a monetary value that the generators may pay to buy offsets ($0.85 per short ton CO_2, equivalent to $3.12 per ton carbon, set in September 2001) [*26*]. This equates to an offset cost of 0.88 mills per kilowatthour [*27*].

New Source Review

On August 27, 2003, the EPA issued a final rule defining certain power plant and industrial facility activities as "routine maintenance, repair and replacement," which are not subject to new source review (NSR) under CAAA90. As stated by the EPA, "these changes provide a category of equipment replacement activities that are not subject to Major NSR requirements under the routine maintenance, repair and replacement (RMRR) exclusion" [*28*]. Essentially this means that power plants and industrial facilities engaging in RMRR activities will not be required to obtain State or EPA approval for those activities and will not have to install the "best available" emissions control technologies that might be required if NSR were triggered.

Although the RMRR exclusion is not new, in the past it has been evaluated on a case-by-case basis. The new rule attempts to give affected entities some regulatory clarity by defining the specific activities that qualify for the exclusion. The new rule "specifies that the replacement of components of a process unit with identical components or their functional equivalents will come within the scope of the exclusion, provided the cost of replacing the component falls below 20 percent of the replacement value of the process unit of which the component is a part, the replacement does not change the unit's basic design parameters, and the unit continues to meet enforceable emission and operational limitations" [*29*]. Knowing the costs and scope of any changes they are considering, industrial and power plant facility owners will be able to determine whether they might trigger NSR.

The potential impact of the new rule is unknown. During its development, some observers argued that uncertainty about whether actions under consideration would trigger NSR had led facility owners to forgo investments that might improve the efficiency, reliability, and/or capacity of their units, and that the change in rules could lead to significant increases in the efficiency of coal-fired power plants and their electricity production [*30*].

Even without the rule change, however, coal-fired generation has been increasing. For example, between 1990 and 2002 coal-fired generation in the electric power sector increased by 21 percent, while coal-fired capacity increased by only 2 percent. Clearly, operators have been able to maintain their coal-fired power plants and increase their output under the old rules. These revisions should enable coal plant operators to continue maintaining their plants and increase their use with less worry about triggering NSR. In *AEO2004*, coal-fired generation is projected to increase significantly as existing plants are used more intensively and new plants are added. No explicit changes to address the impacts of the new NSR rule have been made in *AEO2004*. As more data become available, they will be included in future *AEO*s.

The Energy Policy Act of 2003

The U.S. House of Representatives passed H.R. 6.EH, The Energy Policy Act of 2003 (EPACT03), on April 11, 2003. The Senate passed H.R. 6.EAS (the same bill it had passed in 2002) on July 31, 2003. A Conference Committee was convened to resolve differences between the two bills, and a conference report was approved and issued on November 17, 2003 [*31*]. The House approved the conference report on November 18, 2003, but a Senate vote on cloture failed, and further action has been delayed at least until January 2004.

Consistent with the approach adopted in the *AEO* to include only Federal and State laws and regulations in effect, the various provisions of EPACT03 are not represented in the *AEO2004* projections. This discussion focuses on selected provisions of the current version of EPACT03 that have, in EIA's estimation, significant potential to affect energy consumption and supply at the national level. Proposed provisions in the following areas are addressed:

- Tax credits, grants, low-income subsidies, mandatory standards, and voluntary programs that act to reduce the cost and use of energy in the buildings sectors
- Industrial programs providing tax credits for combined heat and power (CHP) generation, blended cement, and voluntary programs to reduce energy intensity
- Tax credits for alternative fuel vehicles
- Establishment of a renewable fuels standard
- Elimination of the use of methyl tertiary butyl ether (MTBE) in gasoline
- Elimination of oxygen content requirements for reformulated gasoline
- Creation of tax deductions and credits for small refiners to encourage the production of low-sulfur diesel fuels
- Ethanol and biodiesel tax credits
- Extension of royalty relief to natural gas production from deep wells on existing leases in shallow waters
- Establishment and funding of a research program for ultra-deepwater and nonconventional natural gas and other petroleum resources from royalty payments
- Section 29 tax credits for nonconventional fuels production
- Assistance for constructing the Alaska Natural Gas Pipeline
- Establishment of a series of tax credits for natural gas gathering, distribution, and high-volume pipelines and gas processing facilities
- Provisions to improve the reliability of the electricity transmission grid
- Tax incentives and other provisions to encourage generation from renewable and nuclear fuels.

End-Use Energy Demand

EPACT03 includes tax incentives, standards, voluntary programs, and other miscellaneous provisions that affect the end-use demand sectors. Provisions that affect the residential and commercial sectors (the buildings sectors) are discussed together, because many of the legislative proposals affect both sectors.

Buildings

EPACT03 contains several provisions designed to mitigate future energy consumption in the buildings sectors. They encompass a multifaceted policy approach, employing tax credits, grants, low-income subsidies, mandatory standards, and voluntary programs in an attempt to reduce both expenditures for and use of residential and commercial energy. Each of these approaches can yield different results in terms of program effectiveness.

Of all the provisions included in EPACT03, only the mandatory standards for products such as torchiere lighting and traffic signals (Section 133) force a direct impact on buildings sector energy use; the other provisions require homeowners, occupants, builders, and/or government officials to pursue a specific course of action to spur measurable energy savings. In terms of proposed tax credits, for the next 3 years, builders can claim \$1,000 to \$2,000 for each home built that meets certain efficiency criteria (Section 1305). Likewise, homeowners who upgrade the building envelopes of existing homes can claim a 20-percent tax credit (up to \$2,000) from 2004 to 2006 (Section 1304).

Other provisions include production tax credits for efficient refrigerators and clothes washers through 2007, as well as credits for the installation of fuel cells, CHP systems, and solar thermal and photovoltaic equipment (Sections 1307, 1303, 1306, and 1301). Commercial businesses can also claim a tax deduction of \$1.50 per square foot for expenditures on energy-efficient building property (Section 1308). In terms of subsidies, EPACT03 directs funding increases over the next several years for both the Low Income Home Energy Assistance Program (LIHEAP) and the Department of Energy's weatherization program (Sections 121 and 122), which could reduce future energy use by allowing more low-income homes to be weatherized. Other provisions update Executive Order mandates regarding Federal purchasing requirements and energy intensity reductions (Sections 102 through 104); allow for energy conservation measures in congressional buildings (Section 101); and establish a program to install photovoltaic energy systems in public buildings over the next 5 years (Section 205).

Several provisions of EPACT03 either are less specific in terms of what the future law might require or are difficult to assess and, therefore, have less certain impacts. They include the establishment of test procedures for several products (Section 133), programs to educate homeowners on the importance of maintaining heating and cooling equipment (Section 132), and grants to States for rebates on the purchase of energy-efficient products (Section 124).

Industrial

The industrial sector provisions of EPACT03 include tax credit programs for CHP, blended cements, and voluntary programs to reduce industrial energy intensity. Section 1306 would extend the current 10-percent business credit for solar power generation equipment to CHP systems. Qualifying equipment must have electrical capacity of not more than 15 megawatts or mechanical energy no greater than 2,000 horsepower. Qualifying equipment must produce at least 20 percent of its useful output as thermal energy and at least 20 percent as electricity. Such equipment must also have a system efficiency of at least 60 percent. The credit would be effective from December 31, 2003, to January 1, 2007. The tax credit would create an incentive to increase CHP generation, but that incentive would be diminished by the relatively small size limit for qualifying facilities. Further, the short time frame of the credit probably would limit CHP expansion to plants that would have been built in its absence.

Section 110 would encourage Federal agencies to require greater use of blended cements but does not specify the amount of blending that would be allowed. Generally, increasing the recovered mineral component would decrease the amount of new cement production required to produce a given output of concrete.

Section 107 would authorize the Secretary of Energy to enter into voluntary agreements with one or more persons in the industrial sector to reduce their energy intensity by a significant amount compared with recent years. This program appears similar to the existing Climate Vision program, which is part of the Administration's effort to reduce greenhouse gas intensity by 18 percent over the next decade [*32*].

Transportation

Present law provides a maximum tax deduction for alternative fuel motor vehicles of $50,000 for a truck or van weighing over 26,000 pounds and $2,000 for a vehicle weighing 10,000 pounds or less. In addition, current law provides a 10-percent tax credit toward the cost of a qualified electric vehicle, up to $4,000. The tax deductions and credit are scheduled to be phased out between January 1, 2002, and December 31, 2004.

Section 1317 of EPACT03 would extend the existing alternative fuel motor vehicle deduction through December 31, 2006; repeal an existing credit for electric fuel cell vehicles; and provide credits for the purchase of fuel cell powered motor vehicles, hybrid motor vehicles, mixed-fuel motor vehicles, and advanced lean-burn technology motor vehicles. Unused credits could be carried forward 20 years and would apply to hybrid and advanced lean-burn technology vehicles placed in service before 2008 and to fuel cell vehicles placed in service before 2012. Property placed in service after the enactment of EPACT03 could also receive the tax credits. Credits for hybrid and advanced lean-burn technology vehicles would be phased out after cumulative sales of the specific technology exceeded 80,000 units. Section 1318 specifies allowable tax credits by vehicle and fuel type.

Although EPACT03 does not prescribe a change in corporate average fuel economy (CAFE) standards, Section 772 sets out specific items that the Secretary of Transportation should consider when evaluating a potential increase, including technological feasibility, economic practicability, the effect of other government motor vehicles standards on fuel economy, the need of the United States to conserve energy, the effects of fuel economy standards on safety, and the effect of compliance on automobile industry employment. Further, Section 774 would require the Administrator of the National Highway Traffic Safety Administration to initiate a study no later than 30 days after enactment of EPACT03 to look at the feasibility and effects of requiring a significant percentage reduction in automobile fuel consumption beginning in model year 2012.

Petroleum, Ethanol, and Biofuel Tax Provisions

Numerous provisions of EPACT03 would affect the supply, composition, and refining of petroleum and related products. The major issues include:

- Establishment of a renewable fuels standard
- Elimination of MTBE
- Elimination of the oxygen content requirement for reformulated gasoline
- Small refiner deductions to encourage investment in low-sulfur fuel production
- Ethanol and biofuel tax provisions.

Renewable Fuels Standard

Section 1501 of EPACT03 requires the production and use of 3.1 billion gallons of renewable fuel in 2005, increasing to 5.0 billion gallons by 2012. For calendar year 2013 and each year thereafter, the minimum renewable fuels required would be determined by the volume percentage of 5.0 billion gallons over the total gasoline sold in the Nation in 2012. Small refineries with a capacity not exceeding 75,000 barrels per calendar year, and the States of Alaska and Hawaii, are exempted from the renewable fuels standard. Both ethanol and biodiesel are considered as renewable fuels, with a 1.5-gallon credit toward the renewable fuels standard for every gallon of biomass ethanol produced and a 2.5-gallon credit if the biomass ethanol is derived from agricultural residue or is an agricultural byproduct. A renewable fuels credit program would allow refiners, blenders, and importers flexibility to comply with the renewable fuels standard across geographical regions and successive years.

MTBE Phaseout

Section 1502 exempts MTBE and renewable fuels used in motor vehicles from being deemed “defective products.” However, the exemption does not “affect the liability of any person for environmental remediation costs, drinking water contamination, negligence for spills or other reasonably foreseeable events, public or private nuisance, trespass, breach of warranty, breach of contract, or any other liability other than liability based on a claim of defect product.” Section 1503 provides for transition assistance up to $250 million per year between 2005 and 2012 to merchant MTBE producers moving to production of iso-octane, iso-octene, alkylates, or renewable fuels. Section 1504 prohibits the use of MTBE after December 31, 2014, but trace quantities not exceeding 0.5 percent by volume are allowed. The Governor of a State may submit a notification to the EPA authorizing the continued use of MTBE, and the President of the United States may also void the MTBE restrictions by June 30, 2014, based on findings by the National Academy of Sciences on the costs and benefits of motor fuel additives, including MTBE.

Oxygen Requirement for Reformulated Gasoline

Section 1506 would eliminate the oxygen content requirement for reformulated gasoline. It would take effect 270 days after enactment of EPACT03, except for California, which would receive the exemption immediately. Volatile organic compound (VOC) Control Regions 1 and 2 for reformulated gasoline would be consolidated by eliminating the less stringent requirements applicable to gasoline designated for VOC Control Region 2 (northern).

Small Refiners

Section 1324 allows small refiners to deduct 75 percent of qualified capital expenditures in the year of the expense for costs related to compliance with the EPA’s Tier 2 low-sulfur gasoline and highway diesel fuel requirements. The provision applies as a deduction for expenses incurred in a taxable year beginning after December 31, 2002. Gasoline sulfur reductions could be phased in between 2004 and 2007; diesel sulfur reductions would take effect starting in mid-2006.

Section 1325 of EPACT03 provides for a 5-cent-per-gallon tax credit to small refiners of low-sulfur diesel fuel (15 ppm or less) for expenses incurred after December 31, 2002. The total amount of the credit is limited to 25 percent of qualified capital costs incurred to reach compliance with EPA diesel fuel regulations, and no credit is allowed until the refiner obtains certification of compliance. The credit is reduced *pro rata* for refiners processing over 155,000 barrels per day but less than 205,000 barrels per day. It applies to organizations with no more than 1,500 individuals engaged in refinery business operations on any day during the year. For cooperative organizations, the credit can be apportioned among members. The effective period runs from January 1, 2003, to one year after the date the refiner must comply with EPA regulations, but no later than December 31, 2009.

Ethanol and Biofuel Tax Provisions

The current gasoline and highway diesel fuel excise taxes are 18.4 and 24.4 cents per gallon, respectively.

For each gallon of highway fuel, 0.1 cents is deposited in the Leaking Underground Storage Tank Trust Fund, and the balance is deposited in the Highway Trust Fund. Gasoline blended with 10 percent ethanol receives an excise tax reduction of 5.2 cents per gallon. Gasoline blended with 5.7 percent or 7.7 percent ethanol receives a proportionally smaller excise tax reduction. Under current law, if gasoline is blended with ethanol, the General Fund receives 2.5 cents, the Leaking Underground Storage Tank Trust Fund receives 0.1 cent, and the Highway Trust Fund receives the remainder.

Section 1314 would establish a biodiesel fuels credit analogous to the existing alcohol fuels income tax credit. A biodiesel mixture tax credit of 50 cents per gallon of biodiesel produced from recycled oil or $1 per gallon of biodiesel produced from virgin oil or virgin animal fat applies to biodiesel blended with petroleum diesel. A biodiesel credit in the same amount applies to each gallon of neat biodiesel. A taxpayer's biodiesel fuels tax credit is the sum of the biodiesel mixture credit and the biodiesel credit and is claimed against business income tax. The credit would be effective from December 31, 2003, through December 31, 2005.

Section 1315 would give fuel blenders the options of the alcohol fuel mixture excise tax credit and the biodiesel fuel mixture excise tax credit. Gasoline blended with renewable-source alcohol or ethers produced from renewable-source alcohol would be taxed at the full 18.4 cents per gallon. Diesel blended with biodiesel would be taxed at the full 24.4 cents per gallon. A tax credit of 52 or 51 cents per gallon of ethanol blended into gasoline or used to produce ethyl tertiary butyl ether blended into gasoline would be paid out of the General Fund. Receipts to the Highway Trust Fund would not be reduced by the use of ethanol in gasoline if blenders choose these credits. The credit is 60 cents per gallon of alcohol other than ethanol (such as methanol) derived from renewable sources. The excise tax credit for biodiesel is 50 cents per gallon of biodiesel from recycled oil or $1 per gallon of biodiesel from virgin oil or virgin animal fat. The excise tax credits cannot be claimed for alcohol or biodiesel for which an income tax credit is claimed or which are taxed at a reduced excise tax rate. The new alcohol excise tax credits would be available through December 31, 2010, and the new biodiesel excise tax credit would be available through December 31, 2005.

The current alcohol fuels income tax credit includes the alcohol mixture credit, the alcohol credit, and the small ethanol producer credit. Gasoline blended with ethanol qualifies for an alcohol mixture credit of 52 or 51 cents per gallon. Gasoline blended with an alcohol other than ethanol qualifies for an alcohol mixture credit of 60 cents per gallon. Alcohol tax credits in the same amount apply to fuel alcohols not blended with gasoline. A small ethanol producer qualifies for an additional credit up to 10 cents per gallon for annual production of 15 million gallons or less. Small ethanol producers currently cannot have production capacity above 30 million gallons per year. Section 1313 would raise the capacity limit to 60 million gallons per year. Section 1315 would move the expiration date of the alcohol fuels income tax credit from December 31, 2007, to December 31, 2010.

Natural Gas Supply Provisions

EPACT03 includes a number of provisions that would affect natural gas supply, including:

- Extension of royalty relief to natural gas production from deep wells in shallow waters
- Establishment of a research program covering ultra-deepwater offshore and unconventional natural gas and petroleum resources and funding from existing royalties
- Extension and modification of the Section 29 tax credit for nonconventional production
- Assistance for constructing the Alaska Natural Gas Pipeline
- Tax incentives for natural gas gathering and distribution
- Tax incentives for high-volume natural gas pipelines and gas processing facilities.

Royalty Relief for Natural Gas Production from Deep Wells in the Shallow Waters of the Gulf of Mexico

Section 314 of EPACT03 would authorize the Secretary of Energy to publish a final regulation to complete the rulemaking begun by the Notice of Proposed Rulemaking entitled "Relief or Reduction in Royalty Rates—Deep Gas Provisions," published in March 2003. The rule would grant various levels of royalty relief for wells drilled within the first 5 years of a lease in the shallow waters (less than 200 meters) of the Gulf of Mexico. The minimum volume of production with suspended royalty payments is 15 billion cubic feet for wells drilled to at least 15,000 feet and 25 billion cubic feet for wells drilled to more than 18,000 feet. In addition, unsuccessful wells drilled to a depth of at least 15,000 feet would receive a royalty tax credit for 5 billion cubic feet of natural gas. Credits could be received for up to two wells.

Section 314 would further grant royalty suspension volumes of not less than 35 billion cubic feet from ultra-deep wells on leases issued before January 1, 2001. An ultra-deep well is defined as a well drilled to at least 20,000 feet.

Funding and Establishment of a Research Program for Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources

Sections 941 through 949 would provide for the establishment of a research program covering the ultra-deepwater offshore and unconventional natural gas and petroleum resources (onshore) to advance activities related to development, demonstration, and commercialization of new technologies.

A separate fund will be established in the U.S. Treasury under this provision. Program funding will consist of $150 million annually from Federal royalties, rents, and bonuses for each fiscal year from 2004 through 2013. In addition, another $50 million for each corresponding year is authorized is to be appropriated by Congress, and the funds will remain available until expended. Total program impacts range from $1.5 billion to $2.0 billion over the 10-year period, representing more than a doubling of current annual funding for research.

Amounts obligated from the fund will be allocated in each fiscal year as follows. One-half of the funds shall be for activities under Section 942 for an ultra-deepwater program. A nonprofit, tax-exempt consortium will be selected and awarded a contract to perform authorized research activities in this offshore area. The next 35 percent of the funds are allotted for activities under Section 943(d)(1), which includes work related to coalbed methane, deep drilling, natural gas production from tight sands, stranded gas, innovative exploration and production techniques, enhanced recovery techniques, and environmental mitigation of unconventional natural gas and exploration and production of other petroleum resources. The next 10 percent of the funds shall be for activities under Section 943(d)(2) and awarded to consortia of small producers focusing on changes in complex geology and reservoirs, low reservoir pressure, unconventional natural gas reservoirs in coalbeds, deep reservoirs, tight sands, and shales as well as unconventional oil reservoirs in tar sands and oil shales. The remaining 5 percent of the funds are allocated under Section 941(d) to corresponding research activities at the National Energy Technology Laboratory.

Extension and Modification of the Section 29 Tax Credit for Producing Fuel from a Nonconventional Source

Section 1345 of EPACT03 would extend and modify the Section 29 tax credit for producing fuel from nonconventional sources. It would allow a credit of $3 (indexed for inflation with 2002 as the base year) per barrel (or Btu equivalent) for production from all nonconventional sources except landfills for 4 years of production prior to 2010 for new wells placed in service through 2006. Production from existing wells (drilled in 1980-1992), previously eligible through 2002, would also be eligible for the credit through 2006. For landfills regulated by the EPA there would be a credit of $3 for facilities placed in service after June 30, 1998, and before January 1, 2007. These facilities would be eligible for 5 years of credit. The credit in Section 1345 would be limited to an average daily production of 200,000 cubic feet of gas (or oil equivalent) per well or facility. The credit would be fully effective when the price of crude oil is $35 per barrel or less and would phase out gradually as the price rises to $41 per barrel.

Assistance for Constructing the Alaska Natural Gas Pipeline

Section 386 of EPACT03 would give the Secretary of Energy authority to issue Federal loan guarantees for any natural gas pipeline system that carries Alaskan natural gas to the border between Alaska and Canada south of 68 degrees north latitude. This authority would expire 2 years after the final certificate of public convenience and necessity is issued. The guarantee would not exceed: (1) 80 percent of total capital costs (including interest during construction); (2) $18 billion dollars (indexed for inflation at the time of enactment); or (3) a term of 30 years. Other assistance for construction of the Alaska Natural Gas Pipeline would be provided by the tax incentives for natural gas gathering, high-volume natural gas pipelines, and gas processing summarized below.

Tax Incentives for Natural Gas Gathering and Distribution

Section 1321 would provide a 7-year recovery period for natural gas gathering lines, as opposed to the current 15-year recovery period, for tax purposes. It also would allow for alternative minimum tax relief by not adjusting the allowable amount of depreciation. The treatment would apply to property placed in service after the date of enactment. The Joint Committee on Taxation estimates the negative effect on the budget from the provision at $16 million from 2004 to 2013.

Section 1322 would provide a 15-year recovery period for natural gas distribution lines, as opposed to the current 20-year recovery life available for taxpayers. The provision would be effective for property placed in service after the date of enactment.

Tax Incentives for High-Volume Natural Gas Pipelines and Gas Processing Facilities

Section 1355 would allow a 7-year recovery period for natural gas pipelines with a pipe diameter of at least 42 inches, and any related equipment, as opposed to the current 15-year recovery life available for taxpayers. The provision would be effective for property placed in service after the date of enactment. An Alaska pipeline to Canada is expected to satisfy the 42-inch requirement.

Section 1356 would extend the 15-percent tax credit currently applied to costs related to enhanced oil recovery to construction costs for a gas treatment plant that supplies natural gas to a 1 trillion Btu per day pipeline and produces carbon dioxide for injection into hydrocarbon-bearing geological formations. A gas treatment plant on the North Slope that feeds gas into an Alaska pipeline to Canada could be built to satisfy this requirement. The provision would be effective for costs incurred after 2003.

Electricity Provisions

EPACT03 includes provisions targeted at improving the reliability and operation of the electricity transmission grid; investment tax credits for "basic" and "advanced" clean coal generating technologies; tax provisions, targeted programs, and changes in regulatory structure to support the introduction of renewable electricity generation; and nuclear production tax credits.

Reliability and Operation of the Grid

The electricity title of EPACT03 contains numerous provisions aimed at improving the reliability and operation of the electricity grid, encouraging additional investment in critical grid infrastructure, and revising rules on utility ownership structure and power purchase requirements. For example, to improve reliability, it calls for the creation of mandatory grid reliability standards to replace the voluntary standards that exist today. These standards would be administered by new "electric reliability organizations," which are to be certified by the Federal Energy Regulatory Commission (FERC) and responsible for developing and enforcing reliability standards for their regions. Subject to FERC approval, electric reliability organizations can propose and modify reliability standards and issue fines to those who violate them.

To improve grid operation, EPACT03 calls for open nondiscriminatory access to the grid for all market participants. In other words, transmission-owning utilities are required to offer grid services to others under the same terms and conditions that they provide for themselves. The bill would call for FERC to reconsider its standard market design, and no final rule would be issued before October 31, 2006. However, through a sense of the Congress provision, utilities engaging in interstate commerce would be encouraged to voluntarily join regional transmission organizations. The bill states that regional transmission organizations are needed "in order to promote fair, open access to electric transmission service, benefit retail consumers, facilitate wholesale competition, improve efficiencies in transmission grid management, promote grid reliability, remove opportunities for unduly discriminatory or preferential transmission practices, and provide for the efficient development of transmission infrastructure needed to meet the growing demands of competitive wholesale power markets."

To stimulate investment in the Nation's transmission grid, the bill would give the Secretary of Energy the authority to designate national interest electric transmission corridors in areas experiencing transmission constraints or congestion. Once an area has been designated a national interest electric transmission corridor, within certain limitations, the FERC could issue a permit to modify existing or construct new transmission infrastructure. The goal of these provisions is to expedite the review, permitting, and construction of needed grid enhancements. The FERC would also be required to develop incentive rate structures for transmission pricing and to provide incentives for investments in advanced transmission equipment.

EPACT03 also calls for key changes in the Public Utility Holding Company Act of 1935 (PUHCA) and the Public Utility Regulatory Policies Act of 1978 (PURPA). PUHCA places significant limitations on the corporate structure and geographic scope of utility companies. It does not allow utility holding companies to own noncontiguous utilities and limits their investments outside the utility business. EPACT03 would repeal PUHCA but require that public utility holding companies provide Federal and State regulators access to their books. PURPA was enacted to promote alternative energy sources and energy efficiency, and to diversify the electric power industry. One of its key provisions required utilities to purchase power from qualifying cogeneration and small power production facilities. EPACT03 would remove the purchase requirement for new qualifying facilities, provided that the facility has open access to transmission services and wholesale energy markets.

Key Coal-Fired Electricity Provisions

EPACT03 provides investment tax credits for two specific categories of new coal-fired generating capacity. New coal-fired generating units employing "basic" clean coal technologies—such as advanced pulverized coal, fluidized bed, or integrated gasification combined cycle—are eligible for a tax credit that amounts to 15 percent of the basis of the property placed in service during a specific year. The tax credit for this category of coal plants applies to new facilities placed in service before January 1, 2014, and is limited to a national cap of 4,000 megawatts.

New coal-fired generating units employing "advanced" clean coal technologies are eligible for a tax credit that amounts to 17.5 percent of the basis of the property placed in service during a specific year. The "advanced" technologies include primarily the same technologies specified for the "basic" category, but they must meet both a higher standard for energy conversion efficiency and a cap on carbon emissions. The tax credit for this category of coal plants applies to new facilities placed in service before January 1, 2017, and is limited to a national cap of 6,000 megawatts.

Key Renewable Electricity Provisions

EPACT03 contains three types of provision that would affect renewable electricity markets: tax provisions, authorized programs, and changes to regulatory structures. The primary tax provisions relate to the renewable electricity production tax credit, which currently provides a tax credit of 1.8 cents per kilowatthour for 10 years from the initial online date of wind energy and qualifying biomass facilities entering service by December 31, 2003. EPACT03 would extend the eligibility period for the credit through December 31, 2006, and expand the program to include new biomass feedstocks, biomass co-firing facilities, geothermal facilities, solar power, and power from small irrigation systems. Facilities using "closed-loop" biomass supplies (energy crops grown specifically for energy production), either in dedicated use or in co-firing, would be eligible for the full credit value, but facilities using "open-loop" biomass resources (waste or byproducts from other processes) would receive a credit reduced by 33 percent for the first 5 years of operation from the initial online date. Co-firing facilities would receive the credit pro-rated to the thermal content of the biomass fuel. The tax credit and payment period would also be reduced for some of the other newly eligible technologies. Also, the credit would be allowed to reduce Alternative Minimum Tax payments, which should increase its value to project owners subject to Alternative Minimum Tax liability.

Authorized programs, including direct subsidies, research and development activities, and other programs to support renewable electricity, would be established with maximum allowable funding levels; however, actual execution of the programs would depend on annual budget appropriations. Newly authorized programs would include a direct production incentive payment for some new and incremental hydroelectric power facilities; a direct subsidy to encourage the use of forest thinnings for power production; and new research and development programs, such as the use of concentrating solar power to produce hydrogen.

Changes to regulatory structures would affect both hydroelectric licensing and geothermal leasing. The hydroelectric licensing revisions would allow license applicants to propose alternatives to proposed Federal agency fishway and other license conditions. Leasing and royalty procedures for use of geothermal resources on Federal lands would also be streamlined.

Nuclear Electricity Production Tax Credit

EPACT03 introduces a production tax credit for generation from advanced nuclear power facilities, similar to that in existence for renewables. The provision provides a tax credit of 1.8 cents per kilowatthour for the first 8 years of operation by qualified nuclear facilities. (Unlike the renewable provision, the credit is not adjusted for inflation.) Qualifying facilities must enter service after enactment of the bill and by December 31, 2020. There is a national capacity limitation of 6,000 megawatts; the bill does not specify the allocation of the limit but leaves it to the discretion of the Secretary of Energy. The provision also puts a limit of $125 million per 1,000 megawatts of capacity on the annual credit that can be received by any facility.

Issues in Focus

Outlook for Labor Productivity Growth

The *AEO2004* reference case economic forecast is a projection of possible economic growth, from the short term to the longer term, in a consistent framework that stresses demand factors in the short term and supply factors in the long term [*33*]. Productivity is perhaps the most important concept for the determination of employment, inflation, and supply of output in the long term. Productivity is a measure of economic efficiency that shows how effectively economic inputs are converted into output.

Advances in productivity—that is, the ability to produce more with the same or less input—are a significant source of increased potential national income. The U.S. economy has been able to produce more goods and services over time, not only by requiring a proportional increase of labor time but also by making production more efficient. To illustrate the importance of productivity improvements, on the eve of the American Revolution, U.S. gross domestic product (GDP) per capita stood at approximately $765 (in 1992 dollars) [*34*]. Incomes rose dramatically over the next two centuries, propelled upward by the Industrial Revolution, and by 2002 GDP per capita had grown to $30,000 (1992 dollars). Productivity improvements played a major role in the increase in per capita GDP growth.

Productivity is measured by comparing the amount of goods and services produced with the inputs used in production:

- *Labor productivity*—output per hour of all persons—is the ratio of the output of goods and services to the labor hours devoted to the production of that output; it is the most commonly used productivity measure. Labor is an easily identified input to virtually every production process. For the U.S. business sector, labor cost represents about two-thirds of the value of output produced. Increases in labor productivity allow for comparable gains in profits and/or compensation without putting upward pressures on output prices. When labor productivity grows, the economy is able to produce more with the same number of workers.
- *Multifactor productivity* reflects output per unit of some combined set of inputs. A change in multifactor productivity reflects the change in output that cannot be accounted for by the change in combined inputs. As a result, multifactor productivity measures reflect the joint effects of many factors, including new technologies, economies of scale, managerial skill, and changes in the organization of production.

The U.S. Department of Labor, Bureau of Labor Statistics (BLS), is responsible for developing official productivity statistics for the United States. BLS publishes four sets of productivity measures for major sectors and subsectors of the U.S. economy:

- Quarterly and annual output per hour and unit labor costs for the U.S. private business, private nonfarm business, and manufacturing sectors. These are the productivity statistics most often cited by the national media.
- Annual measures for output per hour and unit labor costs for 3-, 4-, 5-, and 6-digit North American Industry Classification System (NAICS) industries in the United States, with complete coverage in manufacturing and in retail trade, as well as some coverage in other sectors.
- Multifactor productivity indexes for the private business, private nonfarm business, and manufacturing sectors of the economy.
- Multifactor productivity indexes for 2- and 3-digit Standard Industrial Classification (SIC) manufacturing industries, such as the railroad transportation industry, the air transportation industry, and the utility and natural gas industry. These include indexes for total manufacturing and for 20 2-digit SIC manufacturing industries on an annual basis, which compare real value-added output measures to aggregate measures of input: labor, capital, energy, non-energy materials, and purchased business services [*35*].

In the *AEO2004* reference case, productivity growth in the nonfarm business sector is projected to average 2.25 percent annually from 2002 to 2025. The low and high macroeconomic growth cases project average annual growth of 1.82 percent and 2.65 percent, respectively. As discussed below, the range of productivity growth covered by the three cases is within the range of historical experience as well as what is projected for the future by various experts in the productivity field. Figure 8 shows 5-year average annual growth rates for the three cases.

Estimates of Historical Productivity Growth and Their Determinants

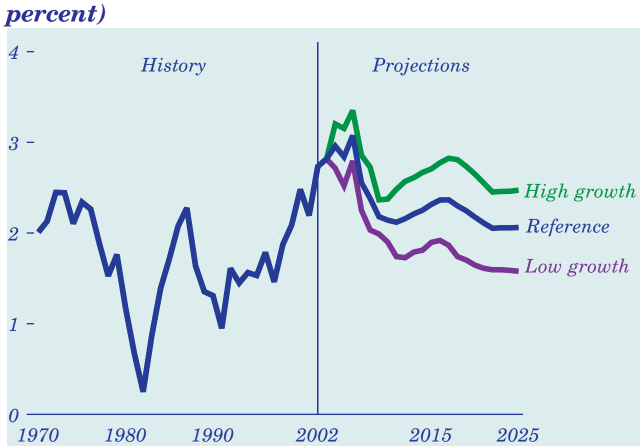
Productivity Growth up to 1995

For the period 1917-1927, labor productivity growth averaged 3.8 percent per year, the highest rate for any comparable 10-year period for the U.S. economy [*36*]. That productivity boom coincided with the adoption of the assembly line and the proliferation of the automobile. Broadcast radio and the electric utility industry saw strong development in the 1920s, and Lindbergh made his famous transatlantic flight, which ushered in the age of aviation. Slow productivity growth in the 1927-1948 period accompanied the Great Depression and World War II. After the war, two factors combined to boost productivity growth: first, output had dropped so far during the Great Depression that simply returning to trend growth required a period of faster economic growth; second, the economy benefited from a wave of innovations, including the building of the interstate highway system, the discovery of transistors, and the emergence of commercial aviation. Between 1948 and 1973, annual labor productivity growth averaged 2.8 percent.

Productivity growth began to slump again in the early 1970s. Higher oil prices undoubtedly played a role in slowing output during the 1970s, but when oil prices returned to pre-1973 levels during the 1980s (in real dollar terms), productivity continued to sag. Other possible explanations include a slower rate of innovations, slower growth of workers' skills, and increased government regulation.

Martin N. Baily has estimated the contributions to nonfarm labor productivity (output per hour) coming from increases in capital per hour worked and labor quality over the period 1948-1995 [*37*]. The "unexplained residual," also termed multifactor productivity (MFP), is defined as the difference between total productivity growth and the contributions from these two factors. Neither capital per hour nor labor quality explains the slowdown in labor productivity in the 1973-1995 period, leaving the explanation or lack thereof to the "unexplained residual" (Table 4). Interestingly, although the contributions from capital per hour did not differ by much between the pre-1973 and post-1973 periods, the contributions from information technology capital rose in the later period, while the contributions from other capital fell.

Figure 8. Labor productivity growth in the nonfarm business sector (5-year average annual growth rate, percent)



Information Technology and the Productivity Growth of the Late 1990s

Numerous studies have attempted to explain the increase in labor productivity from the 1973-95 period to the post-1995 period. The conclusions of Steven Oliner and Daniel Sichel, the 2001 *Economic Report of the President*, and Dale Jorgenson, Mun Ho, and Kevin Stiroh [*38*] were summarized by Baily (Table 5). Although the three studies used slightly different data to support their analyses, there are fundamental similarities in their conclusions. As in Baily's analysis of the earlier time period, information technology was the largest single identifiable factor contributing to labor productivity growth after 1945. The boost to productivity from information technology more than offset the drag on productivity from other capital.

In each of the three studies, the majority of the acceleration in labor productivity growth in the post-1995 period was assigned to the residual (or MFP) effect: 0.8 percent to 0.9 percent of the estimated 1.2-percent and 1.4-percent increases in labor productivity

Table 4. Labor productivity growth in the nonfarm business sector, 1948-1973 and 1973-1995 (average annual percent growth)

Component	1948-1973	1973-1995	Difference
Output per hour	2.9	1.4	-1.5
Contributions from			
Capital per hour	0.8	0.7	-0.1
Information technology	0.1	0.4	0.3
Other	0.7	0.3	-0.4
Labor quality	0.2	0.2	0.0
Residual (MFP)	1.9	0.4	-1.5
R&D	0.2	0.2	0.0

Table 5. Estimated changes in labor productivity growth between 1995-2000 and 1973-1995 (percent)

Component	Oliner and Sichel	2001 Economic Report of the President	Jorgenson, Ho, and Stiroh
Output per hour	1.2	1.4	0.9
Contributions from			
Capital per hour	0.3	0.4	0.5
Information technology	0.6	0.6	0.4
Other	-0.3	-0.2	0.1
Labor quality	0.0	0.0	-0.1
Residual (MFP)	0.8	0.9	0.5
Computer sector	0.2	0.2	0.3
Other	0.3	0.7	0.2

(nonfarm business sector) in the first two studies and 0.5 percent of the estimated 0.9-percent increase in labor productivity (business sector) in the third analysis. In the studies by Oliner and Sichel and Jorgenson, Ho, and Stiroh, more than one-half of the MFP effect was attributed to the computer sector. The 2001 *Economic Report of the President* suggested, however, that most of the increase came from outside the computer sector.

Meyer, Baily, and others see the bunching of productivity-enhancing innovations working in combination with a favorable U.S. economic environment to boost productivity. In Baily's words, "rapid advances in computing power, software and communications capabilities formed a set of powerful complementary innovations." An increasingly deregulated U.S. economy created a highly competitive environment that drove out inefficiencies, displaced low-productivity firms with high-productivity ones, and forced the adoption of new innovations in order to survive. While the new innovations were available globally, the highly competitive environment may explain why U.S. productivity rates benefited more from them than did other world economies. And finally, globalization expanded markets and increased international competition, further raising the productivity of U.S. firms.

More recently, Stiroh has found that the recent productivity revival is broad-based, with nearly two-thirds of the 61 industries in his analysis showing accelerating productivity gains [*39*]. Furthermore, Stiroh found that productivity growth was higher in industries that either produced information technologies or used them intensively. Thus, Stiroh's industry analysis supports the conclusion that information technology capital was a significant contributor to the post-1995 productivity surge.

Future Outlook for Productivity Growth

The issue of productivity growth is very important for the future economic growth of any nation. For the United States this issue has given rise, understandably, to a significant amount of empirical literature that has investigated the determinants of productivity growth in the past and the future. The *AEO2004* projections for productivity growth lie within the range of historical experience and of the future expectations published by experts, as described below.

Most researchers who have studied the issue and prognosticated about the future outlook have an expectation that annual labor productivity growth will be above 2 percent for the next decade or so. Table 6 shows estimates from recent studies of projected growth in labor productivity. The list represents most of the well-known researchers in the productivity field. All the point estimates of future annual labor productivity growth shown in Table 6 are 2.0 percent or higher, and the estimated ranges fall between a low of 1.3 percent and a high of 3.0 percent.

The key question in developing the *AEO2004* reference case forecast was whether the recent surge in productivity growth would continue. The majority view of the productivity experts cited here is that strong growth in labor productivity will continue for several more years. For example, the U.C. Berkeley economist J. Bradford DeLong writes: "Will this new, higher level of productivity growth persist? The answer appears likely to be 'yes.' The most standard of simple applicable growth models . . . predicts that the social return to information technology investment would have to suddenly and discontinuously drop to zero for the upward jump in productivity growth to reverse itself in the near future. More sophisticated models that focus in more detail on the determinants of investment spending or on the sources of increased total factor productivity appear to strengthen, not weaken, forecasts of productivity growth over the next decade" [*40*].

Naysayers about the productivity revival include Steven Roach and Robert Gordon. Roach believes that much of the post-1995 productivity revival is a statistical illusion resulting from the lack of a satisfactory measure of productivity in the white collar services sector. Gordon argues that the role of information technology has been overstated, and that other factors influencing productivity growth—such as the international and domestic economic environment and fiscal and monetary policies—led to the strong

Table 6. Estimates of future steady-state growth in U.S. labor productivity (percent per year)

Source	Point estimate	Range
Oliner and Sichel (2002)	—	2.0 to 2.8
Jorgenson, Ho, and Stiroh (2002)	2.25	1.3 to 3.0
Congressional Budget Office (2002)	2.2	—
2001 Economic Report of the President (2002)	2.1	—
Baily (2002)	—	2.0 to 2.5
Gordon (2002)	—	2.0 to 2.2
Kiley (2001)	—	2.6 to 3.2
Martin (2001)	2.75	2.5 to 3.0
McKinsey (2001)	2.0	1.6 to 2.5
Roberts (2001, updated)	2.6	—
DeLong (2002)	"like the fast-growing late 1990s"	

trend in recent years. Regardless of his views about the role of technology in productivity growth, Gordon's expectation is that productivity will soon return to its trend growth rate of 2.25 percent [*41*].

Lower 48 Natural Gas Supply

Production from domestic natural gas resources is projected to increase as demand grows. Much of the increase is expected to be met from unconventional resources, changing the overall mix of domestic natural gas supply. Of the 18.6 trillion cubic feet of lower 48 natural gas production in 2002, 42 percent was from conventional onshore resources, 32 percent was from unconventional resources, and 26 percent was from offshore resources. By 2025, 43 percent of total lower 48 natural gas production (21.3 trillion cubic feet) is projected to be met by unconventional resources (Figure 9).

The volume of estimated technically recoverable resources is sufficient to support increased reliance on unconventional natural gas sources. Lower 48 remaining technically recoverable resources are identified in five categories (Figure 10):

- *Conventional undiscovered nonassociated resources* are unproved resources of natural gas, not in contact with significant quantities of crude oil in a reservoir, that are estimated to exist in fields that have yet to be discovered, based on geologic formations and their propensity to hold economically recoverable natural gas. The estimate of lower 48 technically recoverable undiscovered conventional nonassociated natural gas resources as of January 1, 2002, is 222 trillion cubic feet.

- *Conventional inferred reserves* are gas deposits in known reservoirs that are considered likely to exist on the basis of a field's geology and past production but have not yet been developed. The bulk of the estimated 232 trillion cubic feet of lower 48 inferred reserves is in onshore reservoirs.

- *Unconventional resources* (tight gas, shale gas, and coalbed methane), estimated at 475 trillion cubic feet, make up the largest category of unproved resources.

- *Associated-dissolved resources*, the remaining unproved lower 48 natural gas resource, occur in crude oil reservoirs as free gas (associated) or as gas in solution with crude oil (dissolved). They are estimated at a total of 136 trillion cubic feet.

- *Proved natural gas reserves* are located in known and developed reservoirs with demonstrated production potential. As of January 1, 2002, lower 48 proved natural gas reserves were estimated to be 175 trillion cubic feet.

Just a few years ago, it was believed that natural gas supplies would increase relatively easily in response to an increase in wellhead prices because of the large domestic natural gas resource base. This perception has changed over the past few years. While average natural gas wellhead prices since 2000 have generally been higher than during the 1990s and have led to significant increases in drilling, the higher prices have not resulted in a significant increase in production. With increasing rates of production decline, producers are drilling more and more wells just to maintain current levels of production. A significant increase in conventional natural gas production is no longer expected. Drilling deeper wells in conventional reservoirs is expected to slow the overall decline in conventional onshore nonassociated gas production, and drilling in deeper waters is expected to offset the decline in shallow offshore production. Increasing

Figure 9. Lower 48 natural gas production, 1990-2025 (trillion cubic feet)

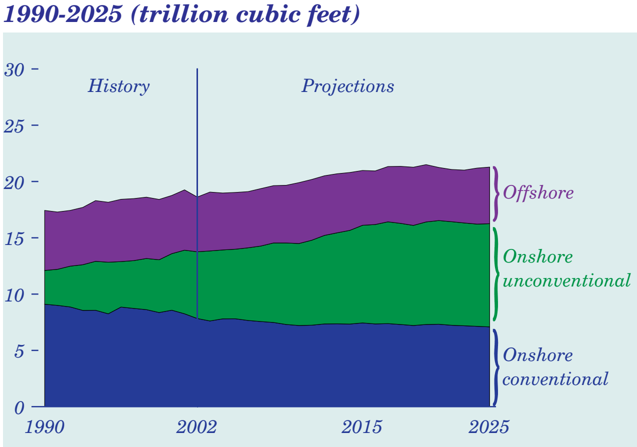
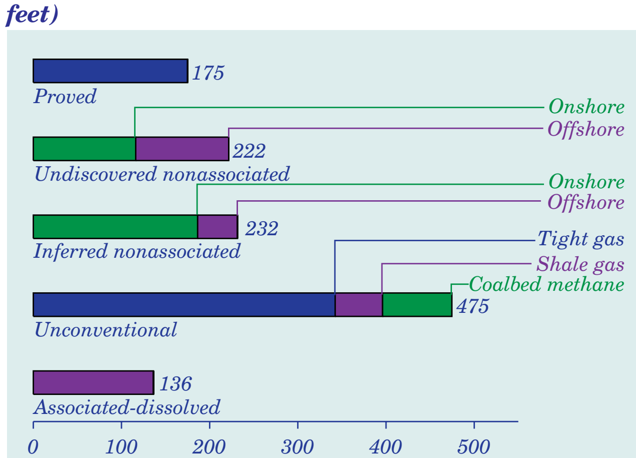


Figure 10. Technically recoverable lower 48 natural gas resources as of January 1, 2002 (trillion cubic feet)



production from unconventional gas plays is drilling and/or technology intensive and is likely to lead to higher wellhead prices.

Conventional Sources

The share of natural gas production from conventional resources is expected to decline over the projection period, from 68 percent in 2002 to 57 percent in 2025. Most of the projected decline is in onshore conventional nonassociated natural gas production, where the majority of exploration and development has occurred historically. Lower 48 offshore natural gas production is expected to remain relatively flat throughout the projection period, as production from fields in the deep waters of the Gulf of Mexico offset the decline in the production in shallow waters.

Onshore

With fewer and smaller new onshore conventional reserve discoveries, emphasis is expected to focus on increasing the expected recovery of currently known fields. Reserve additions from onshore conventional natural gas wells, both exploratory and developmental, are projected to add less than 1 billion cubic feet per well to total reserves in 2025 (Figure 11). The development of deep reservoirs (more than 10,000 feet) in both known fields and new discoveries is projected to play an important role in slowing the decline in the average finding rate for conventional onshore wells. However, drilling to deeper depths increases the average cost of drilling and places upward pressure on prices.

Because larger fields with higher levels of production generally are found first, developed, and replaced with smaller fields, production will tend to decline over time if drilling levels are roughly constant; however, changes in prices influence drilling. Conventional natural gas drilling is expected to increase throughout the projection period, from 6,440 wells in 2002 to 9,140 wells in 2010 and 11,930 wells in 2025 (Figure 12). Less than 10 percent of future natural gas drilling is expected to be exploratory, reflecting the relative maturity of the lower 48 conventional onshore resources. The projected increase in natural gas drilling enables producers essentially to maintain conventional onshore nonassociated production at the current level of approximately 6 trillion cubic feet.

Offshore

Offshore production, primarily in the Gulf of Mexico, is expected to remain a key source of domestic natural gas supply through 2025. Although natural gas production in the shallow waters of the Gulf of Mexico has been declining since 1997, recent developments in deep gas (more than 15,000 feet) in the shallow waters and deepwater (water depth more than 200 meters, or 656 feet) have shown some promise. To offset some of the high costs associated with drilling deep gas wells and deepwater wells, the U.S. Minerals Management Service has offered incentives in the form of royalty relief on qualifying new leases and has proposed additional royalty relief on some existing leases (see "Legislation and Regulations").

Because the deep waters of the Gulf of Mexico contain primarily oil resources, much of the increase in deepwater gas production is expected to come from associated-dissolved gas. Table 7 shows some of the principal deepwater fields that have recently started production or are expected to start production before 2007. Many of the small fields are being developed as subsea tie-backs to existing infrastructure as a way of making them economically viable. In addition to these deepwater fields, two significant deep gas

Figure 11. Conventional onshore nonassociated natural gas reserve additions per well, 1990-2025 (billion cubic feet)

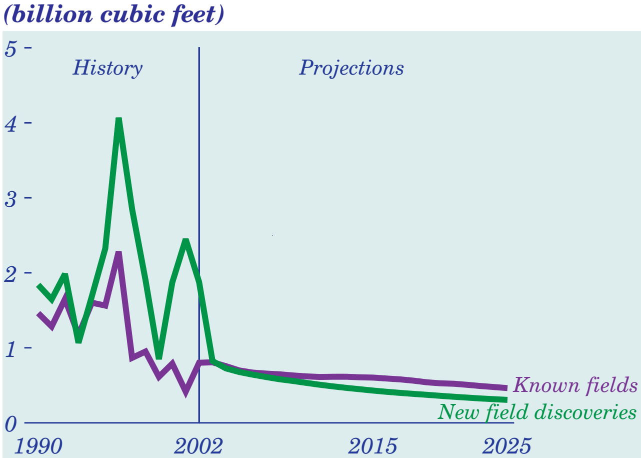
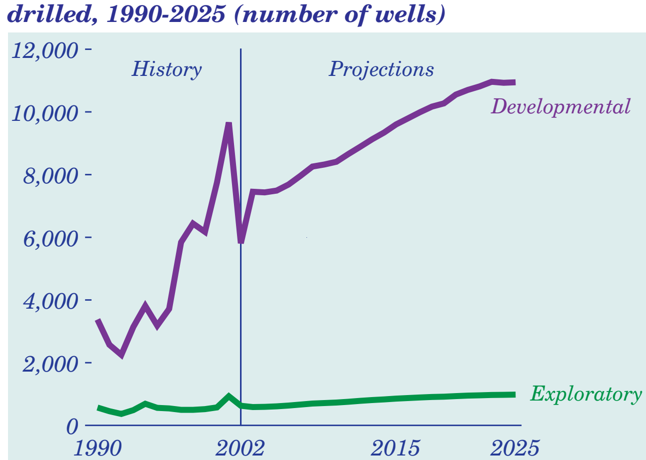


Figure 12. Conventional onshore natural gas wells drilled, 1990-2025 (number of wells)



discoveries—JB Mountain and Mound Pond in shallow waters off the coast of Louisiana—were announced in 2003.

Given the discrete nature of offshore field development, projected offshore natural gas production is expected to be uneven over time. Lower 48 offshore natural gas production is projected to peak in 2010 at 5.4 trillion cubic feet, 11.3 percent higher than in 2002. Associated-dissolved gas, which is primarily in the deep waters of the Gulf of Mexico, is projected to increase by more than 50 percent, from 1.1 trillion cubic feet in 2002 to 1.6 trillion cubic feet in 2010. Projected production of nonasssociated gas in 2010 is about the same as in 2002 at 3.8 trillion cubic feet. In the Gulf of Mexico, shallow gas production is projected to decline at an average annual rate of 0.4 percent, while deepwater gas production is projected to increase at an average annual rate of 4.1 percent between 2002 and 2010 (Figure 13). After 2010, lower 48 offshore natural gas production drops to a low of 4.8 trillion cubic feet, then increases to approximately 5 trillion cubic feet in 2025.

Unconventional Gas

Natural gas extracted from coalbeds (coalbed methane) and from low permeability sandstone and shale formations (tight sands and gas shales) is commonly referred to as unconventional gas. Most of these resources must be subjected to a significant degree of stimulation (e.g., hydraulic fracturing) or other "unconventional" production techniques to attain sufficiently economic levels of production. Unconventional gas has become an increasingly important component of total lower 48 production over the past decade (Figure 14). From 17 percent (3.0 trillion cubic feet) of total production in 1990, the unconventional gas share increased to 32 percent (5.9 trillion cubic feet) in 2002.

Exploration of these abundant (Figure 15) but generally higher cost resources received a boost in the late 1980s and early 1990s with the successful implementation of tax incentives designed to encourage their development. Since then, technologies developed and advanced in pursuit of these resources have contributed to continued growth in production in the absence of the tax incentives. Indeed, increasing production from unconventional gas resources has actually offset a decline in conventional gas production in recent years. By 2025, unconventional gas production is projected to account for 43 percent (9.2 trillion cubic feet) of total lower 48 natural gas production.

Undeveloped Resources

References to undeveloped unconventional resources in *AEO2004* refer to what the United States Geological Survey (USGS) classified as "Continuous-Type (Unconventional) Accumulations" in its 1995 Assessment [*42*]. The resource estimates in that assessment

Table 7. Principal deepwater fields in production or expected to start production by 2007

Field name	Operator	Type	Water depth (feet)	Start Year	Expected peak natural gas production (million cubic feet per day)
Aconcagua	TotalFinaElf	Gas	7,000	2002	80
Aspen	BP	Oil/Gas	3,063	2002	30
Boomvang	Kerr-McGee	Oil/Gas	3,548	2002	200
Camden Hills	TotalFinaElf	Gas	7,210	2002	175
Horn Mountain	BP	Oil/Gas	5,400	2002	68
King Kong	Mariner	Oil/Gas	3,799	2002	150
Nansen	Kerr-McGee	Oil/Gas	3,677	2002	200
Falcon	Pioneer	Gas	3,419	2003	175
Matterhorn	TotalFinaElf	Oil/Gas	3,850	2003	55
Medusa	Murphy	Oil/Gas	2,131	2003	110
Morgus	Shell	Oil/Gas	3,957	2003	55
Nakika Fields	Shell, BP	Oil/Gas	5,700-7,500	2003-2004	325
Front Runner	Pioneer	Oil/Gas	3,329	2004	110
Harrier	Pioneer	Gas	3,400	2004	100
Marco Polo	Anadarko	Oil/Gas	4,286	2004	100
Gunnison	Kerr-McGee	Oil/Gas	3,132	2004	200
Mad Dog	BP	Oil/Gas	4,951	2004	40
Red Hawk	Kerr-McGee	Gas	5,334	2004	150
Llano	Shell	Oil/Gas	2,700	2005	74
Magnolia	ConocoPhilips	Oil/Gas	4,673	2005	150
Entrada	BP	Oil/Gas	4,642	2006	110
Great White	Shell	Oil/Gas	8,000	2006	125
Thunder Horse	BP	Oil/Gas	6,089	2006	55

represent the volume of unproved resources that remain to be added to proved reserves utilizing the technology and development practices existing at the time of the assessment (January 1994). Continuous-type resources are defined to include those "resources that exist as geographically extensive accumulations that generally lack well-defined oil/water or gas/water contacts" [*43*]. This category encompasses "coalbed gas, gas in many of the so-called 'tight sandstone' reservoirs, and auto-sourced oil- and gas-shale reservoirs" [*44*].

Undeveloped resources of unconventional gas are predominantly located in three regions. The bulk of tight sands and coalbed methane (71 percent and 78 percent, respectively) are in the Rocky Mountain region. Sixty-eight percent of undeveloped gas shale resources are in the Northeast region, with most of the remainder in the Southwest region. There are small-to-moderate quantities of tight sands and lesser amounts of gas shales and coalbed methane in the other regions.

Figure 13. Gulf of Mexico natural gas production, 1990-2025 (trillion cubic feet)

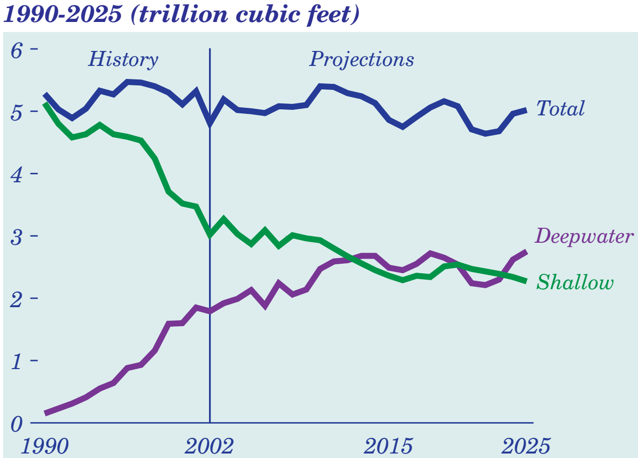
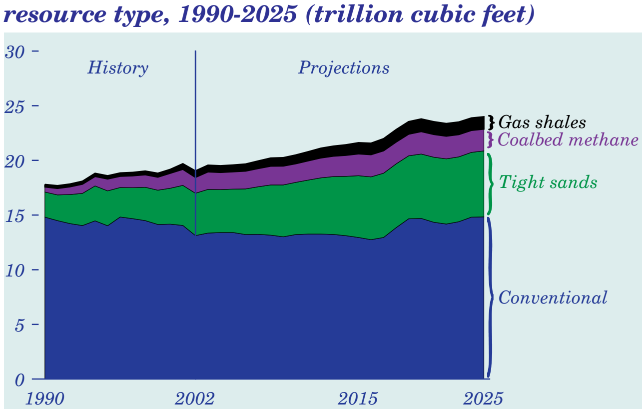


Figure 14. Lower 48 natural gas production by resource type, 1990-2025 (trillion cubic feet)



For *AEO2004*, undeveloped unconventional resources are adjusted to reflect changes indicated by Advanced Resources International (ARI), an independent consultant specializing in unconventional gas. Some plays have been updated to reflect new data, other plays previously lacking data have been assessed as data became available, and new unconventional plays have been identified when appropriate.

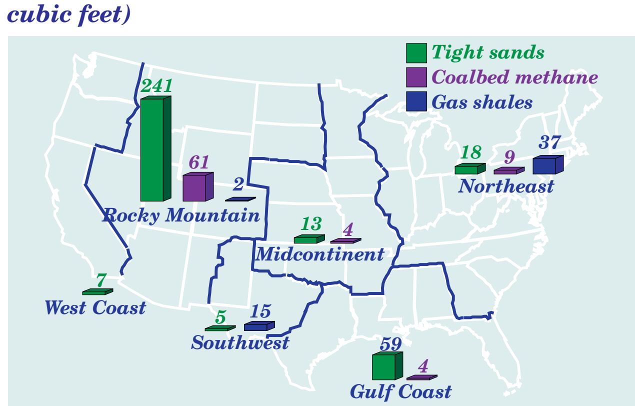
Two examples illustrating the importance of updating are the shale gas (Barnett Shale) in the Fort Worth Basin and coalbed methane in the Powder River Basin. In the 1995 USGS assessment, the Barnett Shale was not assessed due to lack of sufficient data. During the past few years, however, shale gas production from the Fort Worth Basin has been growing at a rapid pace. By obtaining from ARI an interim assessment of the shale gas potential in the basin, EIA was able to project this significant component of current natural gas supply more accurately.

The Powder River Basin was assessed by the USGS in 1995, but the abundant coalbed methane resources were substantially underestimated on the basis of then-available data. Although the USGS has significantly increased its assessment of coalbed methane since 1995, interim consultation with ARI allowed EIA to make this important adjustment years earlier. Several other basins in the Rocky Mountains [*45*] have recently been reassessed by the USGS, but there was insufficient time to reconcile those estimates with the EIA values for comparable areas.

Proved Reserves

Proved reserves of unconventional gas are highest in the Rocky Mountain region for coalbed methane and tight sands and highest in the Northeast for gas shales (Figure 16). Approximately 83 percent (14.6

Figure 15. Unconventional gas undeveloped resources by region as of January 1, 2002 (trillion cubic feet)

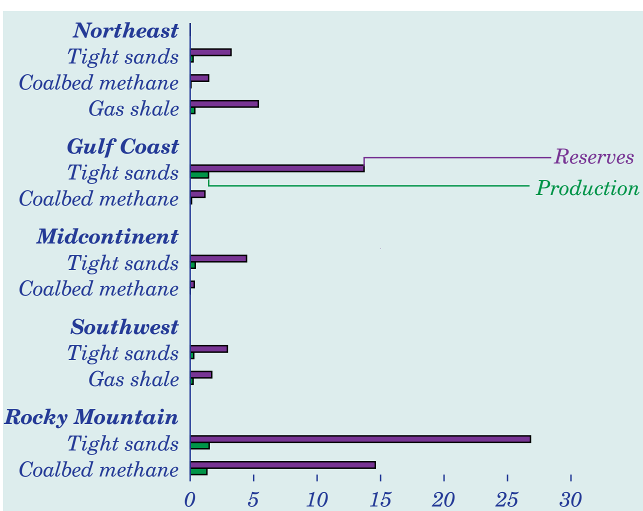


trillion cubic feet) of coalbed methane and 52 percent (26.8 trillion cubic feet) of tight sands proved reserves are located in the Rocky Mountain region. Seventy-six percent (5.4 trillion cubic feet) of gas shales proved reserves are located in the Northeast region, but substantial amounts also exist in the Southwest (1.7 trillion cubic feet). Significant quantities of tight sands proved reserves are located in all the other regions, except for the West Coast. Coalbed methane proved reserves are limited largely to the Northeast (1.5 trillion cubic feet) and the Gulf Coast (1.2 trillion cubic feet), with a small amount (0.3 trillion cubic feet) in the Midcontinent. No significant volume of unconventional gas proved reserves exists in the West Coast region.

Production

Tight Sands. The two regions that are currently the largest producers of gas from tight sands are the Rocky Mountain region and the Gulf Coast region, which account for 39 percent and 37 percent, respectively, of total U.S. tight sands gas production (Table 8). The Rocky Mountain region is projected to experience the most growth in gas production from tight sandstone formations, with 66 percent of total U.S. tight sands gas production expected to originate from this region in 2025. Within the region, tight sands production is projected to increase at the fastest rate (approximately 8 percent per year) in the Wind River basin, with development accelerating in the later years of the forecast. Production from tight sands in the Uinta basin is also expected to grow at a robust rate (about 5 percent per year).

Figure 16. Unconventional gas beginning-of-year proved reserves and production by region, 2002 (trillion cubic feet)



In terms of quantity, the largest contribution from the region will be the Greater Green River basin. *AEO2004* projects the share of total U.S. tight sands gas production sourced from the Green River basin to increase from 15 percent in 2002 to 36 percent by 2025. In the other Rocky Mountain basins, tight sands gas production is projected to rise moderately, except for the Piceance, where production is projected to decline by about 4 percent per year between 2002 and 2025.

Tight sands production from the Gulf Coast region is projected to increase into the middle of the forecast period until primary tight sands plays in the two major basins reach maturity and production begins dropping back toward current levels. Production from tight sandstone formations in other U.S. regions is projected to decline (Midcontinent and Southwest regions) or remain relatively stable (Northeast region).

Coalbed Methane. AEO2004 projects coalbed methane production to remain concentrated largely in the Rocky Mountain region, but the region's share is projected to drop modestly from 88 percent in 2002 to 81 percent by 2025 (Table 9). Within the Rocky Mountain region, growth in coalbed methane production from the prolific Powder River basin and in the Uinta and Raton basins is expected to be offset somewhat by

Table 8. Tight sands gas production by region and basin, 2002-2025 (billion cubic feet)

	Production					
Region/basin	2002	2005	2010	2015	2020	2025
Northeast Region						
Appalachian	232	202	214	243	246	212
Gulf Coast Region						
LA/MS Salt/ Cotton Valley	555	724	991	1,213	1,138	959
Texas Gulf	894	731	811	776	670	589
Total	1,449	1,455	1,802	1,989	1,807	1,548
Midcontinent Region						
Arkoma	149	98	88	92	91	90
Anadarko	259	172	136	99	61	47
Total	408	271	224	190	152	138
Southwest Region						
Permian	285	216	169	163	159	146
Rocky Mountain						
Uinta	91	175	212	255	240	262
Wind River	95	120	194	304	410	588
Denver	109	143	172	201	211	188
Greater Green River	569	657	1,005	1,455	1,792	2,148
Piceance	100	97	78	73	54	37
San Juan	498	607	655	725	758	714
Northern Great Plains	40	33	44	53	61	61
Total	1,502	1,833	2,361	3,066	3,526	3,998
Total	**3,877**	**3,976**	**4,770**	**5,651**	**5,891**	**6,041**

production declines in the relatively mature San Juan basin. Overall growth in the region averages about 1 percent per year.

Elsewhere, significant growth in coalbed methane production is projected for the Northeast region, where the share of total U.S. coalbed methane production increases from 4 percent in 2002 to 8 percent by 2025. Coalbed methane production in the Gulf Coast region is expected to be fairly stable, with declines in the later years of the forecast in the Black Warrior basin offset by increasing production from the Cahaba basin. Although starting from a relatively low level (10 billion cubic feet), coalbed methane production in the Midcontinent region is projected to grow more rapidly than in any other region.

Gas Shales. Natural gas production from tight shale formations occurs predominantly in the Northeast region and the Southwest region (Table 10). Total production from gas shales in the Northeast region is projected to increase at a relatively moderate pace, as production from the Antrim basin remains relatively stable and production in the Appalachian basin grows at about 4 percent per year. In the Southwest region, continued development of gas shales in the Fort Worth-Barnett basin is projected to increase that region's share of total U.S. shale gas production from 39 percent in 2002 to 46 percent by 2025.

Access Restrictions

A current natural gas development issue concerns the ability of producers to access natural gas resources on Federal lands. Most of the unconventional gas resources are in the Rocky Mountains, where they are subject to a variety of access restrictions. In 2002, the Federal Government, under authority of the Energy Policy and Conservation Act (EPCA), conducted an interagency assessment of access restrictions for five major basins in the Rocky Mountains [*46*]. The access assumptions for the Rocky Mountains in *AEO2004* reflect the results of the EPCA assessment.

In *AEO2004*, 7 percent of the undeveloped unconventional gas resources are officially off limits to either drilling or surface occupancy (Table 11). Included in the off-limits category are areas where drilling is precluded by statute (e.g., national parks and wilderness areas) and by administrative decree (e.g., "Wilderness Re-inventoried Areas" and "Roadless Areas"). Also included are those areas of a lease where surface occupancy is prohibited to protect stipulated resources, such as the habitats of endangered species of plants and animals. An additional 26 percent of the resources are judged currently to be developmentally constrained because of the prohibitive effect of compliance with environmental and pipeline regulations created to effect such laws as the National Historic Preservation Act, the National Environmental Policy Act, the Endangered Species Act, the Air Quality Act, and the Clean Water Act.

Approximately 15 percent of the resources are accessible but located in areas where lease stipulations,

Table 9. Coalbed methane production by region and basin, 2002-2025 (billion cubic feet)

Region/basin	Production 2002	2005	2010	2015	2020	2025
Northeast Region						
Appalachian	62	97	134	159	165	147
Illinois	0	0	0	3	8	11
Total	62	97	134	161	173	158
Gulf Coast Region						
Black Warrior	110	111	115	122	97	79
Cahaba	0	3	10	15	29	30
Total	110	113	125	137	126	109
Midcontinent Region	10	21	33	64	107	114
Rocky Mountain						
San Juan	848	828	784	783	685	588
Powder River	325	357	407	531	586	617
Uinta	92	89	92	169	230	255
Raton	54	77	136	151	144	132
Other	1	3	1	0	6	20
Total	1,320	1,354	1,420	1,634	1,650	1,611
Total	**1,502**	**1,586**	**1,712**	**1,997**	**2,056**	**1,992**

Table 10. Shale gas production by region and basin, 2002-2025 (billion cubic feet)

Region/basin	Production 2002	2005	2010	2015	2020	2025
Northeast Region						
Appalachian	173	221	249	360	429	411
Antrim	190	175	173	229	230	201
Illinois New Albany	3	1	1	0	0	0
Total	367	397	423	590	659	612
Southwest Region						
Fort Worth-Barnett	233	222	374	434	500	520
Total	**600**	**619**	**797**	**1,024**	**1,159**	**1,132**

Table 11. Access status of undeveloped unconventional natural gas resources in the Rocky Mountain region, January 1, 2002 (trillion cubic feet)

Access status	Unconventional resources
Officially inaccessible	23.44
Inaccessible due to development constraints	83.71
Accessible with lease stipulations	47.51
Accessible under standard lease terms	172.92
Total	**327.58**

which affect accessibility, are set by a Federal land management agency (either the U.S. Bureau of Land Management or the U.S. Forest Service). The remaining 53 percent of undeveloped Rocky Mountain unconventional gas resources are located either on Federal land without lease stipulations or on private land, and are accessible subject to standard lease terms.

The treatment of access restrictions in the *AEO2004* varies by restriction category. Resources located on land that is officially inaccessible are removed from the operative resource base. Resources located in areas that are developmentally constrained because of environmental and pipeline regulations are initially removed from the resource base, then made available gradually over the forecast period to reflect the tendency of technological progress to enhance the ability of producers to overcome difficulties in complying with the restrictions. Resources that are accessible but located in areas that are subject to lease-stipulated access limitations are accounted for by making two adjustments: exploration and development costs are increased to reflect the increased costs that access restrictions generally add to a project; and time is added to the schedule to complete a project to simulate the delay usually incurred as a result of efforts to comply with access restrictions.

Reassessment of Liquefied Natural Gas Supply Potential

Interest in liquefied natural gas (LNG) as a source for fuel supply in the United States has been rekindled and strengthened as a result of sustained high natural gas prices, declining costs throughout the LNG supply chain (production, liquefaction, transportation, and regasification), and recent regulatory changes (see “Legislation and Regulations”). During the winter of 2000-2001—a colder winter than normal—natural gas prices on the domestic spot market climbed above $10.00 per thousand cubic feet, and the average wellhead price increased to $6.82 per thousand cubic feet in January 2001. At that time, plans were announced for the reopening of mothballed LNG terminals in Maryland (Cove Point) and Georgia (Elba Island), and plans for the construction of additional new facilities were being discussed.

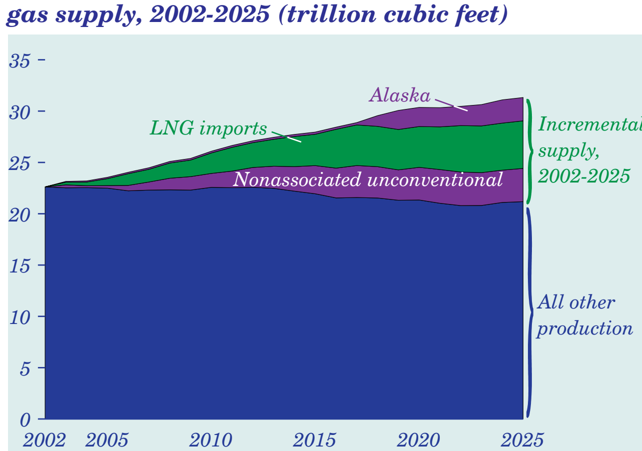
By July 2001, wellhead natural gas prices had dropped below $3.50 per thousand cubic feet, where they remained for most of 2002. Interest persisted in LNG, which generally was thought to be economical in the price range of $3.50 to $4.00 per thousand cubic feet, but momentum slowed as investors waited cautiously to see whether prices would remain below $3.50. In late 2002, average wellhead prices again began to rise, to $3.59 per thousand cubic feet in November and $3.84 in December. They have remained well above $4.00 per thousand cubic feet since then. Average wellhead prices for the first half of 2003 ranged from a low of $4.47 per thousand cubic feet in January to a high of $6.69 in March, contributing to the belief that there has been a fundamental upward shift in natural gas prices.

LNG imports are expected to constitute an increasing proportion of U.S. natural gas supply (Figure 17). Total net imports are projected to supply 21 percent of total U.S. natural gas consumption in 2010 (5.5 trillion cubic feet) and 23 percent in 2025 (7.2 trillion cubic feet), compared with recent historical levels of around 15 percent. Nearly all of the increase in net imports, from 3.5 trillion cubic feet in 2002, is expected to consist of LNG.

LNG imports already have doubled from 2002 to 2003, based on preliminary estimates that show LNG gross imports at 540 billion cubic feet in 2003, compared with 228 billion cubic feet in 2002. Strong growth in LNG is expected to continue throughout the forecast period, with LNG’s share of net imports growing from less than 5 percent in 2002 to 39 percent (2.2 trillion cubic feet) in 2010 and 66 percent (4.8 trillion cubic feet) in 2025.

In the *AEO2004* forecast, four new LNG terminals are expected to open on the Atlantic and Gulf Coasts between 2007 and 2010. The first new LNG terminal in more than 20 years is projected to open on the Gulf Coast in 2007. Although the actual sizes of the new plants will vary, for projection purposes a generic size of 1 billion cubic feet per day is used in *AEO2004* for

Figure 17. Major sources of incremental natural gas supply, 2002-2025 (trillion cubic feet)



new facilities on the Gulf Coast and 250 to 500 million cubic feet per day elsewhere. One facility, expected to serve Florida, is planned for construction in the Bahama Islands, with the gas to be transported through an underwater pipeline to Florida.

Existing U.S. LNG plants are expected to be at, or close to, full capacity by 2007, importing 1.4 trillion cubic feet annually, and new plants are projected to import a total of 812 billion cubic feet in 2010. In addition, a new terminal in Baja California, Mexico, is expected to start moving gas into Southern California in 2007, with volumes reaching 180 billion cubic feet by 2008. Additional capacity in Baja California is expected to be added in 2012, increasing annual deliveries into Southern California to 370 billion cubic feet per year from 2014 through 2025. Other new terminals are expected to be constructed in the Mid-Atlantic and New England regions by 2016, and significant additional capacity is expected along the Gulf Coast by 2025, including expansions of existing terminals and construction of new ones. Imports into new Gulf Coast terminals are projected to total nearly 2.5 trillion cubic feet in 2025.

It is considerably more expensive to build LNG regasification plants at new U.S. sites than to expand capacity at existing sites. In addition, LNG delivered to new sites can be expected to have higher production and shipping costs if it is obtained from new, potentially more distant and expensive supply sources. Delays and regulatory costs are also expected to add to the price of gas for new facilities. As a result, "trigger prices" for the construction of new LNG plants are estimated currently at \$3.62 to \$4.58 per million Btu, compared with less than \$2.87 to \$3.15 per million Btu for expansion at existing plants.

With changing market conditions, most forecasters now expect LNG to become an increasingly important source of incremental natural gas supply for the United States. As of August 2002, there were 16 active proposals to construct new LNG regasification terminals in North America to serve U.S. markets (or partially serve, as in the case of three proposed terminals in Baja California, Mexico), with total annual capacity slightly over 5 trillion cubic feet.

As of December 1, 2003, there were 32 active proposals for new terminals (Table 12): 21 in the United States, 4 in Baja California, Mexico (to serve both Mexico and U.S. markets), 2 in Mexico, 3 in the Bahamas (to serve U.S. markets), and 2 in Canada (to serve Canada and possibly also U.S. markets). The increase in proposed capacity between August 2002 and October 2003 includes both additional terminals and increases in capacity for many of those previously proposed. Proposed projects active during the summer of 2002 were primarily for terminals with a capacity of 1 billion cubic feet per day or less, whereas 9 of the current proposals are for terminals with a capacity of 1 to 2 billion cubic feet per day. If all the U.S. LNG facilities currently being proposed were completed, they would add more than 15 trillion cubic feet to annual U.S. import capacity. In addition, two proposed terminals in Mexico to serve Southern Mexican markets would have the indirect affect of reducing U.S. natural gas exports to Mexico.

Three proposals to construct terminals in the onshore Gulf of Mexico have been filed with the U.S. Federal Energy Regulatory Commission, and one, Cameron LNG (formerly Hackberry), has received preliminary approval (see "Legislation and Regulations"). Two more proposals for the offshore Gulf of Mexico have been filed with the U.S. Coast Guard. Despite this strong activity, proposals for new capacity involve significant risk and uncertainty, and not all are expected to move forward.

The delivery of new LNG supplies to a new U.S. regasification facility requires the financing, permitting, and construction of at least four expensive infrastructure components: gas production and processing facilities in a source country; an LNG liquefaction plant and export terminal; LNG transport tankers; and the LNG regasification and import terminal in the destination country. Additional pipeline capacity—either to the liquefaction plant or away from the regasification facility—might also be needed. If any aspect of the infrastructure chain is delayed by permitting, financing, or construction problems, the potential profitability of the endeavor could be significantly diminished.

Delays in the eventual commissioning of a new LNG supply chain ending in the United States could occur for a number of reasons:

- Changing circumstances in the U.S. natural gas market
- Changing political conditions or government policies, either in the United States or abroad
- Labor strikes or other local opposition (for example, Bolivia recently decided to end its LNG export program because of political unrest)
- Delays in financing (for example, Peru's Camisea LNG project has been delayed by problems in arranging financing with the Andean Development Corporation)
- International competition for LNG supplies.

Global developments are also contributing to the domestic emphasis on LNG, as new liquefaction facilities proliferate around the world and potential supply sources expand. Until 1995, almost all U.S. LNG imports were from Algeria. More recently, shipments have also been received from Nigeria, the United Arab Emirates, Oman, Qatar, Malaysia, Australia, and Trinidad and Tobago. Additional sources of supply exist throughout the world where liquefaction facilities are either being developed or are in the planning stages.

Current worldwide liquefaction capacity and LNG consumption are roughly equivalent at slightly over 6 trillion cubic feet per year, indicating that supply constraints are contributing to the current underutilization of U.S. regasification capacity. The equivalency of capacity and consumption is changing, however, with an additional annual capacity of 2 trillion cubic feet under construction and scheduled to come on line by 2006 and an additional 8.5 trillion cubic feet of capacity planned to come on line by 2011. Trinidad and Tobago, with current annual capacity of approximately 300 billion cubic feet, has now surpassed Algeria as the primary source of supply for U.S. markets. With an additional 157 billion cubic feet scheduled to come on line by 2006 and 570 billion cubic feet under consideration for development by 2011, Trinidad and Tobago (located in relative proximity to the U.S.) is an important player in the future growth of the U.S. LNG market.

As the global market evolves, LNG is becoming an increasingly important energy source for many countries. A number of European and Asian nations already rely heavily on LNG. Japan, in particular, depends on LNG to meet its power generation needs. As the world market for LNG continues to expand,

Table 12. North American LNG regasification proposals as of December 1, 2003 (million cubic feet per day)

Project	*Owners*	*Location*	*Start year*	*Capacity added*
West Coast				
Terminal GNL Mar Adentro de B.C.	*ChevronTexaco*	*Baja California, Mexico (offshore)*	*2007*	*750*
Tijuana Regional Energy Center	*Marathon/Golar LNG/Grupo GGS*	*Baja California, Mexico*	*2006*	*750*
Sound Energy Solutions	*Mitsubishi*	*Long Beach, California*	*2007*	*700*
Terminal LNG de Baja California	*Shell*	*Baja California, Mexico*	*2007*	*1,000*
Energia Costa Azul LNG	*Sempra Energy*	*Baja California, Mexico*	*2007*	*1,000*
Crystal	*Crystal Energy*	*Oxnard, California (offshore)*	*2006*	*600*
Tractebel Mexico	*Tractebel*	*Lazaro Cardenas, Mexico*	*2007*	*500*
Cabrillo Port LNG	*BHP Billiton*	*Oxnard, California (offshore)*	*2008*	*1,500*
Florida/Bahamas				
Ocean Express LNG	*AES*	*Ocean Cay, Bahamas*	*2006*	*850*
Freeport	*El Paso*	*Freeport Grand Island, Bahamas*	*2007*	*500*
Calypso	*Tractebel Bahamas LNG*	*Freeport Grand Cayman, Bahamas*	*2007*	*832*
Gulf Coast				
ExxonMobil LNG	*ExxonMobil*	*Quintana Island, Texas*	*2007*	*1,000*
Sabine Pass/Cheniere	*Cheniere*	*Sabine Pass, Texas*	*2008*	*2,000*
Port Pelican	*ChevronTexaco*	*Louisiana (offshore)*	*2007*	*1,600*
Cameron LNG	*Sempra Energy*	*Hackberry, Louisiana*	*2007*	*1,500*
Altamira	*Shell*	*Altamira, Mexico*	*2004*	*500*
Corpus Christi LNG	*Cheniere Energy*	*Corpus Christi, Texas*	*2008*	*2,000*
ExxonMobil/Sabine Pass LNG	*ExxonMobil*	*Sabine Pass, Texas*	*2008*	*1,000*
Liberty	*HNG Storage/Conversion Gas*	*Cameron, Louisiana*	*2007*	*3,000*
Main Pass Energy Hub	*Freeport-McMoRan Sulphur*	*Gulf of Mexico (offshore)*	*2006*	*1,500*
Gulf Landing	*Shell*	*West Cameron, Louisiana (offshore)*	*2008-2009*	*1,000*
Vermilion 179	*Conversion Gas Imports*	*Louisiana*	*2008*	*1,000*
Mobile Bay LNG	*ExxonMobil*	*Mobile Bay, Alabama*	*2008*	*1,000*
Freeport LNG	*Freeport, Cheniere, Contango*	*Freeport, Texas*	*2006*	*1,500*
Energy Bridge	*El Paso*	*Floating Dock (offshore)*	*2005*	*500*
East Coast				
Canaport	*Irving Oil/Chevron Texaco*	*Canaport, New Brunswick, Canada*	*2006*	*500*
Weaver's Cove	*Poten*	*Fall River, Massachusetts*	*2007*	*400*
Access Northeast Energy	*Access Northeast Energy*	*Bearhead, Nova Scotia, Canada*	*2008*	*500*
Fairwinds LNG	*TransCanada, ConocoPhillips*	*Harpswell, Maine*	*2009*	*500*
Providence LNG	*Keyspan, BG LNG Services*	*Providence, Rhode Island*	*2005*	*500*
Crown Landing	*BP*	*Logan Township, New Jersey*	*2008*	*1,200*
Somerset LNG	*Somerset LNG*	*Somerset, Massachusetts*	*2007*	*430*

natural gas is expected to become more of a global commodity, and the world natural gas market is expected to affect the U.S. market [*47*].

An important aspect of globalization is expansion of the LNG spot market. Internationally, most LNG currently is traded under long-term contracts. In recent years, however, the short-term market has played a more significant role, especially in the United States (Figure 18). Most of the LNG imported at the Everett terminal in Massachusetts remains under long-term contract at relatively stable quantities, but short-term deliveries at Lake Charles, Louisiana, have risen and fallen dramatically over the past few years, primarily in response to domestic natural gas prices. In 2002, all cargoes into Lake Charles were delivered under short-term contracts.

Recent developments in Japan and South Korea illustrate the potential impact of global developments on the U.S. LNG market. In Japan, the forced closing of more than a dozen nuclear reactors in 2001 and 2002 because of reporting discrepancies led to greater reliance on fossil fuels for electricity generation. The result was a significant increase in Japan's demand for LNG, so that the majority of world spot cargoes were delivered to the Japanese market. Japan's increased reliance on LNG probably contributed to the reduction in short-term deliveries of LNG to the United States during the winter of 2001-2002, although low natural gas prices also played a role. In South Korea, an unusually cold winter in 2002-2003 led to the diversion of many spot cargoes to that country to meet unusually high demand for heating. The increase in shipments to South Korea may in part explain the low level of U.S. LNG imports during the winter of 2002-2003, when natural gas spot prices were spiking. These examples suggest that an assessment of future U.S. LNG consumption patterns cannot be based solely on the economics of the U.S. natural gas market.

In the United States, an important factor in the future growth of LNG imports is natural gas market prices. The potential impact of U.S. natural gas prices on LNG imports is illustrated by two *AEO2004* sensitivity cases, the rapid and slow technology cases (Figure 19). The rapid and slow technology cases are used to assess the sensitivity of the projections to changes in assumed rates of progress for oil and natural gas supply technologies. To create the cases, reference case parameters for the effects of technological progress on finding rates, drilling activity, lease equipment and operating costs, and success rates for conventional oil and natural gas wells were adjusted by plus or minus 50 percent. Parameters for a number of key exploration and production technologies for unconventional gas were also adjusted by plus or minus 50 percent, and key parameters for Canadian supply were also adjusted to simulate the assumed impacts of rapid and slow oil and gas technology penetration on Canadian supply potential.

In the projections for 2010, natural gas wellhead prices range from $3.25 per thousand cubic feet (2002 dollars) in the rapid technology case to $3.58 in the slow technology case; and in the 2025 projections, the prices range from $3.80 in the rapid technology case to $5.10 in the slow technology case. The volume of LNG imports across the rapid and slow technology cases varies from 1.6 trillion cubic feet to 2.3 trillion cubic feet, respectively, in 2010 and from 3.8 to 5.5 trillion cubic feet in 2025, compared with 0.2 trillion cubic feet in 2002.

Figure 18. U.S. quarterly LNG imports by contract type, 1996-2003 (billion cubic feet)

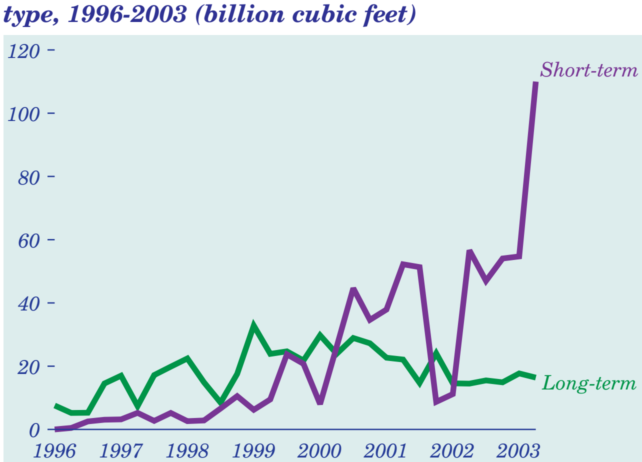
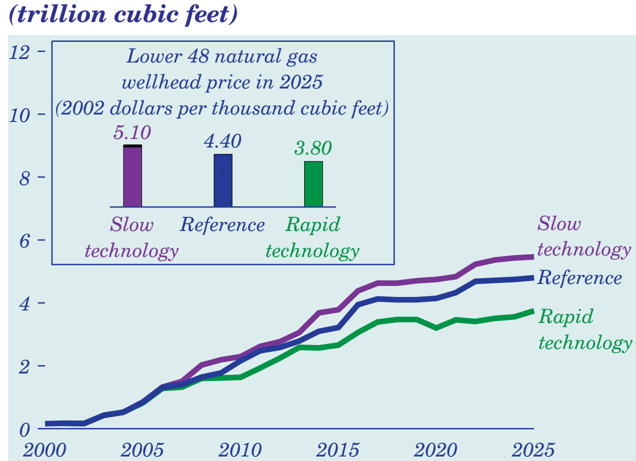


Figure 19. U.S. net imports of LNG, 2000-2025 (trillion cubic feet)



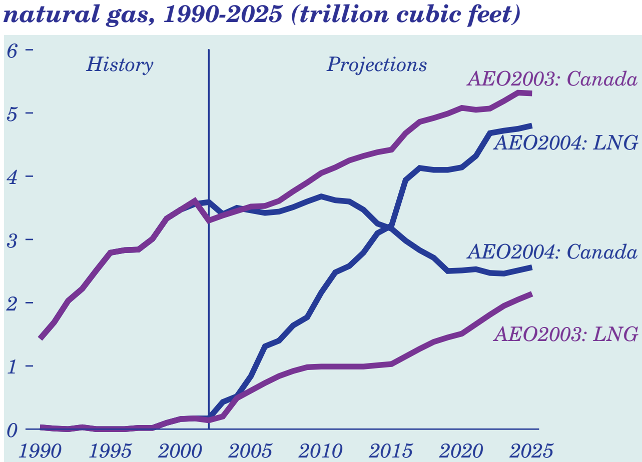
Reassessment of Canadian Natural Gas Supply Potential

Until recently, Canada was expected to remain the primary source of natural gas imports for the United States through 2025, as projected in *AEO2003*; however, the *AEO2004* reference case projects that net imports of LNG will exceed net imports from Canada by 2015 (Figure 20). The primary reason for the change in the *AEO2004* forecast is a significant downward reassessment by the Canadian National Energy Board (NEB) of expected natural gas production in Canada. Both the NEB and the NPC have revised their earlier estimates of total Canadian natural gas production [*48*].

In 1999, NEB estimated total production in Canada in a range of 8.1 to 9.0 trillion cubic feet in 2015 and 7.7 to 9.9 trillion cubic feet in 2025. In contrast, NEB's 2003 estimates show 5.9 to 7.1 trillion cubic feet in 2015 and 4.3 to 6.1 trillion cubic feet in 2025. NPC's 1999 estimate for Canadian production in 2015 was 8.2 trillion cubic feet (no estimate was given for 2025). In 2003, NPC estimated a range of 6.4 to 7.0 trillion cubic feet for 2015 and 5.8 to 6.9 trillion cubic feet for 2025.

Other reasons are declining natural gas production in the province of Alberta, which accounts for more than 75 percent of Canada's natural gas production, and increasing use of natural gas for oil sands production. In its most recent annual reserve report, the Alberta Energy and Utilities Board expects gas production in the province to decline at an average rate of 2 percent per year between 2003 and 2012, while its oil sands production could triple. Because natural gas is one of the fuels used in producing oil sands (see below, "Natural Gas Consumption in Canadian Oil Sands Production"), such a dramatic increase could divert significant amounts of gas from the U.S. import market. Additional factors that could contribute to a decline in Canadian gas exports include higher projections for domestic natural gas demand in Canada and recent disappointments in Canadian drilling results, including smaller discoveries with lower initial production rates and faster decline rates.

Figure 20. U.S. net imports of LNG and Canadian natural gas, 1990-2025 (trillion cubic feet)



Two recent and significant drilling disappointments occurred in northeastern British Columbia's Ladyfern field and the Scotian Shelf Deep Panuke field. Production from the Ladyfern field, heralded as Canada's largest find in 15 years, peaked at 700 million cubic feet per day in 2002 and is declining rapidly. Current production is about 300 million cubic feet per day, and many expect the field to be depleted by the end of 2004. In February 2003, EnCana, initially highly optimistic about the Deep Panuke field, requested that the regulatory approval process for developing the field be placed on hold while it reassesses the economics of development.

The *AEO2004* forecast expects the decline in Canadian imports to be mitigated partially by the construction of a pipeline to move MacKenzie Delta gas into Alberta. Initial flows from the pipeline are expected in 2009, with annual throughput reaching approximately 675 billion cubic feet in 2012 and remaining at that level through 2025.

Natural Gas Consumption in Canadian Oil Sands Production

In recent years, extensive investment has gone into the development of Alberta's oil sands. In 2002, Canada's crude bitumen production from oil sands averaged 790,000 barrels per day, while conventional crude output was 2,140,000 barrels per day (including natural gas liquids). Natural gas is used both to extract the bitumen from the sand and to convert the bitumen into syncrude. Currently, oil sands operations consume approximately 330 billion cubic feet per year of natural gas.

Canadian oil producers have announced a number of new oil sands projects and expansions to existing oil sands facilities. The question has arisen as to whether these existing and future facilities will raise Canada's gas consumption by a significant amount, thereby reducing the amount of Canada gas production, which is available for export to the United States. This discussion will briefly examine this issue.

Most of the existing and proposed oil sands projects are located in the east-central portion of Alberta and are dispersed along a roughly north-south axis of about 200 miles in length. The Canadian oil sands consist of a mixture of sand, bitumen, and water. Based on existing facilities, and project announcements for expansions and new oil sands production facilities, EIA projects total oil sands bitumen production to be 1.7 and 3.3 million barrels per day in 2010 and 2025, respectively (Table 13). In 2010, about 52 percent of the bitumen is projected to be surface mined, and the remaining 48 percent is projected to be produced through in situ production [*49*]. In 2025, approximately 57 percent of the oil sands bitumen is projected to be surface mined, and 43 percent is projected to be produced through the in-situ production method.

To produce synthetic crude oil, the bitumen can be either partly or totally petroleum coked or hydrocracked. Petroleum coking requires less process energy than hydrocracking and does not require a hydrogen feedstock, but 100 barrels of bitumen yields only 79 barrels of syncrude. Hydrocracking, on the other hand, requires both more process energy and a hydrogen feedstock, but 100 barrels of bitumen produces about 106 barrels of syncrude.

There are three potential fuels that can be used either exclusively or in part to produce oil sands syncrude, namely, natural gas, produced bitumen, or petroleum coke, the latter of which is a process byproduct. Depending upon an oil sands facility's design flexibility, the syncrude producer can change the slate of inputs, such as natural gas, and the slate of outputs (e.g., syncrude, petroleum coke) so as to maximize the profit margin associated with the production and upgrading of bitumen into syncrude, based on the cost/price of both the inputs and outputs. Consequently, the consumption of natural gas in these upgrading facilities is expected to change over time as relative prices change. Moreover, the input/output flexibility of any particular bitumen upgrading facility can be enhanced in the future, if prices warrant. Consequently, if natural gas prices were sufficiently high and oil prices sufficiently low, syncrude producers could theoretically eliminate natural gas consumption entirely through the exclusive use of bitumen and petroleum coke to provide the energy and feedstocks to produce and upgrade the bitumen.

Carbon dioxide emissions might also play a role in determining the proportions of natural gas, bitumen, and petroleum coke used for oil sands production and processing. On December 17, 2002, Canada ratified the Kyoto Protocol, which obligates it to reduce carbon dioxide emissions to 6 percent below their 1990 level. Because petroleum coke and bitumen release more carbon dioxide when burned than natural gas does, Canada's Kyoto Protocol obligation could limit the use of petroleum coke and bitumen in the processing of bitumen from Canadian oil sands.

If natural gas were to be used exclusively to produce and convert bitumen into syncrude, then the following volumes of natural gas would be consumed to perform each of the following processes:

- Surface mine 1 barrel of bitumen—approximately 131 cubic feet
- In situ production of 1 barrel of bitumen—1,000 to 1500 cubic feet
- Petroleum coking 1 barrel of bitumen—approximately 168 cubic feet
- Hydrocracking 1 barrel of bitumen—approximately 490 cubic feet.

The natural gas consumption estimates presented in Table 13 assume that natural gas is the *only* energy and feedstock source for the production and upgrading of bitumen into syncrude. Table 13 assumes that the in situ production of bitumen requires 1,250 cubic feet of natural gas per barrel of bitumen. The first estimate (Case I) assumes that the bitumen is exclusively petroleum coked to create syncrude, while the second (Case II) assumes that the bitumen is exclusively hydrocracked. Of course, if oil sands producers were to extensively use bitumen and petroleum coke to provide most of the process energy and hydrogen feedstock requirements, then the actual natural gas

Table 13. Projected Canadian tar sands oil supply and potential range of natural gas consumption in the AEO2004 reference case, 2002-2025

Projection	2002	2005	2010	2015	2020	2025
Tar sands oil supply (million barrels per day)						
Mined bitumen	0.43	0.56	0.87	1.64	1.82	1.87
In situ bitumen	0.36	0.44	0.82	1.33	1.38	1.41
Total unconventional	0.79	1.00	1.69	2.97	3.20	3.28
Potential natural gas consumption (billion cubic feet per year)						
Case I: Petroleum coking of bitumen into syncrude	NA	289	519	867	913	934
Case II: Hydrocracking of bitumen into syncrude	NA	406	718	1,216	1,289	1,319

consumed in future years would be considerably less, potentially as low as zero.

In conclusion, given the potential fuel flexibility of oil sands production facilities, the question of whether Canadian oil sands production will consume significant volumes of natural gas is not easily answered. The answer to this question will depend not only on the relative prices of syncrude and natural gas, but also on the degree to which oil sands producers build fuel-flexible facilities. Consequently, the actual outcome could be as high as 1.3 trillion cubic feet per year or as low as zero.

Natural Gas Consumption in the Industrial Sector

Natural gas consumption in the U.S. industrial sector increased by 1.6 percent per year on average from 1990 to 2000, fell sharply in 2001, and continued to decline in 2002. During the 1990s, the industrial sector accounted for slightly less than 37 percent of total U.S. natural gas consumption, peaking in 1997 at 8.7 quadrillion Btu or 37.5 percent of the total. In the *AEO2004* reference case, industrial natural gas use is projected to return to a path of steady increase after 2003, averaging 1.5-percent annual growth from 2002 to 2025 (Figure 21). Total natural gas consumption for industrial uses is projected to reach 10.6 quadrillion Btu in 2025—3.1 quadrillion Btu higher than in 2002—based on projected growth in industrial output and modestly increasing natural gas prices over the forecast period.

Within the industrial sector, natural gas use for combined heat and power (CHP) applications is projected to increase by 2.6 percent per year, for feedstocks by 0.8 percent per year, and for boiler fuel and direct uses by 1.4 percent per year from 2002 to 2025 (Figure 22). With total industrial output (value of shipments) increasing by 2.6 percent annually over the same period, the natural gas intensity of industrial output in 2025 is projected to be 21 percent lower than in 2002.

As a result of the economic recession that began in 2001 and the rise in natural gas prices since 2000, some industry observers have concluded that segments of the U.S. industrial sector have permanently reduced output through closures of manufacturing plants, and that the result will be a permanent reduction in demand for natural gas. Others note that similar industrial reactions to sharp increases in gas prices and to recessions are not unprecedented, and that the recent drop in demand is likely to be temporary [*50*] once industrial production growth resumes. A history of the recent relationship between industrial production and natural gas consumption is shown in Figure 23. In the absence of severe, multi-year recessions in the industrial sector and sustained higher prices for natural gas, it is reasonable to expect industrial output and natural gas consumption to increase in the future.

AEO2004 projects little or no growth in industrial demand for coal, and most of the projected increase in demand for petroleum products is for asphalt and petroleum byproducts. Natural gas remains the fuel of choice in the industrial sector and will continue to fire most CHP applications. In the *AEO2004* reference case, industrial natural gas prices are projected to rise by 1.4 percent per year on average, to $5.00 per million Btu in 2025—60 cents lower in constant 2002 dollars than the 2003 price (Figure 24).

Some portions of the industrial sector, however, are especially sensitive to natural gas prices—particularly those that use natural gas as a feedstock, such

Figure 21. Industrial natural gas consumption, history and projections, 1990-2025 (quadrillion Btu)

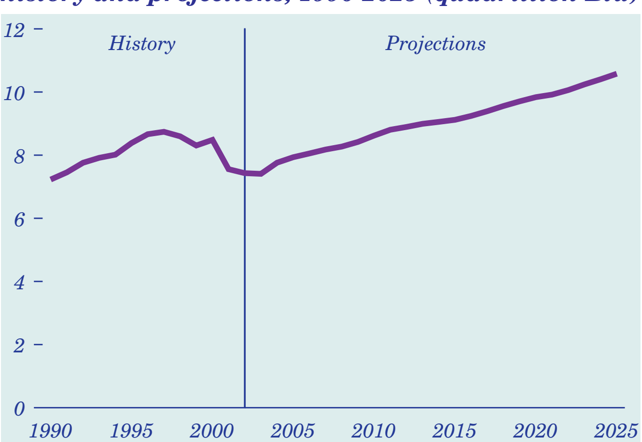
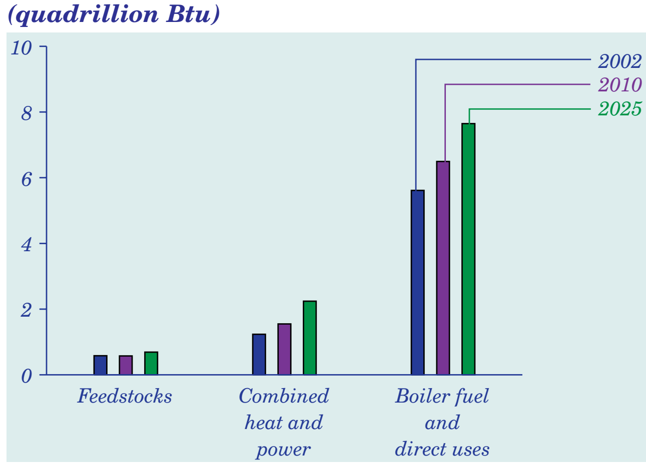


Figure 22. Components of industrial natural gas consumption, 2002, 2010, and 2025 (quadrillion Btu)



as nitrogenous fertilizer production, organic chemical production, and petrochemical production. For example, 0.7 quadrillion Btu of natural gas was used for feedstocks in the chemical industry in 1998 [*51*], accounting for about 10 percent of total natural gas consumption in the manufacturing sector. Petroleum-based products, however, were the largest source of industrial feedstock (for organic chemicals, plastics, synthetic rubber, and petrochemicals), amounting to 3.1 quadrillion Btu, more than four times the quantity of natural gas used as a feedstock in 1998.

One sector particularly sensitive to higher natural gas prices is the nitrogenous fertilizer industry. Natural gas costs account for 70 to 80 percent of the cash cost of fertilizer: production of a ton of ammonia uses 33.5 million Btu of natural gas [*52*]. At the average industrial natural gas price during the 1990s, the embodied cost of energy per ton of ammonia equates to about $120. At the estimated average industrial natural gas price in 2003 ($5.60 per million Btu), the embodied cost of energy is $188 per ton—a 57-percent increase. This significant increase in cost, if passed through completely, would amount to only 9.9 cents per bushel of corn, or 4 percent of the total average price of $2.35 per bushel in 2002 [*53*]. Large percentage increases in costs for ammonia production do not, therefore, necessarily result in proportional increases in the price of agricultural products.

Higher production costs tend to be passed through quickly to the price of ammonia [*54*], although the amount of the pass-through can be reduced by competition from imports. Imports of ammonia historically have accounted for about 20 percent of U.S. demand. Their impact on reducing the amount of pass-through costs can, however, lag over time.

The demand for natural gas as a feedstock to produce ammonia is determined largely by the quantity of ammonia produced, because petroleum-based fuels are not generally a viable economic alternative [*55*]. In 1998, the nitrogenous fertilizer industry consumed 338 trillion Btu of natural gas as a feedstock [*56*]. An additional 234 trillion Btu was consumed for process heating. In principle, the portion of the industry's natural gas consumption used for process heating could be switched to another fuel; however, in 1994 (the most recently available data for fuel switching), the nitrogenous fertilizer industry reported that only 3.1 trillion Btu (1 percent) of its natural gas use was switchable [*57*].

For at least two decades, the nitrogenous fertilizer industry in the United States has been consolidating [*58*]. From 89 plants with an average annual capacity of 171,000 metric tons in 1970, the number of plants fell sharply after 1980, and the average capacity of the remaining plants more than doubled. In 2002 there were only 37 plants operating, with an average capacity of 451,000 metric tons. Total industry capacity in 2002, at 16.7 million metric tons, was only slightly higher than in 1970 (15.2 million metric tons).

The consolidation, or even permanent closure, of nitrogenous fertilizer plants has no meaningful impact on U.S. natural gas markets, because the plants account for only a small portion of total U.S. gas consumption (0.5 quadrillion Btu out of 21.1 quadrillion Btu total in 1998). In addition, permanent closure of fertilizer plants in response to a temporary increase in natural gas prices is unlikely. For example, several producers temporarily idled their plants in the first quarter of 2002, but most of the idled capacity was back on line by the fourth quarter of the year [*59*]. Also, the largest U.S. producer of

Figure 23. Industrial natural gas consumption and output, 1978-2002 (index, 2002 = 1.0)

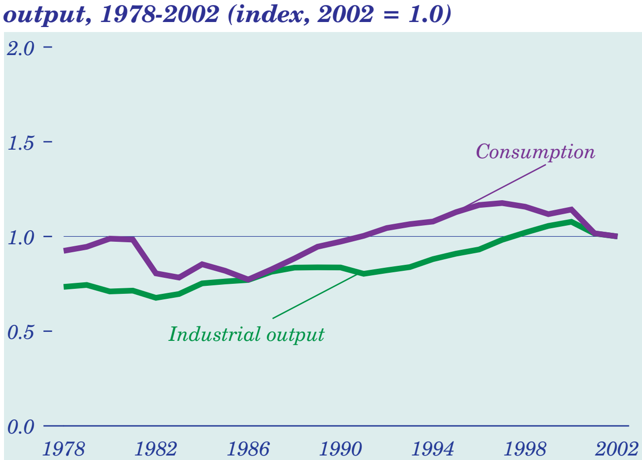
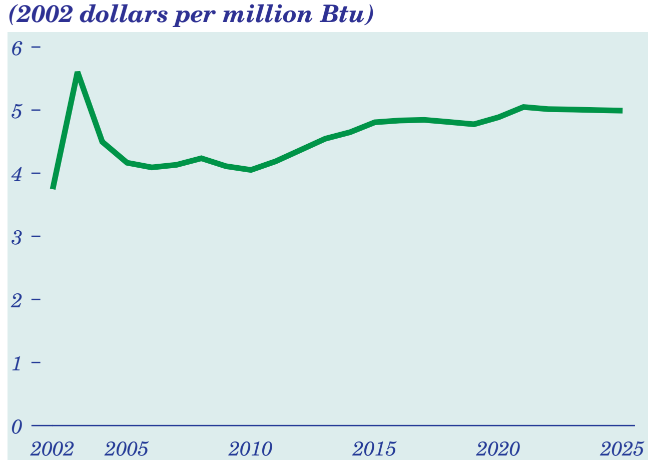


Figure 24. Industrial natural gas prices, 2002-2025 (2002 dollars per million Btu)



nitrogenous fertilizer (Farmland Industries, an agricultural cooperative), which declared bankruptcy in early 2002 [*60*], continued to operate most of its plants.

In the *AEO2004* reference case, industrial sector output is projected to grow by 2.6 percent annually from 2002 to 2025, the same growth rate experienced in the 1990s. The bulk chemical industry is projected to grow by 1.6 percent annually, slightly below its 1.8-percent growth rate during the 1990s. Agriculture is projected to grow by 1.2 percent annually, leading to a projected 0.9-percent annual growth rate for agricultural chemical production, of which nitrogenous fertilizer is a part [*61*]. In 2025, the value of agricultural chemical shipments is projected to be $24 billion, approximately equal to their 1997 value (Figure 25).

Figure 25. Agricultural chemicals value of shipments, history and projections, 1990-2025 (billion 2002 dollars)

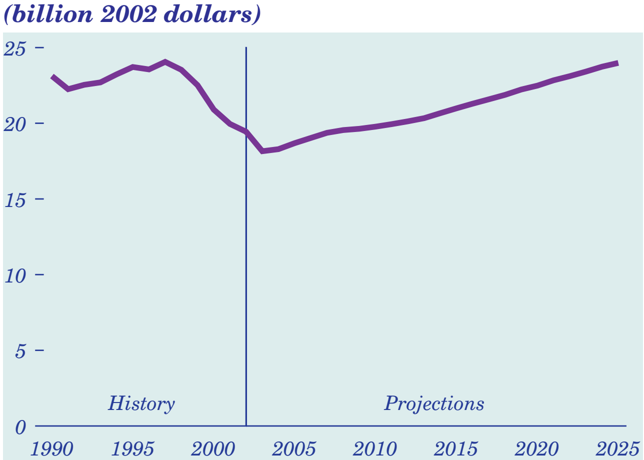
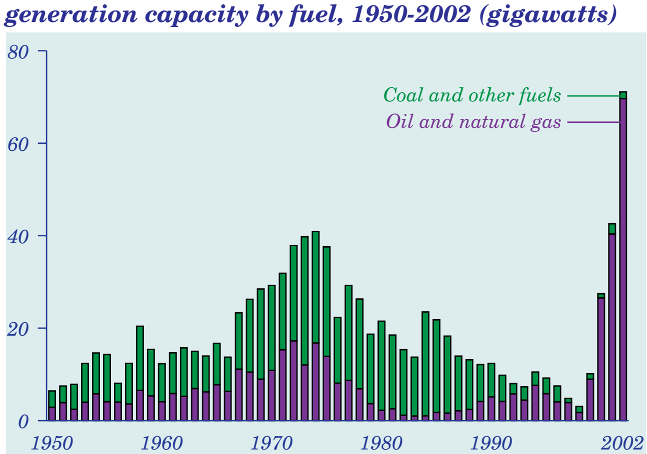


Figure 26. Annual additions to electricity generation capacity by fuel, 1950-2002 (gigawatts)



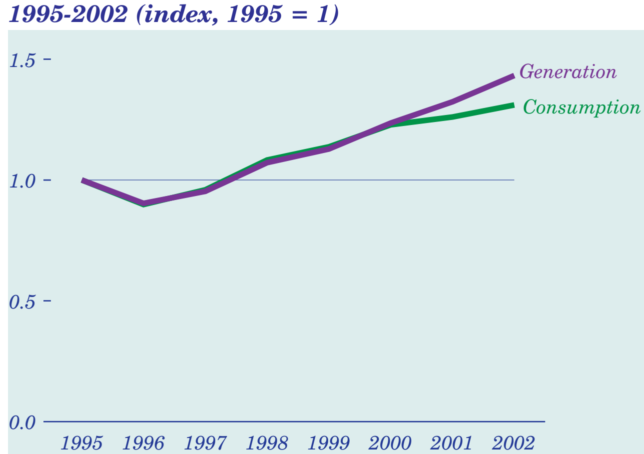
Natural Gas Consumption for Electric Power Generation

Data from EIA's Form EIA-860 survey, "Annual Electric Generator Report," show a dramatic increase in additions to U.S. electricity generation capacity over the past 3 years. In 2000, 2001, and 2002 more than 141 gigawatts of new generating capacity was constructed—far more than in any previous 3-year period. Virtually all of that new capacity uses natural gas as the primary fuel for electricity generation (Figure 26).

Given the recent pace of capacity additions, it is not surprising that the amount of electricity produced from natural gas has increased substantially; however, natural gas consumption in the electric power sector has not increased as rapidly, because the efficiency of gas-fired generation has improved significantly (Figure 27). From 1995 to 2002, natural-gas-fired generation in the power sector increased by 43 percent, but natural gas consumption increased by only 31 percent. Notably, the gap between growth in natural-gas-fired generation and natural gas consumption by power producers began to appear in 2000, when the first wave (27 gigawatts) of the recent surge in capacity expansion occurred.

The role of natural gas in the electric power sector is expected to continue growing for the foreseeable future. At the same time, the disparity between increases in gas-fired generation and in the amount of natural gas consumed by power producers is also expected to continue growing. In addition to the amount of new gas-fired generating capacity added, other factors that will affect the amount of natural gas used to generate electricity over the coming decades include: the rate of growth in electricity sales;

Figure 27. Natural gas consumption and gas-fired electricity generation in the electric power sector, 1995-2002 (index, 1995 = 1)



the efficiencies of new gas-fired plants relative to those of older plants; and the price of natural gas relative to the prices of other fuels, particularly coal.

Relative to the amount of generating capacity operating in 1999, additions over the 2000-2002 period amounted to an increase of 18 percent. Over the same period, electricity sales grew by only 5 percent. Consequently, many of the plants added in recent years are unlikely to be used at full capacity in the early years of their operation. Moreover, an additional 45 gigawatts of new capacity is expected to be added in 2003, all but 2 gigawatts of which will use natural gas. With growth in electricity sales expected to continue at a much more modest pace, the recent disparity between generating capacity growth and sales growth is expected to widen in the near term, and it could be many years before much of the newly added capacity is used intensively.

Where new natural gas plants are used, their generation will often displace generation that would have come from older, less efficient oil- and gas-fired generators. The natural-gas-fired plants that have been added in recent years are much more efficient than older plants. For example, new combined-cycle plants have operating efficiencies between 45 and 50 percent, whereas the efficiencies of older steam plants generally are 33 percent or less. Accordingly, a new plant could generate the same amount of electricity as an older plant while consuming 27 percent less natural gas, or could use the same amount of gas as an older plant while generating 36 percent more electricity [*62*]. The "efficiency gap" between old and new natural-gas-fired power plants is expected to lead power companies to retire many of their older plants, because it will no longer be economical to maintain them. The newer plants, using substantially less fuel, will provide the power that the older plants were generating.

In the *AEO2004* reference case forecast, natural gas consumption in the electric power sector is projected to continue to increase; however, the gap between the growth in natural gas generation and natural gas consumption in the power sector is also projected to widen (Figure 28). In 2025, the amount of electricity generated from natural gas is projected to be 166 percent greater than it was in 1995, but the amount of natural gas consumed for electricity production is projected to increase by only 98 percent. Over the same period, the average efficiency of all generators using natural gas is projected to increase from 33 percent to 45 percent.

Finally, in the later years of the forecast, rising natural gas prices are expected to make new coal-fired capacity economically competitive. When new coal-fired generating plants are added, they will be less expensive to operate than gas-fired plants, including those currently coming into service, and they are expected to be used for baseload generation, meeting customer needs around the clock. The capacity factor for all oil- and gas-fired capacity is projected to decline initially (Figure 29) because of the surge of capacity additions in 2002 and 2003, then rise to about 28 percent in 2018, and then decline as new coal-fired plants come on line. In the *AEO2004* forecast, the end result is that natural gas consumption in the electric power sector is projected to continue growing more slowly than either additions of gas-fired capacity or generation using natural gas.

Figure 28. Natural gas consumption and gas-fired electricity generation in the electric power sector, 1995-2025 (index, 1995 = 1)

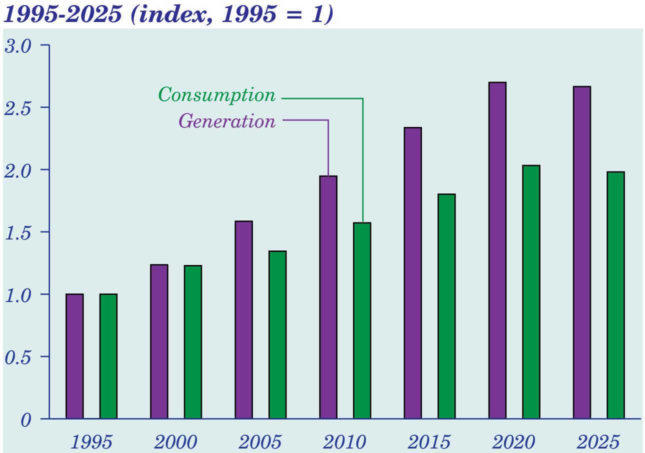
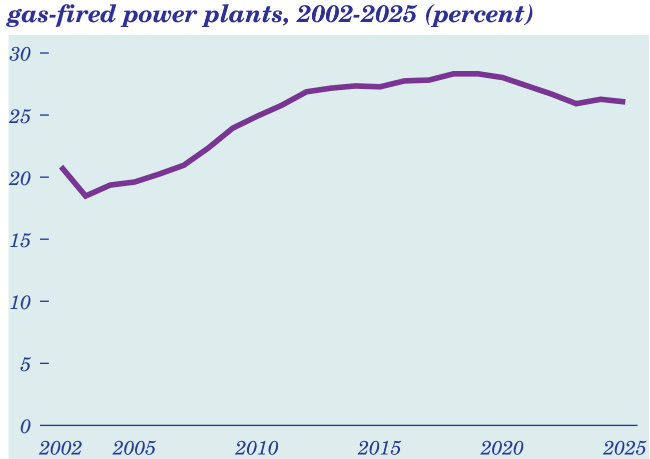


Figure 29. Average capacity factor for oil- and gas-fired power plants, 2002-2025 (percent)



Natural Gas Markets: Comparison of *AEO2004* and National Petroleum Council Projections

The National Petroleum Council (NPC) recently released the first volume of a report describing two possible projections for U.S. natural gas market conditions through 2025 [*63*]. The NPC's Reactive Path and Balanced Future scenarios are compared here with the *AEO2004* reference case. Unlike the *AEO2004* reference case, which assumes the continuation of current laws, policies, regulations, technology trends, and productivity trends through 2025, the two NPC scenarios assume the adoption of new policies, which "move beyond the status quo." Of the two NPC scenarios, the design of the Reactive Path is closer to that of the *AEO2004* reference case than is the design of the Balanced Future scenario.

This discussion focuses on a "global" comparison of the NPC and *AEO2004* projections and assumptions, because the two reports categorize and aggregate energy market data differently. Although the NPC report and *AEO2004* begin from similar estimates of total end-use gas consumption in 2002 (20.5 and 20.8 trillion cubic feet, respectively), the NPC study shows 0.9 trillion cubic feet more gas consumption in the industrial sector and 1.1 trillion cubic feet less gas consumption in the electric power sector in 2002. This accounting difference can be attributed in part to the fact that EIA has revised its data collection and reporting systems for industrial electricity generation, or CHP. In addition, new industrial CHP is reported by the NPC in the electric power sector, whereas historical CHP consumption is counted in the industrial sector. These accounting complications preclude direct comparison of the *AEO2004* and NPC projections for industrial and electric power sector natural gas consumption. Table 14 provides an overview of the *AEO2004* and NPC 2002 data and projections for 2010 and 2025.

The primary similarities between *AEO2004* and the NPC projections include:

- The residential and commercial natural gas consumption projections are almost identical.
- The *AEO2004* gas consumption growth rate associated with electric power generation falls between the growth rates projected in the two NPC scenarios when the accounting is adjusted to be the same for *AEO2004* and the NPC study [*64*].
- The relative proportions of domestic gas production and imports are similar in the *AEO2004* and NPC projections.
- Both *AEO2004* and the NPC projections expect gas imports from Canada to peak in 2009-2010 and decline thereafter.
- Imports of LNG are expected to increase throughout the forecasts, so that by 2025 overseas LNG is the primary source of U.S. natural gas imports.
- Projected volumes of offshore gas production are similar in the two reports.
- Relative to nonassociated conventional gas, unconventional gas is projected to be the least expensive incremental source of lower 48 onshore gas supply.

The primary differences between the *AEO2004* and NPC projection scenarios include:

- The NPC projections expect lower growth in industrial output and a decline in industrial natural gas consumption, leading to lower overall consumption growth than in *AEO2004*.
- The NPC estimate of the cost of developing and producing lower 48 natural gas resources is higher than those in *AEO2004*. As a result, NPC projects higher wellhead prices and less onshore natural gas production.
- The *AEO2004* reference case projects increasing onshore gas production, whereas the NPC scenarios project constant or declining onshore production. This difference can be attributed largely to the *AEO2004* and NPC projections for onshore nonassociated conventional gas production, which is projected to be 5.9 trillion cubic feet in 2025 in the *AEO2004* reference case, compared with 4.2 and 4.1 trillion cubic feet in the NPC Reactive Path and Balanced Future scenarios, respectively.
- The *AEO2004* reference case projects a steady decline in lower 48 onshore associated-dissolved gas production, to 1.2 trillion cubic feet in 2025. Both of the NPC scenarios project a slight decline through 2005, followed by a slight rebound that results in a 2025 projection for lower 48 onshore conventional associated-dissolved gas production that is almost identical to the 2002 level.
- The NPC projects a wide potential range of future gas prices, with Henry Hub spot prices spanning approximately \$3.00 to \$7.00 per million Btu (2002 dollars) in 2025. *AEO2004* projects 2025 wellhead prices at \$4.40 per thousand cubic feet, equivalent to \$4.28 per million Btu (2002 dollars) [*65*].

Forecast Assumptions

Both the NPC Reactive Path scenario and the *AEO2004* reference case assume that U.S. GDP will grow by 3 percent per year through 2025. For U.S. electricity generation, *AEO2004* projects 1.8-percent average annual growth from 2002 through 2025, while the NPC Reactive Path and Balanced Future scenarios project average annual growth of 2.1 percent and 2.0 percent, respectively. *AEO2004* projects 2.6-percent annual growth in industrial output, compared with 1.1 percent in the NPC scenarios.

AEO2004 and the NPC scenarios expect different future oil prices. Both the NPC scenarios assume that U.S. refiner crude oil acquisition prices will decline to $18 per barrel in 2005 (2002 dollars) and continue at that level through 2025. *AEO2004* assumes that the refiner acquisition price for imported crude oil will decline to $23.30 per barrel in 2005 and increase slowly to $27.00 per barrel in 2025 (2002 dollars).

The NPC Reactive Path scenario differs from *AEO2004* in projecting the size and composition of the undiscovered lower 48 natural gas resource base (Figure 30). Generally, *AEO2004* assumes a larger resource (1,065 trillion cubic feet) than the Reactive Path and Balanced Future scenarios (770 and 874 trillion cubic feet, respectively) [*66*]. *AEO2004* assumes more onshore conventional resources (392 trillion cubic feet) than the Reactive Path and Balanced Future scenarios (289 and 297 trillion cubic feet) and more unconventional gas resources (475 trillion cubic feet) than the Reactive Path and Balanced Future scenarios (216 and 234 trillion cubic feet). The Reactive Path and Balanced Future scenarios assume more undiscovered offshore gas resources (265 and 343 trillion cubic feet) than *AEO2004* (197 trillion cubic feet). Accordingly, *AEO2004* projects proportionately more onshore gas production at market-clearing prices than do the NPC scenarios.

Table 14. Overview of U.S. natural gas consumption and supply projections, 2002, 2010, and 2025 (trillion cubic feet)

Projection	2002 AEO2004	2002 Reactive Path	2002 Balanced Future	2010 AEO2004	2010 Reactive Path	2010 Balanced Future	2025 AEO2004	2025 Reactive Path	2025 Balanced Future
Consumption									
Residential	4.92	4.79	4.79	5.53	5.48	5.24	6.09	6.17	5.82
Commercial	3.12	3.11	3.11	3.48	3.50	3.49	4.04	4.09	4.18
Subtotal	**8.04**	**7.91**	**7.91**	**9.01**	**8.97**	**8.73**	**10.13**	**10.26**	**10.00**
Industrial	7.23	8.15	8.15	8.39	7.03	7.41	10.29	7.10	7.38
Electric power	5.55	4.45	4.45	6.66	6.67	6.15	8.39	8.18	7.24
Subtotal	**12.77**	**12.59**	**12.59**	**15.05**	**13.70**	**13.56**	**18.68**	**15.28**	**14.62**
Transportation	0.01	—	—	0.06	—	—	0.11	—	—
Total end use	**20.83**	**20.50**	**20.50**	**24.11**	**22.68**	**22.29**	**28.92**	**25.54**	**24.62**
Pipeline fuel	0.63	0.73	0.73	0.67	0.81	0.78	0.84	0.83	0.77
Lease and plant fuel	1.32	1.20	1.20	1.36	1.25	1.25	1.65	1.25	1.24
Total consumption	**22.78**	**22.43**	**22.43**	**26.15**	**24.73**	**24.32**	**31.41**	**27.62**	**26.62**
Supply									
Production									
Total lower 48	**18.62**	**18.09**	**18.09**	**19.90**	**19.04**	**19.00**	**21.29**	**18.89**	**18.90**
Onshore	13.76	13.00	13.00	14.48	13.34	13.53	16.26	13.74	13.00
Associated-dissolved gas	1.60	1.48	1.48	1.41	1.32	1.32	1.17	1.49	1.45
Nonassociated gas	6.23	6.04	6.04	5.80	5.57	5.55	5.93	4.23	4.13
Unconventional gas	5.93	5.34	5.34	7.28	6.31	6.53	9.17	7.91	7.30
Offshore	4.86	5.09	5.09	5.42	5.69	5.47	5.03	5.15	5.90
Alaska	**0.43**	**0.46**	**0.46**	**0.60**	**0.46**	**0.46**	**2.71**	**2.00**	**1.93**
Total production	**19.05**	**18.54**	**18.54**	**20.50**	**19.50**	**19.45**	**23.99**	**20.90**	**20.83**
Net imports									
Canada	3.59	3.60	3.60	3.68	3.50	3.25	2.56	2.70	1.29
Mexico	-0.26	-0.21	-0.21	-0.34	-0.30	-0.30	-0.12	-0.26	-0.26
LNG	0.17	0.23	0.23	2.16	1.99	2.06	4.80	3.88	4.77
Total net imports	**3.49**	**3.61**	**3.61**	**5.50**	**5.19**	**5.01**	**7.24**	**6.31**	**5.80**
Net storage and LNG withdrawals	—	0.45	0.45	—	0.02	-0.01	—	-0.03	-0.05
Supplemental fuels and ethane	0.08	0.09	0.09	0.10	0.27	0.15	0.10	0.43	0.20
Balance item	0.16	-0.26	-0.26	0.06	-0.25	-0.29	0.09	0.01	-0.17
Total U.S. gas supply	**22.78**	**22.43**	**22.43**	**26.15**	**24.73**	**24.32**	**31.41**	**27.62**	**26.62**

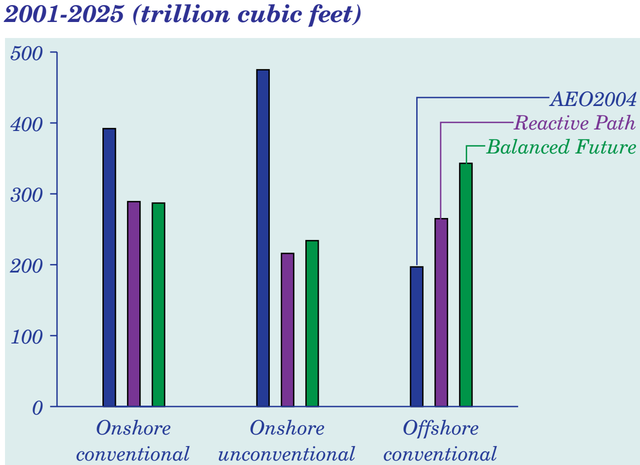
The *AEO2004* and NPC gas resource assumptions differ most significantly with respect to the additional gas resources expected to be discovered in existing onshore conventional oil and gas fields (identified as "field appreciation," "reserve growth," and "inferred resources"). The *AEO2004* assumption is based on USGS resource estimates, which result in an inferred onshore conventional gas resource base of 292 trillion cubic feet. The NPC scenarios are based on a different methodology, which results in 164 trillion cubic feet of inferred resources. Because inferred gas resources are the least expensive incremental source of domestic natural gas supply, the difference in assumptions is responsible in part for the different projections of onshore conventional gas production.

Consumption

The *AEO2004* and NPC projections differ with respect to future levels of natural gas consumption but largely agree on the mix of future supplies. In 2025, *AEO2004* projects total U.S. gas consumption of 31.4 trillion cubic feet, compared with 27.6 trillion cubic feet in the Reactive Path scenario and 26.6 trillion cubic feet in the Balanced Future scenario. Total U.S. consumption of natural gas includes pipeline fuel and production area lease and plant fuel, which is natural gas consumed in production and transportation to end-use markets.

In 2025, the projections for total end-use gas consumption (excluding pipeline, lease, and plant fuel) are 28.9 trillion cubic feet in *AEO2004*, 25.5 trillion cubic feet in the Reactive Path, and 24.6 trillion cubic feet in the Balanced Future scenario (Figure 31). In the *AEO2004* reference case, end-use gas consumption is projected to grow by 1.4 percent per year from 2002 to 2025, compared with 1.0 percent in the Reactive Path and 0.8 percent in the Balanced Future scenario. The differences between the *AEO2004* reference case and the NPC scenarios result largely from different projections for industrial sector natural gas consumption, primarily as a result of the NPC's lower projected growth rate for industrial production.

Figure 30. Lower 48 technically recoverable and accessible unproven natural gas resources, 2001-2025 (trillion cubic feet)



Although NPC and *AEO2004* employ different accounting methods for the treatment of CHP in the industrial sector, one method for comparing the NPC and *AEO2004* industrial and electric power gas consumption projections is to account for the *AEO2004* CHP projection results in the same manner as the NPC scenarios, namely, by allocating incremental CHP gas consumption after 2001 to the electric power sector (Table 15). Based on this reallocation, it is clear that the large difference between the *AEO2004* and NPC end-use gas consumption projections is attributable primarily to significantly different expectations for growth in industrial natural gas consumption. In *AEO2004*, adjusted industrial gas consumption grows by 1.1 percent per year throughout the forecast, whereas the Reactive Path and Balanced Future scenarios project declines of 0.6 percent and 0.4 percent per year, respectively.

In *AEO2004*, natural gas consumption for electric power generation (adjusted for CHP) grows by 2.3 percent per year, which is between the Reactive Path and Balanced Future projections of 2.7 percent and

Figure 31. Total U.S. end-use natural gas consumption, 2001-2025 (trillion cubic feet)

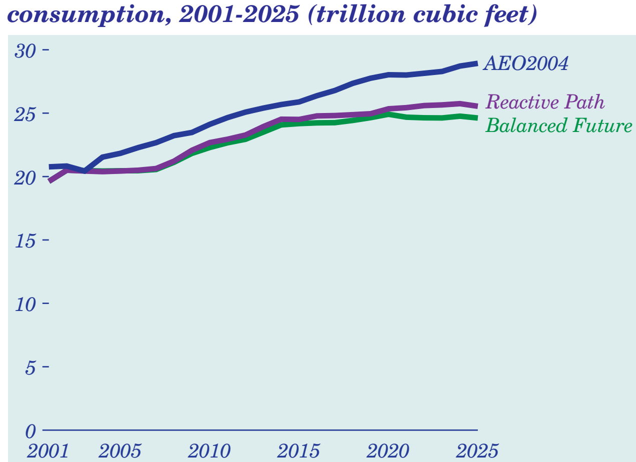


Table 15. Growth rates for natural gas consumption in the industrial and electric power sectors, 2002-2025 (percent per year)

	AEO2004	AEO2004 with CHP adjustment	Reactive Path	Balanced Future
Industrial	1.5	1.1	-0.6	-0.4
Electric Power	1.8	2.3	2.7	2.1

2.1 percent per year, respectively. For residential and commercial end-use consumption, the *AEO2004* and NPC projections are virtually identical throughout the forecast.

In 2025, Henry Hub spot prices for natural gas are projected to be between $5 and $7 (2002 dollars) per million Btu in the Reactive Path scenario and between $3 and $5 per million Btu in the Balanced Future scenario, while end-use natural gas consumption in 2025 is 0.9 trillion cubic feet lower in the Balanced Future than in the Reactive Path scenario. The Balanced Future scenario projects less natural gas consumption despite significantly lower prices, because it assumes that future gas-consuming equipment (including gas-fired generating capacity) will have more flexibility to use other fuels and will be more fuel-efficient than assumed in the Reactive Path scenario.

Supply

In both the NPC study and *AEO2004*, domestic natural gas consumption is satisfied through both domestic gas production and net gas imports [*67*]. In all three scenarios, net imports are projected to grow at a faster rate than end-use gas consumption. *AEO2004* projects average growth in net imports of 3.2 percent per year between 2002 and 2025; the Reactive Path and Balanced Future scenarios project average growth in net imports of 2.5 and 2.1 percent per year, respectively [*68*].

Although the *AEO2004* and NPC end-use gas consumption levels in 2025 are significantly different, the relative proportions of domestic supply and net imports are similar. For 2025, both *AEO2004* and the Reactive Path scenario project that net imports will provide 23 percent of domestic natural gas consumption, with the remaining 77 percent coming from domestic supply sources. The Balanced Future scenario projects corresponding proportions of 22 percent and 78 percent.

Imports and Exports

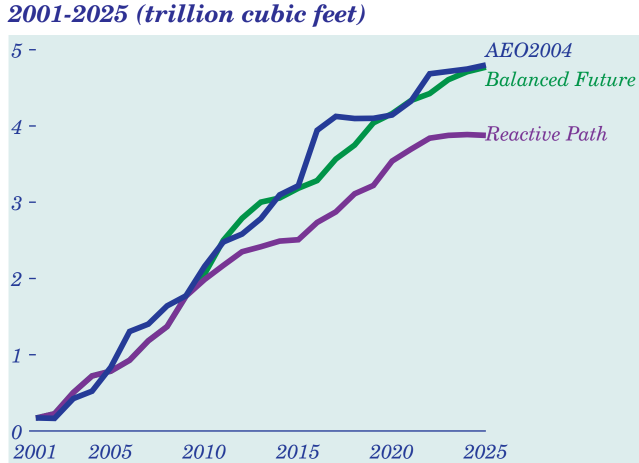
Projected net imports of natural gas (pipeline and LNG) in *AEO2004* are higher than in either of the NPC scenarios. The NPC developed detailed cost estimates for liquefaction, shipping, and regasification facilities and used those estimates to develop exogenous LNG scenario projections. The Balanced Future scenario assumes a more favorable LNG import policy than in the Reactive Path scenario. In the Balanced Future, net LNG imports are projected at 4.8 trillion cubic feet in 2025, compared with 3.9 trillion cubic feet in the Reactive Path scenario (Figure 32). *AEO2004* projects LNG imports on the basis of a comparison between LNG delivery costs and projected natural gas prices. *AEO2004* projects 4.8 trillion cubic feet of net LNG imports in 2025. Although the *AEO2004* projection for net LNG imports in 2025 is almost identical to that in the Balanced Future scenario, in terms of percentage of total net imports, the 66-percent share projected for LNG imports in 2025 in *AEO2004* is closer to the 62-percent share in the Reactive Path than to the 82-percent share in the Balanced Future scenario.

Canada is the other major source of U.S. natural gas imports. In 2025, imports from Canada are projected to make up 35, 43, and 22 percent of total U.S. net imports in the *AEO2004* reference case, NPC Reactive Path, and NPC Balanced Future scenario, respectively. In all the projections, net imports from Canada are projected to peak around 2009 and decline thereafter (Figure 33). *AEO2004* projects 2.6 trillion cubic feet of net imports from Canada in 2025, compared with 2.7 and 1.3 trillion cubic feet in the Reactive Path and Balanced Future scenarios, respectively. Thus, in the NPC study, higher LNG imports are offset by lower imports from Canada. Both *AEO2004* and the NPC scenarios project negligible quantities of net gas exports from the United States to Mexico in 2025, at 0.1 and 0.3 trillion cubic feet, respectively.

Domestic Production

In both the NPC and *AEO2004* projections, natural gas imports increase more rapidly than consumption; thus, all three scenarios project slower growth in U.S. gas production than in consumption. The *AEO2004* reference case projects 1.0-percent average annual growth in domestic natural gas production from 2002 to 2025, compared with 0.5 percent per year in the two NPC scenarios. The projections for total U.S.

Figure 32. Net imports of liquefied natural gas, 2001-2025 (trillion cubic feet)



natural gas production in 2025 are 24.0, 20.9, and 20.8 trillion cubic feet in the *AEO2004* reference case and the Reactive Path and Balanced Future scenarios, respectively (Figure 34). Periods of more rapid increases in U.S. natural gas production are projected for 2018-2020 in *AEO2004* and 2013-2015 in the NPC scenarios, resulting from the advent of North Slope Alaska gas pipeline operations.

The NPC Reactive Path and Balanced Future scenarios both assume that the Alaska gas pipeline will begin operation in 2013 with an initial capacity of 4 billion cubic feet per day. *AEO2004* projects that the pipeline will begin operation in 2018 with a capacity of 3.9 billion cubic feet per day of dry gas, followed in 2023 by a 0.9 billion cubic foot expansion, for a total dry gas throughput capacity in 2025 of 4.8 billion cubic feet per day.

AEO2004 projects total lower 48 production of 21.3 trillion cubic feet of natural gas in 2025, compared with 18.9 trillion cubic feet in the Reactive Path scenario and scenarios—only slightly higher than current production levels. *AEO2004* projects offshore gas production similar to that in the NPC scenarios, but higher onshore gas production. Onshore gas production in *AEO2004* is projected to be 76 percent of total lower 48 production in 2025, compared with 73 percent in the Reactive Path scenario and 69 percent in the Balanced Future scenario. As a result, *AEO2004* projects 16.3 trillion cubic feet of lower 48 onshore gas production in 2025, compared with 13.7 and 13.0 trillion cubic feet in the Reactive Path and Balanced Future scenarios, respectively.

In all three scenarios, lower 48 offshore production fluctuates because sufficient natural gas reserves must be discovered in an area to justify the construction of offshore platforms and pipelines. *AEO2004* projects average offshore gas production of 5.0 trillion cubic feet per year from 2002 through 2025, compared with an average of 5.4 trillion cubic feet per year in the two NPC scenarios.

The projections for cumulative lower 48 natural gas production from 2002 through 2025 are summarized in Table 16. *AEO2004* projects 489 trillion cubic feet of production from the lower 48 gas resource base, proportionately more from onshore (75 percent) than offshore (25 percent). The Reactive Path and Balanced Future projections are similarly apportioned: 72 and 71 percent onshore and the remaining 28 and 29 percent offshore, respectively.

The NPC Balanced Future scenario assumes increased access to Federal offshore areas and onshore lands, while the Reactive Path does not. Federal offshore access adds 79 trillion cubic feet to the offshore technically recoverable and accessible resource base, and greater Federal lands access adds 35 trillion cubic feet to the onshore technically recoverable and accessible gas resource base (see Figure 30) [*69*]. The Balanced Future scenario projects 0.8 trillion cubic feet more cumulative offshore gas production than in the Reactive Path scenario but produces considerably less of the total accessible offshore resource base (Table 17).

Figure 33. Net imports of natural gas from Canada, 2001-2025 (trillion cubic feet)

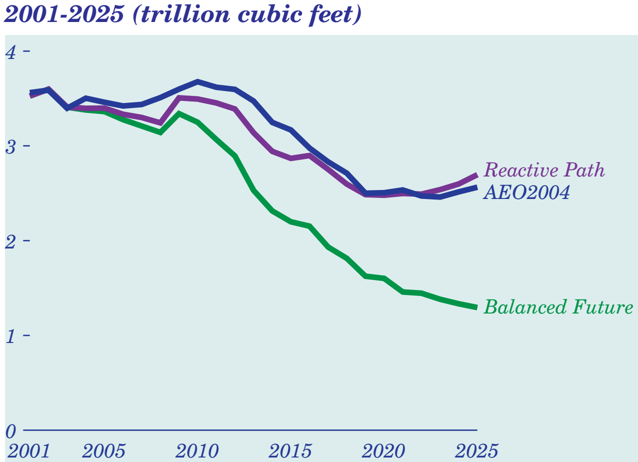


Figure 34. Total U.S. domestic natural gas production, 2001-2025 (trillion cubic feet)

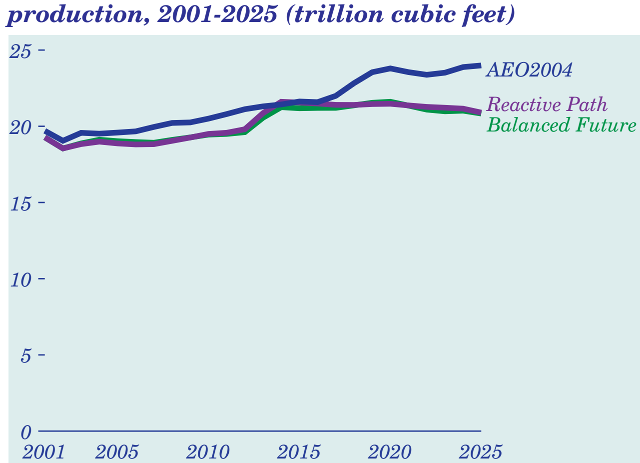


Table 16. Lower 48 cumulative natural gas production, 2002-2025 (trillion cubic feet and percent of total)

	Onshore	*Offshore*	*Total*
AEO2004	*367.8 (75%)*	*120.9 (25%)*	***488.7***
Reactive Path	*327.8 (72%)*	*129.2 (28%)*	***457.0***
Balanced Future	*326.0 (71%)*	*130.0 (29%)*	***456.0***

In the Balanced Future scenario, considerably more gas is produced from regions of the offshore Atlantic and Pacific that are currently not accessible. In 2025, the incremental Atlantic and Pacific offshore gas production is projected to be just over 752 billion cubic feet. Most of the incremental offshore gas production that results from increased Federal access occurs in the offshore Atlantic, where gas production is projected to reach 608 billion cubic feet in 2025. The impact of greater Federal access is not apparent until after 2010, because considerable delays are expected to be encountered in leasing, seismic exploration, drilling, and development.

AEO2004 assumes a much larger volume of onshore gas resources, both conventional and unconventional, than do the NPC scenarios (see Figure 30). Also, *AEO2004* and the NPC scenarios project similar levels of offshore gas production, even though *AEO2004* projects considerably more total production than in the NPC scenarios. As a consequence, most of the difference between the *AEO2004* and NPC gas production projections is attributable to their different projections for onshore natural gas production.

The *AEO2004* projection for unconventional natural gas production is consistently higher than the NPC projections [*70*]. In 2025, *AEO2004* projects 9.2 trillion cubic feet of unconventional gas production, compared with the Reactive Path and Balanced Future projections of 7.9 and 7.3 trillion cubic feet (Figure 35). Although the NPC scenario projections for unconventional gas production are quite different in 2025, they are almost identical up to 2020.

For lower 48 onshore conventional production, *AEO2004* and the NPC scenarios again show considerable differences in their projections for both nonassociated and associated natural gas. *AEO2004* projects a slow decline in nonassociated conventional gas production throughout the forecast, to 5.9 trillion cubic feet in 2025. The Reactive Path and Balanced Future scenarios project more rapid declines to 4.2 and 4.1 trillion cubic feet in 2025, respectively. In all three scenarios, unconventional gas production increases while nonassociated conventional gas production does not, indicating that unconventional gas is the least expensive incremental source of lower 48 onshore natural gas production.

Lower 48 onshore production of associated-dissolved conventional gas declines throughout the *AEO2004* projection, to 1.2 trillion cubic feet in 2025. In the two NPC scenarios, associated-dissolved conventional gas production declines until 2005, then rises from 1.3 trillion cubic feet in 2005 to 1.5 trillion cubic feet in 2025. Associated-dissolved gas production depends directly on crude oil production, and all three scenarios project declining onshore production of crude oil throughout the forecast period. The NPC scenarios, however, project a slower decline than in the *AEO2004* reference case. In addition, the NPC scenarios project more natural gas production per barrel of oil produced in 2025 than does *AEO2004*, which, in combination with NPC's higher projections for oil production, results in the only instance of a higher projection for a component of domestic natural gas supply in 2025 in the NPC forecasts than in *AEO2004*.

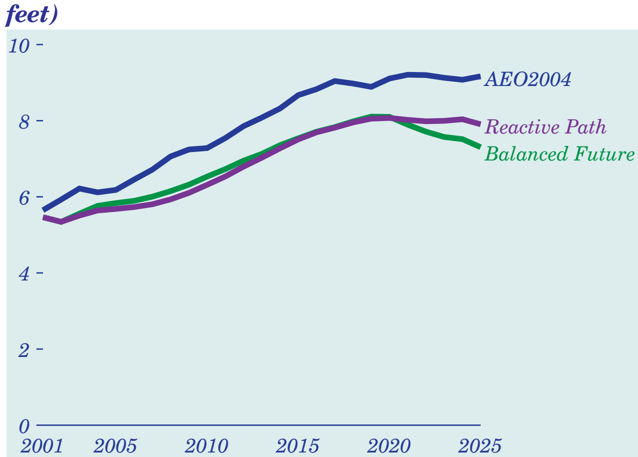
Nuclear Power Plant Construction Costs

With the improved performance of the 104 operating U.S. nuclear power plants, increases in fossil fuel prices, and concerns about global warming, interest in building new nuclear power plants has increased. Because no nuclear plants have been ordered in the United States in nearly three decades, the costs of a new plant are uncertain. To assess the economics of building new nuclear power plants, EIA conducted a series of workshops and seminars focusing on key factors that affect the economics of nuclear power—primarily, the cost of building power plants and the financial risks of constructing and operating them.

Table 17. Portion of the lower 48 natural gas resource base produced, 2002-2025 (percent of technically recoverable and accessible resources)

	Onshore	Offshore	Total
AEO2004	42.4	61.4	**45.9**
Reactive Path	60.8	50.5	**57.5**
Balanced Future	56.8	38.8	**50.2**

Figure 35. Lower 48 onshore unconventional natural gas production, 2001-2025 (trillion cubic feet)



History of Nuclear Power Construction Costs

As was typically the case with fossil-fuel-fired power plants, many of the first-generation U.S. reactors were constructed on a fixed price, turnkey basis. Under this type of contractual arrangement, the vendor assumed all the risk associated with cost overruns and scheduling delays. In total, about 12 units were ordered on a turnkey basis in the early to mid-1960s. Although the costs of the reactors were never made public, one study estimated that the vendors lost more than $1 billion [*71*]. As a result, they eventually stopped offering turnkey contracts to build nuclear power plants and instead went to cost-based contracts.

Factors affecting the costs of non-turnkey U.S. reactors have been the subject of a number of analyses. An EIA analysis found that realized real overnight costs grew from about $1,500 per kilowatt for units beginning construction in the 1960s to about $4,000 per kilowatt for units beginning construction in the early to mid-1970s (all costs in 2002 dollars, except where noted). Lead times also increased, from about 8 years to more than 10 years. Much of the growth in overnight costs and lead times was unforeseen by those preparing the estimates, and overruns in real overnight costs and lead times ranged from 70 to 250 percent [*72*].

Because of severe data limitations and the inherent difficulty in measuring regulatory impacts, there is only qualitative agreement that the following factors caused the growth in nuclear plant costs and lead times [*73*]:

- Increased regulatory requirements that caused design changes (backfits) for plants under construction
- Licensing problems
- Problems in managing "mega projects"
- Misestimation of cost savings (economies of scale) for larger plants
- Misestimation of the need for the capacity.

Historically, the deployment of nuclear plants abroad lagged behind that in the United States. Thus, there was a tendency for utilities in Europe and Asia to learn from the U.S. experience. Now, just the opposite is occurring—the next generation of U.S. nuclear power plants will benefit from foreign learning. Accordingly, EIA's present cost estimates used realized costs of nuclear power plants in Asia as a starting point.

Building New Nuclear Plants in the United States

One of the major uncertainties in building new nuclear power plants involves the regulatory and licensing process. Regulatory actions were one of the factors that contributed to the cost growth in the 1970s and 1980s, and as a result there were significant efforts to reform the process. In the late 1980s, the U.S. Nuclear Regulatory Commission (NRC) modified backfit regulations to make it more difficult to order changes in a plant's design during construction. Additionally, with the passage of the Energy Policy Act of 1992, the licensing process was also changed substantially. Before 1992, a utility needed one license to begin construction and another to begin commercial operation. Public hearings were a prerequisite for both licenses, and in some cases they proved to be very contentious. Now, as long as a firm follows all the agreed-upon procedures, tests, and inspections, separate hearings are not required. The 1992 legislation also allowed for the pre-approval of various designs; as a result, many technical engineering issues can be settled before the licensing process begins.

Beginning in the mid-1990s, the nuclear industry began to design new Generation III (or III+) reactors. In general, the new designs represent incremental improvements over the current generation of light-water reactors. They are simpler and include more "passive" safety features. As discussed below, these design changes have cost implications.

The vendors of two Generation III reactors—the Advanced Boiling Water Reactor (ABWR) and an Advanced Pressurized Water Reactor (the AP1000)—have provided estimates of construction costs. GE's estimate for the ABWR ranges from $1,400 to $1,600 per kilowatt (2000 dollars) for a large, single-unit plant (1,350 megawatts or more). British Nuclear Fuels Limited (BNFL), the manufacture of the AP1000, has estimated that construction costs for the first two-unit 1,100-megawatt reactors will range from $1,210 to $1,365 per kilowatt (2000 dollars). GE's estimate assumes that the government would pay for 50 percent of the first-of-a-kind engineering costs, and BNFL's estimate assumes that the government (or someone other than the purchaser of the plant) would pay for all the first-of-a-kind costs. BNFL also assumes that, because of learning, a third two-unit plant could be built for about $1,040 per kilowatt (2000 dollars) [*74*].

A state-owned Canadian firm, Atomic Energy Canada Limited (AECL), has also stated its intention to market an advanced CANDU reactor, the ACR-700, in the United States. The ACR-700, a design that uses heavy water to moderate the reaction, is substantially different from the AP1000 and ABWR [*75*]. One major advantage of CANDU reactors, which have been built worldwide [*76*], is the ability to refuel the unit while it is operating. Light-water reactors must be taken out of service before they can be refueled. On the other hand, the use of heavy water raises nuclear proliferation issues. The total cost of building "third of a kind" twin-unit plants has been estimated by AECL at about $1,100 to $1,200 per kilowatt.

All the above estimates are much lower than the capital costs that have been realized in the past for nuclear power plants built in the United States and abroad [*77*]. As noted above, the average construction cost of U.S. units that entered commercial operation in the 1980s was about $4,000 per kilowatt. On average, light-water and CANDU reactors have been built in the Far East and elsewhere abroad at costs that are in the low $2,000s per kilowatt. The AP1000 has never been built anywhere in the world. If the vendors are able to achieve their projected costs, their plants are likely to be competitive with other generating options. The key question is whether cost reductions of the magnitude projected by the vendors are achievable.

There is reason to believe that new reactors will be less costly to build than those currently in operation in the United States. Over the past 30 years, there have been technological advances in construction techniques that would reduce costs. In addition, the simplified, standardized, and pre-approved designs clearly result in cost savings. The newer plants have fewer components and therefore would be less costly. At least in the United States, only a few previously built plants were based on standardized designs, and in most cases construction began before the unit was totally designed. The construction of customized units, with the design work being done during the plant's construction, is clearly expensive. Because the designs of advanced reactors are (or will be) pre-approved by the NRC, much of the design work will be done before their construction begins, and this will lower costs. Regulatory changes will also lower regulatory costs and risk.

Although it is reasonable to expect lower construction costs for the new reactors, EIA and other organizations have questioned the size of the cost reductions [*78*]. This is particularly true of the vendors' estimates relative to recently realized costs in Asia.

All the cost estimates from nuclear vendors assume savings from building large multi-unit plants. The estimates for the AP1000 and CANDU reactors assume two unit sites, and those for the ABWR deal with a 1,350- to 1,500-megawatt reactor. As discussed below, the size of these projects has financial implications that cannot be overlooked. Moreover, there is some evidence that cost overruns for earlier U.S. reactors resulted from misestimation of the savings from building large or multi-unit plants.

There are four major parties (and numerous secondary ones) involved in the construction of a nuclear power plant: a firm that manages the construction of the plant, a firm that supplies engineering and architectural support, a firm that supplies the reactor or Nuclear Steam Supply System, and the firm that purchases the unit. All incur costs, and it is important that all their costs be included in the estimate. It is possible that some reported estimates might deal only with the costs to two or three of the parties; in such cases, the estimates would not be inclusive.

Results of EIA-Sponsored Workshops and Seminars and Derivation of EIA Estimates

In addition to sponsoring several workshops and seminars on the subject of nuclear construction costs, EIA also commissioned a series of reviews of the vendor estimates. All the reviewers generally found that the estimates included the costs to the four parties involved with the construction of a nuclear power plant, but they also found that the estimates were not sufficiently detailed to permit verification of their accuracy. Indeed, the only way to verify the estimates would be to reproduce them—an effort that is prohibitively expensive.

EIA's reviewers were forced to use their subjective judgment, and there were differing opinions about the estimates. The reviewers and workshop participants from the nuclear industry think that the cost reductions are achievable, making arguments similar to the ones presented above. One reviewer who is an outside observer of the industry, one workshop participant who is a financial analyst, and some outside researchers were more skeptical. For example, in a recent study from the Massachusetts Institute of Technology (MIT), researchers used $2,000 per kilowatt as a "base case" and employed a 25-percent cost reduction as "unproven but plausible."

The procedure used to derive nuclear construction cost estimates for *AEO2004* is as follows. For non-nuclear technologies, EIA uses cost estimates consistent with realized outcomes for the construction of new generating capacity in the United States. However, because no reactors have been built recently in the United States, EIA's cost estimates are based on foreign cost data. There are two marketable Generation III light-water reactors currently in operation, and another four are under construction in Asia [*79*]. Thus, the starting point for an estimate of building the "next" new U.S. advanced nuclear power plant was the realized cost of the two operating light-water nuclear units in Asia. In *AEO2004*, $2,083 per kilowatt (inclusive of all contingencies) is used as the realized cost for these two reactors [*80*].

The four units that are under construction in Asia will be completed over the next 5 years. The first new U.S. plant could not become operational until 2012 at the earliest. Thus, the construction of the first U.S. plant will benefit from experience gained in the construction of the four units in Asia.

For all advanced technologies that are in the early stages of commercialization, EIA assumes that, because of learning, U.S. capital costs will fall by 5 percent for each of the first three doublings of newly built capacity. The same learning factor is applied to the costs of the four advanced light-water reactors under construction in Asia. Thus, the cost reduction from learning in building four additional reactors (roughly 1.5 doublings of capacity) is about 8.5 percent. As a result, the assumed realized cost, inclusive of contingencies, of the sixth advanced light-water reactor in Asia when it is completed is $1,928. This is the estimate used in the projections [*81*].

As new U.S. nuclear plants are built, because of learning, EIA assumes that costs will continue to fall. For example, if 10 new units were constructed in the United States, costs would continue to fall to about $1,719 per kilowatt (inclusive of all contingencies) as a result of learning. Even if no nuclear plants were built in the United States, EIA assumes that costs would fall to about $1,752 per kilowatt by 2019. As shown in Figure 36, the *AEO2004* cost estimates are below realized costs for older U.S. plants and plants recently built abroad.

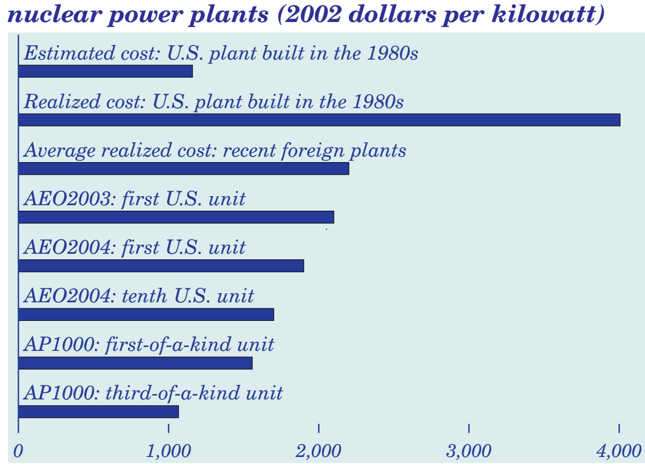
The vendors' estimates of construction lead times are generally about 36 to 48 months from the date of the first concrete pour to the date of initial system testing (or fuel loading). This definition of lead time is often used, because most of the funds are expended over that period. To compute interest costs, EIA uses a slightly different definition of lead times—namely, the time between the commencement of the licensing process to the date of commercial operation. The licensing process will take 12 to 24 months, and there will be an additional 6 months between fuel loading and commercial operation. Thus, EIA assumes a 6-year lead time.

In one of EIA's workshops, the issue of the time and cost for preparing a license application and the expenses incurred in obtaining the license were discussed. Some within the industry think an additional 4 years would be needed to prepare the application and license the first few plants, resulting in a 10-year total lead time. A small cost premium (up to 5 percent) is added by EIA to the cost of just the first four units built. This is called the "technological optimism factor." Because this factor gradually goes to zero as new nuclear plants are constructed, there will be an additional reduction in costs over and above the learning effects. This cost reduction, in part, captures the reduction in expenses associated with the 4-year reduction in lead times as a result of improvements in the licensing process.

Summary of the Projections

Over the past few years, most economic analyses of nuclear power have tended to compare the cost of generating electricity from nuclear technology with the cost of producing power from a combined-cycle natural-gas-fired power plant. As long as natural gas prices remain in the range of $2 to $3 per thousand cubic feet, the cost of building and operating a new gas-fired plant will be much less than the cost of a new coal-fired plant. Therefore, the assumption has been that nuclear power would compete with combined-cycle gas plants. With natural gas prices rising, however, new coal-fired power plants and, to some extent, renewable energy are becoming competitive with new natural gas units in many parts of the United States.

Figure 36. Estimates of overnight capital costs for nuclear power plants (2002 dollars per kilowatt)



The *AEO2004* reference case assumes that nuclear power plant construction costs will fall from $1,928 per kilowatt to $1,752 in 2019. On that basis, no new nuclear power plants would be built before 2025 in the reference case. In two advanced nuclear cases, vendor estimates for the AP1000 and ACR-700 reactors are used. In both advanced cases, the current level of nuclear capital costs is assumed to be lower than in the reference case, and cost reductions are assumed to be greater than in the reference case. Specifically, one advanced case—the vendor estimate case—is based on an average of the AP1000 and ACR-700 reactor first-of-a-kind and *n*th-of-a-kind costs [*82*]. In this case, costs would fall from $1,555 per kilowatt in 2004 to $1,149 in 2019. The second advanced nuclear case—the AP1000 case—uses just the vendor cost estimates for the AP1000. In this case, costs would fall from $1,580 per kilowatt to $1,081 in 2019.

In the AP1000 case, where costs fall to about $1,081 per kilowatt in 2019, EIA projects that about 26 gigawatts of new nuclear power plant capacity would be constructed and become operational by 2025. The 26 gigawatts of new nuclear power plant capacity would displace 19 gigawatts of coal-fired capacity and 7 gigawatts of mainly fossil-fuel-fired capacity. In the average cost case, where costs fall to $1,149 per kilowatt in 2019, 12.8 gigawatts of new nuclear power capacity would be built and become operational by 2025, displacing about 9.4 gigawatts of coal-fired capacity.

If the projections were extended beyond 2025, or if the cost reductions occurred more rapidly than assumed in the two advanced nuclear cases, the projected amount of new nuclear capacity would be much greater. The total assumed capital cost of a pulverized coal plant in 2005 is $1,170 per kilowatt—about 10 percent higher than the vendor's estimate of the AP1000 costs [*83*]. Coal and nuclear fuel costs are 10 mills and 4 mills per kilowatthour, respectively. Historically, non-fuel operating and maintenance costs are roughly the same for the two technologies. Given a nuclear capital cost estimate of $1,081 per kilowatt, both the capital and operating costs would therefore be less for nuclear than for coal-fired power plants. If the $1,081 per kilowatt estimate could be realized, it is possible that nuclear power could eventually be used to satisfy virtually all the baseload demand in the United States in future years.

The Issue of Risk

Another issue that received considerable attention in the EIA workshops was the financial risk in constructing and operating any power plant. There are risks associated with the use of natural gas, coal, and nuclear power. Natural-gas-fired power plants can be built in a few years and are relatively inexpensive, and thus there is little risk in their construction; however, because natural gas prices are volatile, there are risks involved with the operation of gas-fired power plants. Indeed, a number of the workshop participants noted that nuclear power can be used to hedge fuel price risks associated with gas plants.

Environmental factors aside, coal prices are relatively stable, and thus the fuel price risks associated with coal-fired power plants are small. Environmental regulations could change, however, especially with respect to global warming, with major impacts on the economics of operating coal plants. Thus, there are regulatory risks associated with the operation of coal-fired power plants. One workshop participant noted that firms have been able to finance the construction of coal-fired plants because of a perception that changes in environmental regulations will not occur for another 10 to 15 years, and by then the loans will have been repaid.

There are also regulatory risks involved with the construction and operation of nuclear power plants. According to a number of workshop participants, the financial community clearly has not completely discounted the cost overruns that occurred in the 1970s and 1980s. Thus, all the participants agreed that the nuclear industry must demonstrate that a nuclear power plant can be built on time and on budget. Further, the new licensing process has yet to be tested, and there is considerable uncertainty about how it will work. In fact, all the participants agreed that some type of support from a third party (the Federal Government) would be needed before the first few plants could be built.

If nuclear power plants are built in a deregulated environment, their owners—like the owners of any power plant—will be exposed to output price risk. Electricity prices might be lower than anticipated, resulting in insufficient revenues to cover all the operating costs, loan repayments, and returns to shareholders. As a result of market deregulation, electricity is now a commodity, and like any other commodity, in the short run electricity prices are extremely volatile and subject to "boom and bust" cycles. The events of the past few years suggest that if plants become operational in the "bust" part of a cycle, the result can be financial ruin.

Although all units are subject to output price risk, nuclear power plants are affected differently because of their relatively high capital costs and longer lead times. That is, because of nuclear power's relatively high capital costs, relatively more capital is "at risk." Moreover, the uncertainty of any forecast of electricity prices increases as the length of the forecast period increases (a 6-year forecast is more uncertain than a 2-year forecast). Because of nuclear power's relatively long lead times, electricity prices must be anticipated over a relatively long period, leading to more uncertainty.

All the workshop participants outside the nuclear industry argued that stable and predictable revenues resulting from long-term, fixed-price power purchase agreements or other financial or regulatory instruments are crucial to the financing of a nuclear power plant. Long-term (10 to 20 years) firm fixed price purchased power contracts are, however, very difficult and expensive to obtain. Moreover, as a recent EIA report noted, until some structural flaws in electric power markets are corrected, the use of financial derivatives to manage electricity price risk is limited [*84*]. Thus, at least in the short run, it is not clear whether it will be possible to obtain a stable stream of revenues from a nuclear (or other) power plant.

The advanced nuclear cases summarized above and presented in detail in the "Market Trends" section of this report assume that institutional and financial arrangements can be used to mitigate (or shift) output price risk at very little cost to decisionmakers. A fixed-price purchased power contract is one possible financial arrangement that would shift the risk to those holding the contract. Another possible institutional arrangement would be a consortium formed by a group of utilities and vendors to build nuclear power plants. In such a case, the risks would be spread among all the consortium members.

The Renewable Electricity Production Tax Credit

In the late 1970s and early 1980s, environmental and energy security concerns were addressed at the Federal level by several key pieces of energy legislation. Among them, the Public Utility Regulatory Policies Act of 1978 (PURPA), P.L. 95-617, required regulated power utilities to purchase alternative electricity generation from qualified generating facilities, including small-scale renewable generators; and the Investment Tax Credit (ITC), P.L. 95-618, part of the Energy Tax Act of 1978, provided a 10-percent Federal tax credit on new investment in capital-intensive wind and solar generation technologies [*85*].

The Energy Policy Act of 1992 (EPACT) included a provision that addresses problems with the ITC—specifically, the lack of incentives for operation of wind facilities. EPACT introduced the Renewable Electricity Production Tax Credit (PTC), a credit based on annual production of electricity from wind and some biomass resources. The initial tax credit of 1.5 cents per kilowatthour (1992 dollars) for the first 10 years of output from plants entering service by December 31, 1999, has been adjusted for inflation and is currently valued at 1.8 cents per kilowatthour (2002 dollars) [*86*, *87*].

The original PTC applied to generation from tax-paying owners of wind plants and biomass power plants using fuel grown in a "closed-loop" arrangement—crops grown specifically for energy production, as opposed to byproducts of agriculture, forestry, urban landscaping, and other activities. In its early years, the PTC had little discernable effect on the wind and biomass industries it was designed to support. By 1999, however, when the provision was originally set to expire, U.S. wind capacity had begun growing again, and the PTC supported the development of more than 500 megawatts of new wind capacity in California, Iowa, Minnesota, and other States. Wind power development was also encouraged by State-level programs, such as the mandate in Minnesota for 425 megawatts of wind power by 2003 as part of a settlement with Northern States Power (now Xcel Energy) to extend on-site storage of nuclear waste at its nuclear facility [*88*].

In 1999, the PTC was allowed to expire as scheduled, but within a few months it was retroactively extended through the end of 2001 [*89*], and poultry litter was added to the list of eligible biomass fuels. Although wind power development slowed significantly in 2000, 2001 was a record year with as much as 1,700 megawatts installed [*90*]. Again, State and local programs, including a significant renewable portfolio standard (RPS) program in Texas, also supported new wind installations.

The PTC was allowed to expire again on December 31, 2001, while Congress worked on a comprehensive new energy policy bill. It was retroactively extended a second time to December 31, 2003, as part of an omnibus package of extended tax credits passed in response to the economic downturn and terrorist attacks of 2001 [*91*].

Like the 1999 expiration and extension, the extension of the PTC in 2002 was followed by a lull in wind power development. And again, a review of confirmed industry announcements indicates that 2003 will see total new installations of more than 1,600 megawatts of wind capacity. Significantly, while many 2003 builds still rely on multiple incentives (for example, the PTC plus a State program) to achieve economic viability, there are some in Oklahoma and other States that have been developed with little government support beyond the PTC [*92*].

With reductions in capital costs and increases in capacity factors [*93*], wind power technology has improved since the introduction of the ITC and subsequent replacement by the PTC. It is likely that the installations spurred by these incentives allowed the industry to "learn by doing" and thus contributed to improvement of the technology. There were, however, other factors that contributed to cost reductions during the period, including government-funded research and development (both domestic and international) and large markets for wind power technology that were created by subsidy programs in other countries, especially, Denmark and Germany.

The *AEO2004* reference case, assuming no extension of the PTC beyond 2003, projects that the levelized cost of electricity generated by wind plants coming on line in 2006 (over a 20-year financial project life) would range from approximately 4.5 cents per kilowatthour at a site with excellent wind resources [*94*] to 5.7 cents per kilowatthour at less favorable sites. To incorporate the effect of the current 1.8-cent tax credit over the 10-year eligibility period for those plants, the projections account for both the tax implications and the time value of the subsidy. As a tax credit, the PTC represents 1.8 cents per kilowatthour of tax-free money to a project owner. If the owner did not receive the tax credit and wanted to recoup that 1.8 cents with taxable revenue from electricity sales, the owner would have to add 2.8 cents to the sales price of each kilowatthour, assuming a 36-percent marginal tax rate. Applying the same assumptions used to derive the 4.5-cent total levelized cost of wind energy over a 20-year project life, the levelized value of the PTC to the project owner is approximately 2 cents per kilowatthour.

In the reference case, the levelized cost for electricity from new natural gas combined-cycle plants is 4.7 cents per kilowatthour, and for new coal-fired plants the projected cost in 2007 is 4.9 cents per kilowatthour [*95*]. Thus, it is easy to see how the PTC could make wind plants an attractive investment in the current electricity market.

In addition to generation cost comparisons, the difference between an intermittent resource (wind plants) and a dispatched resource (coal- and gas-fired plants) must also be considered. Dispatched generation provides "value" to the grid because it contributes more to the reliability of the system and is generally available to meet daily and seasonal load requirements. An intermittent resource has only limited ability to contribute to grid reliability and does not necessarily produce energy in a daily or seasonal pattern that matches daily or seasonal load variations.

Given the uncertainty regarding both the short-term extension of the PTC and its long-term fate, EIA developed three alternative PTC cases for *AEO2004*. The cases are not meant to indicate a preferred or even likely policy outcome, but rather to provide a useful range of possible outcomes to provide insight into the effects of the PTC program on future energy markets relative to the reference case forecast, which assumes no new PTC subsidy beyond 2003.

The 3-year PTC case assumes that the PTC is extended to December 31, 2006, as provided for in the Energy Bill Conference Report adopted in the House and now before the Senate. The extended program continues to cover wind and currently eligible biomass fuels, and coverage is extended to "open loop" biomass sources (primarily waste or byproducts from other processes) and landfill gas generation, as provided for in the Conference agreement. Otherwise, the structure of the program is assumed to remain the same as under current law.

The 9-year PTC case assumes extension of the program to December 31, 2012, as well as the expansion to all biomass and landfill gas resources. All other assumptions remain the same as under current law. This case assumes a single 9-year extension, rather than a series of short-term expirations and reauthorizations [*96*]. Because the history of the PTC indicates that such a cycle can affect the dynamics of industry expansion, and because the specific tax-liability limitations of project owners are unknown, this case provides upper-end estimates of capacity additions resulting from the PTC with a 9-year extension.

The 9-year half PTC case also assumes an extension of the PTC to 2012 and expansion to biomass and landfill gas resources. In this case, however, a modified program is assumed, with the value of the tax credit set at 0.9 cents per kilowatthour (2003 dollars) for the first 10 years of plant operation, indexed to inflation. The assumptions for this case do not reflect any expectation or proposal for the policy but were selected to provide insight into the limitations of the analysis—specifically, uncertainty about the ability of industry to capture the full tax credit value—as well as an indication of program effects if the value of the tax credit were reduced.

The reference case does not assume the installation of any planned capacity for which construction is indicated to be dependent on extension of the PTC. Such planned capacity is included in the three sensitivity cases through the assumed final extension date—2006 in the 3-year PTC case and 2012 in the 9-year PTC case and the 9-year half PTC case. Otherwise, the sensitivity cases follow the reference case assumptions and are based on a fully integrated run of the National Energy Modeling System (NEMS), ensuring that price feedback effects (such as in natural gas markets) are fully accounted for.

Table 18 compares the key results of the three PTC sensitivity cases with the reference case. The 3-year PTC case, with an expiration date of December 2006, results in an additional 7.9 gigawatts of new wind capacity by 2010 compared to the reference case. By 2025, however, new wind capacity in the 3-year PTC case is only 7.8 gigawatts higher than in the reference case. Between 2007 (after the PTC expires) and 2025, 13.5 gigawatts of new wind capacity is constructed in the 3-year PTC case, compared with 8.6 gigawatts in the reference case for the same period. After 2010, the 3-year PTC case does not project additional wind capacity builds beyond those in the reference case. Compared with the reference case, no additional construction of new biomass facilities by 2010 is projected in the 3-year PTC case. Biomass facilities require longer construction lead times than the 3-year extension and therefore are not able to take advantage of the 3-year extension.

The 3-year PTC case projects the cumulative cost to the U.S. Treasury from the 3-year extension to be $1.7 billion (2002 dollars), using a 7 percent real discount rate [*97*]. This represents the tax revenue not recovered from the tax-paying owners of all wind and dedicated biomass facilities placed in service from the beginning of 2004 to December 31, 2006. It does not include lost revenue from existing facilities (placed in service before December 31, 2003) but does include facilities already planned or committed to be built after 2003.

The 9-year PTC case, with an expiration date of December 2012, results in an additional 32.3 gigawatts of new wind capacity by 2010 compared to the reference case. By 2015, that has increased to 54.7 gigawatts over the reference case, but by 2025, the 9-year PTC case only has an additional 49.4 gigawatts over the reference case. The cumulative cost to the U.S. Treasury for a 9-year, full value extension is $33 billion, compared to the reference case with no extension.

The extension to 2012 also provides an opportunity for new biomass facilities to be constructed to take advantage of the tax credit. By 2010, an additional 2.2 gigawatts of operating biomass capacity is projected in the 9-year PTC case relative to the reference case, increasing to 8.5 gigawatts over the reference case in 2015 and 10 gigawatts in 2025. In 2025, the 13.7 gigawatts of installed biomass capacity in the 9-year PTC case is projected to generate 91 billion kilowatthours, in addition to 230 billion kilowatthours of projected generation from 65.4 gigawatts of installed wind capacity. Although the additional biomass

Table 18. Key projections for renewable electricity in the reference and PTC extension cases, 2010 and 2025

	2003	2010				2025			
Projection	Reference	Reference	3-year PTC	9-year PTC	9-year half PTC	Reference	3-year PTC	9-year PTC	9-year half PTC
Electric power sector net summer capacity (gigawatts)									
Municipal solid waste and landfill gas	3.6	3.9	4.6	4.7	4.4	4.0	4.6	4.7	4.5
Wood and other biomass	1.9	2.2	2.1	4.4	3.2	3.7	4.6	13.7	8.1
Wind	6.5	8.0	15.9	40.3	23.4	16.0	23.8	65.4	38.8
Total electric power industry	936.9	931.7	937.5	958.1	943.3	1,169.9	1,176.7	1,221.0	1,191.7
Electric power sector generation (billion kilowatthours)									
Municipal solid waste and landfill gas	25.6	28.1	33.7	34.5	32.3	28.5	33.9	34.7	32.4
Wood and other biomass	15.7	23.5	23.4	28.4	26.3	29.2	33.4	90.9	51.8
Dedicated plants	10.8	13.3	13.0	22.5	17.5	22.9	28.4	90.9	51.0
Co-firing	5.0	10.3	10.4	6.0	8.8	6.3	5.0	0.0	0.8
Wind	17.4	24.1	52.5	139.3	79.2	53.2	81.8	230.0	136.5
Total electricity generation	3,900.0	4,510.0	4,511.0	4,523.0	4,512.0	5,787.0	5,787.0	5,805.0	5,790.0

capacity projected in the 9-year PTC case relative to the reference case is only 21 percent of the wind capacity added by 2025, because of its higher relative capacity factor, the projected generation from the additional biomass capacity is almost 40 percent of that from the additional wind capacity.

Almost 6.3 billion kilowatthours of biomass co-firing (that is, biomass fuel burned with coal in existing coal-fired plants) is projected in the reference case by 2025. In the 9-year PTC case, no co-fired generation is expected by 2025, largely because the more efficient new dedicated biomass facilities would be able to pay feedstock suppliers higher fuel premiums than the less efficient existing coal facilities retrofitted with co-firing equipment. Total biomass generation (dedicated plus co-firing) in the 9-year PTC case is more than triple total biomass generation in the reference case (91 billion kilowatthours and 29 billion kilowatthours, respectively).

In the 9-year half PTC case, substantial projected increases in wind capacity relative to the reference case projection reflect wind power costs that are, without subsidy, very close to being competitive. Although the 9-year half PTC case projects 27 gigawatts less installed wind capacity in 2025 than the 9-year PTC case, it projects almost 23 gigawatts more than in the reference case. Like the 9-year PTC case, the 9-year half PTC case projects significant leveling off of new wind installations after 2012, when eligibility for the subsidy ends. Between 2015 and 2025, wind capacity in the 9-year half PTC case increases by only 1.1 gigawatts, compared with 5.5 gigawatts of capacity growth in the reference case. Although by 2015 the basic unsubsidized levelized cost [*98*] of wind energy is reduced by about 0.5 cents per kilowatthour below the reference case for the same year, fewer low-cost resources are available once the subsidy has expired (having already been developed with the subsidy in place), and fewer attractive resources are available for development. The cumulative cost of the PTC extension to the U.S. Treasury in the 9-year half PTC case is projected to be $16 billion.

The projection for dedicated biomass capacity in 2025 in the 9-year half PTC case is 4.3 gigawatts higher than in the reference case. Although the additional capacity is sufficient to draw substantial biomass feedstock from the co-firing market, it does not completely eliminate it. Co-firing in 2025 in the 9-year half PTC case is only about 0.8 billion kilowatthours below the reference case projection of 6.3 billion kilowatthours.

U.S. Greenhouse Gas Intensity

On February 14, 2002, President Bush announced the Administration's Global Climate Change Initiative [*99*]. A key goal of the Climate Change Initiative is to reduce U.S. greenhouse gas intensity by 18 percent over the 2002 to 2012 time frame. For the purposes of the initiative, greenhouse gas intensity is defined as the ratio of total U.S. greenhouse gas emissions to economic output.

AEO2004 projects energy-related carbon dioxide emissions, which represented approximately 83 percent of total U.S. greenhouse gas emissions in 2002. Projections for other greenhouse gases are based on projected rates of growth in their emissions, published in the U.S. Department of State's *Climate Action Report 2002* [*100*]. Table 19 combines the *AEO2004* reference case projections for energy-related carbon dioxide emissions with the projections for other greenhouse gases.

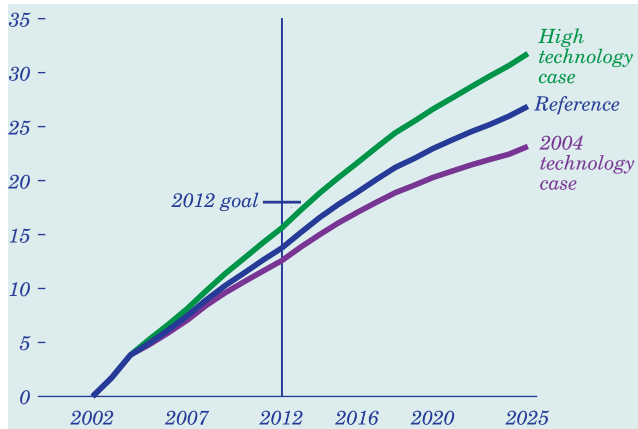
Table 19. Projected changes in U.S. greenhouse gas emissions, gross domestic product, and greenhouse gas intensity, 2002-2025

	Projection			Percent Change	
Measure	2002	2012	2025	2002-2012	2002-2025
Greenhouse gas emissions (million metric tons carbon dioxide equivalent)					
Energy-related carbon dioxide	5,729	6,763	8,142	18.0	42.1
Methane	613	623	616	1.6	0.5
Nitrous oxide	333	358	403	7.5	21.1
Gases with high global warming potential	121	271	595	124.3	393.0
Other carbon dioxide and adjustments for military and international bunker fuel	66	73	84	10.3	26.1
Total greenhouse gases	**6,862**	**8,087**	**9,839**	**17.8**	**43.4**
Gross domestic product (billion 1996 dollars)	9,440	12,906	18,520	36.7	96.2
Greenhouse gas intensity (thousand metric tons carbon dioxide equivalent per billion 1996 dollars of gross domestic product)	727	627	531	-13.8	-26.9

According to the combined emissions projections in Table 19, the greenhouse gas intensity of the U.S. economy is expected to decline by nearly 14 percent between 2002 and 2012, and by 27 percent between 2002 and 2025. The Administration's goal of reducing greenhouse gas intensity by 18 percent by 2012 would require additional emissions reductions of about 394 million metric tons carbon dioxide equivalent.

Although *AEO2004* does not include cases that specifically address alternative assumptions about greenhouse gas intensity, the integrated high technology case does give some indication of the feasibility of meeting the 18-percent reduction target. In the integrated high technology case, which combines the high technology cases for the residential, commercial, industrial, transportation, and electric power sectors,carbon dioxide emissions in 2012 are projected to be 175 million metric tons less than in the *AEO2004* reference case. As a result, U.S. greenhouse gas intensity would fall by almost 16 percent over the 2002-2012 period, still somewhat short of the Administration's goal of 18 percent (Figure 37). An 18-percent decline in intensity is projected to occur by 2014 in the integrated high technology case, as compared with 2016 in the reference case.

Figure 37. Projected improvement in U.S. greenhouse gas intensity, 2002-2025 (percent)



Market Trends

The projections in *AEO2004* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. Thus, they provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as currently enacted; however, the impacts of emerging regulatory changes, when defined, are reflected.

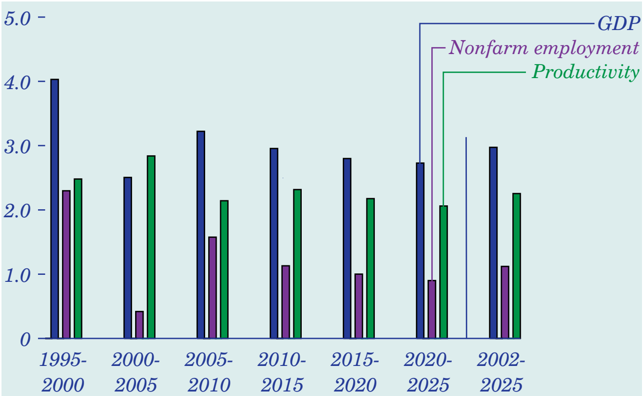
Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics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

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated, including severe weather, political disruptions, strikes, and technological breakthroughs. In addition, future developments in technologies, demographics, and resources cannot be foreseen with any degree of precision. Many key uncertainties in the *AEO2004* projections are addressed through alternative cases.

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

Strong Economic Growth Is Expected To Continue

Figure 38. Average annual growth rates of real GDP and economic factors, 1995-2025 (percent)

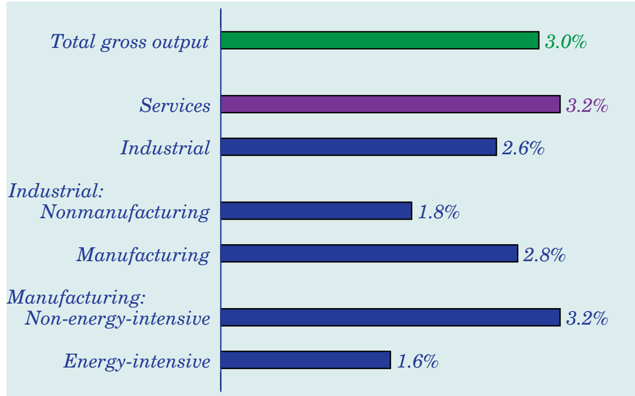


The output of the Nation's economy, measured by gross domestic product (GDP), is projected to grow by 3.0 percent per year between 2002 and 2025 (with GDP based on 1996 chain-weighted dollars) (Figure 38). The projected growth rate is slightly lower than the 3.1-percent rate projected in *AEO2003*. The labor force is projected to increase by 0.9 percent per year between 2002 and 2025, slightly lower than last year's forecast for the same period. Labor productivity growth in the nonfarm business sector is projected at 2.3 percent per year, compared with 2.2 percent per year in *AEO2003.*

Compared with the second half of the 1990s, the projected rates of growth in GDP and nonfarm employment are much lower for 2000-2005, reflecting present economic uncertainties. They are expected to pick up as the economy moves back to its long-term growth path between 2005 and 2010. Total population growth (including armed forces overseas) is expected to remain fairly constant after 2002, growing by 0.8 percent per year on average. Labor force growth is expected to slow as a result of demographic changes, but more people over 65 are expected to remain in the work force. Nonfarm business productivity growth has been strong recently, averaging 2.6 percent per year from 1995 to 2002. That trend is expected to continue through 2004, and productivity growth from 2005 to 2025 is expected to average above 2 percent per year. Disposable income is projected to grow by 3.0 percent and disposable income per capita by 2.2 percent per year. Nonfarm employment is projected to grow by 1.1 percent per year, and employment in manufacturing is projected to shrink by 0.1 percent per year.

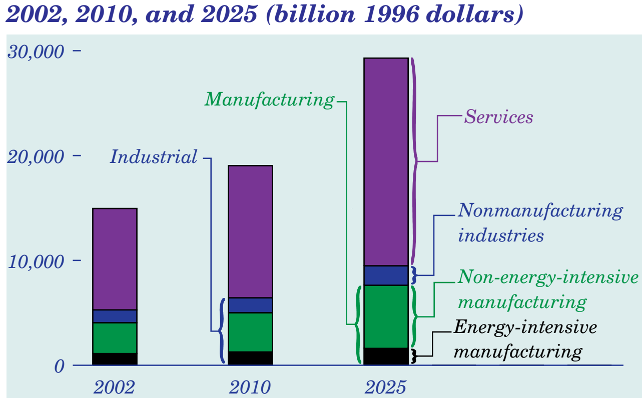
Service Sectors Lead Output Growth, Industrial Output Growth Is Slower

Figure 39. Sectoral composition of output growth rates, 2002-2025 (percent per year)



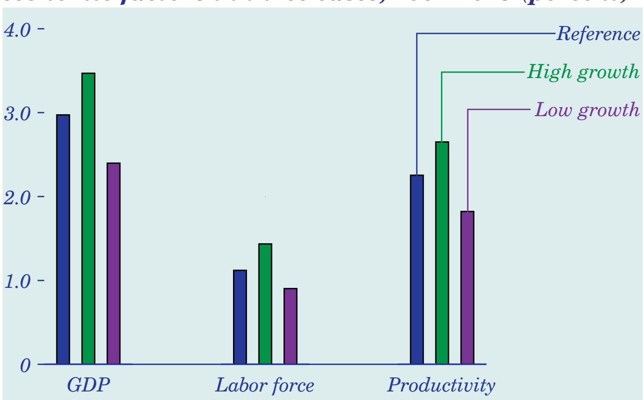
From 2002 to 2025, industrial output is projected to grow by 2.6 percent per year, compared with 3.2-percent average annual growth in the services sector (Figure 39). Manufacturing output is projected to grow by 2.8 percent per year and nonmanufacturing output (agriculture, mining, and construction) by 1.8 percent per year. The energy-intensive manufacturing sectors, which include food and intermediate goods [*101*], are expected to grow more slowly (1.6 percent a year) than the non-energy-intensive manufacturing sectors (3.2 percent a year). Productivity improvement is projected to be slower in the energy-intensive sectors, and higher energy prices are expected to have a greater impact, because the energy-intensive sectors are more sensitive to energy price increases. The industrial sector's share of total output is expected to fall from 35 percent in 2002 to 34 percent in 2010 and 32 percent in 2025. The manufacturing share of total output is projected to fall from 27 percent in 2002 to 26 percent in 2010 and remain at that level through 2025 (Figure 40).

Figure 40. Sectoral composition of gross output, 2002, 2010, and 2025 (billion 1996 dollars)



High and Low Growth Cases Reflect Uncertainty of Economic Growth

Figure 41. Average annual real growth rates of economic factors in three cases, 2002-2025 (percent)



To reflect the uncertainty in forecasts of economic growth, *AEO2004* includes high and low economic growth cases in addition to the reference case (Figure 41). The high and low growth cases show the projected effects of alternative growth assumptions on energy markets. Economic variables in the alternative cases—including GDP and its components, interest rates, disposable income, productivity, population, and employment—are modified from those in the reference case.

The high economic growth case assumes higher projected growth rates for population (1.0 percent per year), nonfarm employment (1.4 percent per year), and productivity (2.7 percent per year). With higher productivity gains, inflation and interest rates are projected to be lower than in the reference case, and economic output is projected to grow by 3.5 percent per year. GDP per capita is expected to grow by 2.4 percent per year, compared with 2.1 percent in the reference case.

The low economic growth case assumes lower growth rates for population (0.6 percent per year), employment (0.9 percent per year), and productivity (1.8 percent per year), resulting in higher projections for prices and interest rates and lower projections for industrial output growth. In the low growth case, economic output is projected to increase by 2.4 percent per year from 2002 through 2025, and growth in GDP per capita is projected to average only 1.8 percent per year.

Long-Run Trend Shows U.S. Economic Growth of About 3 Percent per Year

Figure 42. Average annual GDP growth rate, 1970-2025 (percent, 23-year moving average)

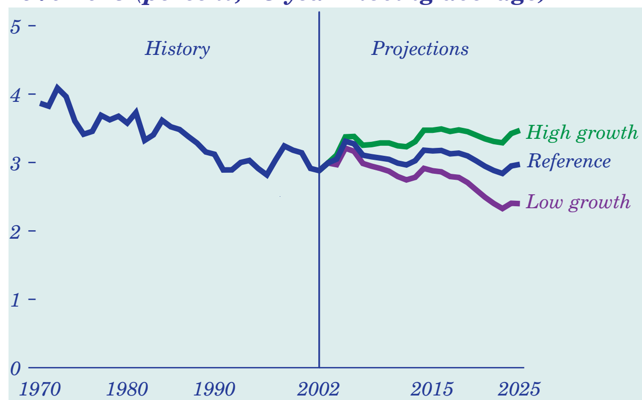
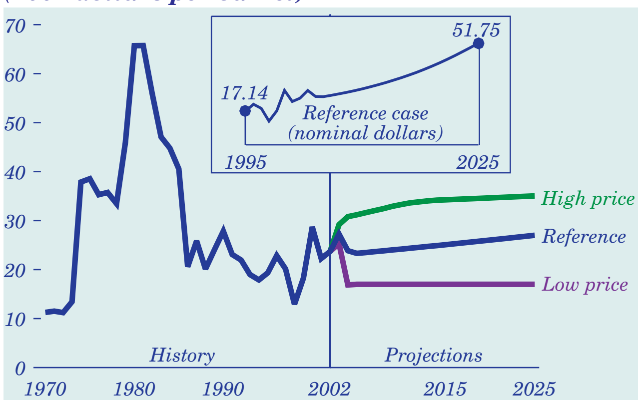


Figure 42 shows the trend in the moving 23-year average annual growth rate for GDP, including projections for the three *AEO2004* cases. The value for each year is calculated as the annual compound growth rate over the preceding 23 years. The 23-year average shows major long-term trends in GDP growth by smoothing more volatile year-to-year changes (although the increase shown for 1997-1998 reflects the negative growth of 1974-1975). Annual GDP growth has fluctuated considerably around the trend. The high and low growth cases capture the potential for different paths of long-term output growth.

One reason for the variability of the forecasts is the composition of economic output, reflected by growth rates of consumption and investment relative to overall GDP growth. In the reference case, consumption is projected to grow by 3.0 percent per year, while investment grows at a 4.8-percent annual rate. In the high growth case, with relatively lower interest rates, growth in investment is projected to average 5.5 percent per year. Higher investment rates lead to faster capital accumulation and higher productivity gains, which, coupled with higher labor force growth, yield higher aggregate economic growth than projected in the reference case. In the low growth case, with relatively higher interest rates, annual growth in investment expenditures is projected to average only 3.7 percent. Lower investment growth rates imply slower capital accumulation. With the labor force also growing more slowly, aggregate economic growth is expected to slow considerably relative to that projected in the reference case.

Projections Vary in Cases With Different Oil Price Assumptions

Figure 43. World oil prices in three cases, 1970-2025 (2002 dollars per barrel)



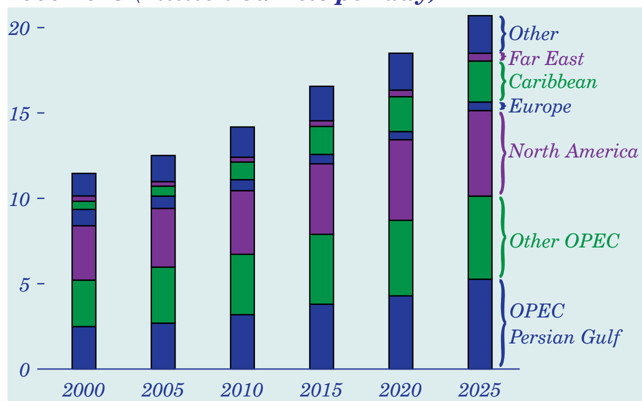
The historical record shows substantial variability in world oil prices, and there is similar uncertainty about future prices. Three *AEO2004* cases with different price paths allow an assessment of alternative views on the course of future oil prices (Figure 43). In the reference case, projected prices initially decline from current levels through 2005 and then rise by about 0.7 percent per year to $27 in 2025 (all prices in 2002 dollars per barrel unless otherwise noted). In nominal dollars, the reference case price is about $51 in 2025. In the low price case, prices are projected to decline from their high in 2003 to $16.99 in 2005 and to remain at that level out to 2025. The high price case projects a price rise of about 2.9 percent per year from 2002 to 2015, with real prices beginning to level off at above $34. The projected leveling off in the high price case is due to the market penetration of alternative energy supplies that could become economically viable at that price.

The price projections in the reference and high price cases are somewhat higher than those in *AEO2003* [*102*]. In view of OPEC's recent success in maintaining production cutbacks and raising world oil prices, it is expected that such market management will continue in the future. Price projections in the low case are lower than those in *AEO2003*, reflecting a greater band of uncertainty across the *AEO2004* price cases.

World demand for oil is expected to total almost 118 million barrels per day in 2025. The largest growth in demand is projected for the developing countries of Asia, at an average rate of 3.0 percent per year. Increases in production from non-OPEC countries are expected to continue throughout the forecast.

Oil Imports Reach More Than 20 Million Barrels per Day by 2025

Figure 44. U.S. gross petroleum imports by source, 2000-2025 (million barrels per day)



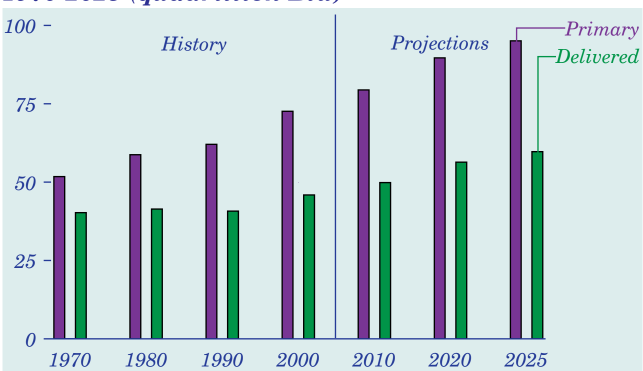
In the reference case, total U.S. gross oil imports are projected to increase from 11.5 million barrels per day in 2002 to 20.7 million barrels per day in 2025 (Figure 44). Crude oil accounts for most of the increase in imports, because distillation capacity at U.S. refineries is expected to be about 5 million barrels per day higher in 2025 than it was in 2002. Net imports of refined petroleum products still are expected to more than double over the next two decades.

Crude oil imports from the North Sea are projected to decline gradually as North Sea production ebbs. Significant imports of petroleum from Canada and Mexico are expected to continue, with much of the Canadian contribution coming from the development of its enormous oil sands resource base. West Coast refiners are expected to import small volumes of crude oil from the Far East to replace the declining production of Alaskan crude oil.

Imports of light products are expected to more than double by 2025, to more than 3 million barrels per day. Most of the projected increase is from refiners in the Caribbean Basin, North Africa, 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.

Annual Growth in Energy Use Is Projected To Continue

Figure 45. Primary and delivered energy consumption, excluding transportation use, 1970-2025 (quadrillion Btu)



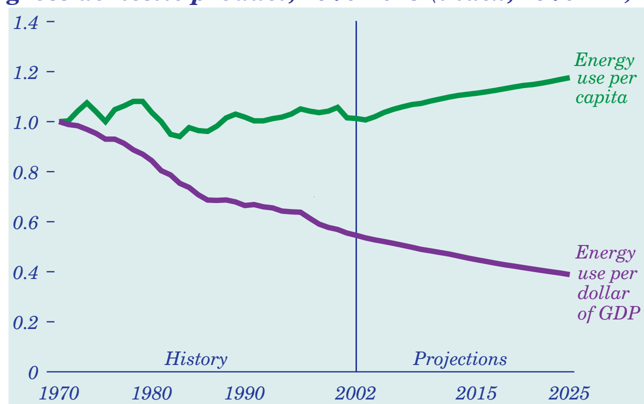
Net energy delivered to consumers represents only a part of total primary energy consumption. Primary consumption includes energy losses associated with the generation, transmission, and distribution of electricity, which are allocated to the end-use sectors (residential, commercial, and industrial) in proportion to each sector's share of electricity use [*103*].

How energy consumption is measured has become more important over time, as reliance on electricity has expanded. In 1970, electricity accounted for only 12 percent of energy delivered to the end-use sectors, excluding transportation. Since then, the growth in electricity use for applications such as space conditioning, consumer appliances, telecommunication equipment, industrial machinery, and office equipment has resulted in greater divergence between primary and delivered energy consumption (Figure 45). This trend is expected to stabilize in the forecast, as more efficient generating technologies offset increased demand for electricity. Both projected primary energy consumption and delivered energy consumption grow by 1.3 percent per 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 dioxide emissions, for example, are closely correlated with primary energy consumption. In the development of carbon dioxide stabilization policies, growth rates for primary energy consumption are generally more important than those for delivered energy.

Average Energy Use per Person Increases in the Forecast

Figure 46. Energy use per capita and per dollar of gross domestic product, 1970-2025 (index, 1970 = 1)

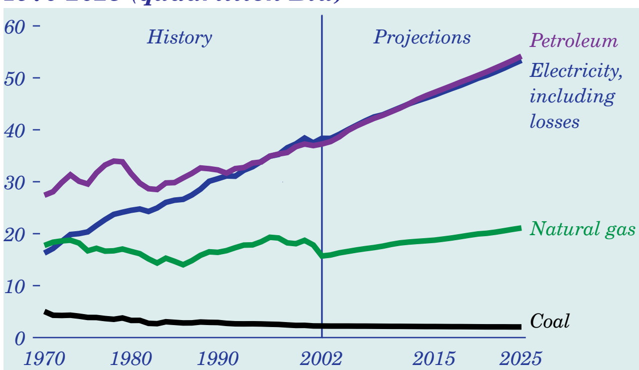


Energy intensity, as measured by energy use per dollar of GDP, is projected to decline at an average annual rate of 1.5 percent, with efficiency gains and structural shifts in the economy offsetting growth in demand for energy services (Figure 46). This rate of improvement is generally consistent with recent historical experience. With energy prices increasing between 1970 and 1986, energy intensity declined at an average annual rate of 2.3 percent, as the economy shifted to less energy-intensive industries, product mix changed, and more efficient technologies were adopted. Between 1986 and 1992, however, when energy prices were generally falling, energy intensity declined at an average rate of only 0.7 percent per year. Since 1992, it has declined on average by 1.9 percent per year.

Energy use per person generally declined from 1970 through the mid-1980s but began to increase as energy prices declined in the late 1980s and the 1990s. Per capita energy use is projected to increase in the *AEO2004* forecast, and the projected demand for energy services in 2025 is markedly higher than in 2002. The average home in 2025 is expected to be 6 percent larger (1,788 square feet in 2025 versus 1,689 square feet in 2002) and to use electricity more intensively. Personal highway travel and air travel per capita are expected to average 2.2 percent and 2.3 percent growth per year, respectively, from 2002 to 2025. The growth in demand for energy services is only partially offset by efficiency gains in the projections, and as a result primary energy use per capita is projected to increase by 0.7 percent per year through 2025.

Petroleum and Electricity Lead Growth in Energy Consumption

Figure 47. Delivered energy use by fossil fuel and primary energy use for electricity generation, 1970-2025 (quadrillion Btu)



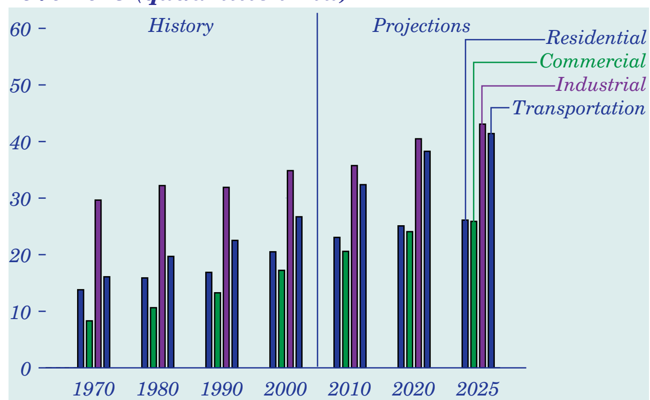
Consumption of petroleum products, mainly for transportation, makes up the largest share of primary energy use in the *AEO2004* forecast (Figure 47). Growth in energy demand for transportation averaged 2.0 percent per year in the 1970s but was slowed in the 1980s by rising fuel prices and new Federal efficiency standards that led to a 2.1-percent annual increase in average vehicle fuel economy. Fuel economy gains are projected to slow as a result of stable fuel prices and the absence of new standards. Growth in population and travel per capita is expected to increase demand for gasoline over the forecast.

Through 2007, increased competition, cost reductions from technological advances, and excess generating capacity from the recent boom in construction are projected to reduce average electricity prices. Price increases are expected after 2008, as higher coal and natural gas prices raise generation costs. Growth in electricity use is expected to be slowed by efficiency improvements and by market saturation of end uses such as air conditioning in some regional markets.

End-use demand for natural gas is projected to grow at a slightly slower rate than overall end-use energy demand, in contrast to the recent trend of more rapid growth in the use of gas as the industry was deregulated. Natural gas is projected to meet 24 percent of end-use energy requirements in 2025. End-use demand for energy from renewables such as wood and ethanol is projected to increase by 1.9 percent per year. Geothermal and solar energy use in buildings is expected to increase by about 2.4 percent per year but to provide less than 1 percent of the energy used for space and water heating.

U.S. Primary Energy Use Exceeds 136 Quadrillion Btu per Year by 2025

Figure 48. Primary energy consumption by sector, 1970-2025 (quadrillion Btu)



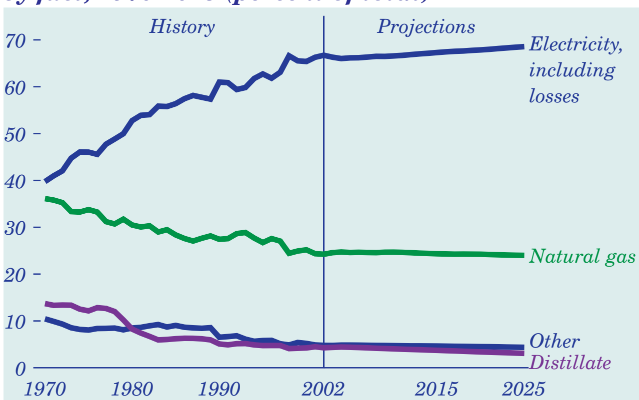
Primary energy use in the reference case is projected to reach 136.5 quadrillion Btu by 2025, 40 percent higher than the 2002 level. In the early 1980s, as energy prices rose, sectoral energy consumption grew relatively little (Figure 48). Between 1980 and 2002, however, declining real energy prices contributed to a marked increase in energy consumption. With higher energy prices since the late 1990s, energy consumption has again slowed.

In the forecast, energy demand in the residential sector is projected to grow at one-third the expected growth rate for GDP and in the commercial sector at just over one-half the GDP growth rate. Demand for energy is expected to grow more rapidly in the transportation sector than in the buildings sectors as a result of increased per capita travel and slower fuel efficiency gains. Assumed efficiency gains, higher real energy prices, and structural shifts between industries are projected to cause industrial demand for primary energy to grow more slowly than GDP.

To bracket the uncertainty inherent in any long-term forecast, alternative cases were used to highlight the sensitivity of the forecast to different oil price and economic growth paths. At the consumer level, oil prices primarily affect the demand for transportation fuels. Projected oil use for transportation in the high world oil price case is 13.2 percent lower than in the low world oil price case in 2025, as consumer choices favor more fuel-efficient vehicles and the demand for travel services is reduced slightly. For 2025, the projection of total annual energy use in the high economic growth case is 15.4 percent greater than in the low economic growth case.

Energy Fuel Shares for Residential Use Are Expected To Remain Stable

Figure 49. Residential primary energy consumption by fuel, 1970-2025 (percent of total)



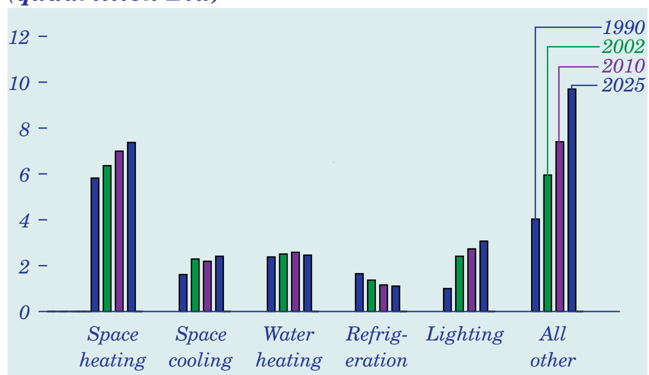
Residential energy use is projected to increase by 25 percent between 2002 and 2025 (10 percent by 2010). Most (76 percent) of the projected growth is related to increased use of electricity. Sustained growth in housing in the South, where almost all new homes use central air conditioning, is an important component of the national trend, along with the penetration of consumer electronics, such as home office equipment and security systems (Figure 49).

Natural gas use in the residential sector is projected to grow by 1.5 percent per year from 2002 to 2010 and 0.9 percent per year to 2025, maintaining a constant share of total residential primary energy consumption. Natural gas prices to residential customers are projected to increase by 9 percent from 2002 to 2025, remaining competitive with heating oil. The number of homes heated with natural gas is projected to increase by more than the number heated with electricity or oil. Distillate use is projected to fall by 10 percent between 2002 and 2025, as energy efficiency gains outpace the increase in the number of homes using home heating oil for space heating applications.

Newly built homes today are, on average, 26 percent larger than the existing housing stock, with correspondingly greater needs for heating, cooling, and lighting. Under current building codes and appliance standards, however, energy use per square foot is typically lower for new construction than for the existing stock. Further reductions in residential energy use per square foot could result from additional gains in equipment efficiency and more stringent building codes, requiring more insulation, better windows, and more efficient building designs.

Efficiency Standards Moderate Residential Energy Use

Figure 50. Residential primary energy consumption by end use, 1990, 2002, 2010, and 2025 (quadrillion Btu)



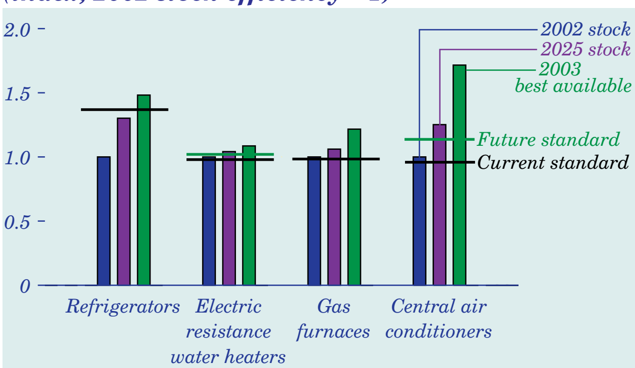
Energy use for space heating, the most energy-intensive end use in the residential sector, grew by 0.7 percent per year from 1990 to 2002 (Figure 50). Future growth is expected to be slowed by higher equipment efficiency and more stringent building codes. Gains in building shell efficiency are projected to reduce demand for space heating per household by about 4 percent in 2010 and 9 percent in 2025 relative to 2002.

A variety of appliances are now subject to minimum efficiency standards, including heat pumps, air conditioners, furnaces, refrigerators, and water heaters. Current (July 2001) standards for a typical residential refrigerator limit electricity use to 478 kilowatt-hours per year. Energy use for refrigeration is projected to decline by 2.0 percent per year from 2002 to 2010 and 0.9 percent per year to 2025 as older refrigerators are replaced with new models. With no new standards for refrigerators assumed in the forecast, the decline slows when large numbers of the older, less efficient units have been replaced.

The "all other" category (including small appliances such as personal computers, dishwashers, clothes washers, and dryers), which grew by 3.3 percent per year from 1990 to 2002 and accounted for 29 percent of residential primary energy use in 2002, is projected to account for 37 percent in 2025. Voluntary standards, both within and outside the appliance industry, are expected to forestall even larger increases. Even so, the "all other" category is projected to exceed other components of residential demand by 2025, growing at annual rates of 2.8 percent from 2002 to 2010 and 2.1 percent from 2002 to 2025.

Available Technologies Can Slow Growth in Residential Energy Use

Figure 51. Efficiency indicators for selected residential appliances, 2002 and 2025 (index, 2002 stock efficiency =1)

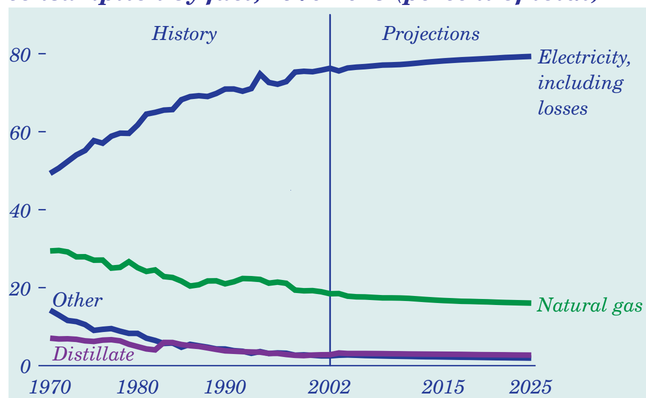


The *AEO2004* reference case projects an increase in the stock efficiency of residential appliances, as stock turnover and technology advances in most end-use services reduce residential energy intensity over time. For most appliances covered by the National Appliance Energy Conservation Act of 1987, the most recent Federal efficiency standards are higher than the 2002 stock, ensuring an increase in stock efficiency (Figure 51) without any additional new standards. Future updates to the Federal standards could have a significant effect on residential energy consumption, but they are not included in the reference case. The new efficiency standards for water heaters, clothes washers, central air conditioners, and heat pumps that were announced in January 2001 are included in the reference case.

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

Electricity Share of Commercial Energy Use Is Expected To Increase

Figure 52. Commercial primary energy consumption by fuel, 1970-2025 (percent of total)

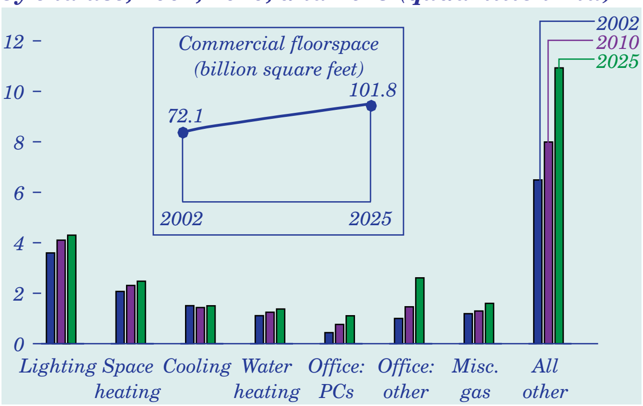


Projected energy use trends in the commercial sector show stable shares for all fuels, with growth in overall consumption slowing from its pace over the past three decades (Figure 52). Commercial energy use, including electricity-related losses, is projected to grow by 1.7 percent per year between 2002 and 2025, slightly faster than the projected growth rate for commercial floorspace of 1.5 percent. Energy consumption per square foot is projected to show little increase, with efficiency standards, voluntary government programs aimed at improving efficiency, and other technology improvements expected to balance the effects of a projected increase in demand for electricity-based services and generally stable or declining fuel prices.

Electricity accounted for 76 percent of commercial primary energy consumption in 2002, and its share is projected to increase to 79 percent in 2025. Expected efficiency gains in electric equipment are projected to be offset by the continuing penetration of new technologies and greater use of office equipment. Natural gas, which accounted for 18 percent of commercial energy consumption in 2002, is projected to decline to a 16-percent share by the end of the forecast. Distillate fuel oil made up only 3 percent of commercial demand in 2002, down from 6 percent in the years before deregulation of the natural gas industry. The fuel share projected for distillate remains at 3 percent in 2025, as fuel oil continues to compete with natural gas for space and water heating uses. With stable prices projected for conventional fuels, no appreciable growth in the share of renewable energy in the commercial sector is anticipated.

Lighting Is the Commercial Sector's Most Important Energy Application

Figure 53. Commercial primary energy consumption by end use, 2002, 2010, and 2025 (quadrillion Btu)

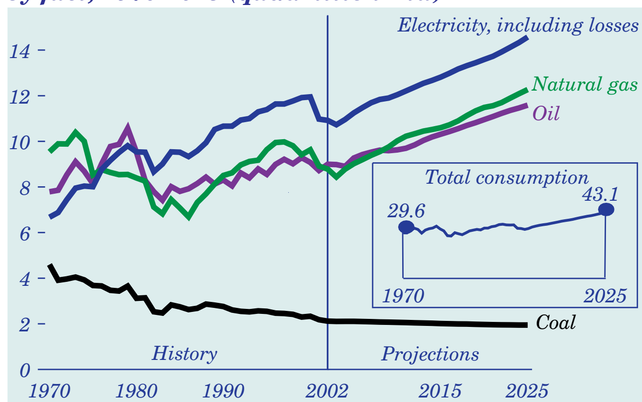


Through 2025, lighting is projected to remain the most important individual end use in the commercial sector [*104*]. Energy use for lighting is projected to increase slightly, as growth in lighting requirements outpaces adoption of more energy-efficient lighting equipment. Efficiency of space heating, space cooling, and water heating is also expected to improve, moderating growth in overall commercial energy demand. A projected increase in building shell efficiency, which affects the energy required for space heating and cooling, contributes to the trend (Figure 53).

The highest growth rates are expected for end uses that have not yet saturated the commercial market. Energy use for personal computers is projected to grow by 4.1 percent per year and for other office equipment, such as copiers, fax machines, and larger computers, by 4.3 percent per year through 2025. The projected growth in electricity use for office equipment reflects a trend toward more powerful equipment, increases in the market for commercial electronic equipment, and, while electricity prices fluctuate somewhat (declining in the early years and increasing later), generally low real electricity prices. Natural gas use for such miscellaneous uses as cooking and self-generated electricity is expected to grow by 1.3 percent per year. New telecommunications technologies and medical imaging equipment are projected to increase electricity demand in the "all other" end-use category, which also includes ventilation, refrigeration, minor fuel consumption, and energy use for a myriad of other uses, such as municipal water services, service station equipment, and vending machines. Annual growth of 2.3 percent is expected for the "all other" category.

Industrial Energy Use Could Grow by 33 Percent by 2025

Figure 54. Industrial primary energy consumption by fuel, 1970-2025 (quadrillion Btu)

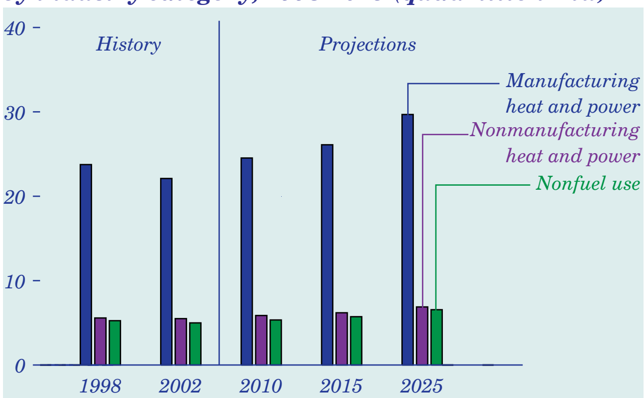


From 1970 to 1986, with demand for coking coal reduced by declines in steel production and with natural gas use falling as a result of end-use restrictions and curtailments, electricity's share of industrial energy use increased from 23 percent to 33 percent. The natural gas share fell from 32 percent to 24 percent, and coal's share fell from 16 percent to 9 percent. After 1986, natural gas began to recover its share as end-use regulations were lifted and supplies became more certain and less costly. As on-site cogeneration increased, the share of industrial delivered energy use made up by purchased electricity leveled off.

Primary energy use in the industrial sector—which includes the agriculture, mining, and construction industries in addition to traditional manufacturing—is projected to increase by 1.2 percent per year (Figure 54). Electricity (for machine drive and some production processes) and natural gas (given its ease of handling) are the major energy sources for heat and power in the industrial sector. Industrial purchased electricity use is projected to increase by 43 percent from 2002 to 2025, with competition in the generation market keeping electricity prices low. Despite a projected increase in natural gas prices after 2002, its use for energy in the industrial sector is expected to increase by 15 percent from 2002 to 2010 and by 41 percent from 2002 to 2025. Petroleum use for energy in the industrial sector is projected to grow by 19 percent from 2002 to 2025. Coal use is expected to decline by 3 percent from 2002 to 2010 and by 8 percent from 2002 to 2025, as new steelmaking technologies continue to reduce demand for metallurgical coal. Coal use for boiler fuel and as a substitute for coke in steelmaking remains essentially flat.

Industrial Energy Use Grows Steadily in the Projections

Figure 55. Industrial primary energy consumption by industry category, 1998-2025 (quadrillion Btu)



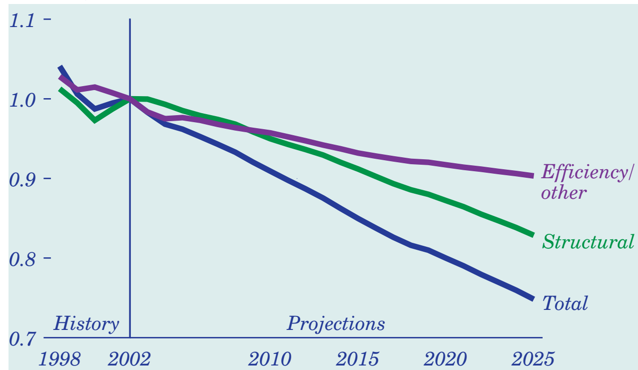
About 70 percent of the energy consumed in the industrial sector is used to provide heat and power for manufacturing. The remainder is approximately equally distributed between nonmanufacturing heat and power uses and nonfuel uses, such as raw materials and asphalt (Figure 55).

Nonfuel use of energy (feedstocks and asphalt) in the industrial sector is projected to grow at the same rate as heat and power consumption (1.2 percent per year). The feedstock portion of nonfuel use is projected to grow by 1.2 percent per year, slower than the growth in output in the bulk chemical industry (1.6 percent through 2025), because of changes in the product mix. In 2025, feedstock consumption is projected to be 4.9 quadrillion Btu. Asphalt use is projected to grow by 1.3 percent per year to 1.7 quadrillion Btu in 2025. The construction industry is the principal consumer of asphalt for paving and roofing. Asphalt use does not grow as rapidly as construction output (2.2 percent per year through 2025), because not all construction activities require asphalt.

Petroleum refining, chemicals, and pulp and paper are among the largest end-use consumers of energy for heat and power in the manufacturing sector. These three energy-intensive industries used 8.1 quadrillion Btu of delivered energy in 2002. The major fuels used in petroleum refineries are still gas, natural gas, and petroleum coke. In the chemical industry, natural gas accounts for approximately 55 percent of the delivered energy consumed for heat and power. The pulp and paper industry uses the most renewables, in the form of wood and spent liquor.

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

Figure 56. Components of improvement in industrial delivered energy intensity, 1998-2025 (index, 2002 = 1)

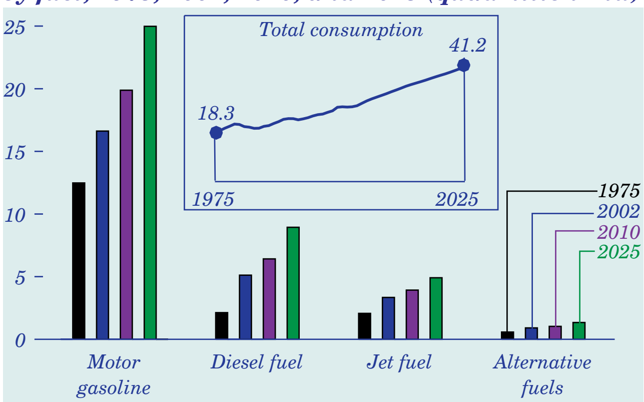


Changes in industrial energy intensity (consumption per unit of output) can be separated into two effects. One component reflects underlying increases in equipment and production efficiencies; the other arises from structural changes in the composition of industrial value of shipments. Since 1970, the use of more energy-efficient technologies, combined with relatively low growth in the energy-intensive industries, has dampened growth in industrial energy consumption. Thus, despite a 41-percent increase in industrial shipments, total energy use in the sector grew by only 1 percent between 1980 and 2002. Energy consumption is projected to grow more slowly than industrial shipments in the *AEO2004* reference case.

Industrial value of shipments is projected to grow by 2.6 percent between 2002 and 2025. The share of total industrial shipments attributed to the energy-intensive industries is projected to fall from 21 percent in 2002 to 17 percent in 2025. Consequently, even if no specific industry experienced a decline in intensity, aggregate industrial energy intensity would decline. Figure 56 shows projected changes in energy intensity due to structural effects and efficiency effects separately [*105*]. From 2002 to 2025, industrial delivered energy intensity is projected to drop by 26 percent. The changing composition of industrial output is expected to result in a drop in energy intensity of approximately 17 percent by 2025. Thus, two-thirds of the expected change in delivered energy intensity for the sector is attributable to structural shifts and the remainder to changes in energy intensity associated with projected increases in equipment and production efficiencies.

Alternative Fuels Make Up 2.1 Percent of Light-Duty Vehicle Fuel Use in 2025

Figure 57. Transportation energy consumption by fuel, 1975, 2002, 2010, and 2025 (quadrillion Btu)



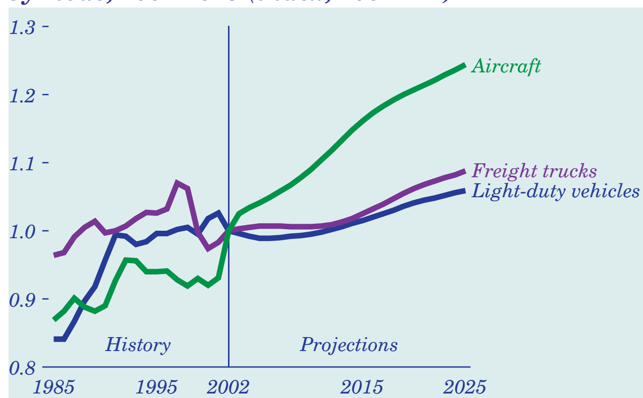
Energy demand for transportation is projected to grow from 26.8 quadrillion Btu in 2002 to 41.2 quadrillion Btu in 2025 (Figure 57). Petroleum products dominate energy use in the sector. In the reference case, motor gasoline use increases by 1.8 percent per year from 2002 to 2025, when it makes up 60 percent of transportation energy use. Alternative fuels are projected to displace 136,800 barrels of oil equivalent per day [*106*] in 2010 and 166,500 barrels per day (2.1 percent of light-duty vehicle fuel consumption) in 2025, in response to current environmental and energy legislation intended to reduce oil use. Gasoline's share of demand is expected to be sustained, however, by low gasoline prices and slower fuel efficiency gains for conventional light-duty vehicles (cars, vans, pickup trucks, and sport utility vehicles) than were achieved during the 1980s.

Assumed industrial output growth of 2.6 percent per year from 2002 to 2025 leads to an increase in freight transport, with a corresponding 2.3-percent annual increase in diesel fuel use. Economic growth and low projected jet fuel prices yield an annual increase in air travel of 2.3 percent from 2002 to 2025 and a 1.8-percent average annual increase in jet fuel use.

In the forecast, energy prices directly affect the level of oil use through travel costs and average vehicle fuel efficiency. Most of the price sensitivity is seen as variations in motor gasoline use in light-duty vehicles, because the stock of light-duty vehicles turns over more rapidly than do the stocks for other modes of travel. In the high world oil price case, gasoline use increases by 1.2 percent per year, compared with 2.1 percent per year in the low oil price case.

Average Horsepower for New Cars Is Projected To Grow by 24 Percent

Figure 58. Transportation stock fuel efficiency by mode, 2002-2025 (index, 2002 = 1)



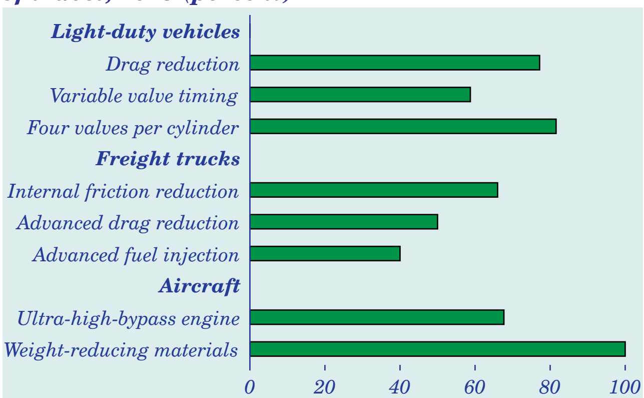
Fuel efficiency is projected to improve more slowly from 2002 to 2025 than it did during the 1980s. Fuel economy for the light-duty vehicle stock is projected to improve by 6 percent, and for the stock of freight trucks from 6.0 miles per gallon in 2002 to 6.5 in 2025 (Figure 58). A larger gain (22.2 percent) is expected for aircraft. Fuel economy standards for cars are assumed to stay at current levels and light truck standards increase to 22.2 miles per gallon by 2007 [*107*]. Projected low fuel prices and higher personal incomes are expected to increase the demand for larger, more powerful vehicles, with average horsepower for new cars projected to be 23.9 percent above the 2002 average in 2025 (Table 20). Advanced technologies and materials are expected to provide increased performance and size while improving new vehicle fuel economy [*108*]. Advanced technologies are projected to boost the average fuel economy of new light-duty vehicles by about 1.5 miles per gallon, to 25.3 miles per gallon, in 2010 and by about 3 miles per gallon, to 26.9 miles per gallon, in 2025.

Table 20. New car and light truck horsepower ratings and market shares, 1990-2025

	Cars			Light trucks		
Year	Small	Medium	Large	Small	Medium	Large
1990						
Horsepower	119	145	176	132	157	185
Sales share	0.60	0.28	0.12	0.48	0.21	0.30
2000						
Horsepower	145	177	221	173	185	229
Sales share	0.50	0.35	0.15	0.30	0.34	0.36
2010						
Horsepower	176	217	251	213	216	280
Sales share	0.50	0.35	0.15	0.30	0.34	0.35
2025						
Horsepower	192	237	269	224	221	286
Sales share	0.50	0.35	0.15	0.30	0.34	0.35

New Technologies Promise Better Vehicle Fuel Efficiency

Figure 59. Technology penetration by mode of travel, 2025 (percent)



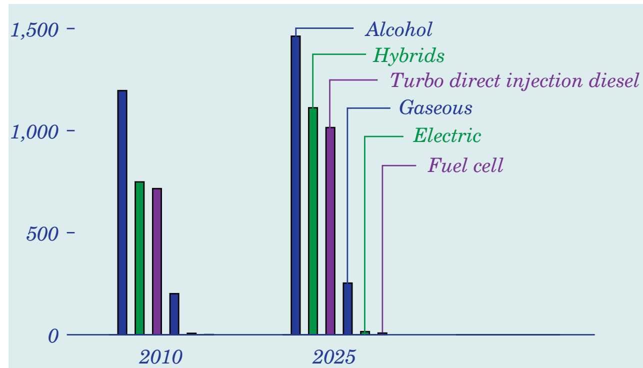
New automobile fuel economy is projected to remain relatively constant through 2010 but to increase to 30.8 miles per gallon in 2025 as a result of advances in fuel-saving technologies (Figure 59). Three of the most promising would provide more than 4 percent higher fuel economy each: advanced drag reduction, variable valve timing and lift, and technologies that reduce internal engine friction. Advanced drag reduction reduces air resistance over the vehicle; variable valve timing optimizes the timing of air intake into the cylinder with the spark ignition during combustion; and reduced engine friction increases engine efficiency through more efficient designs, bearings, and coatings that reduce resistance between moving parts.

Due to concerns about economic payback, the trucking industry is more sensitive to the marginal cost of fuel-efficient technologies; however, several technologies can increase fuel economy significantly, including components to reduce internal friction (2-percent improvement), advanced drag reduction (2 percent), and advanced fuel injection systems (5 percent). These technologies are expected to penetrate the heavy-duty truck market by 2025. Advanced technology penetration is projected to increase the average fuel efficiency of new freight trucks from 6.7 miles per gallon in 2002 to 7.1 miles per gallon in 2025.

New aircraft fuel efficiencies are projected to increase by 16 percent from 2002 levels by 2025. Ultra-high-bypass engine technology can potentially increase fuel efficiency by 10 percent, and increased use of weight-reducing materials may contribute up to a 15-percent improvement.

Advanced Technologies Could Reach 19 Percent of Sales by 2025

Figure 60. Sales of advanced technology light-duty vehicles by fuel type, 2010 and 2025 (thousand vehicles sold)

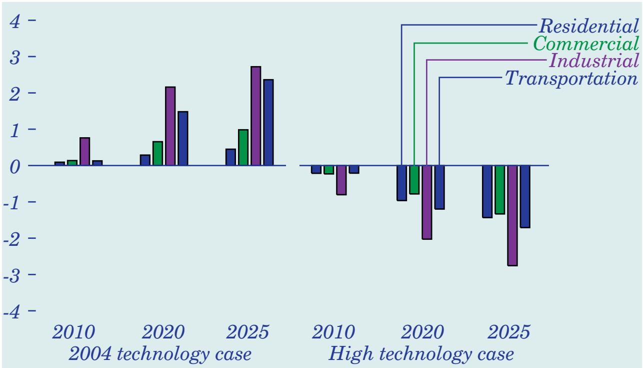


Advanced technology vehicles, representing automotive technologies that use alternative fuels or require advanced engine technology, are projected to reach 3.9 million vehicle sales per year and make up 19.0 percent of total light-duty vehicle sales in 2025. Alcohol flexible-fueled vehicles are projected to continue to lead advanced technology vehicle sales, at 1.4 million vehicles in 2025 (Figure 60). Hybrid electric vehicles, introduced into the U.S. market by two manufacturers in 2000, are anticipated to sell well: 750,000 units are projected to be sold in 2010, increasing to 1.1 million units in 2025. Sales of turbo direct injection diesel vehicles are projected to increase to 716,000 units in 2010 and 1 million units in 2025.

About 80 percent of advanced technology sales are as a result of Federal and State mandates for fuel economy standards, emissions programs, or other energy regulations. Currently, manufacturers selling alcohol flexible-fueled vehicles receive fuel economy credits that count toward compliance with corporate average fuel economy regulations. In the *AEO2004* forecast, the majority of projected gasoline hybrid, fuel cell, and electric vehicle sales result from compliance with low-emission vehicle programs in California, New York, Maine, Vermont, and Massachusetts.

Alternative Cases Analyze Effects of Advances in Technology

Figure 61. Variation from reference case primary energy use by sector in two alternative cases, 2010, 2020, and 2025 (quadrillion Btu)



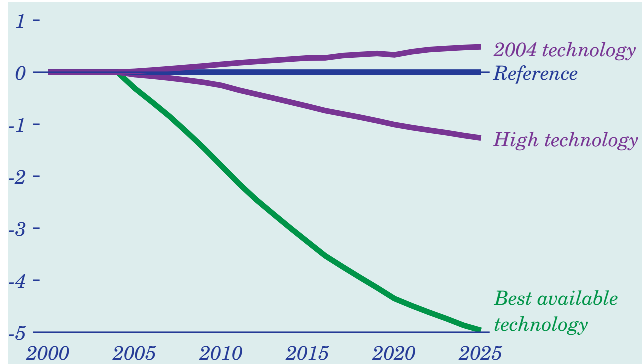
The availability and market penetration of new, more efficient technologies are uncertain. Alternative cases for each sector, based on a range of assumptions about technological progress, show the effects of these assumptions (Figure 61). The alternative cases assume that current equipment and building standards are met but do not include feedback effects on energy prices or on economic growth.

For the residential and commercial sectors, the 2004 technology case holds equipment and building shell efficiencies at 2004 levels. The best available technology case assumes that the most energy-efficient equipment and best residential building shells available are chosen for new construction each year regardless of cost, and that the efficiencies of existing residential and all commercial building shells improve from their reference case levels. The high technology case assumes earlier availability, lower costs, and higher efficiencies for more advanced technologies than in the reference case.

The 2004 technology cases for the industrial and transportation sectors and the high technology case for the industrial sector use the same assumptions as the buildings sector cases. For transportation, the high technology assumptions include lower costs and improved efficiencies for advanced light-duty vehicles and aircraft technologies and improved efficiencies for conventional light-duty vehicles, freight trucks, and air, rail, and marine travel, as reflected in several studies of potential improvement in transportation technologies [*109*].

Advanced Technologies Could Reduce Residential Energy Use by 19 Percent

Figure 62. Variation from reference case primary residential energy use in three alternative cases, 2002-2025 (quadrillion Btu)



The *AEO2004* reference case includes the effects of several different policies aimed at increasing residential end-use efficiency, including minimum efficiency standards and voluntary energy savings programs to promote energy efficiency through innovations in manufacturing, building, and mortgage financing. In the 2004 technology case, assuming no increase in efficiency of equipment or building shells beyond that in 2004, 2 percent more energy would be required in 2025 than in the reference case (Figure 62).

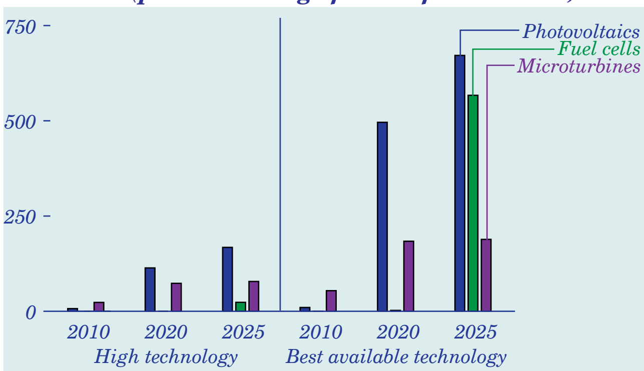
In the best available technology case, assuming that the most energy-efficient technology considered is always chosen regardless of cost, projected residential primary energy use in 2025 is 19 percent lower than in the reference case and 20 percent lower than in the 2004 technology case. Through 2025, projected additional investment of $367 billion relative to that in the reference case would be necessary to save a projected $144 billion in energy costs in the best available technology case [*110*].

The high technology case does not constrain consumer choices. Instead, the most energy-efficient technologies are assumed to be available earlier, with lower costs and higher efficiencies. The consumer discount rates used to determine the purchased efficiency of all residential appliances in the high technology case do not vary from those used in the reference case; that is, consumers value efficiency equally across the two cases. Energy consumption in 2025 in the high technology case is projected to be 5 percent lower than in the reference case; however, the savings are not as great as those projected in the best available technology case.

Energy Demand in Alternative Technology Cases

Advanced Technologies Could Slow Electricity Sales Growth for Buildings

Figure 63. Buildings sector electricity generation from advanced technologies in alternative cases, 2010-2025 (percent change from reference case)



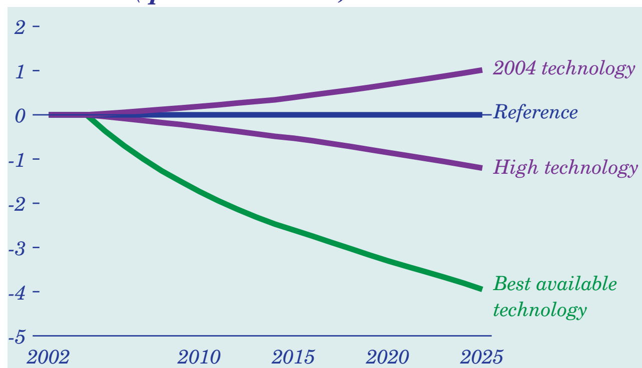
Alternative technology cases for the buildings sectors include a range of assumptions for the availability and market penetration of advanced distributed generation technologies (solar photovoltaic systems, fuel cells, and microturbines). Some of the heat produced by fossil-fuel-fired generating systems may be used to satisfy heating requirements, increasing system efficiency and the attractiveness of the advanced technologies, particularly in alternative cases with more optimistic technology assumptions.

In the high technology case, buildings are projected to generate 8 billion kilowatthours (38 percent) more electricity in 2025 than in the reference case (Figure 63), most of which offsets residential and commercial electricity purchases. In the best available technology case, projected electricity generation in buildings in 2025 is 30 billion kilowatthours (153 percent) higher than in the reference case. In the 2004 technology case, assuming no further technological progress or cost reductions after 2004, electricity generation in buildings in 2025 is 9 billion kilowatthours (46 percent) lower than projected in the reference case.

The additional natural gas use projected for fuel cells and microturbines to provide heat and power in commercial buildings in the high technology case offsets reductions from improved building shells and end-use equipment. Although the best technology case projects even higher adoption of these technologies, the additional end-use savings projected when the most efficient technologies are chosen, regardless of cost, outweigh the additional natural gas consumption needed to fuel distributed generation systems.

Advanced Technologies Could Reduce Commercial Energy Use by 15 Percent

Figure 64. Variation from reference case primary commercial energy use in three alternative cases, 2002-2025 (quadrillion Btu)

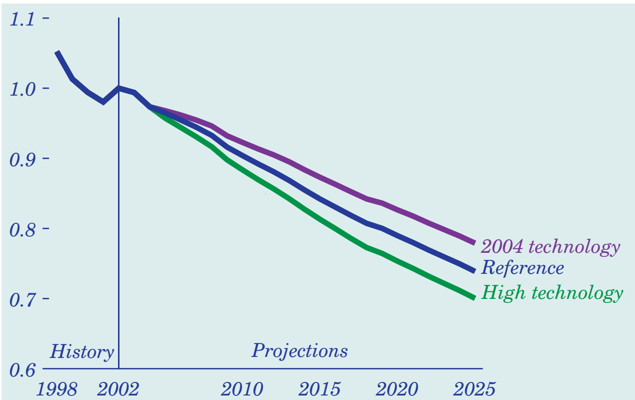


The *AEO2004* reference case incorporates efficiency improvements for commercial equipment and building shells, limiting commercial energy intensity (energy use per square foot of floorspace) to a 0.2-percent annual increase over the forecast. The 2004 technology case assumes that future equipment and building shells will be no more efficient than those available in 2004. The high technology case assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment than in the reference case and more rapid improvement in building shells. The best available technology case assumes that only the most efficient technologies will be chosen, regardless of cost, and that building shells will improve at a faster rate than assumed in the high technology case.

In the 2004 technology case, projected energy use in 2025 is 4 percent higher than the 25.9 quadrillion Btu used in the reference case (Figure 64), as a result of an 0.4-percent average annual increase in commercial primary energy intensity. The high technology case projects an additional 5-percent energy savings in 2025 relative to the reference case, with little change in primary energy intensity from 2002 to 2025. In the best available technology case, commercial primary energy intensity is projected to improve by 0.5 percent per year, and projected energy use in 2025 is 15 percent lower than in the reference case. More optimistic assumptions result in additional projected energy savings from both renewable and conventional fuel-using technologies. In 2025, commercial solar photovoltaic systems are projected to generate 86 percent more electricity in the high technology case than in the reference case.

Alternative Technology Cases Show Range of Industrial Efficiency Gains

Figure 65. Industrial primary energy intensity in two alternative cases, 1998-2025 (index, 2002 = 1)



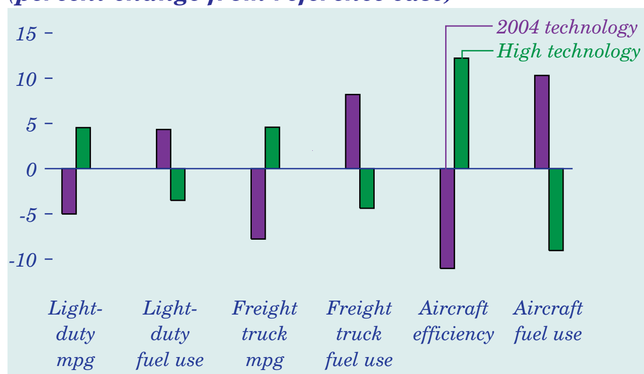
Efficiency gains in both energy-intensive and non-energy-intensive industries are projected to reduce overall energy intensity in the industrial sector. Expected output growth in metal-based durables (3.8 percent per year), driven primarily by investment and export-related demand, is a key factor. In the reference case, this non-energy-intensive group of industries is projected to grow more than twice as fast as the energy-intensive sectors (1.6 percent per year).

In the high technology case, 2.2 quadrillion Btu less energy is projected to be used in 2025 than for the same level of output in the reference case. Industrial primary energy intensity is projected to improve by 1.5 percent per year through 2025 in this case, compared with 1.3-percent annual improvement in the reference case (Figure 65). Industrial cogeneration capacity is projected to increase more rapidly in the high technology case (3.2 percent per year) than in the reference case (2.4 percent per year).

In the 2004 technology case, industry is projected to use 2.3 quadrillion Btu more energy in 2025 than in the reference case. Energy efficiency remains at the level achieved by new equipment in 2004, but average efficiency still improves as old equipment is retired. Aggregate industrial energy intensity is projected to decline by 1.1 percent per year because of reduced efficiency gains. The change in industrial structure is the same in the 2004 technology and high technology cases as in the reference case, because the same macroeconomic assumptions are used for the three cases. Industrial cogeneration capacity is projected to increase by 2.2 percent per year from 2002 to 2025 in the 2004 technology case.

Vehicle Technology Advances Reduce Transportation Energy Demand

Figure 66. Changes in key components of the transportation sector in two alternative cases, 2025 (percent change from reference case)



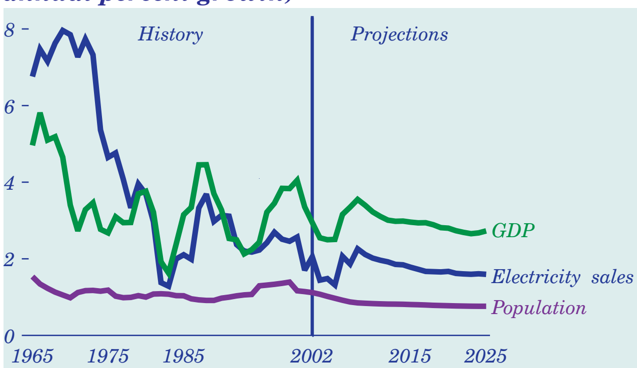
The transportation high technology case assumes lower costs and higher efficiencies for new technologies. Projected energy use for transportation is 1.7 quadrillion Btu (4.2 percent) lower in 2025 than in the reference case. In 2025, about 49 percent (0.9 quadrillion Btu) of the difference is attributed to the improved efficiency of light-duty vehicles. Advances in conventional technologies and in vehicle attributes for advanced technologies are projected to raise the average efficiency of the light-duty vehicle fleet to 21.8 miles per gallon, as compared with a projected increase to 20.9 miles per gallon in the reference case (Figure 66).

Projected fuel demand for freight trucks in 2025 is 0.3 quadrillion Btu lower in the high technology case than in the reference case, and the projected stock efficiency is 4.6 percent higher. Advanced aircraft technologies are also projected to improve aircraft efficiency by 12 percent above the reference case projection, reducing the projected fuel use for air travel in 2025 by 0.5 quadrillion Btu.

In the 2004 technology case, with new technology efficiencies fixed at 2004 levels, efficiency improvements can result only from stock turnover. In 2025, the total projected energy demand for transportation is 2.4 quadrillion Btu (5.8 percent) higher than in the reference case. The average fuel economy of new light-duty vehicles is projected to be 24.8 miles per gallon in 2025 in the 2004 technology case, 2.1 miles per gallon lower than projected in the reference case.

Electricity Use Is Expected To Grow More Slowly Than GDP

Figure 67. Population, gross domestic product, and electricity sales, 1965-2025 (5-year moving average annual percent growth)



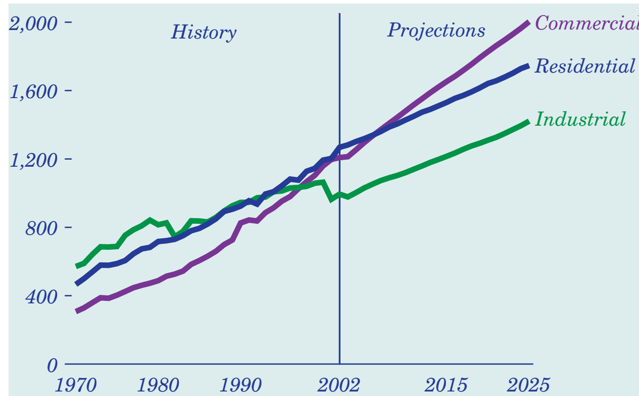
As generators and combined heat and power plants adjust to the evolving structure of the electricity market, they face slower growth in demand than in the past. Historically, demand for electricity has been related to economic growth; that positive relationship is expected to continue, but the ratio is uncertain.

During the 1960s, electricity demand grew by more than 7 percent per year, nearly twice the rate of economic growth (Figure 67). In the 1970s and 1980s, however, the ratio of electricity demand growth to economic growth declined to 1.5 and 1.0, respectively. Several factors have contributed to this trend, including increased market saturation of electric appliances, improvements in equipment efficiency and utility investments in demand-side management programs, and more stringent equipment efficiency standards. Throughout the forecast, growth in demand for office equipment and personal computers, among other equipment, is offset by slowing growth or reductions in demand for space heating and cooling, refrigeration, water heating, and lighting. Continued saturation of electric appliances, installation of more efficient equipment, and the promulgation of efficiency standards are expected to hold growth in electricity sales to an average of 1.8 percent per year between 2002 and 2025.

Changing consumer markets could mitigate the slowing of electricity demand growth seen in the *AEO2004* projections. New electric appliances are introduced frequently. If new uses of electricity are more substantial than currently expected, they could offset some or all of the projected efficiency gains.

Continued Growth in Electricity Use Is Expected in All Sectors

Figure 68. Annual electricity sales by sector, 1970-2025 (billion kilowatthours)



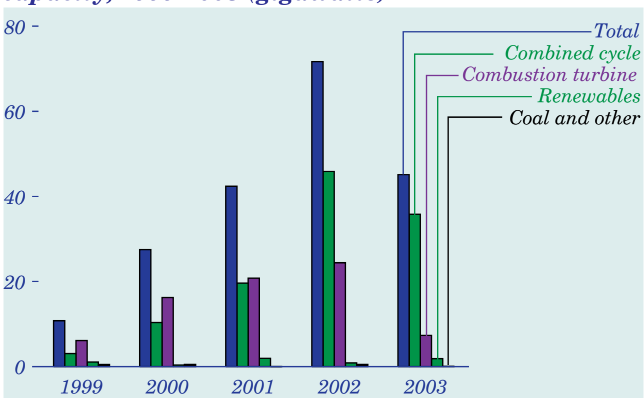
Electricity consumption is projected to increase in all the end-use sectors (Figure 68). The highest growth rate is projected for the commercial sector, at 2.2 percent per year from 2002 to 2025, compared with 1.6 percent for industrial and 1.4 percent for residential electricity demand. Residential demand, which grew faster in the past, varies by season, day, and time of day. Driven by summer peaks, the periodicity of residential demand increases the peak-to-average load ratio for load-serving entities, which must rely on quick-starting turbines or internal combustion units to meet peak demand. From 2000 to 2003, 69 gigawatts of peaking capacity was added—more than the total additions of 59 gigawatts of peaking capacity projected for 2004 to 2025.

The projected growth in commercial and industrial electricity demand from 2002 to 2025 (2.2 and 1.6 percent per year, respectively) will require significant additions of baseload generating capacity. From 2000 to 2003, 112 gigawatts of combined-cycle capacity, which is efficient in both baseload and cycling applications, was installed. As a result, only about 12 gigawatts of currently unplanned baseload capacity is projected to be added from 2004 to 2010. After 2010, more rapid growth in baseload capacity is expected.

In addition to sectoral sales, combined heat and power plants in 2002 produced 134 billion kilowatthours for their own use in industrial and commercial processes, such as petroleum refining and paper manufacturing. Combined heat and power generation is expected to increase to 210 billion kilowatthours in 2025, as demand for manufactured products increases.

Recent Surge in Capacity Additions Is Expected To Meet Near-Term Needs

Figure 69. Additions to electricity generating capacity, 1999-2003 (gigawatts)



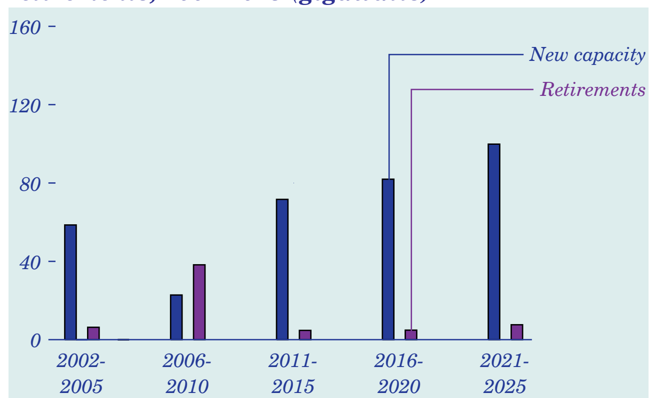
From 1960 to 1969, U.S. power suppliers brought 180 gigawatts of new generating capacity on line—an average of 18 gigawatts per year—and over the next 5 years, from 1970 to 1974, the pace doubled to an average of 36 gigawatts per year. Nearly 314 gigawatts of new capacity was brought on between 1970 and 1979, almost 75 percent more than in the previous 10 years. New capacity additions slowed to 172 gigawatts in the 1980s and 84 gigawatts in the 1990s, and by the mid- to late 1990s, many regions of the country needed or were close to needing new capacity in order to meet consumer requirements reliably.

In 2000 and 2001, higher wholesale electricity prices sent strong signals to power plant developers that supplies were tightening, and they embarked on a dramatic building campaign. Although they had not built 20 gigawatts of new capacity in a single year since 1985, they built 27 gigawatts in 2000, 42 gigawatts in 2001 and 72 gigawatts in 2002 and are on pace to build 45 gigawatts in 2003 (Figure 69). More recently, however, developers have reported that they are delaying or canceling planned plants. New additions slowed in 2003, and that trend is expected to continue in the near term.

Most of the recent additions are natural-gas-fired. Of the 187 gigawatts added between 2000 and 2003, 175 gigawatts is natural-gas-fired, including 110 gigawatts of efficient combined-cycle capacity and 65 gigawatts of combustion turbine capacity, which is used mainly when demand for electricity is high. Only about 5 gigawatts of new renewable plants—mostly wind—and less than 1 gigawatt of new coal-fired capacity were added over the same period.

Retirements and Rising Demand Are Expected To Require New Capacity

Figure 70. New generating capacity and retirements, 2002-2025 (gigawatts)

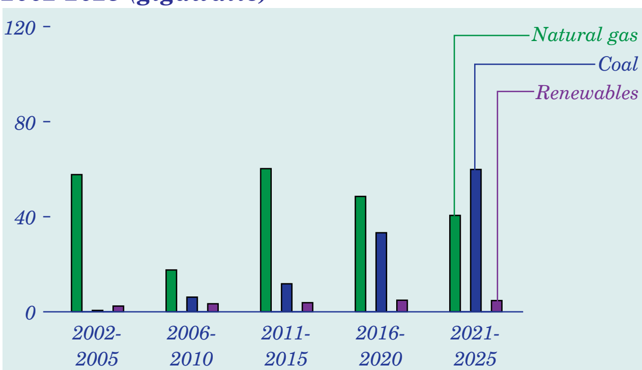


Although recent capacity additions will meet near-term needs for electricity generation, more capacity will be needed eventually, as electricity use grows and older, inefficient plants are retired. From 2002 to 2025, 356 gigawatts of new generating capacity is expected to be needed (Figure 70), most of it after 2010, when the current excess supply situation has subsided. For example, between 2002 and 2010, only 88 gigawatts of new capacity (57 gigawatts of which is already in development) is projected to be needed—equivalent to approximately 11 gigawatts of capacity annually. Between 2011 and 2025, however, the amount of new capacity needed is projected to grow to 268 gigawatts—an average of 19 gigawatts annually.

In addition to meeting the growing demand for electricity, new plants will be built to replace older plants that are expected to be retired. From 2002 to 2025, a total of 62 gigawatts of capacity is expected to be retired, virtually all fossil fired. The largest component of retirements is expected to be older oil- and natural-gas-fired steam plants, as well as smaller amounts of older oil- and natural-gas-fired combustion turbines and coal-fired plants, which are not competitive with newer natural gas combustion turbine or combined-cycle plants. For oil- and natural-gas-fired steam plants, 35 out of 134 gigawatts of existing capacity is expected to be retired. For combustion turbines and coal-fired plants, 15 and 10 gigawatts of capacity are expected to be retired, respectively. Many older oil- and natural-gas-fired steam plants have efficiencies less than 30 percent. In contrast, the efficiencies of new combined-cycle plants are near 50 percent, and they are expected to continue to improve.

Early Capacity Additions Use Natural Gas, Coal Plants Are Added Later

Figure 71. Electricity generation capacity additions by fuel type, including combined heat and power, 2002-2025 (gigawatts)



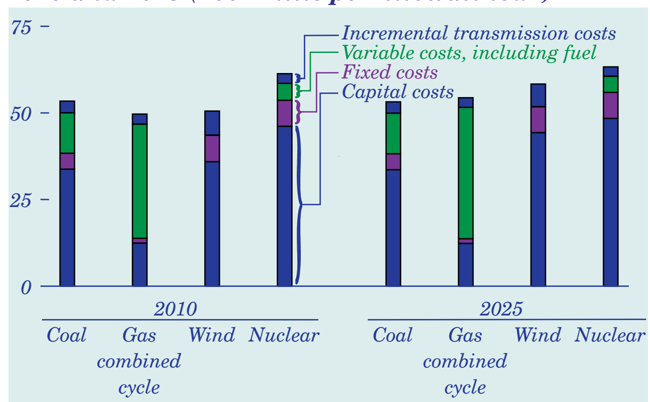
With growing demand after 2010, 356 gigawatts of new generating capacity (including end-use combined heat and power) will be needed by 2025, with about half coming on line between 2016 and 2025. Of the new capacity, nearly 62 percent is projected to be natural-gas-fired combined-cycle, combustion turbine, or distributed generation technology (Figure 71).

As natural gas prices rise later in the forecast, new coal-fired capacity is projected to become increasingly competitive, accounting for nearly one-third of all the capacity expansion expected over the forecast. Two new coal-fired plants (just over 1 gigawatt of capacity) are already under construction, scheduled for operation by 2006. From 2011 to 2025, 105 gigawatts of new coal-fired capacity is expected to be brought on line—more than one-half of it after 2020. From 2011 on, coal-fired capacity is expected to account for 40 percent of all capacity additions. Coal additions comprise 40 percent of total unplanned additions over the forecast. Most of the coal capacity is expected to be advanced pulverized coal. With higher capital costs and relatively inexpensive fuel, integrated coal gasification additions are limited to 6 gigawatts of commercial penetration.

Renewable technologies account for just over 5 percent of expected capacity expansion by 2025—primarily wind and biomass units. Distributed generation, mostly gas-fired microturbines, is expected to add just over 12 gigawatts. Oil-fired steam plants, which have higher fuel costs and lower efficiencies, are not expected to account for any new capacity in the forecast, other than limited industrial combined heat and power applications.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 72. Levelized electricity costs for new plants, 2010 and 2025 (2002 mills per kilowatthour)



Technology choices for new generating capacity are made to minimize cost while meeting local and Federal emissions constraints. The choice of technology for capacity additions is based on the least expensive option available (Figure 72) [*111*]. The reference case assumes a capital recovery period of 20 years. In addition, the cost of capital is based on competitive market rates, to account for the risks of siting new units.

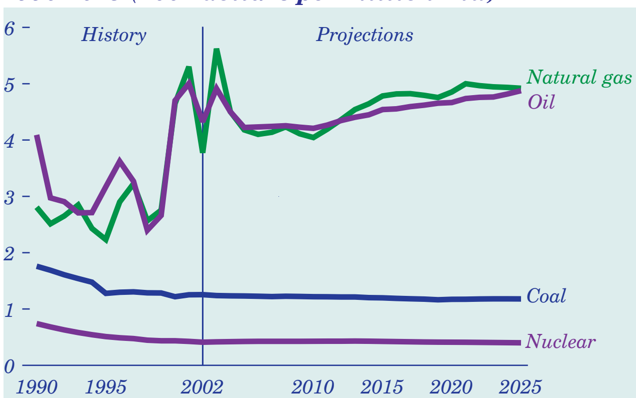
The costs (other than fuel) and performance characteristics for new plants are expected to improve over time (Table 21), at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, the costs are assumed to decline. The decline continues at a slower rate as more units are built. The performance (efficiency) of new plants is also assumed to improve, with heat rates for advanced combined cycle and coal gasification units declining to 6,350 and 7,200 Btu per kilowatthour, respectively, by 2010.

Table 21. Costs of producing electricity from new plants, 2010 and 2025

	2010		2025	
Costs	Advanced coal	Advanced combined cycle	Advanced coal	Advanced combined cycle
	2002 mills per kilowatthour			
Capital	33.77	12.46	33.62	12.33
Fixed	4.58	1.36	4.58	1.36
Variable	11.69	32.95	11.74	37.91
Incremental transmission	3.38	2.89	3.26	2.78
Total	**53.43**	**49.65**	**53.20**	**54.38**

Natural Gas Fuel Costs Are Expected To Rise, Coal and Nuclear To Decline

Figure 73. Fuel prices to electricity generators, 1990-2025 (2002 dollars per million Btu)

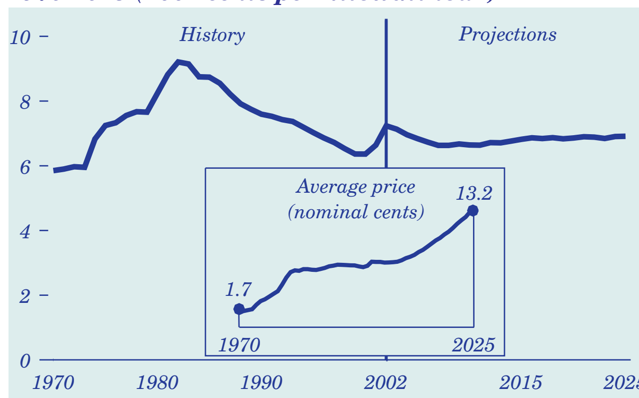


Electricity production costs are a function of the costs for fuel, operations and maintenance, and capital. Fuel costs make up most of the operating costs for fossil-fired units. Falling coal prices have reduced the fuel share of operating costs for coal-fired plants—to about 74 percent in 2001—whereas volatile prices and rapidly increasing usage rates have raised the fuel share for natural-gas-fired combined-cycle plants, to 90 percent in 2001. For nuclear units, fuel costs typically are a much smaller portion of total production costs. Nonfuel operations and maintenance costs are a larger component of the operating costs for nuclear power units than for plants that use fossil fuels.

The impact of higher natural gas prices in the projections is offset by increased generation from coal-fired and nuclear power plants and by higher generation efficiencies as new capacity is installed. After recent price spikes, natural gas prices to electricity suppliers are projected to rise by 1.2 percent per year in the forecast, from $3.77 per million Btu in 2002 to $4.92 in 2025 (Figure 73). Sufficient supplies of uranium and fuel processing services are expected to keep nuclear fuel costs around $0.40 per million Btu (roughly 4 mills per kilowatthour) through 2025. Delivered petroleum prices to utilities are expected to increase by 0.5 percent per year from 2002 to 2025, leading to a slight decrease in oil-fired generation. Despite increasing fuel costs, the market share of total generation met by natural gas is projected to increase from 18 percent in 2002 to 23 percent in 2025 due to the greater efficiency of natural gas capacity.

Average Electricity Prices Decline From 2001 Highs, Then Gradually Rise

Figure 74. Average U.S. retail electricity prices, 1970-2025 (2002 cents per kilowatthour)

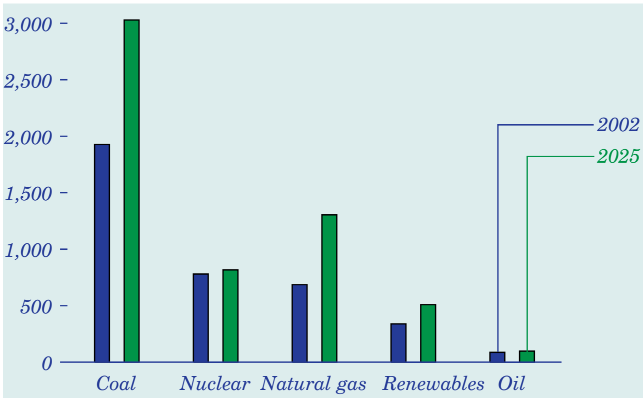


Average U.S. electricity prices, in real 2002 dollars, are expected to decline by 8 percent, from 7.2 cents per kilowatthour in 2002 to 6.6 cents in 2008 (Figure 74), and to remain relatively stable until 2011. From 2011 they are projected to increase gradually, by 0.3 percent per year, to 6.9 cents per kilowatthour in 2025, generally following the trend of the generation component of electricity price, which currently makes up 64 percent of electricity prices. The distribution component, accounting for about 28 percent of the total electricity price, is expected to decline at an average annual rate of 0.7 percent as the cost of the distribution infrastructure is spread out over a growing amount of total electricity sales. Transmission prices are expected to increase at an average annual rate of 0.9 percent because of the increased investment needed to meet the projected growth in electricity demand. Delivered electricity prices for residential, commercial, and industrial customers are projected to fall by 5, 10, and 9 percent, respectively, from 2002 to 2013 and then to regain about half of those losses by 2025.

In 2003, 17 States and the District of Columbia had competitive retail electricity markets in operation. Four States—Montana, Nevada, New Mexico, and Oklahoma—have delayed opening competitive retail markets. Arkansas repealed its restructuring legislation in February 2003. California's competitive retail market remains suspended, and some of its large power contracts have been renegotiated. States have cited a lack of operational wholesale markets and inadequate generation and transmission capacity as reasons for delaying retail competition.

Natural Gas Is Expected To Surpass Nuclear Power in Electricity Supply

Figure 75. Electricity generation by fuel, 2002 and 2025 (billion kilowatthours)

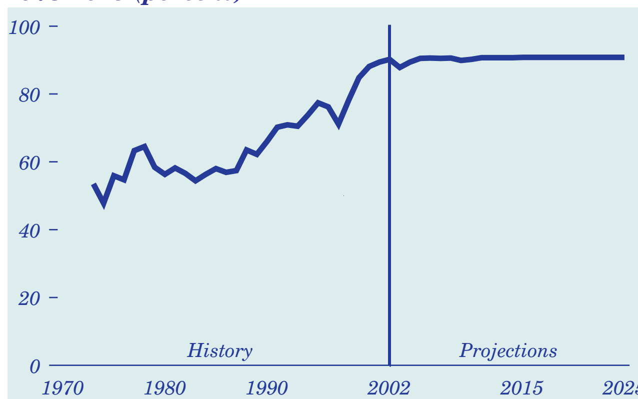


As they have since early in this century, coal-fired power plants are expected to remain the key source of electricity through 2025 (Figure 75). In 2002, coal accounted for 1,928 billion kilowatthours or 50 percent of total generation, including output at combined heat and power plants. Coal-fired generation is projected to maintain a 50-percent share through 2010 and grow to 52 percent in 2025 at 3,029 billion kilowatthours. The huge investment in existing coal-fired plants and high utilization rates at those plants are expected to keep coal in its dominant position. By 2025, it is projected that 25 gigawatts of coal-fired capacity will be retrofitted with scrubbers to comply with environmental regulations. A total of 112 gigawatts of new coal-fired capacity is projected to be added through 2025, primarily after 2015, when higher natural gas prices lead to the increasing share for coal-fired generation. As a result of improvements in performance and ongoing expansions of existing capacity, electricity generation from nuclear power plants is expected to increase modestly through 2017 before leveling off through the remainder of the forecast period.

In percentage terms, natural-gas-fired generation shows the largest increase in the forecast, from 18 percent of total electricity supply in 2002 to 21 percent in 2010 and 23 percent in 2025. As a result, by 2007, natural gas is expected to overtake nuclear power as the Nation's second-largest source of electricity. Generation from oil-fired plants is projected to remain fairly small throughout the forecast.

Nuclear Power Plant Capacity Factors Are Expected To Increase Modestly

Figure 76. Nuclear power plant capacity factors, 1973-2025 (percent)



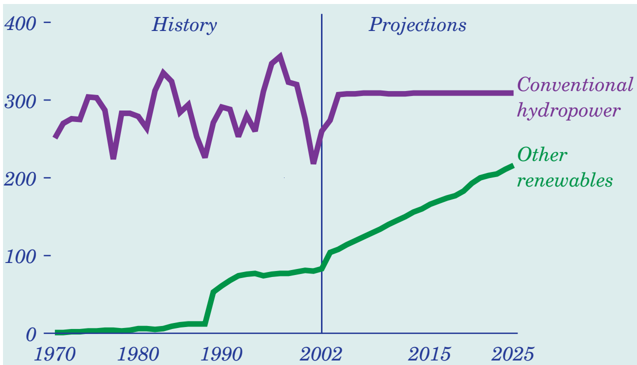
The United States currently has 104 operable nuclear units, which provided 20 percent of total electricity generation in 2002. The performance of U.S. nuclear units has improved in recent years, to a national average capacity factor of 90 percent in 2002 (Figure 76). It is assumed that these performance improvements will be maintained as plants age, leading to a weighted average capacity factor of 91 percent after 2010.

In the reference case, no nuclear units are projected to be retired from 2002 to 2025. Nuclear capacity grows slightly due to assumed increases at existing units. The U.S. Nuclear Regulatory Commission (NRC) approved 18 applications for power uprates in 2002, and another 9 were approved or pending in 2003. The reference case assumes that all the uprates will be carried out, as well as others expected by the NRC over the next 15 years, leading to an increase of 3.9 gigawatts in total nuclear capacity by 2025. No new nuclear units are expected to become operable between 2002 and 2025, because natural gas and coal-fired units are projected to be more economical.

Nuclear units would be retired if their operation were no longer economical relative to the cost of building replacement capacity. By 2025, the majority of nuclear units will be beyond their original licensed lifetimes. As of October 2003, license renewals for 16 nuclear units had been approved by the NRC, and 16 other applications were being reviewed. As many as 26 additional applicants have announced intentions to pursue license renewals over the next 3 years, indicating a strong interest in maintaining the existing stock of nuclear plants.

Increases in Nonhydropower Renewable Generation Are Expected

Figure 77. Grid-connected electricity generation from renewable energy sources, 1970-2025 (billion kilowatthours)

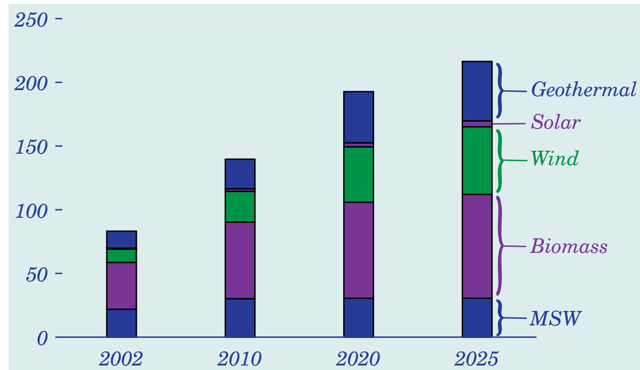


In the *AEO2004* reference case, despite improvements and incentives, grid-connected generators that use renewable fuels (including combined heat and power and other end-use generators) are projected to remain minor contributors to U.S. electricity supply, increasing from 343 billion kilowatthours of generation in 2002 (9.0 percent of total generation) to 525 billion kilowatthours in 2025 (9.1 percent of generation). Low precipitation in 2002 held hydroelectric generation to 260 billion kilowatthours. In the reference case, conventional hydropower provides 309 billion kilowatthours annually, amounting to 5.3 percent of total generation in 2025 (Figure 77).

Nonhydroelectric renewables account for 6.6 percent of projected additions to U.S. generating capacity from 2002 to 2025 and 6.8 percent of the projected increase in generation. Generation from nonhydropower renewables is projected to increase from 83 billion kilowatthours in 2002 (2.2 percent of generation) to 216 billion in 2025 (3.7 percent of generation). Biomass is the largest source of nonhydroelectric renewable generation in the forecast, including combined heat and power systems and biomass co-firing in coal-fired power plants. Electricity output from biomass combustion is projected to increase from 37 billion kilowatthours in 2002 (1.0 percent of generation) to 81 billion kilowatthours in 2025 (1.3 percent of generation). Most of the increase (54 percent) is expected from combined heat and power and the rest primarily from dedicated biomass plants. Nevertheless, generation using biomass co-fired in coal-burning plants reaches as much as 16 percent of biomass generation in 2016 before declining to 6 percent in 2025.

Biomass, Wind, and Geothermal Lead Growth in Renewables

Figure 78. Nonhydroelectric renewable electricity generation by energy source, 2002-2025 (billion kilowatthours)

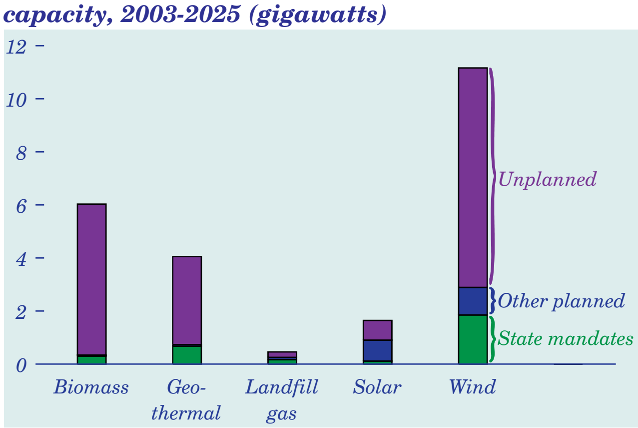


AEO2004 projects significant increases in electricity generation from both wind and geothermal power (Figure 78). From 4.8 gigawatts in 2002, total wind capacity is projected to increase to 8.0 gigawatts in 2010 and 16.0 gigawatts in 2025. Generation from wind capacity is projected to increase from about 11 billion kilowatthours in 2002 (0.3 percent of generation) to 53 billion in 2025 (0.9 percent). Nevertheless, the mid-term prospects for wind power are uncertain, depending on future cost and performance, transmission availability, extension of the Federal production tax credit after 2003, other incentives, energy security, public interest, and environmental preferences. Geothermal output, all located in the West, is projected to increase from 13 billion kilowatthours in 2002 (0.3 percent of generation) to 47 billion in 2025 (0.8 percent).

Generation from municipal solid waste and landfill gas is projected to increase by nearly 9 billion kilowatthours, to about 31 billion kilowatthours (0.5 percent of generation) in 2025. No new waste-burning capacity is expected to be added in the forecast. Solar technologies are not expected to make significant contributions to U.S. grid-connected electricity supply through 2025. In total, grid-connected photovoltaic and solar thermal generators together provided about 0.6 billion kilowatthours of electricity generation in 2002 (0.02 percent of generation), and they are projected to supply nearly 5 billion kilowatthours (0.08 percent) in 2025 [*112*].

State Mandates Call for More Generation From Renewable Energy

Figure 79. Additions of renewable generating capacity, 2003-2025 (gigawatts)

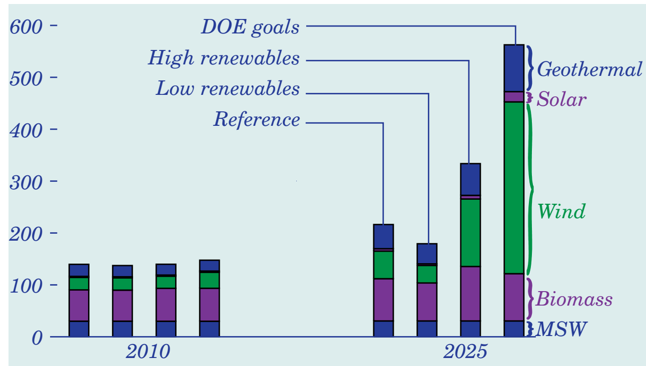


AEO2004 projects additions of 23 gigawatts of new nonhydroelectric renewable generating capacity from 2002 to 2025, including 18 gigawatts in the electric power sector, 4 gigawatts in combined heat and power, and 1 gigawatt in small-scale end-use applications. In the electric power sector, 3.1 gigawatts of new capacity is projected as a result of State mandates (wind power 1.9 gigawatts, geothermal 0.7 gigawatts, biomass 0.3 gigawatts, landfill gas 0.2 gigawatts, and solar photovoltaic plus thermal, 0.1 gigawatts) and the rest from commercial projects (Figure 79). The commercial projects include 0.08 gigawatts of central-station solar thermal and 0.3 gigawatts of grid-connected central-station photovoltaic capacity that is assumed to be built for testing, demonstration, environmental, and other reasons.

In the reference case, a number of States with mandates and renewable portfolio standards are projected to add significant amounts of renewable capacity after 2002. They include California (1,210 megawatts), Minnesota (921 megawatts), Nevada (470 megawatts), Pennsylvania (95 megawatts, built in West Virginia), Texas (270 megawatts), New Mexico (205 megawatts), and Massachusetts (175 megawatts). Other States with smaller requirements include Arizona, Connecticut, Illinois, and Wisconsin. Most identified new capacity is expected to be constructed in the near term—43 percent by 2003 and two-thirds by 2006. Because the Federal production tax credit for wind plants is scheduled to expire on December 31, 2003, 1,664 megawatts (58 percent) of currently planned new wind capacity is projected to be built before the end of 2003.

With Lower Cost Assumptions, Wind and Geothermal Capacity Increase

Figure 80. Nonhydroelectric renewable electricity generation by energy source in four cases, 2010 and 2025 (billion kilowatthours)



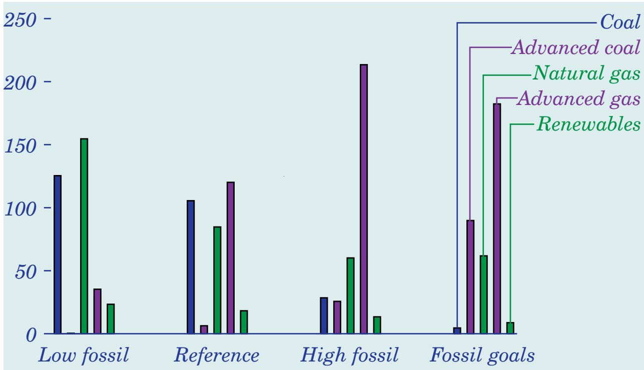
The low renewables case assumes that the cost and performance characteristics for key nonhydropower renewable energy technologies remain fixed at current levels; the high renewables case assumes cost reductions of 10 percent on a site-specific basis [*113*]; the DOE goals case assumes lower capital costs, higher capacity factors, and lower operating costs, based on the renewable energy goals of the U.S. Department of Energy [*114*]. In each case, assumptions for nonrenewable technologies are the same as in the reference case.

In the low renewables case, construction of new renewable capacity is considerably lower than projected in the reference case (Figure 80). In the high renewables case, additions of geothermal, biomass, and wind capacity are substantially higher than projected in the reference case, with most of the incremental capacity added between 2010 and 2025; however, nonhydropower renewables remain relatively small contributors to total generation, at 139 billion kilowatthours (3.1 percent of the total) in 2010 and 334 billion kilowatthours (5.7 percent) in 2025.

In the DOE goals case, still more wind and geothermal generating capacity is projected to be added. Geothermal electricity generation in 2010 is lower in the DOE goals case than in the reference case, but in 2025 it is almost double the reference case projection, at 90 billion kilowatthours, or approximately 1.6 percent of total generation. Generation from wind power in 2010 is 29 percent higher in the DOE goals case, at 31 billion kilowatthours, than in the reference case, and in 2025 it is more than six times higher, at 331 billion kilowatthours or 5.7 percent of total generation.

Gas-Fired Technologies Lead New Additions of Generating Capacity

Figure 81. Cumulative new generating capacity by technology type in four fossil fuel technology cases, 2002-2025 (gigawatts)

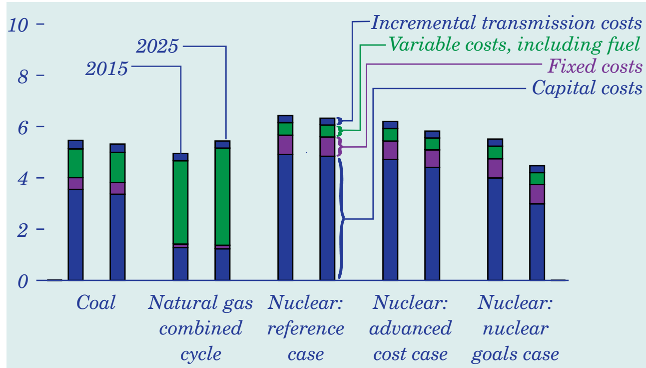


The *AEO2004* reference case uses the cost and performance characteristics of generating technologies to select the mix and amounts of new generating capacity for each year in the forecast. Values for technology characteristics are determined in consultation with industry and government specialists, but uncertainty surrounds the assumptions for new technologies. In the high fossil fuel case, capital costs, heat rates, and operating costs for advanced fossil-fired generating technologies (integrated coal gasification combined cycle, advanced combined cycle, and advanced combustion turbine) reflect a 10-percent reduction from reference case levels in 2025. The fossil goals case assumes improved costs and efficiencies as a result of accelerated research and development, as specified by the Department of Energy's Fossil Energy program goals. The low fossil fuel case assumes no change in capital costs and heat rates for advanced technologies from their 2004 levels.

Natural gas technologies make up the largest share of new capacity additions in all cases, but the mix of current and advanced technologies varies (Figure 81). In the high fossil and fossil goals cases, advanced technologies are used for 78 percent (213 gigawatts) and 75 percent (182 gigawatts) of projected gas-fired capacity additions, compared with 19 percent (35 gigawatts) in the low fossil case. The coal share of total capacity additions varies from 16 percent to 37 percent. In the low fossil case, only a negligible amount of advanced coal-fired generating capacity is added. In the high cases, advanced coal technologies are more competitive, making up almost half of all coal-fired capacity additions in the high fossil fuel case and 95 percent in the fossil goals case.

Sensitivity Case Looks at Possible Reductions in Nuclear Power Costs

Figure 82. Levelized electricity costs for new plants by fuel type in the advanced nuclear cost case, 2015 and 2025 (2002 cents per kilowatthour)

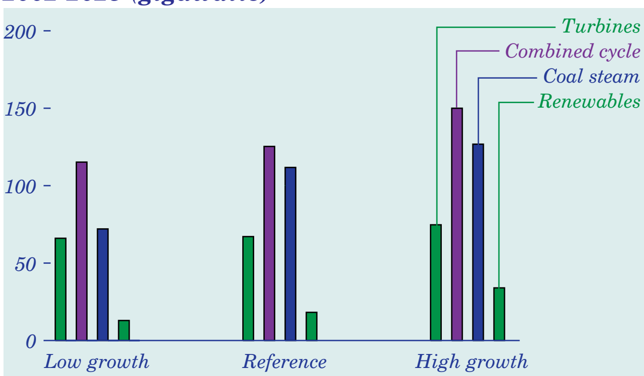


The *AEO2004* reference case assumptions for the cost and performance characteristics of new technologies are based on cost estimates by government and industry analysts, allowing for uncertainties about new, unproven designs. Two advanced nuclear cost cases analyze the sensitivity of the projections to yet lower costs for new nuclear power plants. The advanced nuclear cost case assumes capital and operating costs 10 percent below the reference case in 2025, reflecting a 19-percent reduction in overnight capital costs from 2005 to 2025. The nuclear goals case assumes reductions relative to the reference case of 18 percent initially and 38 percent in 2025. These costs are consistent with estimates from British Nuclear Fuels Limited for the manufacture of its advanced pressurized-water reactor (AP1000). Cost and performance characteristics for all other technologies are assumed to be the same as those in the reference case.

Projected nuclear generating costs in the advanced nuclear cost case are not competitive with the generating costs projected for new coal- and natural-gas-fired units, but toward the end of the projection period the costs assumed in the nuclear goals case are competitive (Figure 82). No nuclear capacity is added when costs are reduced by only 10 percent relative to the reference case, but with the greater reductions assumed in the nuclear goals case, 26 gigawatts of new nuclear capacity is added by 2025. The additional nuclear capacity displaces primarily coal and a smaller amount of natural gas capacity. The projections in Figure 82 are average generating costs, assuming generation at the maximum capacity factor for each technology; the costs and relative competitiveness of the technologies could vary across regions.

Rapid Economic Growth Would Boost New Natural Gas and Coal Capacity

Figure 83. Cumulative new generating capacity by technology type in three economic growth cases, 2002-2025 (gigawatts)



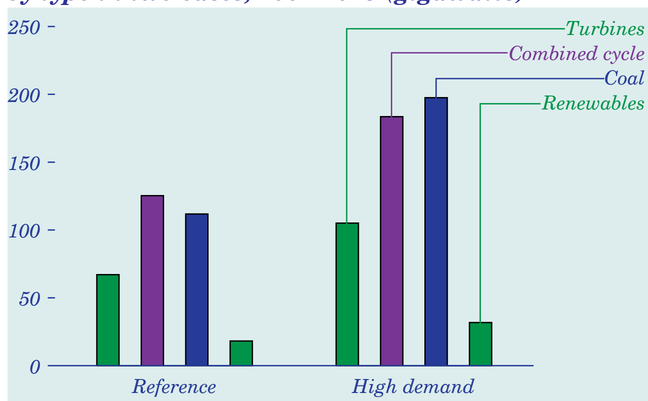
The projected annual average growth rate for GDP from 2002 to 2025 ranges from 3.5 percent in the high economic growth case to 2.4 percent in the low economic growth case. The difference leads to a 5-percent change in projected electricity demand in 2010 and a 14-percent change in 2025, with a corresponding difference of 138 gigawatts in the amount of new capacity projected to be built from 2002 to 2025 in the high and low economic growth cases.

More than one-half of the new capacity projected to be needed in the high economic growth case beyond that added in the reference case is expected to consist of new natural-gas-fired plants. The stronger demand growth assumed in the high growth case is also projected to stimulate additions of coal-fired and renewable plants, accounting for 23 and 24 percent, respectively, of the increase in projected capacity additions in the high economic growth case over those projected in the reference case (Figure 83). In the low economic growth case, total capacity additions are reduced by 65 gigawatts, and 61 percent of that projected reduction is in coal-fired capacity additions.

Average electricity prices in 2025 are 6 percent higher in the high economic growth case than in the reference case, due to higher natural gas prices and the costs of building additional generating capacity. Electricity prices in 2025 in the low economic growth case are projected to be 5 percent lower than in the reference case. In the high economic growth case, a 4-percent increase in consumption of fossil fuels results in a 4-percent increase in carbon dioxide emissions from electricity generators in 2025.

High Demand Increases Capacity Needs, Particularly for Coal

Figure 84. Cumulative new generating capacity by type in two cases, 2002-2025 (gigawatts)

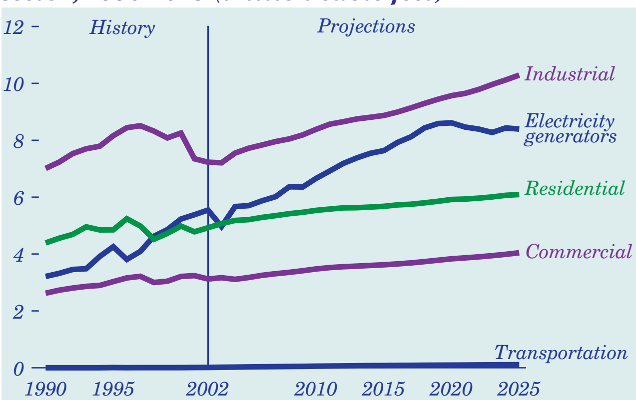


Electricity consumption grows in the forecast, but the projected rate of increase is less than historical rates because of assumptions made about improvements in end-use efficiency, demand-side management programs, and population and economic growth. Different assumptions result in substantial changes in the projections. In a high demand case, electricity demand is assumed to grow by 2.5 percent per year from 2002 to 2025, as compared with annual growth of 2.2 percent per year from 1990 to 1999. In the reference case, electricity demand is projected to grow by 1.8 percent per year. As a result, electricity demand is 6 percent higher in the high demand case than in the reference case in 2010 and 18 percent higher in 2025.

In the high demand case, 41 gigawatts more generating capacity is projected to be built from 2002 to 2010 than in the reference case. The difference grows to 206 gigawatts in 2025 (Figure 84). The shares of coal- and natural-gas-fired capacity additions in the electric power sector (including combustion turbine, combined cycle, distributed generation, and fuel cell) are projected to be 37 percent and 58 percent, respectively, in the high demand case and 33 percent and 61 percent in the reference case. Increases in fossil fuel consumption of 6 percent in 2010 and 18 percent in 2025 lead to a higher level of carbon emissions from electricity generators (5 percent higher in 2010 and 18 percent higher in 2025). More rapid growth in electricity demand also leads to higher projected prices for electricity in 2025, averaging 7.1 cents per kilowatthour in the high demand case, compared with 6.9 cents in the reference case. Higher projected fuel prices, especially for natural gas, are the primary reason for the higher electricity prices.

Projected Increases in Natural Gas Use Are Led by Electricity Generators

Figure 85. Natural gas consumption by end-use sector, 1990-2025 (trillion cubic feet)



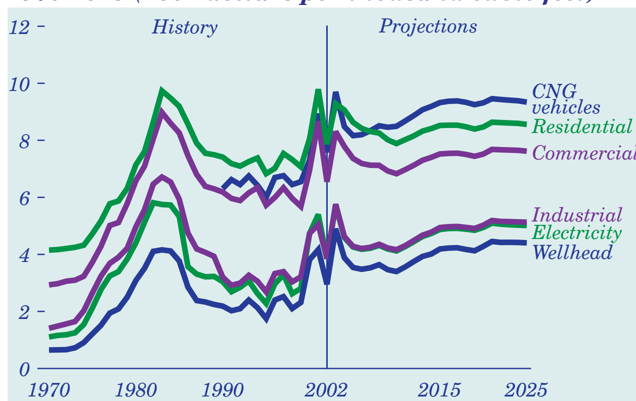
Total natural gas consumption is projected to increase from 2002 to 2025 in all the *AEO2004* cases. The projections for domestic natural gas consumption in 2025 range from 29.1 trillion cubic feet per year in the low economic growth case to 34.2 trillion cubic feet in the rapid technology case, as compared with 22.6 trillion cubic feet in 2002. In the reference case, natural gas consumption in the electric power sector is projected to increase from 5.6 trillion cubic feet in 2002 to 6.7 trillion cubic feet in 2010 and 8.4 trillion cubic feet in 2025 (Figure 85). Demand by electricity generators is expected to account for 29 percent of total end-use natural gas consumption in 2025, as compared with 27 percent in 2002.

Most new electricity generation capacity is expected to be fueled by natural gas, because natural-gas-fired generators are projected to have advantages over coal-fired generators that include lower capital costs, higher fuel efficiency, shorter construction lead times, and lower emissions. Toward the end of the forecast, however, when natural gas prices rise substantially, coal-fired power plants are expected to be competitive for new capacity additions.

Demand growth is also expected in the residential, commercial, industrial, and transportation sectors. In the reference case, industrial consumption is projected to increase from 7.3 trillion cubic feet in 2002 to 8.4 trillion cubic feet in 2010 and 10.3 trillion cubic feet in 2025. In the residential and commercial sectors, natural gas consumption is projected to increase by 0.9 percent and 1.1 percent per year, respectively, from 2002 to 2025.

Delivered Prices Increase More Slowly Than Wellhead Prices

Figure 86. Natural gas prices by end-use sector, 1970-2025 (2002 dollars per thousand cubic feet)



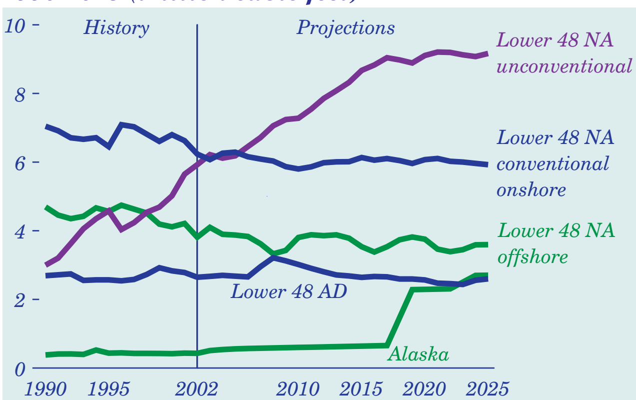
Prices for natural gas delivered to the end-use sectors are expected to fall in the early years of the forecast as wellhead prices decline (Figure 86). After 2006 wellhead prices are projected to start increasing, and delivered natural gas prices begin to increase in 2012. The increase in wellhead gas prices is expected to be offset in part by a projected decline in average transmission and distribution margins.

The average end-use price is projected to increase by 54 cents per thousand cubic feet from 2006 to 2025 (in constant 2002 dollars), compared with a projected increase of 97 cents per thousand cubic feet in the average price of domestic and imported natural gas supplies. The slower increase in delivered prices reflects continued depreciation of existing infrastructure, increased pipeline utilization, and more imports of LNG directly into end-use markets.

The natural gas transmission and distribution margin reflects both the volume of gas delivered and the infrastructure arrangements of the sector. The industrial and electricity generation sectors have the lowest end-use prices, because they receive most of their natural gas directly from interstate pipelines, avoiding local distribution charges. Summer-peaking electric generators reduce transmission costs by using interruptible transportation rates during the summer, when there is spare pipeline capacity. As power generators take a larger share of the natural gas market, however, they are expected to rely more on higher cost firm transportation service. The compressed natural gas vehicle margin is expected to increase, because the cost of the refueling infrastructure must be added to serve non-fleet vehicles.

Unconventional Production Becomes the Largest Source of U.S. Supply

Figure 87. Natural gas production by source, 1990-2025 (trillion cubic feet)



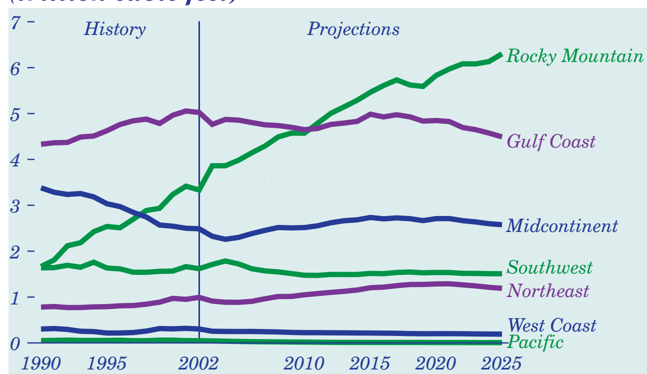
As a result of technological improvements and rising natural gas prices, natural gas production from unconventional sources (tight sands, shale, and coalbed methane) is projected to increase more rapidly than conventional production. In the reference case, lower 48 unconventional gas production is projected to grow from 5.9 trillion cubic feet in 2002 to 9.2 trillion cubic feet in 2025 (Figure 87), increasing from 32 percent of total lower 48 production in 2002 to 43 percent in 2025. Production of lower 48 nonassociated (NA) conventional natural gas is projected to decline from 10.0 trillion cubic feet in 2002 to 9.5 trillion cubic feet in 2025, as resource depletion causes exploration and production costs to increase. Offshore NA natural gas production is projected to fluctuate around 3.7 trillion cubic feet throughout the forecast, because sufficient reserves of natural gas must be discovered in an offshore region to justify investment in the necessary production and transportation infrastructure.

Production of associated-dissolved (AD) natural gas from lower 48 crude oil reserves is projected to increase from 2.7 trillion cubic feet in 2002 to 3.2 trillion cubic feet in 2008 [*115*]. After 2008, both onshore and offshore AD gas production are projected to decline, and total lower 48 AD gas production falls to 2.6 trillion cubic feet in 2025.

The North Slope Alaska natural gas pipeline is expected to begin transporting Alaskan gas to the lower 48 States in 2018. In 2025, total Alaskan gas production is projected to be 2.7 trillion cubic feet in the reference case.

Growing Production Is Expected from the Rocky Mountain Region

Figure 88. Lower 48 onshore natural gas production by supply region, 1990-2025 (trillion cubic feet)



In the reference case, total foreign and domestic natural gas supplies are projected to grow by 3.5 trillion cubic feet from 2002 to 2010 and by 8.7 trillion cubic feet from 2002 to 2025. Domestic natural gas production is expected account for 57 percent of the total growth in supply, and net imports are projected to account for the remaining 43 percent.

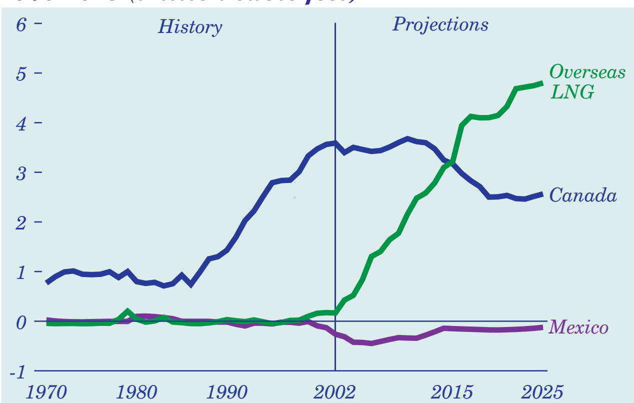
Over the forecast period, the largest increase in lower 48 onshore natural gas production is projected to come from the Rocky Mountain region, predominantly from the large volume of unconventional resources located in the region [*116*]. Rocky Mountain natural gas production is projected to increase from 3.3 trillion cubic feet in 2002 to 4.6 trillion cubic feet in 2010 and 6.3 trillion cubic feet in 2025 (Figure 88).

The other lower 48 onshore production regions are projected either to show moderate increases in production, followed by declines after 2020, or to remain relatively constant through 2020 and decline thereafter. The regional declines after 2020 largely reflect the depletion of the conventional natural gas resource base.

Because production from the Rocky Mountain region is projected to increase throughout the forecast while the other lower 48 onshore regions do not, Rocky Mountain production makes up an increasing share of total lower 48 onshore natural gas production. In 2002, Rocky Mountain production was 24 percent of total lower 48 onshore production. Its share is projected to increase to 32 percent in 2010 and 39 percent in 2025.

Net Imports of Natural Gas Grow in the Projections

Figure 89. Net U.S. imports of natural gas, 1970-2025 (trillion cubic feet)



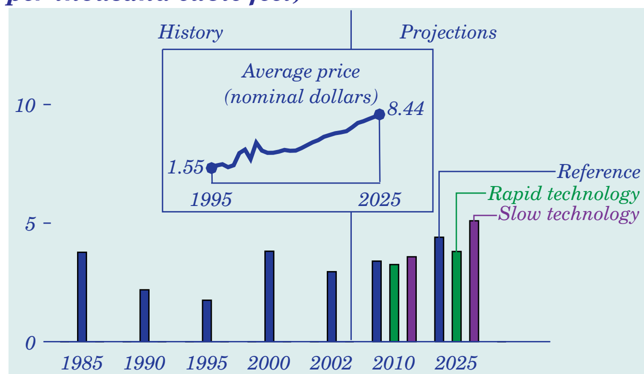
Net imports of natural gas make up the difference between U.S. production and consumption. Imports are expected to be priced competitively with domestic sources. Supplies of natural gas from overseas sources, imported through U.S. LNG terminals, account for most of the projected increase in net imports in the reference case (Figure 89). When planned expansions at the four existing terminals are completed, new LNG terminals are projected to start coming into operation in 2007, and net LNG imports increase from 0.2 trillion cubic feet in 2002 to 2.2 and 4.8 trillion cubic feet in 2010 and 2025, respectively.

Net imports of natural gas from Canada are projected to peak at 3.7 trillion cubic feet in 2010, then decline gradually to 2.6 trillion cubic feet in 2025. The depletion of conventional resources in the Western Sedimentary Basin is expected to reduce Canada's future production and export potential, and prospects for significant production increases in eastern offshore Canada have diminished over the past few years. There is also considerable uncertainty about the economic viability and timing of coalbed methane production in western Canada. The reference case does project that a MacKenzie Delta natural gas pipeline will begin moving supplies to U.S. buyers in 2009.

Historically, although Mexico has considerable natural gas resources, the United States has been a net exporter of gas to Mexico. In the reference case, net exports of U.S. natural gas to Mexico are projected to grow until 2006, when imports of natural gas from western Mexico are projected to begin entering the United States from an LNG import terminal in Baja California, Mexico [*117*].

Technology Advances Could Moderate Future Natural Gas Prices

Figure 90. Lower 48 natural gas wellhead prices in three cases, 1985-2025 (2002 dollars per thousand cubic feet)



In the reference case, average lower 48 wellhead natural gas prices are projected to decline from 2003 levels to $3.40 per thousand cubic feet (2002 dollars) in 2010 and then increase to $4.40 per thousand cubic feet in 2025 (Figure 90). Technically recoverable natural gas resources (Table 22) are expected to be adequate to support projected production increases. As lower 48 natural gas resources are depleted, wellhead prices increase, causing an increasing proportion of U.S. natural gas supply to come from Alaska, as well as imports from Canada and other countries.

In the slow oil and gas technology case, advances in exploration and production technologies are assumed to be 50 percent slower than in the reference case. As a result, natural gas development costs are higher, wellhead prices are higher ($3.58 and $5.10 per thousand cubic feet in 2010 and 2025), natural gas consumption is reduced, and construction of liquefied natural gas (LNG) import terminals is advanced relative to the reference case projections.

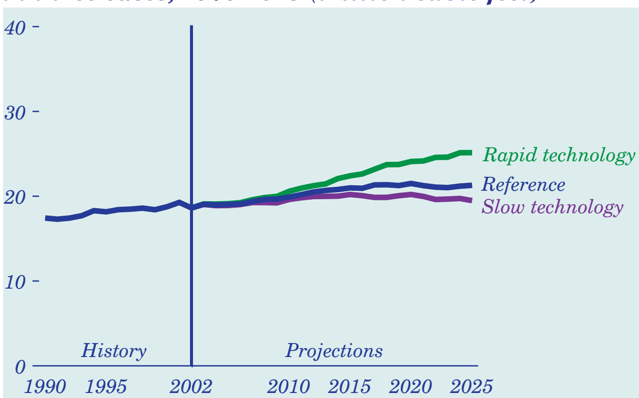
The rapid technology case assumes 50 percent faster technology progress than in the reference case, resulting in lower development costs, lower wellhead prices ($3.25 and $3.80 per thousand cubic feet in 2010 and 2025), and increased consumption of natural gas. LNG imports are reduced in the rapid technology case, and construction of LNG terminals is slowed relative to the reference case projections.

Table 22. Technically recoverable U.S. natural gas resources as of January 1, 2002 (trillion cubic feet)

Proved	Unproved	Total
183.5	1,096.0	1,279.5

Natural Gas Supply Projections Reflect Technological Progress

Figure 91. Lower 48 natural gas production in three cases, 1970-2025 (trillion cubic feet)



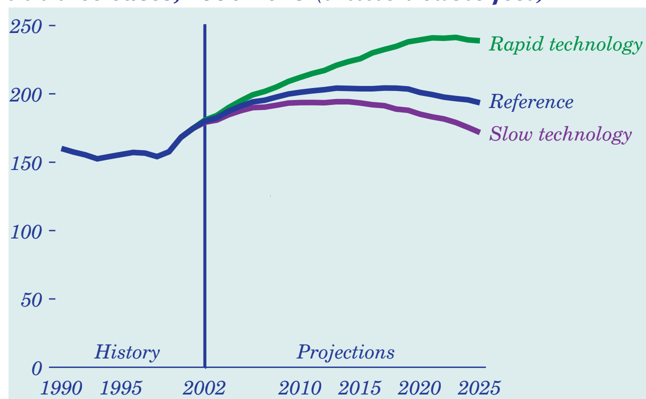
Because the impacts of technological progress are cumulative, the rapid and slow technology cases diverge increasingly from the reference case path in the later years of the forecast (Figure 91). In the reference case, lower 48 natural gas production is projected to total 21.3 trillion cubic feet in 2025. The corresponding projections are 25.1 trillion cubic feet in the rapid technology case and 19.5 trillion cubic feet in the slow technology case.

The cost-reducing effects of rapid technological progress primarily affect the economic recoverability of the large resource base of unconventional natural gas, because the conventional gas resource base is farther along the depletion curve than the unconventional resource base, especially in the later years of the forecast. In 2025, the rapid and slow technology cases project 12.9 and 8.4 trillion cubic feet of unconventional natural gas production, respectively.

The rate of technological progress also affects the contributions of other natural gas supply sources. Because rapid progress is projected to increase the rate of production of lower 48 natural gas resources, both an Alaska gas pipeline and new LNG terminals are less viable economically in the rapid technology case than in the reference case, and their construction is delayed. In the slow technology case, with lower 48 wellhead prices projected to increase more rapidly, earlier completion is expected for the Alaska pipeline and for new LNG terminals, and more LNG facilities are built. Projected LNG imports in 2025 total 3.8 trillion cubic feet in the rapid technology case and 5.5 trillion cubic feet in the slow technology case.

Rapid Technology Assumptions Raise Natural Gas Reserve Projections

Figure 92. Lower 48 natural gas reserves in three cases, 1990-2025 (trillion cubic feet)



The *AEO2004* projections for lower 48 natural gas reserves reflect expected levels of natural gas well drilling resulting from projected cash flows and profitability. In the reference case, lower 48 reserves grow to 204 trillion cubic feet in 2013, remain relatively constant until 2018, and then decline slowly to 194 trillion cubic feet in 2025 (Figure 92).

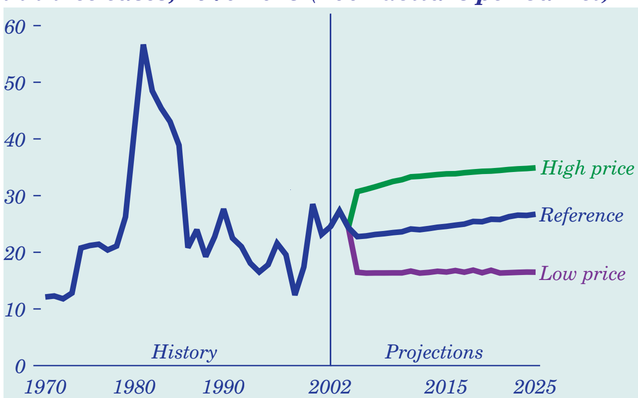
In the rapid technology case, the finding and success rates for gas well drilling are improved and exploration and production costs are reduced, resulting in more drilling activity and reserve additions. In this case, lower 48 reserves are projected to peak at 241 trillion cubic feet in 2023, then decline to 239 trillion cubic feet in 2025.

In the slow technology case, finding and success rates are lower, exploration and production costs are higher and drilling activity and reserve additions are lower than projected in the reference case. Lower 48 reserves are projected to peak at 194 trillion cubic feet in 2013, then decline to 172 trillion cubic feet in 2025.

In all three cases, the natural gas resource base is sufficient in the early years of the forecast to support the increases in drilling activity and reserve additions that are stimulated by higher projected prices, and additions generally exceed production. In later years, rising costs of gas well development reduce drilling activity, and resource depletion reduces reserve additions per well. As a result, total reserves are projected to decline.

Oil Prices Are Expected To Remain Near Recent Historical Levels

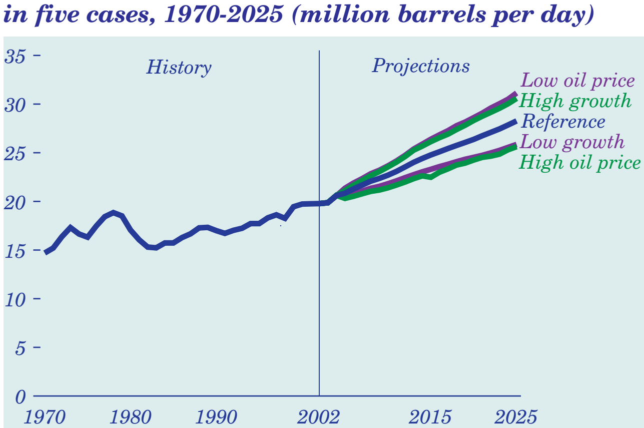
Figure 93. Lower 48 crude oil wellhead prices in three cases, 1970-2025 (2002 dollars per barrel)



Crude oil prices are determined largely in an international marketplace by the balance between production in OPEC and non-OPEC nations and demand. In the reference case, the average lower 48 crude oil price is projected to be $23.61 per barrel in 2010 and $26.72 per barrel in 2025 (Figure 93). In the high world oil price case, the lower 48 crude oil price increases to $32.80 per barrel in 2010 and $34.90 per barrel in 2025. In the low world oil price case, the lower 48 price generally declines to $16.36 per barrel in 2010, then rises to $16.49 per barrel in 2025.

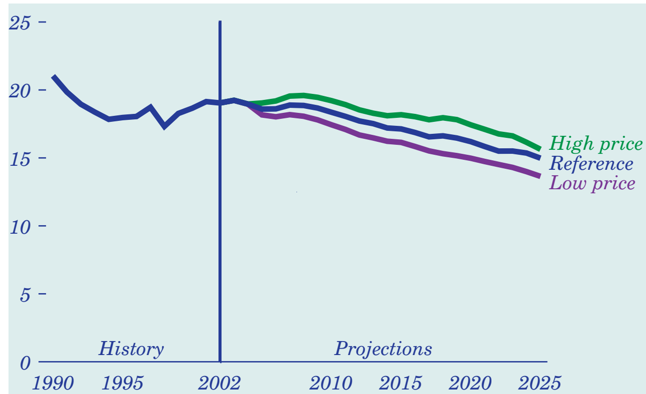
The projections for U.S. petroleum consumption vary with changes in assumptions about economic growth; however, larger variations result from changes in assumptions about world oil prices. Total petroleum consumption in 2025, projected at 28.3 million barrels per day in the reference case, ranges from 25.6 to 31.1 million barrels per day in the high and low world oil price cases (Figure 94).

Figure 94. U.S. petroleum consumption in five cases, 1970-2025 (million barrels per day)



Oil Reserve Projections Are Sensitive to Oil Price Assumptions

Figure 95. Lower 48 crude oil reserves in three cases, 1990-2025 (billion barrels)



Lower 48 crude oil reserves are sensitive to crude oil price projections (Figure 95). In the reference and high and low world oil price cases, lower 48 oil reserves decline as resources are depleted. In the low and high oil price cases, projected lower 48 reserves are 13.6 and 15.6 billion barrels in 2025, respectively, compared with 15.0 billion barrels in the reference case.

The variation in crude oil prices in the world oil price cases primarily affects the development and production of offshore oil resources (Table 23), because smaller deepwater fields that are not profitable when price are low are expected to become profitable when oil prices rise.

Crude oil reserve additions reflect the number of oil wells completed during the forecast period, the size of the crude oil resource base (Table 24), and the pace of technological progress. In the reference case, technological progress is expected to continue at the historical rate.

Table 23. Onshore and offshore lower 48 crude oil production in three cases, 2025 (million barrels per day)

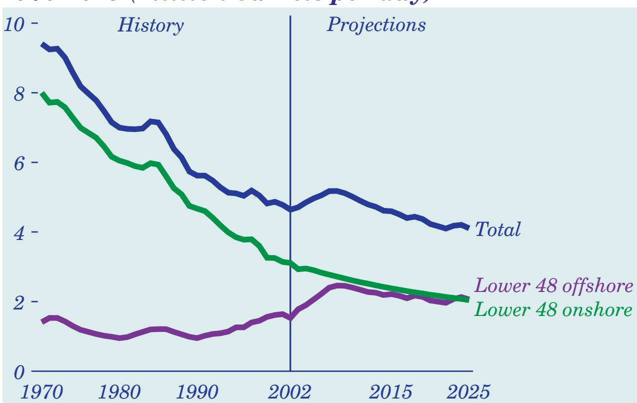
	Onshore	Offshore	Total
Low oil price	1.87	1.68	3.55
Reference	2.04	2.06	4.11
High oil price	2.13	2.17	4.31

Table 24. Technically recoverable U.S. oil resources as of January 1, 2002 (billion barrels)

Proved	Unproved	Total
24	130	154

Lower 48 Crude Oil Production Is Expected To Decline After 2008

Figure 96. Lower 48 crude oil production by source, 1970-2025 (million barrels per day)



In the reference case, total lower 48 crude oil production is projected to increase from 4.6 million barrels per day in 2002 to 5.2 million barrels per day in 2008, then decline to 4.1 million barrels per day in 2025 (Figure 96). In the low oil price case, lower 48 production is projected to peak in 2007 at 5.0 million barrels per day and decline to 3.6 million barrels per day in 2025. In the high oil price case, lower 48 oil production is projected to peak in 2008 at 5.3 million barrels per day and decline to 4.3 million barrels per day in 2025. The projected peaks in oil production are attributable to offshore production. In the reference case, total offshore oil production (including the Gulf of Mexico and offshore California) rises to 2.5 million barrels per day in 2008, then declines to 2.1 million barrels per day in 2025. Oil production in the Gulf of Mexico is projected to peak in 2009 at 2.4 million barrels per day and decline in the later years of the forecast (Table 25).

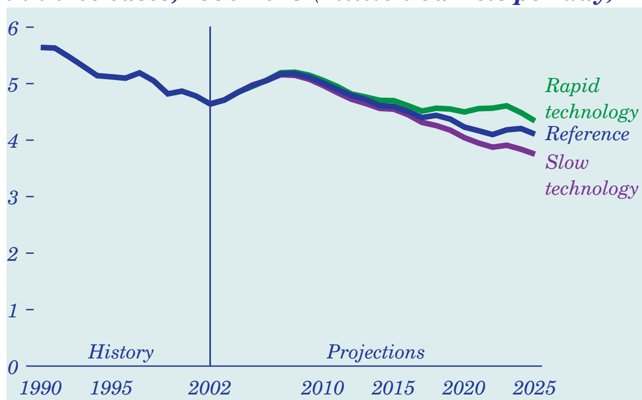
Offshore crude oil production is more sensitive than onshore production to oil prices. In the low and high oil price cases, lower 48 offshore production is projected to be 1.7 and 2.2 million barrels per day, respectively, in 2025. Onshore lower 48 oil production is projected to decline in all cases, with 2025 values ranging from 1.9 million barrels per day in the low oil price case to 2.1 million barrels per day in the high oil price case.

Table 25. Crude oil production from Gulf of Mexico offshore, 2002-2025 (million barrels per day)

	2002	2010	2015	2020	2025
Shallow	0.6	0.7	0.6	0.7	0.5
Deep	0.8	1.6	1.6	1.3	1.5
Total	**1.4**	**2.4**	**2.2**	**2.0**	**2.0**

More Rapid Technology Advances Could Raise Oil Production Slightly

Figure 97. Lower 48 crude oil production in three cases, 1990-2025 (million barrels per day)



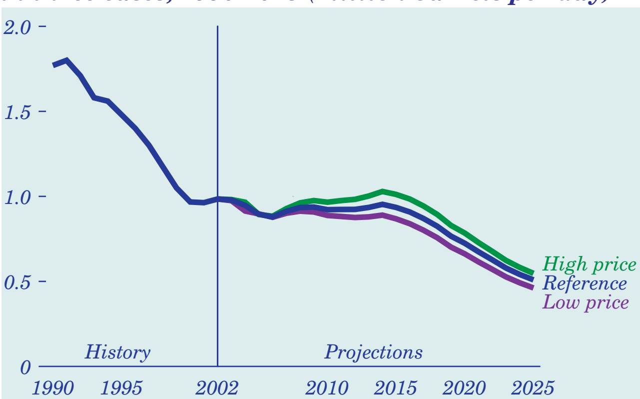
Lower 48 crude oil production is projected to reach 4.3 and 3.8 million barrels per day in 2025 in the rapid and slow technology cases, respectively, compared with 4.1 million barrels per day in the reference case (Figure 97). The technology cases assume the same world oil prices as in the reference case, but the rate of technological progress is assumed to be 50 percent higher (in the rapid technology case) or lower (in the slow technology case) than the historical rate. With domestic oil demand determined largely by oil prices and economic growth rates, consumption is not expected to change significantly in the technology cases. Thus, changes in production resulting from the different rates of technological progress result in different levels of petroleum imports. In 2025, net petroleum imports are projected to range from 19.0 million barrels per day in the rapid technology case to 20.4 million barrels per day in the slow technology case.

In the lower 48 States, offshore crude oil production is more sensitive than onshore production to changes in technology. Consequently, as technologies change, investments are shifted between onshore and offshore exploration and drilling, and production volumes reflect the reallocation of capital.

Cumulative offshore production from 2002 to 2025 is projected to be 1.17 billion barrels (6.3 percent) higher in the rapid technology case and 1.00 billion barrels (5.4 percent) lower in the slow technology case than in the reference case. Cumulative onshore production is about 0.3 percent lower in the rapid oil and gas technology case and 0.3 percent higher in the slow technology case than in the reference case.

Crude Oil Production in Alaska Depends on Oil Price Assumptions

Figure 98. Alaskan crude oil production in three cases, 1990-2025 (million barrels per day)



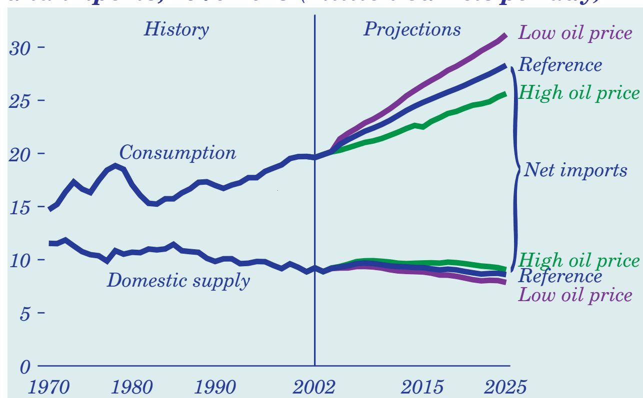
Alaskan crude oil production is expected mainly on the Alaskan North Slope, which includes the National Petroleum Reserve-Alaska (NPR-A) and the State lands surrounding Prudhoe Bay. NPR-A lease sales were held on May 5, 1999, and June 3, 2002. Because oil and gas producers are prohibited from building permanent roads in NPR-A, oil exploration and production is expected to be about 30 percent more expensive than is typical for the North Slope of Alaska. Because drilling is currently prohibited in the Arctic National Wildlife Refuge (ANWR), *AEO2004* does not project any production from ANWR.

In the reference case, crude oil production from Alaska is expected to continue at about 900 thousand barrels per day through 2016 (Figure 98), with a projected drop in North Slope oil production offset by new oil production from NPR-A. After 2016, total Alaskan crude oil production is projected to decline, to 510 thousand barrels per day in 2025. Declining production levels are projected for the North Slope, NPR-A, and southern Alaskan oil fields from 2016 to 2025.

As in the lower 48 States, oil production in Alaska is projected to be sensitive to changes in oil prices. Higher prices make more of the reservoir oil in-place profitable, particularly in the North Slope heavy oil fields. In the high oil price case, Alaska's oil production is above 1 million barrels per day from 2013 to 2015, then declines to 550 thousand barrels per day in 2025. In the low price case, with a lower expected reservoir recovery factor, Alaska's oil production is projected to fall below 900 thousand barrels per day after 2009, to 460 thousand barrels per day in 2025.

Imports Fill the Gap Between Domestic Supply and Demand

Figure 99. Petroleum supply, consumption, and imports, 1970-2025 (million barrels per day)



In 2002, net imports of petroleum accounted for 53 percent of domestic petroleum consumption. Increasing dependence on petroleum imports is projected, reaching 70 percent in 2025 in the reference case (Figure 99). The corresponding import shares of total consumption in 2025 are expected to be 65 percent in the high oil price case and 75 percent in the low oil price case.

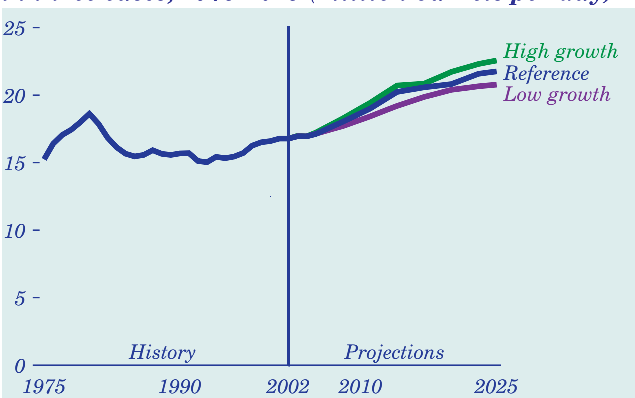
Although crude oil is expected to continue as the major component of petroleum imports, refined products are projected to represent a growing share. More imports would be needed as the projected growth in demand for refined products exceeds the expansion of domestic refining capacity. Refined products are projected to make up 13 percent of net petroleum imports in 2025 in the high oil price case and 25 percent in the high growth case, compared with 20 percent in the reference case, increasing from a 13-percent share in 2002 (Table 26).

Table 26. Petroleum consumption and net imports in five cases, 2002 and 2025 (million barrels per day)

Year and projection	Product supplied	Net imports	Net crude imports	Net product imports
2002	19.8	10.5	9.1	1.4
2025				
Reference	28.3	19.7	15.7	3.9
Low oil price	31.1	23.3	18.2	5.1
High oil price	25.6	16.6	14.3	2.2
Low growth	25.9	17.6	15.0	2.6
High growth	30.6	21.8	16.4	5.4

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

Figure 100. Domestic refining capacity in three cases, 1975-2025 (million barrels per day)



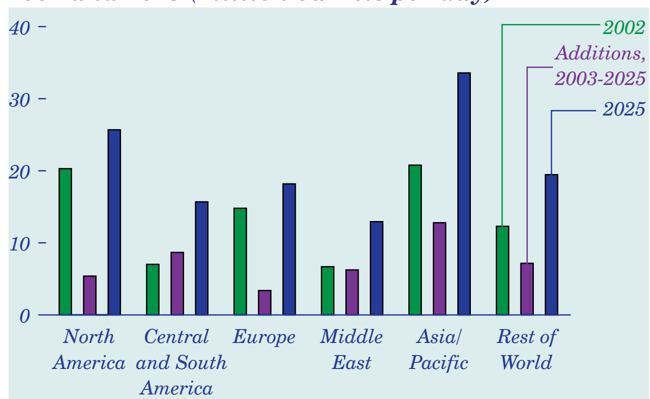
Falling demand for petroleum and deregulation of the domestic refining industry in the 1980s led to 13 years of decline in U.S. refinery capacity. That trend was reversed in 1996, and 1.4 million barrels per day of distillation capacity was added between 1996 and 2002. Financial and legal considerations make it unlikely that new refineries will be built in the United States, but additions at existing refineries are expected to increase total U.S. refining capacity in all the *AEO2004* cases (Figure 100).

Distillation capacity is projected to grow from the 2002 year-end level of 16.8 million barrels per day to 21.8 million barrels per day in 2025 in the reference case, 20.6 million barrels per day in the high oil price case, and 23.8 million barrels per day in the low oil price case, compared with the 1981 peak of 18.6 million barrels per day. Almost all the capacity additions are projected to occur on the Gulf Coast. Existing refineries are expected to continue to be utilized intensively (91 to 95 percent of operable capacity) throughout the forecast. The 2002 utilization rate was 91 percent, well above the lows of 69 percent during the 1980s and 88 percent during the early 1990s but consistent with capacity utilization rates since the mid-1990s.

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

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

Figure 101. Worldwide refining capacity by region, 2002 and 2025 (million barrels per day)



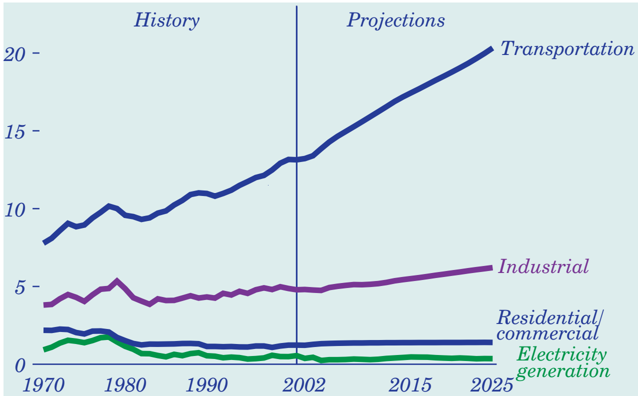
Worldwide crude oil distillation capacity was 81.9 million barrels per day at the end of 2002. To meet the growth in international oil demand in the reference case, worldwide refining capacity is expected to increase by about 53 percent—to more than 125 million barrels per day—by 2025. Substantial growth in distillation capacity is expected in the Middle East, Central and South America, and the Asia/Pacific region (Figure 101).

The Asia/Pacific region has been the fastest growing refining center over the past decade. In the mid-1990s, it surpassed Western Europe as the world's second largest refining center (after North America) in terms of distillation capacity; and in 2002, the Asia/Pacific region surpassed even North America. 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 lower 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.

Petroleum Use Increases Mainly in the Transportation Sector

Figure 102. Petroleum consumption by sector, 1970-2025 (million barrels per day)

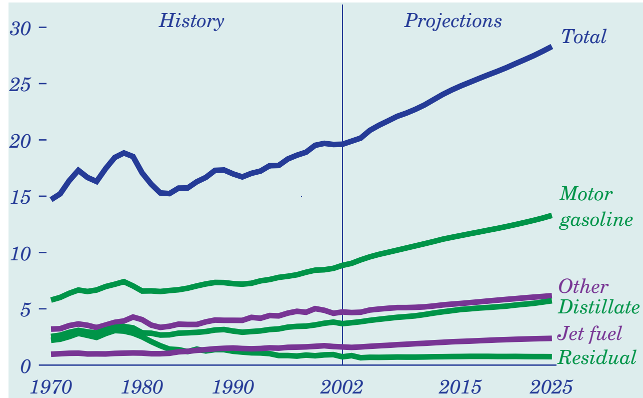


U.S. petroleum consumption is projected to increase by 8.7 million barrels per day from 2002 to 2025. Most of the increase is in the transportation sector, which accounted for two-thirds of U.S. petroleum use in 2002 (Figure 102). Petroleum use for transportation increases by 7.1 million barrels per day in the reference case, as the number and usage of vehicles grow. In the industrial sector, which currently accounts for 24 percent of U.S. petroleum use, consumption in 2025 is projected to be higher than in 2002 by 1.4 million barrels per day in the reference case.

In the reference case, distillate oil use for home heating is expected to decline as oil loses market share to liquefied petroleum gas (LPG), natural gas and electricity. Petroleum use for electricity generation peaks in 2015 and then declines to 14,000 barrels per day below 2002 levels. Increased oil use for heating and electricity generation is projected, however, in the low oil price case. In the low oil price case, natural gas use for home heating is projected to grow in the Northeast, the last stronghold of home heating oil. Compared with 2002, U.S. residential and commercial heating oil use is projected to be 29,000 barrels per day lower in 2025 in the high oil price case and 147,000 barrels per day higher in the low oil price case. For electricity generation, oil- and gas-fired steam plants are being retired in favor of natural gas combined-cycle units. Oil use for electricity generation (excluding combined heat and power) is projected to be 176,000 barrels per day lower in 2025 than in 2002 in the high price case and 1.5 million barrels per day higher in the low price case.

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

Figure 103. Consumption of petroleum products, 1970-2025 (million barrels per day)

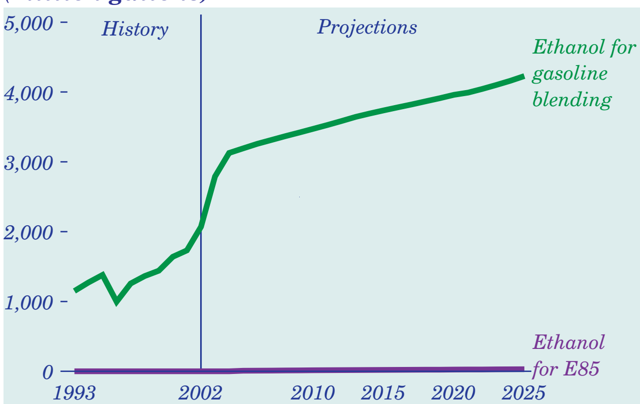


About 93 percent of the projected growth in petroleum consumption consists of increased consumption of “light products,” including gasoline, diesel, heating oil, jet fuel, kerosene, liquefied petroleum gases, and petrochemical feedstocks, which are more difficult and costly to produce than heavy products (Figure 103). Although refinery investments and enhancements are expected to increase the ability of domestic refineries to produce light products, imports of light products are expected to more than double by 2025.

In the forecast, gasoline continues to account for about 47 percent of all the petroleum used in the United States. From 2002 to 2025, U.S. gasoline consumption is projected to rise from 8.9 million barrels per day to 13.3 million barrels per day. Consumption of distillate fuel is projected to be 2.0 million barrels per day higher in 2025 than it was in 2002. An even greater percentage increase is projected for diesel fuel, as a larger portion of total distillate supply is used for diesel production and less is used in other sectors. With air travel also expected to increase, jet fuel consumption is projected to be 759,000 barrels per day higher in 2025 than in 2002. Consumption of LPG is projected to increase by about 689,000 barrels per day from 2002 to 2025, largely for use as a feedstock in the industrial sector. Consumption of “other” petroleum products—including LPG, petrochemical feedstocks, still gas used to fuel refineries, asphalt and road oil, and other miscellaneous products—is projected to grow by 1.4 million barrels per day. Residual fuel use is projected to increase slightly, from about 700,000 barrels per day in 2002 to 751,000 barrels per day in 2025, mostly for fuel in the electricity generation sector.

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

Figure 104. U.S. ethanol consumption, 1993-2025 (million gallons)



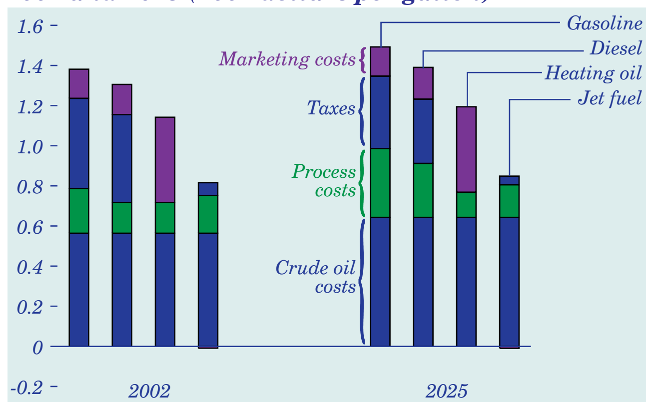
U.S. ethanol production, with corn as the primary feedstock, totaled 139,000 barrels per day in 2002. Production is projected to increase to 278,000 barrels per day in 2025 (Figure 104), with about 27 percent of the growth from conversion of cellulosic biomass (such as wood and agricultural residues). Ethanol is used primarily in the Midwest as a gasoline volume extender and octane enhancer and also serves as an oxygenate in areas that are required to use oxygenated fuels (minimum 2.7 percent oxygen content by volume) during the winter months to reduce carbon monoxide emissions. The high renewables case projects similar production, but all the projected growth is from cellulose, due to more rapid improvement in the technology. In the reference case, corn-based ethanol production drops from 100 percent of total ethanol output in 2009 to 86 percent in 2025.

Ethanol is expected to replace MTBE as the oxygenate for reformulated gasoline (RFG) in 17 States that have placed limits on MTBE use mainly because of concerns about groundwater contamination. It is assumed that the Federal requirement for 2 percent oxygen in RFG will continue in all States. Ethanol consumption in E85 vehicles is also projected to increase, from the national total of 7.8 million gallons in 2002 to 42 million gallons in 2025.

The Federal Highway Bill of 1998 extended the excise tax exemption for ethanol through 2007 with reductions from 54 cents per gallon to 53 cents in 2001, 52 cents in 2003, and 51 cents in 2005. It is assumed that the exemption will continue to be extended at 51 cents per gallon (nominal dollars).

Refining Costs for Most Petroleum Products Rise in the Forecast

Figure 105. Components of refined product costs, 2002 and 2025 (2002 dollars per gallon)



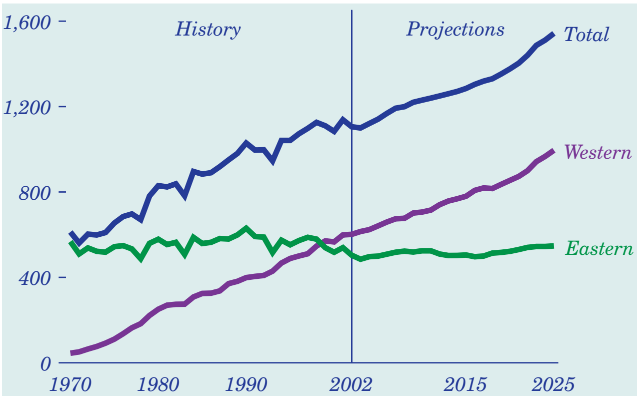
Refined product prices are determined by crude oil costs, refining process costs (including refiner profits), marketing costs, and taxes (Figure 105). In the *AEO2004* projection, crude oil continues as the largest part of product prices. Marketing costs remain stable, but the contributions of processing costs and taxes are projected to change considerably.

Refining costs for gasoline and diesel fuel, including processing costs and profits, are expected to increase by 12 cents a gallon from 2002 to 2025 (2002 dollars), primarily due to growth in demand for gasoline and diesel fuels and new Federal requirements for low-sulfur gasoline (2004 to 2007) and ultra-low-sulfur diesel fuel (2006 to 2010). Refining costs for heating oil and jet fuel fall by 2.6 to 2.8 cents a gallon from 2002 to 2025. Tighter gasoline and diesel specifications cause some refiners to shift production from gasoline and diesel to jet fuel and heating oil, which have less stringent specifications.

Whereas processing costs tend to increase refined product prices in the forecast, the assumption that Federal motor fuel taxes remain at nominal 2002 levels tends to reduce prices. Although Federal motor fuel taxes have been raised occasionally in the past, the assumption of constant nominal Federal taxes is consistent with history. The net impact of the assumption is an expected decrease in Federal taxes (in 2002 dollars) from 2002 to 2025—9 cents per gallon for gasoline, 12 cents for diesel fuel, and 2 cents for jet fuel. State motor fuels taxes are assumed to keep up with inflation, as they have in the past.

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

Figure 106. Coal production by region, 1970-2025 (million short tons)



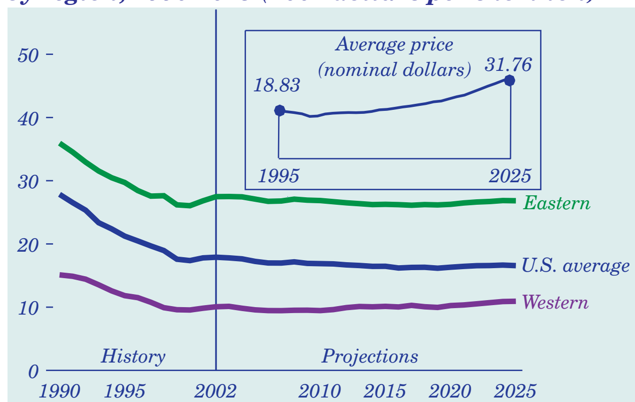
Continued improvements in mine productivity (which have averaged 5.9 percent per year since 1980) are projected to cause falling real minemouth prices throughout the forecast relative to historical levels. Higher electricity demand and lower prices, in turn, are projected to yield increasing coal demand, but the demand is subject to the overall sulfur emissions cap in the Clean Air Act Amendments of 1990, which encourages progressively greater reliance on the lowest sulfur coals (from Wyoming, Montana, Colorado, and Utah).

The use of western coals can result in up to 85 percent lower sulfur dioxide emissions than the use of many types of higher sulfur eastern coals. As coal demand grows over the forecast, however, new coal-fired generating capacity is required to use the best available control technology (scrubbers or advanced coal technologies), which can reduce sulfur emissions by 90 percent or more, providing market opportunities for higher sulfur coal throughout the forecast.

From 2002 to 2025, production of high- and medium-sulfur coal is projected to increase from 578 to 664 million tons (0.6 percent per year), and low-sulfur coal production is projected to rise from 527 to 879 million tons (2.2 percent per year). As a result of the competition between low-sulfur coal and post-combustion sulfur removal, western coal production is expected to continue to increase, but its projected annual growth rate falls from 8.4 percent, achieved between 1970 and 2002, to 2.2 percent in the forecast period. Western coal production is projected to rise from 601 million tons in 2002 to 706 million tons in 2010 and 996 million tons in 2025 (Figure 106).

Rate of Decline in Minemouth Coal Price Is Expected To Slow

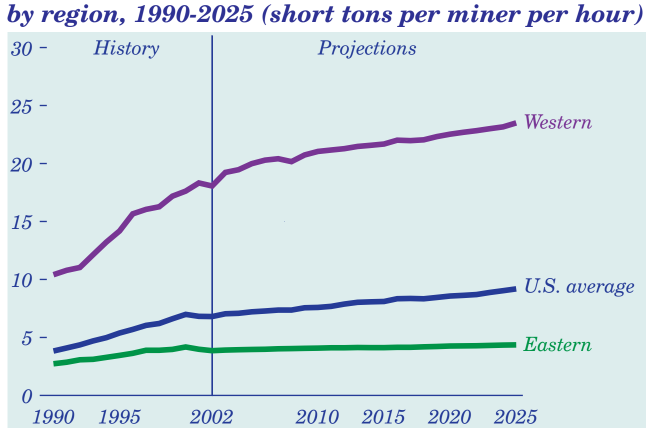
Figure 107. Average minemouth price of coal by region, 1990-2025 (2002 dollars per short ton)



The average minemouth coal price, which fell by 3.6 percent per year (in constant dollars) from 1990 to 2002, is projected to continue declining, from $17.90 in 2002 to $16.19 per ton in 2016 (2002 dollars), as mine productivity rises and lower cost production in the West increases. Average minemouth prices trend upward after 2016, as productivity improvements slow and increasing coal demand creates a need for new coal-mining capacity. In 2025, the average minemouth price is projected to remain lower than the real price in 2002 at $16.57 per ton (Figure 107).

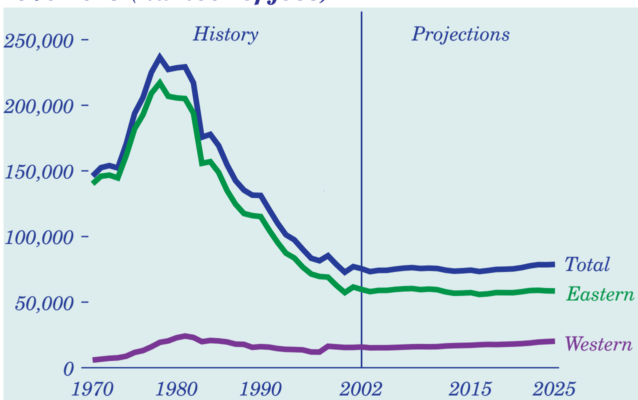
The mines of the Northern Great Plains, with thick seams and low overburden ratios, have had higher labor productivity than other coalfields, and their advantage is expected to be maintained throughout the forecast. Average U.S. coal mining labor productivity (Figure 108) is projected to follow the trend for eastern mines most closely, because eastern mining is more labor-intensive than western mining.

Figure 108. Coal mining labor productivity by region, 1990-2025 (short tons per miner per hour)



Coal Mine Employment Is Expected To Remain Near Current Levels

Figure 109. U.S. coal mine employment by region, 1970-2025 (number of jobs)



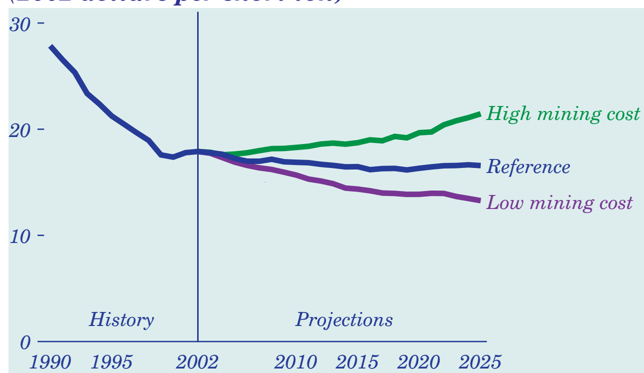
Gains in coal mine labor productivity result from technology improvements, economies of scale, and better mine design. At the national level, average labor productivity is also expected to be influenced by changing regional production shares. Competition from low-sulfur, low-cost western and imported coals is projected to limit the growth of eastern low-sulfur coal mining. The boiler performance of western low-sulfur coal has been tested successfully by many electricity generators, and its use in eastern markets is projected to increase.

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

As labor productivity improved from 1970 to 2002, the average number of miners working daily fell by 2.0 percent per year. Over the forecast period, substantial increases in coal production, coupled with the expectation that productivity improvements will be considerably less than during the past 20 years, result in a stable outlook for employment in the coal industry (Figure 109). The average number of employees working at U.S. coal mines is projected to increase from 75,000 in 2002 to 79,000 in 2025.

Lower Mining Cost Assumptions Lead to More Coal Consumption

Figure 110. Average minemouth coal prices in three mining cost cases, 1990-2025 (2002 dollars per short ton)



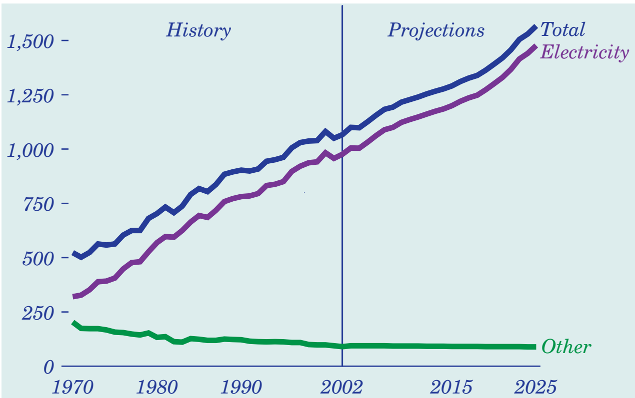
Alternative assumptions about future mining costs affect projected coal prices and the choice of fuels for electricity generation. In two alternative mining cost cases, minemouth prices, delivered prices, and the resulting fuel consumption patterns in the electricity sector vary with changes in projected mining costs.

Productivity is assumed to increase by 1.3 percent per year through 2025 in the reference case, while wage rates and equipment costs are constant in 2002 dollars. The national average minemouth coal price is projected to decline by 0.3 percent per year to $16.57 per ton in 2025 (Figure 110).

In the low mining cost case, productivity is assumed to increase by 2.9 percent per year, and real wages and equipment costs are assumed to decline by 0.5 percent per year [*118*]. As a result, the average minemouth price falls by 1.3 percent per year to $13.27 per ton in 2025, 20 percent less than projected in the reference case. Projected U.S. coal consumption is 44 million tons (2.8 percent) higher in the low mining cost case than in the reference case in 2025, primarily as a result of switching to coal from natural gas in the electricity sector when gas prices rise later in the forecast. The high mining cost case assumes that productivity declines by 0.6 percent per year and real wages and equipment costs increase by 0.5 percent per year. Consequently, the average minemouth price of coal is projected to increase by 0.8 percent per year, to $21.45 per ton in 2025, 29 percent higher than in the reference case. Coal consumption in 2025 is 142 million tons (9.1 percent) lower in the high mining cost case than in the reference case, because less coal-fired capacity is projected to be added.

Coal Consumption for Electricity Continues To Rise in the Forecast

Figure 111. Electricity and other coal consumption, 1970-2025 (million short tons)

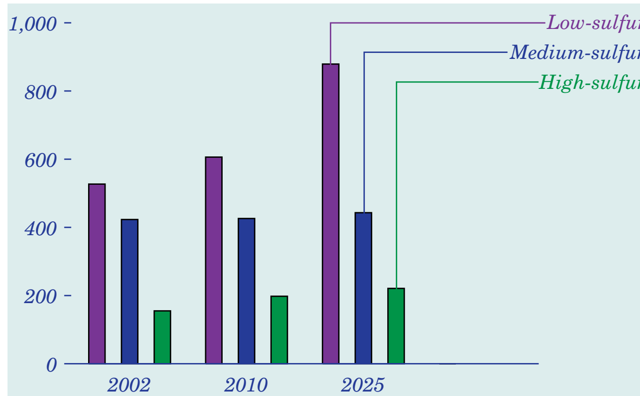


Domestic coal demand is projected to increase by 501 million tons in the reference case forecast, from 1,066 million tons in 2002 to 1,567 million tons in 2025 (Figure 111), because of projected growth in coal use for electricity generation. Total coal demand in other end-use sectors is projected to remain relatively constant.

Coal consumption for electricity generation is projected to increase from 976 million tons in 2002 to 1,477 million tons in 2025 as the utilization of existing coal-fired generation capacity increases and, in later years, new capacity is added. The average utilization rate for coal-fired power plants is projected to increase from 70 percent in 2002 to 83 percent in 2025. Because coal consumption (in tons) per kilowatthour generated is higher for subbituminous coal and lignite than for bituminous coal, the expected shift to western coal is projected to increase the tonnage consumed per kilowatthour of generation, particularly in the Midwest and Southeast regions.

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

Figure 112. Coal production by sulfur content, 2002, 2010 and 2025 (million short tons)



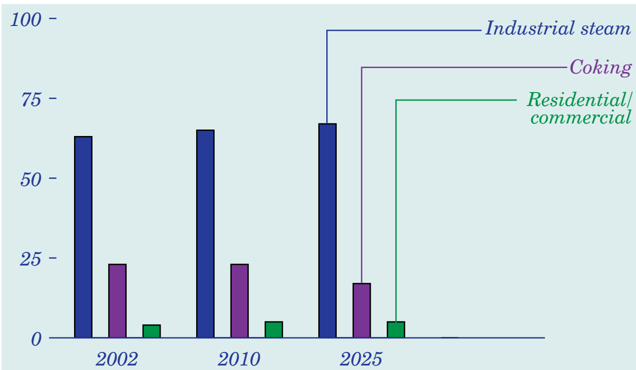
Phase 1 of CAAA90 required 261 coal-fired generating units to reduce sulfur dioxide emissions to about 2.5 pounds per million Btu of fuel. Phase 2, which took effect on January 1, 2000, tightened the annual emissions limits imposed on large, higher emitting plants and also set restrictions on smaller, cleaner plants fired with coal, oil, and gas [*119*].

During Phase 1, many generators switched either partially or entirely from higher sulfur bituminous to low-sulfur subbituminous coal, incurring relatively modest capital investments. Such fuel switching often generated sulfur dioxide allowances beyond those needed for Phase 1 compliance, and the excess allowances generated during Phase 1 were banked for use in Phase 2 or sold to other generators. In the forecast, fuel switching for regulatory compliance and for cost savings is projected to reduce the composite sulfur content of all coal produced (Figure 112). The main sources of low-sulfur coal are the Central Appalachian, Powder River Basin, and Rocky Mountain regions and coal imported from Colombia, Venezuela, and Indonesia.

Coal users could face additional costs in the future if additional or new restrictions on emissions are adopted. An example of a proposal to further reduce emissions from U.S. power plants is the Bush Administration's Clear Skies Initiative. Relative to current law and regulations, the Administration's proposal specifies further restrictions on emissions of nitrogen oxides and sulfur dioxide and would introduce a national cap on mercury emissions.

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

Figure 113. Coal consumption in the industrial and buildings sectors, 2002, 2010, and 2025 (million short tons)



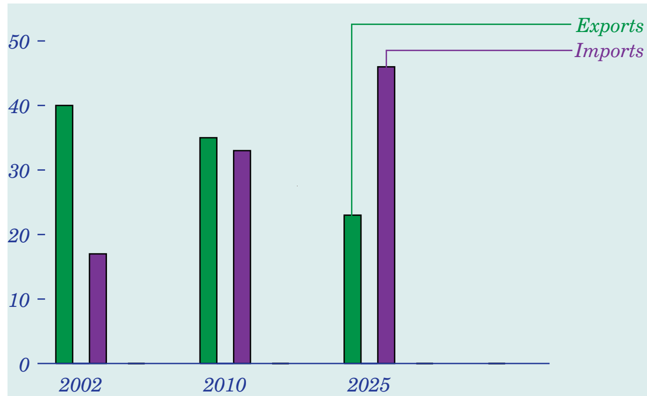
For applications other than electricity generation, a projected increase of 4 million tons in industrial steam coal consumption between 2002 and 2025 (0.3-percent annual growth) is expected to be more than offset by a decrease of 5 million tons in coking coal consumption (Figure 113). Increasing consumption of industrial steam coal is projected to result primarily from greater use of existing coal-fired boilers in energy-intensive industries.

The projected decline in domestic consumption of coking coal results from the expected displacement of raw steel production from integrated steel mills (which use coal coke for energy and as a material input) by increased production from minimills (which use electric arc furnaces that require no coal coke) and by increased imports of semi-finished steels. The amount of coke required per ton of pig iron produced is also declining, as process efficiency improves and injection of pulverized steam coal is used increasingly in blast furnaces. Domestic consumption of coking coal is projected to fall by 1.2 percent per year from 2002 to 2025.

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

Declining U.S. Coal Exports, Rising Imports Are Projected

Figure 114. U.S. coal exports and imports, 2002, 2010, and 2025 (million short tons)



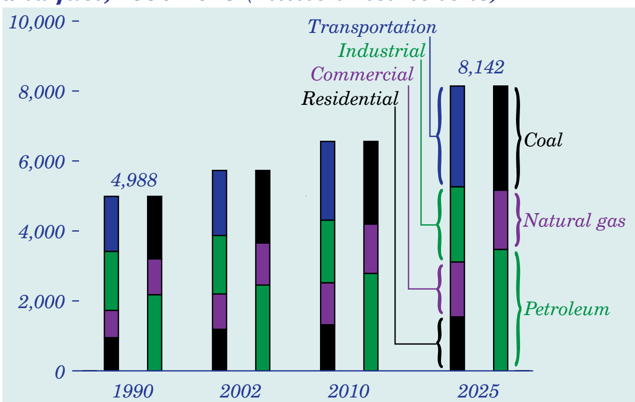
U.S. coal exports declined sharply from 1998 to 2002, from 78 million tons to 40 million tons, and are projected to continue declining in the reference case to 23 million tons in 2025 (Figure 114). Recent declines in U.S. coal exports occurred against the backdrop of a world coal market that saw an increase in trade from 546 million tons in 1998 to 656 million tons in 2002. While low-cost supplies from China, Indonesia, Russia, and Australia satisfied much of the growth in international steam coal demand, low-cost supplies of coking coal from Australia supplanted substantial amounts of U.S. coking coal in the world market.

The U.S. share of total world coal trade is projected to fall from 6 percent in 2002 to less than 3 percent in 2025, as international competition intensifies and coal imports to Europe and the Americas grow more slowly or decline. From 2002 to 2025, U.S. steam coal exports are projected to drop from 19 million tons to 10 million tons, despite substantial projected growth in world steam coal trade. U.S. coking coal exports are also projected to decline, from 21 million tons in 2002 to 13 million tons in 2025, while a small increase in the world trade in coking coal is expected.

U.S. imports of low-sulfur coal are projected to grow from 17 million tons in 2002 to 46 million tons in 2025. For many coastal power plants, imports will be the least costly option for meeting emissions targets. The addition and expansion of existing coal import facilities in the United States, along with a reduction in demand for coal in Europe, are likely to contribute to projected increases in coal imports. Much of the low-sulfur coal projected to be imported is expected to come from Colombia, Venezuela, and Indonesia.

Higher Energy Consumption Forecast Increases Carbon Dioxide Emissions

Figure 115. Carbon dioxide emissions by sector and fuel, 1990-2025 (million metric tons)



Carbon dioxide emissions from energy use are projected to increase on average by 1.5 percent per year from 2002 to 2025, to 8,142 million metric tons (Figure 115). Emissions per capita are projected to grow by 0.7 percent per year from 2002 to 2025.

Carbon dioxide emissions in the residential sector, including emissions from the generation of electricity used in the sector, are projected to increase by an average of 1.1 percent per year, reflecting increased electrification and penetration of computers, electronics, and appliances in the sector. Significant growth in office equipment and computers, as well as floorspace, is also projected for the commercial sector. As a result, carbon dioxide emissions from the commercial sector are projected to increase by 1.9 percent per year from 2002 to 2025. Industrial emissions are projected to grow by 1.1 percent per year, as shifts to less energy-intensive industries and efficiency gains help to moderate growth in energy use.

In the transportation sector, carbon dioxide emissions grow at an average annual rate of 1.9 percent. Increases in highway, rail, and air travel are partially offset by efficiency improvements in rail freight and aircraft, but passenger vehicle fuel economy is projected to increase only slightly above 2002 levels.

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

Electricity Generation Is a Major Source of Carbon Dioxide Emissions

Figure 116. Carbon dioxide emissions from the electric power sector by fuel, 1990-2025 (million metric tons)

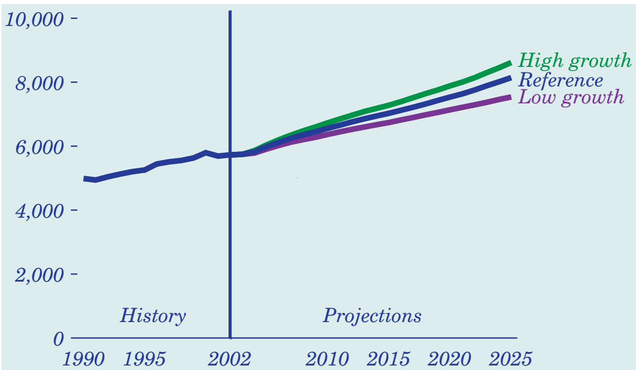
The use of fossil fuels in the electric power industry accounted for 39 percent of total energy-related carbon dioxide emissions in 2002, and that share is projected to increase to 41 percent in 2025. Coal is projected to account for 55 percent of the power industry's electricity generation in 2025 and 84 percent of electricity-related carbon dioxide emissions (Figure 116). In 2025, natural gas is projected to account for 20 percent of electricity generation but only 14 percent of electricity-related carbon dioxide emissions.

From 2002 to 2025, the electric power industry is projected to retire 62 gigawatts of generating capacity—about 7 percent of the 2002 total—and to see a 49-percent increase in electricity sales. As a result, the industry is projected to add 317 gigawatts of new fossil-fueled capacity by 2025. Although much of the new capacity is expected to be relatively efficient combined-cycle plants fueled by natural gas, the net effect will be to raise the industry's carbon dioxide emissions by 1,050 million metric tons, or 47 percent, from 2002 levels.

The electric power industry is projected to increase its reliance on renewable energy, which generally does not contribute to carbon dioxide emissions. Renewable generation is expected to increase by 180 billion kilowatthours, or 53 percent, from 2002 to 2025, helping to offset the projected increase in carbon dioxide emissions from fossil fuels. Average carbon dioxide emissions per kilowatthour of total generation are projected to decline by about 2 percent from 2002 to 2010 and remain at about that level through 2025.

Emissions Projections Change With Economic Growth Assumptions

Figure 117. Carbon dioxide emissions in three economic growth cases, 1990-2025 (million metric tons)



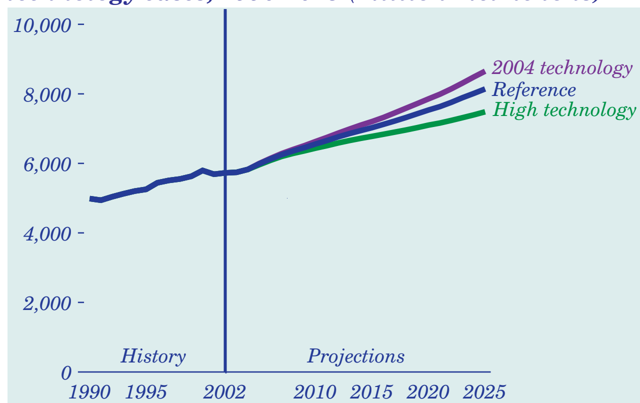
The high economic growth case assumes higher growth in population, labor force, and productivity than in the reference case, leading to higher industrial output, lower inflation, and lower interest rates. GDP growth in the high growth case averages 3.5 percent a year from 2002 to 2025, compared with 3.0 percent a year in the reference case. In the low economic growth case, GDP growth averages 2.4 percent per year.

Higher projections for manufacturing output and income increase the demand for energy services in the high economic growth case: projected energy consumption is 3 percent higher than in the reference case in 2010 and 7 percent higher in 2025. As a result, carbon dioxide emissions are projected to be 6 percent higher than in the reference case in 2025, at 8,615 million metric tons (Figure 117). Total energy intensity, measured as primary energy consumption per dollar of GDP, declines by 1.7 percent per year from 2002 to 2025 in the high growth case, as compared with 1.5 percent in the reference case. With more rapid projected growth in energy consumption, there is expected to be a greater opportunity for turnover in the stock of energy-using technologies, adding new equipment and increasing the overall efficiency of the capital stock.

Projected total energy consumption is 3 percent lower in the low growth case than in the reference case in 2010 and 7 percent lower in 2025. Carbon dioxide emissions in 2025 are also 7 percent lower, at 7,538 million metric tons. Energy intensity is projected to decline at an average rate of 1.2 percent from 2002 to 2025 in the low economic growth case.

Technology Advances Could Reduce Carbon Dioxide Emissions

Figure 118. Carbon dioxide emissions in three technology cases, 1990-2025 (million metric tons)

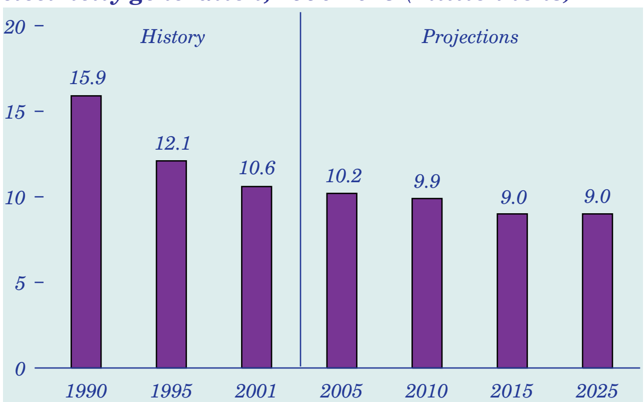


The reference case assumes continuing improvement in energy-consuming and producing technologies, consistent with historic trends, as a result of ongoing research and development. In the high technology case it is assumed that increased spending on research and development will result in earlier introduction, lower costs, and higher efficiencies for end-use technologies than assumed in the reference case. The costs and efficiencies of advanced fossil-fired and new renewable generating technologies are also assumed to improve from reference case values [*120*]. Energy intensity is expected to decline on average by 1.7 percent per year through 2025 in the high technology case, as compared with 1.5 percent in the reference case. As a result, energy consumption is projected to be 5 percent lower than in the reference case in 2025, at 129 quadrillion Btu, and carbon dioxide emissions are projected to be 8 percent lower than in the reference case, at 7,472 million metric tons (Figure 118).

The 2004 technology case assumes that future equipment choices will be made from the equipment and vehicles available in 2004; that new building shell and plant efficiencies will remain at their 2004 levels; and that advanced generating technologies will not improve over time. Energy efficiency improves in the 2004 technology case as new equipment is chosen to replace older stock and the capital stock expands, and energy intensity declines by 1.3 percent per year from 2002 to 2025. Energy consumption reaches 143 quadrillion Btu in 2025 in the 2004 technology case, and carbon dioxide emissions in 2025 are projected to be 6 percent higher than in the reference case, at 8,654 million metric tons.

Sulfur Dioxide Emissions Are Cut in Response to Tightening Regulations

Figure 119. Sulfur dioxide emissions from electricity generation, 1990-2025 (million tons)



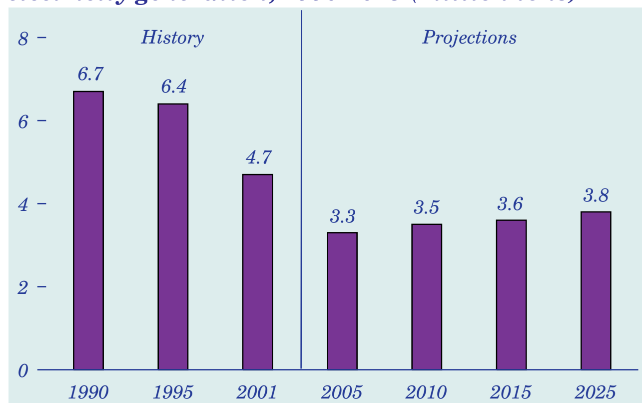
CAAA90 called for annual emissions of sulfur dioxide (SO_2) by electricity generators in the power sector to be reduced to approximately 12 million tons in 1996, 9.48 million tons per year from 2000 to 2009, and 8.95 million tons per year thereafter. Because companies can bank allowances for future use, however, the long-term cap of 8.95 million tons per year is not expected to be reached until after 2014. More than 95 percent of the SO_2 produced by generators results from coal combustion and the rest from residual oil.

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

In recent years, power companies have announced plans to add scrubbers to 23 gigawatts of capacity, in order to comply with State or Federal initiatives. Beyond those that have been announced, 2 gigawatts of additional capacity is projected to be retrofitted with scrubbers. Total SO_2 emissions are projected to decline from 10.6 million tons in 2001 to 9.0 million tons in 2025 (Figure 119). The price of SO_2 emission allowances is projected generally to range from $150 to $250 per ton between 2005 and 2025.

Nitrogen Oxide Emissions Are Projected To Stay Below 2000 Levels

Figure 120. Nitrogen oxide emissions from electricity generation, 1990-2025 (million tons)



Nitrogen oxide (NO_x) emissions from electricity generation in the U.S. power sector are projected to fall as new regulations take effect (Figure 120). The required reductions are intended to reduce the formation of ground-level ozone, for which NO_x emissions are a major precursor. Together with volatile organic compounds and hot weather, NO_x emissions contribute to unhealthy air quality in many areas during the summer months.

For several years, the EPA and the States have studied the movement of ozone from State to State. The States in the Northeast have argued that emissions from coal-fired power plants in the Midwest make it difficult for them to meet national air quality standards for ground-level ozone, and they have petitioned the EPA to force plant operators to reduce emissions by more than required under current rules.

The Ozone Transport Rule called for capping NO_x emissions in 22 Midwestern and Eastern States during the summer season, and following a court challenge, emissions limits were finalized for 19 States. The limits, included in the projections beginning in 2004, are projected to stimulate the addition of emissions control equipment to many existing plants, further lowering NO_x emissions by 0.5 million tons between 2003 and 2004. After 2004, NO_x emissions are projected to increase gradually, to 3.8 million tons in 2025. Overall, selective catalytic reduction equipment is projected to be added to approximately 92 gigawatts of capacity, and NO_x allowance prices are projected to increase from roughly $4,000 per ton in 2004 to $5,500 per ton in 2025.

Forecast Comparisons

Forecast Comparisons

The *AEO2004* forecast period extends through 2025. One other organization—Global Insight, Incorporated (GII)—produces a comprehensive energy projection with a similar time horizon. Several others provide forecasts that address one or more aspects of energy markets over different time horizons. Recent projections from GII and others are compared here with the *AEO2004* projections.

Economic Growth

From 2002 to 2025, the projected growth in gross domestic product (GDP), based on 1996 chain-weighted dollars, is 3.0 percent per year. This projected growth is slightly lower than the 3.1-percent average annual growth projected in *AEO2003* (Table 27). The *AEO2004* forecast was based on the August 2003 long-range forecast of GII, modified to reflect EIA's view on world oil prices.

Through 2008, the *AEO2004* forecast of 3.3-percent average annual growth in GDP is similar to other forecasts: the GII forecast is 3.3 percent, the same as the November 2003 forecast by Oxford Economic Forecasting (OEF), and both the July 2003 forecast by the Office of Management and Budget (OMB) and the August 2003 forecast by the Congressional Budget Office (CBO) show 3.2-percent average annual growth through 2008. From 2002 through 2013, the *AEO2004*, GII, and OEF forecasts show 3.2-percent growth per year, while the CBO forecast is 3.0 percent per year. From 2002 to 2025, the GII forecast shows 3.0-percent average annual growth in GDP. The range of average annual economic growth rates around the *AEO2004* reference case is from 2.4 percent in the low economic growth case to 3.5 percent in the high economic growth case.

World Oil Prices

Comparisons with other oil price forecasts—including GII, the International Energy Agency (IEA), Petroleum Economics, Ltd. (PEL), Petroleum Industry Research Associates, Inc. (PIRA), Natural Resources Canada (NRCan), Deutsche Bank A.G. (DB), Energy and Environmental Analysis, Inc. (EEA), National Petroleum Council (NPC), Strategic Energy & Economic Research, Inc. (SEER), and Centre for Global Energy Studies (CGES)—are shown in Table 28 (GII, Spring-Summer 2003; IEA, September 2002; PEL, April 2003; PIRA, October 2003; NRCan, 1997, reaffirmed in September 2002; DB, September 2003; EEA, October 2003; NPC, October 2003; SEER, November 2003; CGES, January 2003). The world oil price measure varies by forecast. In some it is the spot price for West Texas Intermediate (WTI), Brent, or a basket of crude oils. *AEO2004* uses the composite U.S. refiners' acquisition cost of crude oil, including transportation and fees. There is no simple way to put the forecasts for oil prices (Table 28) on a common basis. With the exception of PEL and CGES, which fall below the *AEO2004* low world oil price case in 2020, the range between the *AEO2004* low and high world oil price cases spans the range of published forecasts.

Total Energy Consumption

The *AEO2004* forecast of end-use sector energy consumption shows higher growth for petroleum and natural gas than occurred between 1980 and 2002, and growth in projected electricity consumption is only slightly less (1.8 percent compared to 1.9 percent) (Table 29). Much of the projected growth in petroleum consumption is driven by increased

Table 27. Forecasts of annual average economic growth, 2002-2025

	Average annual percentage growth		
Forecast	2002-2008	2002-2013	2002-2025
AEO2003	3.2	3.3	3.1
AEO2004			
Reference	3.3	3.2	3.0
Low growth	2.8	2.7	2.4
High growth	4.0	3.8	3.5
GII	3.3	3.2	3.0
OMB	3.2	NA	NA
CBO	3.2	3.0	NA
OEF	3.3	3.2	NA

NA = not available.

Table 28. Forecasts of world oil prices, 2005-2025 (2002 dollars per barrel)

Forecast	2005	2010	2015	2020	2025
AEO2003	23.57	24.28	25.01	25.77	26.89
AEO2004					
Reference	23.30	24.17	25.07	26.02	27.00
High price	31.16	33.27	34.23	34.63	35.03
Low price	16.98	16.98	16.98	16.98	16.98
GII	21.77	21.95	24.03	25.68	27.06
IEA	21.75	21.75	23.82	25.89	27.96
PEL	20.96	21.27	18.41	15.60	NA
PIRA	23.80	23.90	26.70	N/A	NA
NRCan	22.57	22.57	22.57	22.57	NA
DB	18.13	18.03	18.41	18.16	18.26
EEA	20.99	20.33	19.84	19.36	NA
NPC	18.00	18.00	18.00	18.00	18.00
SEER	21.08	19.86	20.88	22.49	24.53
CGES	23.82	21.27	18.41	15.60	NA

NA = not available.

demand in the industrial sector for petrochemical and manufacturing applications as economic activity expands, and in the transportation sector as improvements in efficiency are unable to offset increases in miles traveled. Natural gas consumption is expected to increase in the residential, commercial, and industrial sectors as environmental and economic pressures benefit natural gas at the expense of petroleum and coal consumption. Coal consumption in those end-use sectors is expected to decline slightly as a result of increased fuel switching and growing concern about emissions.

Electricity is expected to remain the fastest growing source of delivered energy (although not outpacing historical growth rates), because many traditional uses of electricity (such as for air conditioning) approach saturation while average equipment efficiencies rise. The *AEO2004* projections are generally consistent with the outlook from GII; however, GII forecasts slower growth in natural gas consumption and electricity losses as well as slightly faster growth in petroleum consumption, resulting from differences in relative prices and projected growth in each sector.

Electricity

The *AEO2004* electricity forecast assumes that wholesale markets in most U.S. regions will be restructured, resulting in average wholesale electricity prices that approach long-run marginal costs. The same cannot be said for retail markets at the State level: as of 2003, only 17 States and the District of Columbia had competitive retail markets in operation. Further, a number of States have delayed opening competitive retail markets, Arkansas has repealed retail restructuring, and California has suspended restructuring. The *AEO2004* forecast assumes that no additional retail markets will be restructured, but that the partial restructuring (particularly in wholesale markets) will lead to increased competition in the electric power industry, lower operating and maintenance costs, lower general and administrative costs, early retirement of inefficient generating units, and other cost reductions.

Table 29. Forecasts of average annual growth rates for energy consumption, 2002-2025 (percent)

Energy use	History 1980-2002	Projections	
		AEO2004	GII
Petroleum*	1.0	1.6	1.8
Natural gas*	0.7	1.3	0.8
Coal*	-1.4	-0.3	-0.4
Electricity	1.9	1.8	1.7
Delivered energy	0.9	1.5	1.5
Electricity losses	1.7	1.3	0.7
Primary energy	1.1	1.5	1.3

**Excludes consumption by electricity generators in the electric power sector but includes consumption for end-use combined heat and power generation.*

Comparison across the *AEO2004*, GII, and EEA forecasts shows slight variation in projected electricity sales (Table 30). The forecasts for total electricity sales in 2025 range from 4,861 billion kilowatthours in the *AEO2004* low economic growth case to 5,527 billion kilowatthours in the *AEO2004* high economic growth case. The *AEO2004* reference case projection of 5,207 billion kilowatthours is framed by the GII forecast (5,072) and the Energy Ventures Analysis (EVA) forecast (5,341), with the SEER forecast at 5,319 billion kilowatthours. Demand growth rates range from 1.7 percent in the GII forecast to 1.8 percent in the *AEO2004* reference case and 2.1 percent in the *AEO2004* high economic growth case. All price forecasts reflect competition in wholesale markets and slow growth in electricity demand relative to GDP growth, exerting downward pressure on real electricity prices through 2025. Rising natural gas prices balance some of the downward pressure and tend to push electricity prices up in the later years of the forecasts.

AEO2004 projects a slight decline in real electricity prices over the full period of the forecast, although average prices increase slightly during the last several years as capacity margins tighten and natural gas prices climb. In contrast, GII projects a decline over the second half of the forecast as lower natural gas prices to generators ($4.03 per quadrillion Btu in GII compared with $4.92 per quadrillion Btu in *AEO2004* in 2025) contribute to a decline in average electricity prices from 7.1 cents per kilowatthour in 2010 and 2015 to 6.9 cents per kilowatthour in 2025 in the GII forecast. EVA, providing the only other price forecast, projects steady electricity prices over the forecast period.

Both *AEO2004* and GII incorporate large amounts of planned capacity in the short term, with *AEO2004* projecting about 53 gigawatts through 2004 and GII projecting about 75 gigawatts, virtually all of which is expected to be gas-fired. These two forecasts project a glut of capacity with falling prices in the near term, along with steady capacity margins that begin to erode only in the later years.

All five forecasts project that demand will grow fastest in the commercial sector and that more cycling and baseload capability will be built than peaking units. All the forecasts except EVA show significant net additions to coal-fired capacity: 101 gigawatts by 2025 in *AEO2004*, 57 gigawatts in the EEA forecast by 2020, and 130 gigawatts in the GII forecast by 2025. GII projects 2.5 gigawatts of nuclear retirements, more than *AEO2004,* which projects no retirements and 3.9 gigawatts of expansion through uprating of existing capacity.

The EVA forecast of fuel-mix proportions differs substantially from *AEO2004* and the other forecasts. Whereas all the other forecasts project that coal will provide about one-half and natural gas about one-quarter of electricity generation throughout the period, EVA projects much greater reliance on natural gas by 2025. The EVA forecast assumes that legislation similar to Clear Skies—including further restrictions on sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury emissions—will be in effect by 2010. The EVA forecast also includes a $5 per ton tax on carbon dioxide emissions beginning in 2013. This combination (further environmental restrictions and a tax on carbon dioxide) allows for only marginal growth in coal-fired generation, with natural gas making up the shortfall (natural-gas- and coal-fired generation are nearly equal by 2025). Natural gas prices, and consequently electricity prices, are held in check by large gains in the efficiency of natural gas combined-cycle capacity.

Natural Gas

The differences among published forecasts of natural gas prices, production, consumption, and imports (Table 31) indicate the uncertainty of future market trends. Because the forecasts depend heavily on the underlying assumptions that shape them, the assumptions made in each forecast should be considered when different projections are compared.

The *AEO2004* reference case is within the range of projections for total natural gas consumption in the other forecasts throughout the forecast period. The lowest projected totals for natural gas consumption are from the NPC Balanced Future scenario, and the highest are from the EVA forecast. For residential and commercial natural gas consumption, DB projects the largest growth. The lowest consumption levels for these sectors are generally projected by GII or PIRA. The *AEO2004* reference case projections fall in the middle of the range for residential consumption and toward the low end for commercial consumption. Natural gas consumption in the industrial and electric power sectors is more difficult to compare, given potential definitional differences. The EVA forecast shows the fastest growth in natural gas consumption in combined totals for the industrial and electric power sectors, whereas the NPC Reactive Path and Balanced Future scenarios and the DB forecast show much slower growth than the other forecasts.

Domestic natural gas consumption is met by domestic production and net imports. All forecasts show domestic production providing a decreasing share of total natural gas supply, with *AEO2004* and both NPC cases showing a smaller shift in that direction and significantly lower net imports. The two NPC cases generally project the lowest levels of pipeline and liquefied natural gas (LNG) imports, with the highest levels projected by EVA for both sources. Only EVA and GII project pipeline imports higher in 2025 than they are today; the NPC Balanced Future scenario projects pipeline imports in 2025 at less than one-third of current volumes. PIRA and EVA, as well as GII and DB in 2025, show net imports as providing a notably higher share of total supply than in the other forecasts.

Wellhead natural gas price projections in the *AEO2004* reference case are higher than in the other available forecasts (not all forecasts provide wellhead price projections), with the exception of EEA. Of the three forecasts that project end-use prices (*AEO2004*, GII, and EEA), *AEO2004* shows the highest end-use-to-wellhead margins for the electric power sector and the lowest end-use-to-wellhead margins for the industrial sector. For the residential and commercial sectors, the projected margins in *AEO2004* fall in the middle range of the available forecasts. Margins are notably lower for the residential and commercial sectors in the EEA forecast and for the electric power sector in the GII forecast (some of the differences may reflect definitional variations).

Petroleum

The GII, DB, and PIRA forecasts of world oil prices and domestic petroleum production, consumption, and imports can be compared with the *AEO2004* reference, low world oil price, and high world oil price cases (Table 32). The *AEO2004* reference case projects a world oil price of $25.07 per barrel (2002 dollars) in 2015, compared with projections from GII at

Table 30. Comparison of electricity forecasts, 2015 and 2025 (billion kilowatthours, except where noted)

Projection	*2002*	*AEO2004*			*Other forecasts*			
		Reference	*Low economic growth*	*High economic growth*	*GII*	*EVA*	*EEA*	*SEER*
					2015			
Average end-use price (2002 cents per kilowatthour)	***7.2***	***6.8***	***6.5***	***7.2***	***7.1***	***6.8***	***NA***	***NA***
Residential	*8.4*	*8.1*	*7.7*	*8.6*	*8.3*	*8.2*	*NA*	*NA*
Commercial	*7.8*	*7.2*	*6.8*	*7.6*	*7.6*	*7.5*	*NA*	*NA*
Industrial	*5.0*	*4.7*	*4.4*	*5.0*	*4.7*	*4.4*	*NA*	*NA*
Net energy for load, including CHP	***3,851***	***4,936***	***4,754***	***5,109***	***4,766***	***5,118***	***4,889***	***4,976***
Coal	*1,928*	*2,373*	*2,331*	*2,376*	*2,281*	*2,083*	*2,268*	*2,403*
Oil	*88*	*122*	*105*	*142*	*50*	*20*	*115*	*60*
Natural gas [a]	*687*	*1,120*	*1,013*	*1,258*	*1,162*	*1,627*	*1,264*	*1,221*
Nuclear	*780*	*812*	*812*	*812*	*783*	*827*	*765*	*801*
Hydroelectric/other [b]	*346*	*477*	*465*	*485*	*460*	*534*	*397*	*467*
Nonutility sales to grid [c]	*27*	*63*	*54*	*74*	*NA*	*NA*	*41*	*NA*
Net imports	*22*	*32*	*28*	*36*	*30*	*27*	*38*	*24*
Electricity sales	***3,492***	***4,429***	***4,263***	***4,583***	***4,289***	***4,534***	***4,405***	***4,470***
Residential	*1,268*	*1,531*	*1,515*	*1,546*	*1,557*	*1,659*	*1,557*	*1,555*
Commercial/other [d]	*1,230*	*1,682*	*1,663*	*1,701*	*1,582*	*1,685*	*1,584*	*1,650*
Industrial	*994*	*1,216*	*1,086*	*1,335*	*1,151*	*1,190*	*1,263*	*1,265*
Capability, including CHP (gigawatts) [e]	***921***	***1,037***	***1,006***	***1,067***	***997***	***1,046***	***1,049***	***NA***
Coal	*315*	*326*	*323*	*325*	*357*	*300*	*339*	*NA*
Oil and natural gas	*390*	*480*	*454*	*509*	*400*	*375*	*478*	*NA*
Nuclear	*99*	*102*	*102*	*102*	*98*	*102*	*95*	*NA*
Hydroelectric/other	*117*	*130*	*128*	*131*	*142*	*269* [f]	*137*	*NA*
					2025			
Average end-use price (2002 cents per kilowatthour)	***7.2***	***6.9***	***6.6***	***7.3***	***6.9***	***6.8***	***NA***	***NA***
Residential	*8.4*	*8.1*	*7.6*	*8.8*	*8.1*	*8.2*	*NA*	*NA*
Commercial	*7.8*	*7.3*	*6.9*	*7.8*	*7.5*	*7.4*	*NA*	*NA*
Industrial	*5.0*	*4.8*	*4.5*	*5.1*	*4.5*	*4.3*	*NA*	*NA*
Net energy for load, including CHP	***3,851***	***5,794***	***5,408***	***6,159***	***5,630***	***6,080***	***NA***	***5,797***
Coal	*1,928*	*3,029*	*2,735*	*3,169*	*2,911*	*2,320*	*NA*	*3,044*
Oil	*88*	*97*	*103*	*105*	*26*	*22*	*NA*	*64*
Natural gas [a]	*687*	*1,317*	*1,249*	*1,457*	*1,410*	*2,278*	*NA*	*1,457*
Nuclear	*780*	*816*	*816*	*816*	*785*	*841*	*NA*	*754*
Hydroelectric/other [b]	*346*	*527*	*498*	*604*	*473*	*593*	*NA*	*462*
Nonutility sales to grid [c]	*27*	*95*	*72*	*120*	*NA*	*NA*	*NA*	*NA*
Net imports	*22*	*8*	*7*	*8*	*24*	*26*	*NA*	*16*
Electricity sales	***3,492***	***5,207***	***4,861***	***5,527***	***5,072***	***5,341***	***NA***	***5,319***
Residential	*1,268*	*1,747*	*1,686*	*1,781*	*1,840*	*1,986*	*NA*	*1,747*
Commercial/other [d]	*1,230*	*2,038*	*1,967*	*2,095*	*1,883*	*2,037*	*NA*	*2,100*
Industrial	*994*	*1,422*	*1,207*	*1,650*	*1,350*	*1,317*	*NA*	*1,472*
Capability, including CHP (gigawatts) [e]	***921***	***1,217***	***1,149***	***1,291***	***1,164***	***1,168***	***NA***	***NA***
Coal	*315*	*416*	*377*	*432*	*444*	*329*	*NA*	*NA*
Oil and natural gas	*390*	*557*	*536*	*598*	*476*	*452*	*NA*	*NA*
Nuclear	*99*	*103*	*103*	*103*	*98*	*104*	*NA*	*NA*
Hydroelectric/other	*117*	*141*	*134*	*159*	*146*	*283* [f]	*NA*	*NA*

[a]Includes supplemental gaseous fuels. [b]"Other" includes conventional hydroelectric, pumped storage, geothermal, wood, wood waste, municipal waste, other biomass, solar and wind power, plus a small quantity of petroleum coke. [c]For *AEO2004*, includes only net sales from combined heat and power plants. [d]"Other" includes sales of electricity to government, railways, and street lighting authorities. [e]EIA capacity is net summer capability, including combined heat and power plants. GII capacity is nameplate, excluding cogeneration plants. [f]EVA "other" includes all CHP.

CHP = combined heat and power. NA = not available.

Sources: ***AEO2004:*** AEO2004 National Energy Modeling System, runs AEO2004.D101703E (reference case), LM2004.D101703A (low economic growth case), and HM2004.D101703A (high economic growth case). **GII:** Global Insight, Inc., *Spring/Summer 2003 U.S. Energy Outlook* (July 2002). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (July 2003). **EEA:** Energy and Environmental Analysis, Inc., *EEA's Compass Service Base Case* (October 2003). **SEER:** Strategic Energy and Economic Research, Inc., *2003 Energy Outlook* (May 2003).

Table 31. Comparison of natural gas forecasts, 2015 and 2025 (trillion cubic feet, except where noted)

Projection	2002	AEO2004 Reference	Other forecasts						
			GII[a]	EEA[b]	NPC Reactive Path	NPC Balanced Future	EVA	PIRA	DB
					2015				
Lower 48 wellhead price (2002 dollars per thousand cubic feet)	**2.95**	**4.19**	**3.62**	**4.25**	**NA**	**NA**	**3.44**	**3.74[c]**	**3.03**
Dry gas production[d]	**19.05**	**21.62**	**20.80**	**21.86**	**21.55**	**21.18**	**21.66[e]**	**17.89**	**20.59**
Net imports	**3.49**	**6.24**	**7.01**	**6.76**	**5.11**	**5.12**	**9.68[f]**	**8.58**	**6.67**
Pipeline	3.33	3.02	3.65	3.92	2.61	1.94	4.78[f]	3.84	NA
LNG	0.17	3.22	3.36[g]	3.70	2.51	3.18	4.90	4.75	NA
Consumption	**22.78**	**28.03**	**27.88**	**28.32**	**26.67**	**26.30**	**31.11**	**26.58**	**26.78**
Residential	4.92	5.68	5.41	5.83	5.75	5.48	5.58	5.06	5.97
Commercial	3.12	3.62	3.35	3.97	3.77	3.80	3.77	3.41	4.06
Industrial[h]	7.23	8.87	8.53[i]	7.70[j]	7.21	7.41	7.67[k]	6.53[l]	8.31
Electricity generators[m]	5.55	7.64	8.62[n]	8.89[o]	7.77	7.48	11.73	9.38[p]	6.45
Other[q]	1.96	2.22	1.98	1.94	2.16	2.12	2.36[r]	2.20	2.00
End-use prices (2002 dollars per thousand cubic feet)									
Residential	7.86	8.52	8.37	7.66	NA	NA	NA	NA	NA
Commercial	6.55	7.52	7.20	6.88	NA	NA	NA	NA	NA
Industrial[h]	3.85	4.94	4.86[s]	5.26	NA	NA	NA	NA	NA
Electricity generators[m]	3.85	4.87	4.01	4.88	NA	NA	NA	NA	NA
					2025				
Lower 48 wellhead price (2002 dollars per thousand cubic feet)	**2.95**	**4.40**	**3.76**	**NA**	**NA**	**NA**	**3.69**	**NA**	**3.02**
Dry gas production[d]	**19.05**	**23.99**	**20.76**	**NA**	**20.90**	**20.83**	**24.26[e]**	**NA**	**19.04**
Net imports	**3.49**	**7.24**	**9.91**	**NA**	**6.31**	**5.80**	**11.72[f]**	**NA**	**11.16**
Pipeline	3.33	2.44	3.61	NA	2.44	1.03	5.26[f]	NA	NA
LNG	0.17	4.80	6.30[g]	NA	3.88	4.77	6.46	NA	NA
Consumption	**22.78**	**31.41**	**30.75**	**NA**	**27.62**	**26.62**	**35.89**	**NA**	**29.66**
Residential	4.92	6.09	5.87	NA	6.17	5.82	5.94	NA	6.66
Commercial	3.12	4.04	3.62	NA	4.09	4.18	4.16	NA	4.78
Industrial[h]	7.23	10.29	9.35[i]	NA	7.10	7.38	8.57[k]	NA	9.18
Electricity generators[m]	5.55	8.39	9.83[n]	NA	8.18	7.24	14.50	NA	6.78
Other[q]	1.96	2.59	2.08	NA	2.08	2.01	2.72[r]	NA	2.27
End-use prices (2002 dollars per thousand cubic feet)									
Residential	7.86	8.56	8.33	NA	NA	NA	NA	NA	NA
Commercial	6.55	7.62	7.17	NA	NA	NA	NA	NA	NA
Industrial[h]	3.85	5.13	4.94[r]	NA	NA	NA	NA	NA	NA
Electricity generators[m]	3.85	5.01	4.13	NA	NA	NA	NA	NA	NA

NA = not available.

[a]Conversion factor: 1,000 cubic feet = 1.026 million Btu. [b]The EEA projection shows a cyclical price trend; forecast values for an isolated year may be misleading. [c]Henry Hub daily cash natural gas price in 2002 dollars per million Btu. [d]Does not include supplemental fuels. [e]Includes supplemental fuels. [f]Gross imports to the Lower 48. [g]Net LNG imports equal LNG imports minus exports of 0.065 trillion cubic feet. [h]Includes consumption for combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public; excludes consumption by nonutility generators. [i]Excludes gas used in cogeneration or other nonutility generation. [j]Includes natural gas consumed in cogeneration. [k]Includes transportation fuel consumed in natural gas vehicles. [l]Excludes gas demand for nonutility generation. [m]Includes consumption of energy by electricity-only and CHP plants; includes small power producers and exempt wholesale generators. [n]Includes gas used in cogeneration or other nonutility generation. [o]Includes independent power producers and excludes cogenerators. [p]Equals the sum of gas demand for nonutility generation plus gas demand for utility generation. [q]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles. [r]Includes lease, plant, and pipeline fuel. [s]On system sales or system gas (i.e., does not include gas delivered for the account of others).

Sources: **2002 and *AEO2004*:** AEO2004 National Energy Modeling System, runs AEO2004.D101703E (reference case). **GII:** Global Insight, Inc., *Spring/Summer 2003 U.S. Energy Outlook* (July 2002). **EEA:** Energy and Environmental Analysis, Inc., *EEA's Compass Service Base Case* (October 2003). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (July 2003). **NPC:** National Petroleum Council, *Balancing Natural Gas Policy—Fueling the Demands of a Growing Economy*, Volume I, Summary of Findings and Recommendations (Washington, DC, September 2003), web site www.npc.org/NG_Volume_1.pdf. **PIRA:** PIRA Energy Group (October 2003). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski on November 3, 2003.

Table 32. Comparison of petroleum forecasts, 2015, 2020, and 2025 (million barrels per day, except where noted)

Projection	2002	AEO2004 Reference	AEO2004 Low world oil price	AEO2004 High world oil price	Other forecasts GII	Other forecasts DB	Other forecasts PIRA
				2015			
World oil price (2002 dollars per barrel)	**23.68**	**25.07**	**16.98**	**34.23**	**24.03**	**18.41**	**26.70** [a]
Crude oil and NGL production	**7.50**	**7.84**	**7.38**	**8.25**	**7.82**	**7.37**	**6.82**
Crude oil	*5.63*	*5.53*	*5.25*	*5.87*	*5.48*	*5.43*	*4.59*
Natural gas liquids	*1.88*	*2.31*	*2.13*	*2.38*	*2.34*	*1.94*	*2.23*
Total net imports	**10.54**	**15.52**	**17.54**	**12.79**	**15.89**	**15.11**	**15.52**
Crude oil	*9.13*	*13.47*	*14.51*	*11.24*	*10.72*	*NA*	*12.98*
Petroleum products	*1.41*	*2.05*	*3.03*	*1.55*	*5.18*	*NA*	*2.54*
Petroleum demand	**19.61**	**24.80**	**26.42**	**22.49**	**24.97**	**24.07**	**23.45**
Motor gasoline	*8.86*	*11.51*	*11.99*	*10.00*	*11.32*	*10.74*	*9.45*
Jet fuel	*1.61*	*2.10*	*2.11*	*2.07*	*2.44*	*1.98*	*2.35*
Distillate fuel	*3.68*	*4.94*	*5.67*	*4.65*	*4.56*	*4.75*	*4.65* [b]
Residual fuel	*0.74*	*0.77*	*0.97*	*0.62*	*0.52*	*0.85*	*0.69*
Kerosene	*0.04*	*0.07*	*0.08*	*0.07*	*0.04*	*NA*	*NA*
Liquefied petroleum gas	*2.17*	*2.47*	*2.58*	*2.40*	*2.43*	*NA*	*NA*
Other	*2.51*	*2.94*	*3.03*	*2.68*	*3.66* [c]	*5.76*	*6.32*
Import share of product supplied (percent)	**53.80**	**62.60**	**66.40**	**56.90**	**63.60**	**62.80**	**66.00**
				2020			
World oil price (2002 dollars per barrel)	**23.68**	**26.02**	**16.98**	**34.63**	**25.68**	**18.16**	**NA**
Crude oil and NGL production	**7.50**	**7.43**	**6.76**	**8.06**	**7.75**	**6.05**	**NA**
Crude oil	*5.63*	*4.95*	*4.51*	*5.48*	*5.36*	*4.20*	*NA*
Natural gas liquids	*1.88*	*2.48*	*2.25*	*2.58*	*2.39*	*1.85*	*NA*
Total net imports	**10.54**	**17.49**	**20.33**	**14.62**	**17.94**	**18.28**	**NA**
Crude oil	*9.13*	*14.50*	*16.40*	*12.77*	*11.29*	*NA*	*NA*
Petroleum products	*1.41*	*2.99*	*3.93*	*1.85*	*6.65*	*NA*	*NA*
Petroleum demand	**19.61**	**26.41**	**28.66**	**24.26**	**26.99**	**25.99**	**NA**
Motor gasoline	*8.86*	*12.30*	*12.92*	*10.96*	*12.20*	*11.57*	*NA*
Jet fuel	*1.61*	*2.27*	*2.27*	*2.19*	*2.80*	*2.16*	*NA*
Distillate fuel	*3.68*	*5.24*	*6.33*	*5.00*	*4.80*	*5.12*	*NA*
Residual fuel	*0.74*	*0.77*	*1.00*	*0.63*	*0.45*	*0.89*	*NA*
Kerosene	*0.04*	*0.07*	*0.07*	*0.07*	*0.04*	*NA*	*NA*
Liquefied petroleum gas	*2.17*	*2.64*	*2.74*	*2.56*	*2.53*	*NA*	*NA*
Other	*2.51*	*3.12*	*3.33*	*2.85*	*4.18* [c]	*6.26*	*NA*
Import share of product supplied (percent)	**53.80**	**66.20**	**70.90**	**60.30**	**66.50**	**70.30**	**NA**
				2025			
World oil price (2002 dollars per barrel)	**23.68**	**27.00**	**16.98**	**35.03**	**27.06**	**18.26**	**NA**
Crude oil and NGL production	**7.50**	**7.08**	**6.25**	**7.41**	**7.69**	**5.01**	**NA**
Crude oil	*5.63*	*4.61*	*4.02*	*4.85*	*5.24*	*3.25*	*NA*
Natural gas liquids	*1.88*	*2.47*	*2.24*	*2.55*	*2.46*	*1.76*	*NA*
Total net imports	**10.54**	**19.68**	**23.28**	**16.56**	**19.94**	**21.32**	**NA**
Crude oil	*9.13*	*15.74*	*18.21*	*14.34*	*11.87*	*NA*	*NA*
Petroleum products	*1.41*	*3.94*	*5.07*	*2.22*	*8.07*	*NA*	*NA*
Petroleum demand	**19.61**	**28.30**	**31.20**	**25.63**	**28.96**	**28.07**	**NA**
Motor gasoline	*8.86*	*13.30*	*14.12*	*11.53*	*12.86*	*12.46*	*NA*
Jet fuel	*1.61*	*2.37*	*2.40*	*2.27*	*3.16*	*2.35*	*NA*
Distillate fuel	*3.68*	*5.71*	*7.11*	*5.41*	*5.02*	*5.51*	*NA*
Residual fuel	*0.74*	*0.75*	*1.02*	*0.64*	*0.45*	*0.93*	*NA*
Kerosene	*0.04*	*0.07*	*0.07*	*0.06*	*0.04*	*NA*	*NA*
Liquefied petroleum gas	*2.17*	*2.79*	*2.91*	*2.68*	*2.62*	*NA*	*NA*
Other	*2.51*	*3.30*	*3.58*	*3.05*	*4.81* [c]	*6.82*	*NA*
Import share of product supplied (percent)	**53.80**	**69.50**	**74.60**	**64.60**	**68.90**	**75.90**	**NA**

NA = Not available.

Notes: [a]WTI at Cushing, Oklahoma. [b]Includes kerosene. [c]GII "other" petroleum demand total does not include kerosene, which is reported separately in GII's forecast.

Sources: ***AEO2004:*** AEO2004 National Energy Modeling System, runs AEO2004.D101703E (reference case), LW2004.D101703B (low world oil price case), and HW2004.D101703B (high world oil price case). **GII:** Global Insight, Inc., *Spring/Summer 2003 U.S. Energy Outlook* (July 2003). **DB:** Deutsche Bank AG, "World Oil Supply and Demand Estimates," e-mail from Adam Sieminski, November 3, 2003. **PIRA:** PIRA Energy Group (October 2003).

$24.08 per barrel, DB at $18.41 per barrel, and PIRA at $26.70 per barrel. PIRA's higher projection, however, does not compare directly with the other forecasts, because its pricing point (West Texas Intermediate at Cushing, Oklahoma) differs from those in the other forecasts (refiners' acquisition cost of imported crude oil) and tends to be higher.

The *AEO2004* reference case and GII price projections for 2020 and 2025 are also in a similar range, with the DB projections being significantly lower. The PIRA oil price forecast extends only to 2015. The *AEO2004* reference case and GII projections for 2025 are almost identical, but DB's projection is nearly $4.00 per barrel lower. The DB price forecast is more in line with the *AEO2004* low price case forecast of $16.98 per barrel throughout the forecast period. DB's oil price projections follow from the lower expected product demand than in the *AEO2004* reference case, especially for gasoline. GII's oil price projections follow from lower crude oil costs.

The *AEO2004* reference case and GII project domestic crude oil and natural gas liquids (NGL) production of about 7.8 million barrels per day in 2015. All other forecasts, except the *AEO2004* high world oil price case, are more pessimistic about U.S. production in 2015. DB and PIRA are below even the *AEO2004* low world oil price case, by 10,000 barrels per day and 560,000 barrels per day, respectively.

GII is more optimistic about domestic crude oil and NGL production in 2025 than are DB and *AEO2004*. GII's projection is 280,000 barrels per day above the *AEO2004* high world oil price case. DB is at the opposite end of the spectrum, projecting production at 1.24 million barrels per day below the *AEO2004* low world oil price case and 2.40 million barrels per day below the *AEO2004* high world oil price case.

All the forecasts project that imports will meet more than one-half of expected petroleum product demand in 2015. Both the *AEO2004* reference case and PIRA project net imports of crude oil and petroleum products at 15.52 million barrels per day in 2015. GII's projection is 370,000 barrels per day higher than those two forecasts, and DB's projection is 410,000 barrels per day lower. When imports are considered as a percentage of demand, a slightly different pattern emerges. Although DB's projected quantity of imports is below the *AEO2004* reference case, its import share of product supplied is slightly higher (0.2 percent), because DB projects lower overall product demand in 2015. The *AEO2004* high world oil price and low world oil price cases project the lowest and highest import shares, respectively.

The forecasts project that imports will be needed to meet approximately two-thirds or more of product demand in 2025. GII projects 260,000 barrels per day more and DB projects 1.64 million barrels per day more than the *AEO2004* reference case projection. In 2025, GII projects a higher volume of both imports and product demand than the *AEO2004* reference case, with a lower share of imports needed to meet product demand. The *AEO2004* high world oil price case projects the lowest share of imports in 2025, at 64.6 percent, and DB projects the highest share at 75.9 percent (1.3 percent above the *AEO2004* low world oil price case).

GII expects slower expansion of domestic refinery capacity than do the other forecasts and, therefore, projects larger quantities of petroleum product imports and correspondingly lower crude oil imports. GII projects petroleum product imports 2.15 million barrels per day above the *AEO2004* low world oil price case projection of 3.03 million barrels per day in 2015, and 3.00 million barrels per day above the *AEO2004* low world oil price case of 5.07 million barrels per day in 2025.

GII projects higher levels of total petroleum demand in 2015, 2020, and 2025 than the *AEO2004* reference case and a different product slate, with higher levels of jet fuel demand and lower levels of demand for gasoline, distillate, and residual fuel. GII expects more growth in air travel than do the other forecasts. While the DB forecast generally projects lower levels of petroleum demand in total and by product than do the *AEO2004* and GII forecasts, it includes higher levels of demand for residual fuel oil in 2015, 2020, and 2025. The *AEO2004* low world oil price case projects the highest amounts of gasoline, distillate, and residual fuel demand in 2015, 2020, and 2025. PIRA projects the lowest level of gasoline demand in 2015, 550,000 barrels per day below the *AEO2004* high world oil price case. The *AEO2004* high world oil price case projects the lowest level of gasoline demand in 2025.

Coal

The unknown factors affecting the future of the coal industry, including the continued uncertainty of pending environmental regulations, are evident when the *AEO2004* forecast is compared against those of

Table 33. Comparison of coal forecasts, 2015, 2020, and 2025 (million short tons, except where noted)

Projection	2002	AEO2004			Other forecasts	
		Reference	Low economic growth	High economic growth	EVA	Hill & Associates
				2015		
Production	**1,105**	**1,285**	**1,262**	**1,288**	**1,114**	**1,204**
Consumption by sector						
Electricity generation	976	1,200	1,180	1,200	1,042	1,144
Coking plants	23	21	21	21	18	18
Industrial/other	67	70	67	73	60	62
Total	**1,066**	**1,291**	**1,269**	**1,295**	**1,120**	**1,224**
Net coal exports	**22.7**	**-6.1**	**-6.1**	**-6.1**	**-6.2**	**-20.4**
Exports	39.6	31.6	31.6	31.6	29.5	28.4
Imports	16.9	37.7	37.7	37.7	35.7	48.8
Minemouth price						
(2002 dollars per short ton)	17.90	16.47	15.84	16.75	17.02 [a]	17.78 [b,c]
(2002 dollars per million Btu)	0.87	0.81	0.78	0.82	0.83 [a]	0.81 [b,c]
Average delivered price to electricity generators						
(2002 dollars per short ton)	25.96	24.34	23.17	25.10	NA	21.82 [c]
(2002 dollars per million Btu)	1.26	1.22	1.16	1.25	NA	1.08 [c]
				2020		
Production	**1,105**	**1,377**	**1,337**	**1,382**	**1,159**	**1,208**
Consumption by sector						
Electricity generation	976	1,301	1,263	1,305	1,095	1,158
Coking plants	23	19	19	19	17	17
Industrial/other	67	71	68	75	57	59
Total	**1,066**	**1,391**	**1,349**	**1,399**	**1,169**	**1,234**
Net coal exports	**22.7**	**-14.4**	**-12.2**	**-15.7**	**-10.4**	**-25.6**
Exports	39.6	27.4	29.5	26.0	29.7	22.6
Imports	16.9	41.7	41.7	41.7	40.1	48.2
Minemouth price						
(2002 dollars per short ton)	17.90	16.32	15.78	16.92	16.91 [a]	16.94 [b,c]
(2002 dollars per million Btu)	0.87	0.80	0.78	0.83	0.83 [a]	0.77 [b,c]
Average delivered price to electricity generators						
(2002 dollars per short ton)	25.96	24.01	22.87	25.03	NA	21.08 [c]
(2002 dollars per million Btu)	1.26	1.20	1.15	1.24	NA	1.04 [c]
				2025		
Production	**1,105**	**1,543**	**1,420**	**1,586**	**1,237**	**NA**
Consumption by sector						
Electricity generation	976	1,477	1,355	1,510	1,184	NA
Coking plants	23	17	17	17	16	NA
Industrial/other	67	72	68	84	55	NA
Total	**1,066**	**1,567**	**1,441**	**1,612**	**1,254**	**NA**
Net coal exports	**22.7**	**-22.7**	**-19.8**	**-24.8**	**-17.8**	**NA**
Exports	39.6	23.0	26.0	21.0	30.0	NA
Imports	16.9	45.7	45.7	45.7	47.8	NA
Minemouth price						
(2002 dollars per short ton)	17.90	16.57	15.67	17.95	16.97 [a]	NA
(2002 dollars per million Btu)	0.87	0.82	0.78	0.88	0.84 [a]	NA
Average delivered price to electricity generators						
(2002 dollars per short ton)	25.96	24.31	22.75	26.29	NA	NA
(2002 dollars per million Btu)	1.26	1.22	1.14	1.30	NA	NA

[a]The average coal price is a weighted average of the projected spot market FOB mine price for all domestic coal.
[b]The minemouth price represents an average for domestic steam coal only. Exports and coking coal are not included in the average.
[c]The prices provided by Hill & Associates were converted from 2003 dollars to 2002 dollars in order to be consistent with *AEO2004*.
Btu = British thermal unit. NA = Not available.

Sources: ***AEO2004:*** AEO2004 National Energy Modeling System, runs AEO2004.D101703E (reference case), LM2004.D101703A (low economic growth case), and HM2004.D101703A (high economic growth case). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (July 2003). **Hill & Associates:** Hill & Associates, Inc., *The Outlook for U.S. Steam Coal: Long-Term Forecast to 2022* (August 2003).

EVA and Hill & Associates, Inc. The *AEO2004* reference case does not anticipate when and how new environmental requirements may take effect, whereas the other forecasts may represent such assumptions. For instance, although *AEO2004* does represent the provisions of the State implementation plan (SIP) call for 19 States where NO_x caps have been finalized, it does not include revised limits on emissions of particulates, because no specific plan is yet in place. Hill & Associates assumes a 21-State SIP call in effect by 2005 and also assumes further reductions of allowable SO_2 levels—4.35 million tons by 2010—in accordance with expectations of future restrictions on particulate emissions. EVA assumes that legislation similar to Clear Skies (including further restrictions on SO_2, NO_x, and mercury) will be in effect by 2010. EVA's forecast also includes a $5 per ton fee on carbon dioxide emissions beginning in 2013. Neither Hill & Associates nor *AEO2004* represents mercury or carbon dioxide reductions in its reference case.

Given the more restrictive assumptions of the EVA forecast, it is not surprising that *AEO2004* projects higher coal consumption levels than EVA in 2015, 2020, and 2025. *AEO2004* also projects higher coal consumption levels than Hill & Associates, which may be explained partly by Hill & Associate's assumption of additional restrictions on SO_2 emissions. *AEO2004* and EVA show an increase in coal production and consumption from 2002 to 2025, whereas the Hill & Associates forecast remains fairly flat through 2020 (and does not extend to 2025).

The *AEO2004* reference case projects a decline in real coal prices from 2002 to 2015 and 2020, followed by a small increase from 2020 to 2025 (Table 33). Hill & Associates projects average minemouth prices—excluding coking coal and exports—that are roughly the same as projected in the *AEO2004* reference case in 2015 and 3 cents per million Btu lower in 2020. The slightly higher minemouth prices projected in *AEO2004*, relative to Hill & Associates, may be due in part to the higher production levels projected in *AEO2004*. The EVA forecast of national average minemouth prices, lower than the 2002 minemouth price, varies little between 2015 and 2020 and increases by less than 1 percent (based on short tons) from 2020 to 2025.

As western production makes further inroads into markets traditionally served by eastern coal, the average heat content of the coals produced and consumed will drop as well, reflecting the lower thermal content per ton of western coals. The *AEO2004* and EVA forecasts indicate similar average heat contents (calculated by dividing dollars per ton by dollars per million Btu). The average heat content of coal production in the EVA forecast is roughly 20.6, 20.4, and 20.3 million Btu per ton in 2015, 2020, and 2025, respectively, compared the *AEO2004* reference case projections of 20.3, 20.3, and 20.2 million Btu per ton. Those similarities suggest comparable shares of western production in the two forecasts. In contrast, the average heat content associated with coal production in the Hill & Associates projections for 2015 and 2020 is about 22 million Btu per ton, indicating a relatively larger share of eastern production.

Gross exports of coal represent a small and declining part of domestic coal production. In *AEO2004*, their share of total production is expected to fall from 4 percent in 2002 to roughly 2 percent in 2020 and 1 percent in 2025. Currently, coal is the only domestic energy resource for which exports still exceed imports. All the forecasts project that this will change, and that the United States eventually will import more coal than it exports. Hill & Associates projects the fastest rate of increase in net coal imports, with 20.4 million tons more coal imported than exported in 2015. Both EVA and *AEO2004* project similar levels of net imports in 2025, at 17.8 and 22.7 million tons, respectively. Strong price competition from other exporters and the loss of markets as Europe moves away from coal for environmental reasons are among the causes for the long-term decline in export projections.

The coal forecasts reviewed reflect the uncertainties facing the U.S. coal industry as it simultaneously adapts to the financial pressures arising from increasing environmental restrictions on coal use (both here and in Europe), restructuring of the U.S. electricity generation industry, and increasing competition from the relatively unexploited coalfields of international competitors.

List of Acronyms

ABWR	Advanced Boiling Water Reactor
AD	Associated-dissolved (natural gas)
AECL	Atomic Energy Canada Limited
AEO2003	*Annual Energy Outlook 2003*
AEO2004	*Annual Energy Outlook 2004*
ALAPCO	Association of Local Air Pollution Control Officials
AMT	Alternative Minimum Tax
ANWR	Arctic National Wildlife Refuge
AP1000	Advanced Pressurized Water Reactor
ARI	Advanced Resources International
AT-PZEV	Advanced technology partial zero-emission vehicle
BLS	Bureau of Labor Statistics
BNFL	British Nuclear Fuels Limited plc
Btu	British thermal unit
CAAA90	Clean Air Act Amendments of 1990
CAFE	Corporate average fuel economy
CARB	California Air Resources Board
CBO	Congressional Budget Office
CCAP	Climate Change Action Plan
CGES	Centre for Global Energy Studies
CHP	Combined heat and power
CO_2	Carbon dioxide
DB	Deutsche Bank A.G.
DES	Department of Environmental Services (New Hampshire)
E85	Fuel containing a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume
EEA	Energy and Environmental Analysis, Inc.
EFSEC	Energy Facility Site Evaluation Council (Washington State)
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPACT	Energy Policy Act of 1992
EPACT03	Energy Policy Act of 2003
EPCA	Energy Policy and Conservation Act
FERC	Federal Energy Regulatory Commission
GE	General Electric
GDP	Gross domestic product
GII	Global Insight, Incorporated
HAP	Hazardous air pollutant
IEA	International Energy Agency
ITC	Investment Tax Credit
LEV	Low-emission vehicle
LEVP	Low Emission Vehicle Program
LIHEAP	Low Income Home Energy Assistance Program
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MACT	Maximum Achievable Control Technology
MFP	Multifactor productivity
MIT	Massachusetts Institute of technology
MMS	Minerals Management Service
MTBE	Methyl tertiary butyl ether
NA	Nonassociated (natural gas)
NAICS	North American Industry Classification System
NAAQS	National Ambient Air Quality Standards
NBP	NO_x budget program
NEB	Canadian National Energy Board
NEMS	National Energy Modeling System
NGL	Natural gas liquids
NHTSA	National Highway Traffic Safety Administration
NO_x	Nitrogen oxides
NPC	National Petroleum Council
NPR-A	National Petroleum Reserve-Alaska
NRC	U.S. Nuclear Regulatory Commission
NRCan	Natural Resources Canada
NSR	New source review
OBD	On-board diagnostics
OEF	Oxford Economic Forecasting
OMB	Office of Management and Budget
OPEC	Organization of Petroleum Exporting Countries
PEL	Petroleum Economics, Ltd.
PIRA	Petroleum Industry Research Associates, Inc.
PM	Particulate matter
ppm	Parts per million
PSD/NSR	Prevention of Significant Deterioration/ New Source Review
PSEG	Public Service Enterprise Group Fossil, LLC
PSNH	Public Service of New Hampshire
PTC	Renewable Electricity Production Tax Credit
PUHCA	Public Utility Holding Company Act of 1935
PURPA	Public Utility Regulatory Policies Act of 1978
PZEV	Partial zero-emission vehicle
RFG	Reformulated gasoline
RMRR	Routine maintenance, repair and replacement
RPS	Renewable portfolio standard
SCR	Selective catalytic reduction
SEER	Strategic Energy & Economic Research, Inc.
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SNCR	Selective noncatalytic reduction
SO_2	Sulfur dioxide
STAPPA	State and Territorial Air Pollution Program Administrators
SULEV	Super-ultra-low-emission vehicles
TVA	Tennessee Valley Authority
ULEV	Ultra-low-emission vehicle
ULSD	Ultra-low-sulfur diesel
USGS	United States Geological Survey
VOC	Volatile organic compound
ZEV	Zero-emission vehicle

Notes and Sources

Text Notes

Legislation and Regulations

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

[*2*]For more information on the Environmental Protection Agency's implementation of the fine particulate standard see http://www.epa.gov/airlinks/pm25_desig_guidance_final.pdf.

[*3*]For more information on the Environmental Protection Agency's implementation of the mercury emissions reduction see http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.html#REG.

[*4*]The Minerals Management Service (MMS) is the federal agency in the U.S. Department of the Interior that manages the nation's oil, natural gas, and other mineral resources on the outer continental shelf (OCS) in federal offshore waters. The agency also collects, accounts for, and disburses mineral revenues from Federal and American Indian leases, including royalty payments for oil and gas production from the OCS.

[*5*]A play is a set of known or postulated oil and (or) gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, trapping mechanism, and hydrocarbon type.

[*6*]The open season is a period when all parties are given equal consideration. Also, when a company becomes an open access transporter, it is generally expected to have an "open season" to accept bids for transportation. During that time, all shippers are treated equally in the queue for service, with space divided on a *pro rata* basis. When the open season is over, shippers are generally treated on a first come first served basis.

[*7*]The complete regulations are available in "Regulations of Connecticut State Agencies, Title 22a, Section 22a-174-1 to 22a-174-200," at web site www.dep.state.ct.us/air2/regs/mainregs.htm.

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[*12*]Emission Control Plans," web site www.state.ma.us/dep/bwp/daqc/daqcpubs.htm.

[*13*]B.G. Rabe, "Greenhouse and Statehouse: The Evolving State Government Role in Climate Change" (Pew Center on Global Climate Change, November 2002), web site www.pewclimate.org.

[*14*]Web site www.state.ma.us/dep/bwp/daqc/daqcpubs.htm#regs.

[*15*]"Multiple Pollutant and Annual Budget Trading and Banking Program," Chapter Env-A2900, web site www.des.state.nh.us/ard/ardrules.htm.

[*16*]D. Andzelm, "The New Hampshire Clean Power Strategy: A Review," *Alberta Environment* (June 25, 2002), web site www3.gov.ab.ca/env/air/emissions_trading/.

[*17*]B.G. Rabe, "Greenhouse and Statehouse: The Evolving State Government Role in Climate Change" (Pew Center on Global Climate Change, November 2002), web site www.pewclimate.org.

[*18*]U.S. Environmental Protection Agency, Office of Regulatory Enforcement Division, EPA Region 2 Air Compliance Branch, "PSEG Fossil LLC Civil Judicial Settlement Fact Sheet" (January 2002), web site http://cfpub.epa.gov/compliance/resources/cases/civil/.

[*19*]See web site www.dec.state.ny.us/website/dar/adopted.html.

[*20*]U.S. Environmental Protection Agency, web site www.epa.gov/oar/oaq_caa.html.

[*21*]State and Territorial Air Pollution Program Administrators (STAPPA) and the Association of Local Air Pollution Control Officials (ALAPCO), "Comparison of State Multi-Pollutant Strategies for Power Plants" (provided by Amy Royden, April 2003).

[*22*]North Carolina Department of Environment and Natural Resources, *Mercury Emissions and Mercury Controls for Coal-fired Electric Utility Boilers* (September 2003), web site http://daq.state.nc.us/news/leg/Mercury1_912003.pdf.

[*23*]North Carolina Department of Environment and Natural Resources, *CO_2 Emission Reduction Options for Coal-fired Electric Utility Boilers and Other Stationary Sources* (September 2003), web site http://daq.state.nc.us/news/leg/CO2_912003.pdf.

[*24*]North Carolina Department of Environment and Natural Resources and the North Carolina Utilities Commission, *Implementation of the "Clean Smokestacks Act"* (May 30, 2003), web site www.ncuc.commerce.state.nc.us/.

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[*26*]S. Sadler, "Oregon Carbon Dioxide Emission Standards for New Energy Facilities," Oregon Office of Energy, Oregon Energy Facility Siting Council, Rule Division 24, OAR 345-024-0500 (1997), web sites www.energy.state.or.us and www.climatetrust.org.

[*27*]Assuming a plant heat rate of 10,000 Btu per kilowatthour and a CO_2 emission factor of 25.50 kg carbon per million Btu.

[*28*]See 40 CFR Parts 51 and 52, [FRL-7414-6; RIN 2060-AK28; Electronic Docket OAR-2002-0068; Legacy Docket A-2002-04], Prevention of Significant Deterioration (PSD) and Non-attainment New Source Review (NSR): Equipment Replacement Provision of the Routine Maintenance, Repair and Replacement Exclusion, at web site www.epa.gov/air/nsr-review/ERP_merged_8-27bh.pdf.

[*29*]See 40 CFR Parts 51 and 52, [FRL-7414-6; RIN 2060-AK28; Electronic Docket OAR-2002-0068; Legacy Docket A-2002-04], "Prevention of Significant Deterioration (PSD) and Non-attainment New Source Review (NSR): Equipment Replacement Provision of the Routine Maintenance, Repair and Replacement Exclusion," web site www.epa.gov/air/nsr-review/ERP_merged_8-27bh.pdf.

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Issues in Focus

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[*45*]The following basins (study areas) were reassessed by the USGS as part of a Federal interagency study of access restrictions in the Rocky Mountains: the Paradox/San Juan, the Uinta/Piceance, the Greater Green River, the Powder River, and the Montana Thrust Belt. The study, *Scientific Inventory of Onshore Federal Land's Oil and Gas Resources and Reserves and the Extent and Nature of Restrictions or Impediments to Their Development* (January 2003), was conducted under the authority of the Energy Policy and Conservation Act (EPCA).

[*46*]EIA, based on resource allocation parameters developed by Advanced Resources International from results of the study, *Scientific Inventory of Onshore Federal Land's Oil and Gas Resources and Reserves and the Extent and Nature of Restrictions or Impediments to Their Development*.

[*47*]The United States has been exporting LNG to Japan for more than 30 years, from a liquefaction plant in Kenai, Alaska, with a capacity of 68 billion cubic feet per year. The volume exported in 2002 was 63 billion cubic feet.

[*48*]EIA uses NEB projections as the major basis for estimating Canadian natural gas production. NEB's 1999 forecast was published in *Canadian Energy Supply and Demand to 2025*. Its 2003 projections were published in *Canada's Energy Future, Scenarios for Supply and Demand to 2025*. NPC's 1999 projections were published in *Natural Gas, Meeting the Challenges of the Nation's Growing Natural Gas Demand*. Its 2003 forecast was published in *Balancing Natural Gas Policy—Fueling the Demands of a Growing Economy*,Volume I, Summary of Findings and Recommendations.

[*49*]In situ bitumen production is accomplished through the injection of steam into the underground reservoir, which drives the bitumen to the production wells. Surface-mined bitumen uses the same mining techniques as are used for surfaced-mined coal.

[*50*]Examples of the first view (permanent loss) include Cambridge Economic Research Associates, *North American Natural Gas Watch*, "Pricing at Scarcity" (Spring 2003); and Charles River Associates, *The Potential for*

Natural Gas Demand Destruction, presentation to the Canadian Gas Association Annual Executive Conference (June 27, 2003), web site www.wdysevents.com/registrations/directpapers.asp?event=angm03web&paper=partridge. Examples of the opposite view include J.M. Dukert, "What Do Natural Gas Numbers Show? . . . Surprise!," *Dialogue*, Newsletter of the United States Association for Energy Economics, Vol. 11, No. 2 (July 2003), pp. 30-32; and R.S. Linden, "Is It Real or Is It Hype?," *Public Utilities Fortnightly* (August 2003), pp. 32-37.

[*51*]The most recently reported industrial-sector consumption data are for 1998. See Energy Information Administration, *Manufacturing Consumption of Energy 1998*, web site www.eia.doe.gov/emeu/mecs/mecs98/datatables/contents.html.

[*52*]Data provided by The Fertilizer Institute. Note that the nitrogenous fertilizer industry produces ammonia, which contains 82 percent nitrogen. Nitrogen is the nutrient that is used in fertilizer applications.

[*53*]The average fertilizer application for corn (the most fertilizer-intensive crop) was 137 pounds per acre during the 2002 crop year. That application rate implies that the embodied cost of energy in fertilizer was about $8.19 per acre during the 1990s. In 2003, the estimated embodied cost of energy increases to $12.85 per acre. In 2002, each acre produced an average of 130 bushels of corn.

[*54*]U.S. General Accounting Office, *Natural Gas: Domestic Nitrogen Fertilizer Production Depends on Natural Gas Price Availability and Prices* (September 2003), p. 6.

[*55*]The nitrogenous fertilizer industry reported that no petroleum was used as a feedstock in 1998. Calculated from Energy Information Administration, *Manufacturing Consumption of Energy 1998*, web site www.eia.doe.gov/emeu/mecs/mecs98/datatables/contents.html.

[*56*]The values reported are for Nitrogenous Fertilizer Manufacturer, NAICS Code 325311. The most recently reported data are for 1998. Values for additional years are NEMS projections. See Energy Information Administration, *Manufacturing Consumption of Energy 1998*, web site www.eia.doe.gov/emeu/mecs/mecs98/datatables/contents.html.

[*57*]Energy Information Administration, *Manufacturing Consumption of Energy 1994*, DOE/EIA-0512(94) (Washington, DC, December 1997), Table A59.

[*58*]U.S. Geological Survey, *Minerals Yearbook*, "Nitrogen," various issues.

[*59*]U.S. Geological Survey, *Mineral Commodity Summaries*, "Nitrogen (Fixed) Ammonia" (January 2003), p. 118.

[*60*]Farmland Industries, "Farmland Files for Protection Under Chapter 11," News Release (May 31, 2002).

[*61*]The NEMS model does not further disaggregate agricul tural chemicals (NAICS Code 32531) into its industrial segments; consequently, the agricultural chemicals industry is used as a proxy for the nitrogenous fertilizer industry (NAICS Code 325311). Over the 1997-2001 period, agricultural chemicals and nitrogenous fertilizer experienced similar growth rates (falling by 6 percent and 5 percent, respectively, per year). Nitrogenous fertilizer accounted for about 15 percent of the value of shipments in agricultural chemicals. Calculated from data in U.S. Census Bureau, *Annual Survey of Manufactures, Statistics for Industry Groups and Industries: 2001* (Washington, DC, January 2003).

[*62*]The calculations assume 33 percent efficiency (heat rate of 10,339) for an older gas-fired steam plant and 45 percent efficiency (heat rate of 7,582) for a new gas-fired combined-cycle plant.

[*63*]National Petroleum Council, *Balancing Natural Gas Policy—Fueling the Demands of a Growing Economy*,Volume I, Summary of Findings and Recommendations (Washington, DC, September 2003), web site www.npc.org/NG_Volume_1.pdf.

[*64*]The *AEO2004* and NPC accounting methods for the industrial and electric power sectors differ. For comparison, the *AEO2004* industrial and electric power sector projections have been adjusted to be consistent with the NPC accounting methodology.

[*65*]The Henry Hub spot price and the average wellhead price for natural gas are not equivalent measures. The difference between Henry Hub and wellhead gas prices fluctuates over time, and the Henry Hub price can exceed the average wellhead price by as little as a few cents per million Btu or as much as 70 cents per million Btu.

[*66*]Although the *AEO2004* and NPC gas resource base assumptions are different, a smaller NPC gas resource base does not necessarily imply a more expensive exploration and production cost profile. The NPC gas resource exploration and production cost profile is not available, so a direct comparison with the *AEO2004* resource base is not possible.

[*67*]The NPC modeling framework projects monthly gas consumption and supply, including gas injections and withdrawals from gas storage fields. Consequently, the NPC model in any particular year can project a net gas storage injection, which is accounted for as gas consumption, or a net gas storage withdrawal, which is accounted for as gas supply. The *AEO2004* modeling framework projects annual gas consumption and supply and assumes that gas storage injections and withdrawals exactly counterbalance over the course of a year.

[*68*]The NPC scenarios use a 2002 net gas import figure of 3.6 trillion cubic feet, compared with 3.5 trillion cubic feet in *AEO2004*.

[*69*]The Balanced Future scenario also recategorizes 28 trillion cubic feet of 58 trillion cubic feet of high cost, long-lead-time onshore gas resources in the Rocky Mountains as being fully accessible at the average cost and development delay.

[*70*]The *AEO2004* and NPC scenarios use somewhat different definitions for "unconventional gas." *AEO2004* includes all natural gas contained in sandstone reservoirs with permeability less than 0.1 millidarcies; the NPC definition includes such reservoirs only if they are "continuous basin-centered" deposits. In this discussion, however, the NPC unconventional gas production numbers conform with the *AEO2004* definition.

[*71*]See H. Burness, W.D. Montgomery, and J. Quirk, "The Turnkey Era in Nuclear Power," *Land Economics*, Vol. 56 (May 1980), pp. 188-202.

[*72*] Energy Information Administration, *An Analysis of Nuclear Power Plant Construction Costs*, DOE/EIA-0485 (Washington, DC, March 1986).

[*73*]See, for example, Energy Information Administration, *An Analysis of Nuclear Power Plant Construction Costs*,

DOE/EIA-0485 (Washington, DC, March 1986), Appendix B.

[*74*]U.S. Department of Energy, Office of Nuclear Energy, Science, and Technology, *A Roadmap to Deploy New Nuclear Power Plants in the United States by 2010* (Washington, DC, October 2001), Vol. 2. GE is also designing a newer BWR, the ESBWR, which is simpler and has more passive safety features than the ABWR. A cost estimate for the ESBWR has not yet been prepared.

[*75*]All the operating reactors in the United States use light water as a moderator. With the exception of the United Kingdom's gas-cooled reactors and CANDU units, the same is generally true in Europe and Asia. Both the ABWR and AP1000 are light-water reactors.

[*76*]The ACR-700 has never been built.

[*77*]In general, the information about the cost of foreign nuclear power plants is not as good as the U.S. data. The realized overnight costs for foreign units that entered commercial operation in the 1980s tended to range in the mid-$2,000s per kilowatt. There is also some evidence of growth in foreign nuclear power capital costs. See G. McKerron, "Why Do Nuclear Power Plant Construction Costs Continue To Increase?," *Energy Policy* (July 1992). It must be noted that this research is somewhat controversial. Additionally, recent experience suggests that costs of building nuclear power plants in Asia are falling.

[*78*]See, for example, *The Future of Nuclear Power* (Massachusetts Institute of Technology, August 2003).

[*79*]There are a number of pressurized light-water reactors (PWRs) either operating or under construction in South Korea that are improvements on existing PWRs and thus could be considered advanced—the System 80+ reactors manufactured by BNFL (Westinghouse). However, the vendor has chosen not to market those reactors in the United States but instead to focus on the AP1000. Therefore, they are not considered here. See U.S. Department of Energy, Office of Nuclear Energy, Science, and Technology, *A Roadmap to Deploy New Nuclear Power Plants in the United States by 2010* (Washington, DC, October 2001), Vol. 1, p. 21.

[*80*] There are a number of problems with "transferring" foreign costs and experience to the United States. The most obvious is the use of exchange rates, which may distort the underling cost differences. The firm that supplied the cost data to EIA used a Purchasing Power Parity Index, instead of official exchange rates, which corrects for some (but not all) problems with currency conversions. Additionally, some have argued that because of practices that are unique to Asia, the cost of building the same plant in the United States would be less than in Asia. For example, some have argued that payments to residents surrounding plants in Asia are included in the construction costs, and because such payments would not be made in the United States, the cost of building the same plant in the United States would be less than in Asia. Thus, $2,060 per kilowatt, which was used as the starting point in the calculations, is actually less than the realized costs of the two operating advanced plants. The exact amount of the cost reduction cannot be made public because of proprietary agreements with the firm supplying the cost information.

[*81*]Exclusive of contingencies, the estimated nuclear construction cost is about $1,650 per kilowatt. EIA uses a project contingency of 10 percent and a "technological optimism factor" of 5 percent.

[*82*]The AP1000 estimates were obtained from U.S. Department of Energy, Office of Nuclear Energy, Science, and Technology, *A Roadmap to Deploy New Nuclear Power Plants in the United States by 2010* (Washington, DC, October 2001), Vol. 2, Chapter 4, Table II. The direct overnight construction costs for the CANDU reactor were obtained from "New Fuel for the CANDU-And a New CANDU, Too!," *Nukem Market Report* (June 2002), web site www.aecl.ca/images/up-NUKEMJune2002.pdf. The first-of-a-kind costs were estimated by EIA. EIA also examined a case in which nuclear capital costs were reduced by 10 percent. Becuase the case did not result in the construction of any new nuclear units, the results are not presented.

[*83*]The vendor's estimate of the cost (inclusive of contingency) of the third-of-a-kind twin-unit AP1000 is about $1,066 per kilowatt.

[*84*]Energy Information Administration, *Derivatives and Risk Management in the Petroleum, Natural Gas, and Electricity Industries*, SR/SMG/2002-01 (Washington, DC, October 2002).

[*85*]The rate was later raised to 15 percent by the Crude Oil Windfall Profits Act of 1980, which extended the credit to December 31, 1985, when it was allowed to lapse for wind.

[*86*]Dollars are expressed in year 2002 values, except as otherwise noted.

[*87*]See IRS Form 8835, *Renewable Electricity Production Credit* for the year 2002, web site www.irs.gov/pub/irs-pdf/f8835.pdf.

[*88*]Interstate Renewable Energy Council, *Minnesota Renewable Energy Incentives* (September 22, 2003), database of State incentives for renewable energy, web site www.dsire.org. Note that 425 megawatts, the original mandated term in 1994, has subsequently been extended to 825 megawatts by 2006 and 1,125 by 2010.

[*89*]Tax Relief Extension Act of 1999, Public Law 106-170.

[*90*]EIA's *Annual Energy Review 2002*, Table 8.7a, indicates 1,487 megawatts of net installations in 2001 for plants over 10 megawatts. See web site www.eia.doe.gov/emeu/aer/elect.html. The American Wind Energy Association estimates 1,697 megawatts of installations of all sizes in 2001. See web site www.awea.org/faq/instcap.html.

[*91*]Job Creation and Worker Assistance Act of 2002, Public Law 107-147.

[*92*]Wind power facilities also receive a 5-year accelerated depreciation allowance.

[*93*]For further discussion of cost and performance improvements, see C. Namovicz, "Modeling Wind and Intermittent Generation in the National Energy Modeling System (NEMS)," in American Wind Energy Association, *WindPower 2003 Conference Proceedings* (2003).

[*94*]Cost includes "busbar" costs plus transmission interconnection charge, but does not include additional grid services that may be required to facilitate integration of wind power. Excellent wind resources refer to sites in wind power Class 6 or better, as defined by the Pacific Northwest Laboratory as a site with an annual average wind speed at 50 meter hub height of 8.0 meters per second (17.9 miles per hour) or higher. See D.L. Elliot et al.,

Wind Energy Resource Atlas of the United States (Pacific Northwest Laboratory, March 1987), p. 3.

[*95*]Note that the levelized cost of both natural gas and coal plants depends on expected utilization rates. For comparison purposes, an 85-percent utilization rate is assumed for coal and 87 percent for combined cycle. Effective utilization rates (capacity factors) for current technology wind plants range from 33 to 40 percent, depending on quality of resource. The 40-percent capacity factor corresponds to the lowest levelized wind cost.

[*96*]The uncertainty of the expiration/extension cycle cannot be easily emulated within the current structure of the National Energy Modeling System.

[*97*]All dollars are year 2002 unless otherwise indicated. A 7-percent discount rate is used to evaluate time-series monetary calculations in accordance with OMB Circular A-94, *Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs*. See web site www.whitehouse.gov/omb/circulars/a094/a094.pdf.

[*98*]Cost for the construction of a simple wind plant on favorable land, excluding factors such as more difficult terrain, upgrading of existing transmission, or higher value land uses that would be increasingly encountered because better resources were already utilized.

[*99*]"President Announces Clear Skies & Global Climate Change Initiatives" (February 14, 2002), web site www.whitehouse.gov/news/releases/2002/02/20020214-5.html.

[*100*]U.S. Department of State, *U.S. Climate Action Report 2002* (Washington, DC, May 2002), Chapter 5, "Projected Greenhouse Gas Emissions," pp. 70-80, web site http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsUSClimateActionReport.html. Some adjustments have been made to the projections to reflect the most recent (2002) data published by EIA, as well as to estimate the intervening years of the projections, which were provided only for 5-year intervals in the State Department report. In addition, the projections were extrapolated to provide estimates through 2025.

Market Trends

[*101*]Energy-intensive industries include food, paper, bulk chemicals, petroleum refining, glass, cement, steel, and aluminum.

[*102*]The reference case represents EIA's current judgment regarding Organization of Petroleum Exporting Countries' (OPEC) expected behavior in the mid-term where production is adjusted to keep world oil prices in the $22 to $28 per barrel range. Since OPEC, particularly the Persian Gulf nations, is expected to be the dominant supplier of oil in the international market over the mid-term, the organization's production choices will significantly affect world oil prices. The low oil price scenario could result from a future market where all oil production becomes more competitive. The high price scenario could result from a more cohesive and market-assertive OPEC with lower production goals and other non-financial (geopolitical) considerations.

[*103*]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.

[*104*]The definition of the commercial sector for *AEO2004* is based on data from the 1999 Commercial Buildings Energy Consumption Survey (CBECS). See Energy Information Administration, 1999 CBECS Public Use Data Files (October 2002), web site www.eia.doe.gov/emeu/cbecs/. Nonsampling and sampling errors (found in any statistical sample survey) resulted in a higher commercial floorspace estimate than found with the 1995 CBECS. In addition, 1999 CBECS energy intensities varied from earlier estimates, providing a different composition of end-use consumption. These factors contribute to the pattern of commercial energy use projected for *AEO2004*. Further discussion is provided in Appendix G.

[*105*]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).

[*106*]Estimated as consumption of alternative transportation fuels in crude oil Btu equivalence. Alternative fuels include ethanol, electricity, hydrogen, natural gas, and propane.

[*107*]*Federal Register*, Volume 68, No. 66, Monday, April 7, 2003, pp.16868-16900.

[*108*]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.

[*109*]U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond*, ORNL/CON-444 (Washington, DC, September 1997); J. DeCicco et al, *Technical Options for Improving the Fuel Economy of U.S. Cars and Light Trucks by 2010-2015* (Washington, DC: American Council for an Energy Efficient Economy, April 2001); M.A. Weiss et al, *On the Road in 2020: A Life-Cycle Analysis of New Automotive Technologies* (Cambridge, MA: Massachusetts Institute of Technology, October 2000); A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001); and Energy and Environmental Analysis, Inc., *Documentation of Technologies included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (prepared for Energy Information Administration, September 30, 2002).

[*110*]Values for incremental investments and energy expenditure savings are discounted back to 2003 at a 7-percent real discount rate.

[*111*]Unless otherwise noted, the term "capacity" in the discussion of electricity generation indicates utility, nonutility, and combined heat and power capacity. The costs reflect the arithmetic average of the regional cost.

[*112*]*AEO2004* does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2001, EIA estimates that as much as 112 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2001, plus an additional 305 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See *Annual Energy Review 2002*, Table 10.6 (annual PV shipments, 1989-2001). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.

[*113*]Hydroelectric and landfill gas assumptions are unchanged from the reference case. Assumptions are obtained or derived from the Electric Power Research Institute and DOE, Office of Energy Efficiency and Renewable Energy, *Renewable Energy Technology Characterizations*, EPRI-TR-109496 (Washington, DC, December 1997), web site www.eren.doe.gov/power/techchar.html.

[*114*]Based on technology characterizations found in the National Renewable Energy Laboratory *2003 Power Technologies Databook*. See web site www.nrel.gov/analysis/power_databook/. Cost and performance projections in the *Databook* are sourced to U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy publications and documents.

[*115*]Associated-dissolved natural gas is produced in conjunction with crude oil. Nonassociated gas is produced without crude oil production.

[*116*]Unconventional gas includes tight (low permeability), sandstone gas, shale gas, and coalbed methane.

[*117*]Gas exports from the United States to Mexico continue to exceed imports from Mexico through the end of the projections.

[*118*]Variations in mining costs are not necessarily limited to changes in labor productivity and wage rates. Other factors that affect mining costs and, subsequently, the price of coal include such items as severance taxes, royalties, fuel costs, and the costs of parts and supplies.

[*119*]U.S. Environmental Protection Agency, web site www.epa.gov/airmarkets/arp/overview.html (October 25, 2002).

[*120*]**Buildings:** Energy Information Administration (EIA), *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Arthur D. Little, Inc., October 2001). Industrial: EIA, *Industrial Model: Update on Energy Use and Industrial Characteristics* (Arthur D. Little, Inc., September 2001). **Transportation:** U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond,* ORNL/CON-444 (Washington, DC, September 1997); J. DeCicco and M. Ross, *An Updated Assessment of the Near-Term Potential for Improving Automotive Fuel Economy* (Washington, DC: American Council for an Energy-Efficient Economy, November 1993); and A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001). **Fossil-fired generating technologies:** U.S. Department of Energy, Office of Fossil Energy. **Renewable generating technologies:** U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, and Electric Power Research Institute, *Renewable Energy Technology Characterizations*, EPRI-TR-109496 (Washington, DC, December 1997).

Table Notes and Sources

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

Table 1. Total energy supply and disposition in the *AEO2004* reference case: summary, 2001-2025: Tables A1, A19, and A20. **Note:** 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.

Table 2. Emissions from electricity generators in selected States, 2002: U.S. Environmental Protection Agency, web site www.epa.gov/airmarkets/emissions/prelimarp/index.html.

Table 3. Existing State air emissions legislation with potential impacts on the electricity generation sector: Sources cited in text.

Table 4. Labor productivity growth in the nonfarm business sector, 1948-1973 and 1973-1995: Source: M.N. Baily, "The New Economy: Post Mortem or Second Wind?," *Journal of Economic Perspectives*, Vol. 16, No. 2 (Spring 2002).

Table 5. Estimated changes in labor productivity growth between 1995-2000 and 1973-1995: M.N. Baily, "The New Economy: Post Mortem or Second Wind?," *Journal of Economic Perspectives*, Vol. 16, No. 2 (Spring 2002).

Table 6. Estimates of future steady-state growth in U.S. labor productivity: S.D. Oliner and D.E. Sichel, "Information Technology and Productivity: Where Are We Now and Where Are We Going?," *Federal Reserve Board Finance and Economics Discussion Series*, No. 2002-29 (May 2002), Table 5, web site www.federalreserve.gov/pubs/feds/2002/200229/200229abs.html.

Table 7. Principal deepwater fields in production or expected to start production by 2007: EIA computations based on MMS, *Gulf of Mexico Outer Continental Shelf Daily Oil and Gas Production Rate Projections From 2003-2007* (MMS 2003-028) and announcements in the trade press.

Table 8. Tight sands gas production by region and basin, 2002-2025: History: Advanced Resources International (ARI) with adjustments by EIA. **Projections:** AEO2004 National Energy Modeling System, run AEO2004.D101703E.

Table 9. Coalbed methane production by region and basin, 2002-2025: History: Advanced Resources International (ARI). **Projections:** AEO2004 National Energy Modeling System, run AEO2004.D101703E.

Table 10. Shale gas production by region and basin, 2002-2025: History: Advanced Resources International (ARI). **Projections:** AEO2004 National Energy Modeling System, run AEO2004.D101703E.

Table 11. Access status of undeveloped unconventional natural gas resources in the Rocky Mountain region, January 1, 2002: EIA, based on resource allocation parameters developed by Advanced Resources International from results of the study, *Scientific Inventory of Onshore Federal Land's Oil and Gas Resources and Reserves and the Extent and Nature of Restrictions or Impediments to Their Development*.

Table 12. North American LNG regasification proposals as of December 1, 2003: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 13. Projected Canadian tar sands oil supply and potential range of natural gas consumption in the *AEO2004* reference case, 2002-2025: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 14. Overview of U.S. natural gas consumption and supply projections, 2002, 2010, and 2025: AEO2004 National Energy Modeling System run AEO2004.D101703E and NPC spreadsheets npcsm4a_GasProduction InBCF.xls, npcsm4a_Gas DemandBySectorInBCF.xls, npcsm4a_RegionalGas BalanceInBCF.xls, npcsm4ma_Gas ProductionInBCF.xls, npcsm4ma_GasDemandBySector InBCF.xls, npcsm4ma_RegionalGasBalanceInBCF.xls, Supply_CurrentPath.xls, and Supply_BalancedFuture.xls. **Note:** The sum of the three components of NPC's lower 48 onshore gas production (associated, nonassociated, and unconventional) do not equal NPC's total lower 48 onshore gas production. Typically, the sum of these three components is 100 to 150 billion cubic feet less than total lower 48 onshore production.

Table 15. Growth rates for natural gas consumption in the industrial and electric power sectors, 2002-2025: AEO2004 National Energy Modeling System run AEO2004.D101703E and NPC spreadsheets npcsm4a_GasProductionInBCF.xls and npcsm4a_GasDemandBySectorInBCF.xls. **Note:** In *AEO2004*, incremental CHP natural gas consumption after 2001 is subtracted from the industrial sector and added to electric power sector gas consumption. In 2025, 979 billion cubic feet of gas is reallocated by this method.

Table 16. Lower 48 cumulative natural gas production, 2002-2025: *AEO2004* National Energy Modeling System run AEO2004.D101703E and NPC spreadsheets npcsm4a_GasProductionInBCF.xls (one for each scenario) and Supply_CurrentPath.xls and Supply_BalancedFuture.xls.

Table 17. Portion of the lower 48 natural gas resource base produced, 2002-2025: AEO2004 National Energy Modeling System run AEO2004.D101703E and NPC spreadsheets npcsm4a_GasProductionInBCF.xls (one for each scenario), Supply_CurrentPath.xls, and Supply_BalancedFuture.xls.

Table 18. Key projections for renewable electricity in the reference and PTC extension cases, 2010 and 2025: AEO2004 National Energy Modeling System, runs AEO2004.D101703E, PTC3.D102003A, PTC9.D102003A, and PTC9H. D102003A.

Table 19. Projected changes in U.S. greenhouse gas emissions, gross domestic product, and greenhouse gas intensity, 2002-2025: 2002 emissions: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2002*, DOE/EIA-0573(2002) (Washington, DC, November 2003). **Carbon dioxide emissions and gross domestic product:** AEO2004 National Energy Modeling System, run AEO2004.D101703E. **Other gases and adjustments:** U.S. Department of State, *U.S. Climate Action Report 2002* (Washington, DC, May 2002), pp. 70-80 (2002 and 2012 values calculated by interpolation). **Note:** Greenhouse gas emissions totals exclude carbon sequestration, for consistency with Administration figures.

Table 20. New car and light truck horsepower ratings and market shares, 1990-2025: History: U.S. Environmental Protection Agency, Office of Transportation and Air Quality, *Light-Duty Automotive Technology And Fuel Economy Trends: 1975-2003*, EPA-420-S-03-004, April 2003. **Projections:** AEO2004 National Energy Modeling System, run AEO2004.D101703E.

Table 21. Costs of producing electricity from new plants, 2010 and 2025: AEO2004 National Energy Modeling System, run AEO2004.D101703E.

Table 22. Technically recoverable U.S. natural gas resources as of January 1, 2002: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 23. Onshore and offshore lower 48 crude oil production in three cases, 2025: AEO2004 National Energy Modeling System, runs AEO2004.D101703E, LW2004.D101703B, and HW2004.D101703B.

Table 24. Technically recoverable U.S. oil resources as of January 1, 2002: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 25. Crude oil production from Gulf of Mexico offshore, 2002-2025: AEO2004 National Energy Modeling System, run AEO2004.D101703E.

Table 26. Petroleum consumption and net imports in five cases, 2002 and 2025: 2002: Energy Information Administration, *Petroleum Supply Annual 2001, Vol. 1*, DOE/EIA-0340(2001)/1 (Washington, DC, June 2001). **2025:** Tables A11, B11, and C11.

Figure Notes and Sources

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

Figure 1. Energy price projections, 2002-2025: *AEO2003* and *AEO2004* compared: *AEO2003* projections: Energy Information Administration, *Annual Energy Outlook 2003*, DOE/EIA-0383(2003) (Washington, DC, January 2003). ***AEO2004* projections:** Table A1.

Figure 2. Energy consumption by fuel, 1970-2025: Energy Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384(2002) (Washington, DC, October 2003). **Projections:** Tables A1 and A18.

Figure 3. Energy use per capita and per dollar of gross domestic product, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384(2002) (Washington, DC, October 2003). **Projections:** Table A20.

Figure 4. Electricity generation by fuel, 1970-2025: History: Energy Information Administration (EIA), Form EIA-860B, "Annual Electric Generator Report—Nonutility"; EIA, *Annual Energy Review 2002*, DOE/EIA-0384(2002) (Washington, DC, October 2003); and Edison Electric Institute. **Projections:** Table A8.

Figure 5. Total energy production and consumption, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384(2002) (Washington, DC, October 2003). **Projections:** Table A1.

Figure 6. Energy production by fuel, 1970-2025: History: Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384(2002) (Washington, DC, October 2003). **Projections:** Tables A1 and A18.

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Figure 117. Carbon dioxide emissions in three economic growth cases, 1990-2025: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2002*, DOE/EIA-0573(2002) (Washington, DC, October 2003). **Projections:** Table B19.

Figure 118. Carbon dioxide emissions in three technology cases, 1990-2025: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2002*, DOE/EIA-0573(2002) (Washington, DC, October 2003). **Projections:** Table F4.

Figure 119. Sulfur dioxide emissions from electricity generation, 1990-2025: History: 1990 and 1995: U.S. Environmental Protection Agency, *National Air Pollutant Emissions Trends, 1990-1998*, EPA- 454/R-00-002 (Washington, DC, March 2000). **2001:** U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 2001*, web site www.epa.gov/airmarkets/emissions/prelimarp/index.html. **Projections:** Table A8.

Figure 120. Nitrogen oxide emissions from electricity generation, 1990-2025: History: 1990 and 1995: U.S. Environmental Protection Agency, *National Air Pollutant Emissions Trends, 1990-1998*, EPA- 454/R-00-002 (Washington, DC, March 2000). **2001:** U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 200*1, web site www.epa.gov/airmarkets/emissions/prelimarp/index.html. **Projections:** Table A8.

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 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Production							
Crude Oil and Lease Condensate	12.16	11.91	12.56	11.71	10.49	9.77	-0.9%
Natural Gas Plant Liquids	2.55	2.56	3.10	3.20	3.47	3.47	1.3%
Dry Natural Gas	20.23	19.56	21.05	22.20	24.43	24.64	1.0%
Coal	23.97	22.70	25.25	26.14	27.92	31.10	1.4%
Nuclear Power	8.03	8.15	8.29	8.48	8.53	8.53	0.2%
Renewable Energy[1]	5.25	5.84	7.18	7.84	8.45	9.00	1.9%
Other[2]	0.53	1.13	0.88	0.79	0.81	0.84	-1.3%
Total	**72.72**	**71.85**	**78.30**	**80.36**	**84.09**	**87.33**	**0.9%**
Imports							
Crude Oil[3]	20.26	19.84	24.51	29.37	31.55	34.21	2.4%
Petroleum Products[4]	5.04	4.75	5.76	6.00	7.83	9.63	3.1%
Natural Gas	4.06	4.10	6.54	7.29	7.56	8.29	3.1%
Other Imports[5]	0.59	0.52	0.95	1.06	1.12	1.18	3.6%
Total	**29.95**	**29.21**	**37.76**	**43.72**	**48.06**	**53.30**	**2.6%**
Exports							
Petroleum[6]	2.01	2.03	2.15	2.18	2.13	2.15	0.2%
Natural Gas	0.38	0.52	0.91	0.90	0.93	0.88	2.3%
Coal	1.26	1.03	0.89	0.80	0.69	0.56	-2.6%
Total	**3.65**	**3.58**	**3.95**	**3.88**	**3.75**	**3.59**	**0.0%**
Discrepancy[7]	**2.09**	**-0.24**	**0.34**	**0.46**	**0.48**	**0.56**	**N/A**
Consumption							
Petroleum Products[8]	38.49	38.11	44.15	48.26	51.35	54.99	1.6%
Natural Gas	23.05	23.37	26.82	28.74	31.21	32.21	1.4%
Coal	22.04	22.18	25.23	26.32	28.30	31.73	1.6%
Nuclear Power	8.03	8.15	8.29	8.48	8.53	8.53	0.2%
Renewable Energy[1]	5.25	5.84	7.18	7.84	8.46	9.00	1.9%
Other[9]	0.08	0.07	0.11	0.11	0.07	0.03	-4.6%
Total	**96.94**	**97.72**	**111.77**	**119.75**	**127.92**	**136.48**	**1.5%**
Net Imports - Petroleum	**23.29**	**22.56**	**28.13**	**33.20**	**37.25**	**41.69**	**2.7%**
Prices (2002 dollars per unit)							
World Oil Price (dollars per barrel)[10]	22.25	23.68	24.17	25.07	26.02	27.00	0.6%
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.14	2.95	3.40	4.19	4.28	4.40	1.8%
Coal Minemouth Price (dollars per ton)	17.79	17.90	16.88	16.47	16.32	16.57	-0.3%
Average Electricity Price (cents per kilowatthour)	7.4	7.2	6.6	6.8	6.9	6.9	-0.2%

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, 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, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[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.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Annual 2001*, DOE/EIA-0131(2001) (Washington, DC, February 2003). 2002 natural gas supply values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June2003). 2001 coal minemouth prices: EIA, *Annual Coal Report 2002*, DOE/EIA-0584(2002) (Washington, DC, November 2003). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). 2002 petroleum supply values: EIA, *Petroleum Supply Annual 2002,* DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). Other 2001 and 2002 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002) and EIA, *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003). **Projections:** EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

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

Sector and Source	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Energy Consumption							
Residential							
Distillate Fuel	0.90	0.89	0.93	0.89	0.85	0.80	-0.5%
Kerosene	0.11	0.07	0.11	0.11	0.10	0.09	1.3%
Liquefied Petroleum Gas	0.50	0.53	0.56	0.59	0.61	0.64	0.8%
Petroleum Subtotal	1.51	1.48	1.60	1.59	1.56	1.53	0.1%
Natural Gas	4.92	5.06	5.69	5.84	6.08	6.26	0.9%
Coal	0.01	0.01	0.01	0.01	0.01	0.01	-0.3%
Renewable Energy[1]	0.36	0.39	0.40	0.41	0.41	0.41	0.1%
Electricity	4.10	4.33	4.87	5.22	5.60	5.96	1.4%
Delivered Energy	**10.91**	**11.28**	**12.58**	**13.06**	**13.66**	**14.17**	**1.0%**
Electricity Related Losses	9.28	9.60	10.48	10.92	11.43	11.95	1.0%
Total	**20.18**	**20.88**	**23.06**	**23.98**	**25.10**	**26.12**	**1.0%**
Commercial							
Distillate Fuel	0.49	0.49	0.62	0.65	0.67	0.70	1.6%
Residual Fuel	0.09	0.08	0.13	0.13	0.13	0.13	2.2%
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	1.4%
Liquefied Petroleum Gas	0.09	0.09	0.10	0.10	0.10	0.10	0.3%
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.2%
Petroleum Subtotal	0.74	0.72	0.92	0.95	0.97	1.00	1.4%
Natural Gas	3.33	3.21	3.57	3.72	3.94	4.16	1.1%
Coal	0.10	0.10	0.10	0.10	0.10	0.10	0.0%
Renewable Energy[3]	0.09	0.10	0.10	0.10	0.10	0.10	0.0%
Electricity	4.09	4.12	5.05	5.64	6.24	6.83	2.2%
Delivered Energy	**8.34**	**8.25**	**9.74**	**10.51**	**11.35**	**12.19**	**1.7%**
Electricity Related Losses	9.24	9.15	10.86	11.79	12.73	13.70	1.8%
Total	**17.58**	**17.40**	**20.60**	**22.30**	**24.07**	**25.89**	**1.7%**
Industrial[4]							
Distillate Fuel	1.21	1.16	1.17	1.27	1.34	1.43	0.9%
Liquefied Petroleum Gas	2.10	2.22	2.35	2.53	2.74	2.94	1.2%
Petrochemical Feedstock	1.16	1.22	1.35	1.43	1.54	1.62	1.2%
Residual Fuel	0.15	0.20	0.21	0.23	0.22	0.23	0.5%
Motor Gasoline[2]	0.16	0.16	0.16	0.17	0.18	0.19	0.8%
Other Petroleum[5]	4.27	4.03	4.38	4.68	4.93	5.17	1.1%
Petroleum Subtotal	9.04	9.00	9.63	10.31	10.95	11.59	1.1%
Natural Gas	7.56	7.43	8.62	9.12	9.84	10.58	1.5%
Lease and Plant Fuel[6]	1.12	1.35	1.40	1.48	1.65	1.69	1.0%
Natural Gas Subtotal	8.67	8.78	10.02	10.60	11.49	12.27	1.5%
Metallurgical Coal	0.71	0.62	0.64	0.58	0.52	0.47	-1.2%
Steam Coal	1.51	1.47	1.41	1.43	1.45	1.47	-0.0%
Net Coal Coke Imports	0.02	0.03	0.01	0.01	0.00	0.01	-4.5%
Coal Subtotal	2.25	2.12	2.06	2.01	1.97	1.95	-0.4%
Renewable Energy[7]	1.64	1.66	2.00	2.26	2.48	2.70	2.1%
Electricity	3.29	3.39	3.82	4.15	4.47	4.85	1.6%
Delivered Energy	**24.89**	**24.94**	**27.53**	**29.32**	**31.36**	**33.35**	**1.3%**
Electricity Related Losses	7.44	7.53	8.22	8.67	9.12	9.72	1.1%
Total	**32.33**	**32.47**	**35.75**	**37.99**	**40.48**	**43.07**	**1.2%**

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

Sector and Source	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Transportation							
Distillate Fuel[8]	5.32	5.12	6.42	7.25	8.02	8.94	2.5%
Jet Fuel[9]	3.43	3.34	3.93	4.36	4.69	4.91	1.7%
Motor Gasoline[2]	16.17	16.62	19.88	21.62	23.11	24.98	1.8%
Residual Fuel	0.84	0.71	0.79	0.80	0.82	0.83	0.6%
Liquefied Petroleum Gas	0.02	0.02	0.06	0.07	0.08	0.08	6.7%
Other Petroleum[10]	0.19	0.24	0.25	0.27	0.30	0.32	1.2%
Petroleum Subtotal	25.96	26.06	31.34	34.37	37.00	40.07	1.9%
Pipeline Fuel Natural Gas	0.64	0.65	0.69	0.72	0.83	0.86	1.2%
Compressed Natural Gas	0.01	0.01	0.06	0.08	0.10	0.11	9.2%
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	7.6%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	0.07	0.08	0.09	0.10	0.11	0.12	2.1%
Delivered Energy	**26.69**	**26.79**	**32.18**	**35.28**	**38.05**	**41.16**	**1.9%**
Electricity Related Losses	0.17	0.17	0.19	0.21	0.22	0.24	1.6%
Total	**26.85**	**26.96**	**32.37**	**35.48**	**38.27**	**41.40**	**1.9%**
Delivered Energy Consumption for All Sectors							
Distillate Fuel	7.92	7.66	9.15	10.07	10.88	11.88	1.9%
Kerosene	0.15	0.09	0.16	0.15	0.14	0.13	1.7%
Jet Fuel[9]	3.43	3.34	3.93	4.36	4.69	4.91	1.7%
Liquefied Petroleum Gas	2.70	2.86	3.07	3.28	3.53	3.76	1.2%
Motor Gasoline[2]	16.37	16.83	20.09	21.84	23.34	25.22	1.8%
Petrochemical Feedstock	1.16	1.22	1.35	1.43	1.54	1.62	1.2%
Residual Fuel	1.07	1.00	1.13	1.16	1.17	1.19	0.8%
Other Petroleum[12]	4.45	4.26	4.61	4.93	5.21	5.46	1.1%
Petroleum Subtotal	37.25	37.26	43.48	47.22	50.50	54.18	1.6%
Natural Gas	15.81	15.71	17.94	18.76	19.95	21.11	1.3%
Lease and Plant Fuel[6]	1.12	1.35	1.40	1.48	1.65	1.69	1.0%
Pipeline Natural Gas	0.64	0.65	0.69	0.72	0.83	0.86	1.2%
Natural Gas Subtotal	17.57	17.72	20.03	20.96	22.43	23.66	1.3%
Metallurgical Coal	0.71	0.62	0.64	0.58	0.52	0.47	-1.2%
Steam Coal	1.62	1.58	1.52	1.54	1.56	1.58	-0.0%
Net Coal Coke Imports	0.02	0.03	0.01	0.01	0.00	0.01	-4.5%
Coal Subtotal	2.36	2.23	2.17	2.12	2.08	2.06	-0.3%
Renewable Energy[13]	2.09	2.15	2.50	2.76	2.99	3.21	1.8%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	11.55	11.92	13.83	15.11	16.41	17.77	1.8%
Delivered Energy	**70.83**	**71.27**	**82.03**	**88.17**	**94.42**	**100.87**	**1.5%**
Electricity Related Losses	26.12	26.45	29.75	31.57	33.50	35.61	1.3%
Total	**96.94**	**97.72**	**111.77**	**119.75**	**127.92**	**136.48**	**1.5%**
Electric Power[14]							
Distillate Fuel	0.33	0.16	0.16	0.44	0.26	0.27	2.4%
Residual Fuel	0.91	0.69	0.51	0.60	0.59	0.54	-1.1%
Petroleum Subtotal	1.25	0.85	0.66	1.04	0.85	0.81	-0.2%
Natural Gas	5.48	5.65	6.79	7.78	8.78	8.55	1.8%
Steam Coal	19.68	19.96	23.05	24.20	26.22	29.67	1.7%
Nuclear Power	8.03	8.15	8.29	8.48	8.53	8.53	0.2%
Renewable Energy[15]	3.16	3.69	4.68	5.08	5.47	5.79	2.0%
Electricity Imports	0.08	0.07	0.11	0.11	0.07	0.03	-4.6%
Total	**37.67**	**38.36**	**43.58**	**46.68**	**49.92**	**53.37**	**1.4%**

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

Sector and Source	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Total Energy Consumption							
Distillate Fuel	8.26	7.82	9.31	10.51	11.14	12.15	1.9%
Kerosene	0.15	0.09	0.16	0.15	0.14	0.13	1.7%
Jet Fuel[9]	3.43	3.34	3.93	4.36	4.69	4.91	1.7%
Liquefied Petroleum Gas	2.70	2.86	3.07	3.28	3.53	3.76	1.2%
Motor Gasoline[2]	16.37	16.83	20.09	21.84	23.34	25.22	1.8%
Petrochemical Feedstock	1.16	1.22	1.35	1.43	1.54	1.62	1.2%
Residual Fuel	1.98	1.69	1.64	1.76	1.76	1.72	0.1%
Other Petroleum[12]	4.45	4.26	4.61	4.93	5.21	5.46	1.1%
Petroleum Subtotal	38.49	38.11	44.15	48.26	51.35	54.99	1.6%
Natural Gas	21.30	21.36	24.73	26.54	28.73	29.66	1.4%
Lease and Plant Fuel[6]	1.12	1.35	1.40	1.48	1.65	1.69	1.0%
Pipeline Natural Gas	0.64	0.65	0.69	0.72	0.83	0.86	1.2%
Natural Gas Subtotal	23.05	23.37	26.82	28.74	31.21	32.21	1.4%
Metallurgical Coal	0.71	0.62	0.64	0.58	0.52	0.47	-1.2%
Steam Coal	21.30	21.54	24.57	25.74	27.78	31.25	1.6%
Net Coal Coke Imports	0.02	0.03	0.01	0.01	0.00	0.01	-4.5%
Coal Subtotal	22.04	22.18	25.23	26.32	28.30	31.73	1.6%
Nuclear Power	8.03	8.15	8.29	8.48	8.53	8.53	0.2%
Renewable Energy[16]	5.25	5.84	7.18	7.84	8.46	9.00	1.9%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity Imports	0.08	0.07	0.11	0.11	0.07	0.03	-4.6%
Total	**96.94**	**97.72**	**111.77**	**119.75**	**127.92**	**136.48**	**1.5%**
Energy Use and Related Statistics							
Delivered Energy Use	70.83	71.27	82.03	88.17	94.42	100.87	1.5%
Total Energy Use	96.94	97.72	111.77	119.75	127.92	136.48	1.5%
Population (millions)	285.92	288.93	309.28	321.95	334.61	347.53	0.8%
Gross Domestic Product (billion 1996 dollars)	9215	9440	12190	14101	16188	18520	3.0%
Carbon Dioxide Emissions (million metric tons carbon equivalent)	5691.7	5729.3	6558.8	7028.4	7535.6	8142.0	1.5%

[1]Includes wood used for residential heating. See Table A18 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table A18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Fuel consumption includes consumption for combined heat and power, which produces electricity, both for sale to the grid and for own use, and other useful thermal energy.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[10]Includes aviation gasoline and lubricants.
[11]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[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 net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2001 and 2002 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2001 and 2002 population and gross domestic product: Global Insight macroeconomic model T250803. 2001 and 2002 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2002,* DOE/EIA-0573(2002) (Washington, DC, October 2003). **Projections:** EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

Table A3. Energy Prices by Sector and Source
(2002 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Residential	**15.95**	**14.73**	**14.21**	**14.93**	**15.08**	**15.38**	**0.2%**
Primary Energy[1]	9.85	8.14	8.15	8.72	8.76	8.89	0.4%
Petroleum Products[2]	10.95	9.87	9.90	10.38	10.86	11.26	0.6%
Distillate Fuel	9.09	8.23	7.82	8.06	8.39	8.53	0.2%
Liquefied Petroleum Gas	15.05	12.92	13.89	14.46	14.79	15.19	0.7%
Natural Gas	9.53	7.65	7.67	8.29	8.24	8.32	0.4%
Electricity	25.51	24.73	23.30	23.77	23.73	23.88	-0.2%
Commercial	**15.67**	**14.68**	**13.77**	**14.62**	**14.93**	**15.28**	**0.2%**
Primary Energy[1]	8.07	6.35	6.48	7.04	7.11	7.22	0.6%
Petroleum Products[2]	7.25	6.88	6.34	6.53	6.83	6.98	0.1%
Distillate Fuel	6.38	6.07	5.45	5.66	6.01	6.15	0.1%
Residual Fuel	3.51	4.21	4.13	4.27	4.41	4.55	0.3%
Natural Gas	8.44	6.37	6.64	7.32	7.31	7.41	0.7%
Electricity	23.43	22.82	20.39	21.02	21.21	21.48	-0.3%
Industrial[3]	**7.24**	**6.31**	**6.44**	**6.96**	**7.21**	**7.42**	**0.7%**
Primary Energy	5.87	4.77	5.14	5.64	5.88	6.07	1.1%
Petroleum Products[2]	7.73	6.35	6.84	7.15	7.54	7.81	0.9%
Distillate Fuel	6.62	6.21	5.68	5.85	6.24	6.40	0.1%
Liquefied Petroleum Gas	12.48	8.28	9.72	10.29	10.66	11.11	1.3%
Residual Fuel	3.31	3.89	3.74	3.88	4.03	4.17	0.3%
Natural Gas[4]	4.91	3.75	4.05	4.81	4.89	4.99	1.3%
Metallurgical Coal	1.71	1.87	1.96	1.90	1.84	1.77	-0.2%
Steam Coal	1.51	1.52	1.58	1.55	1.53	1.53	0.0%
Electricity	15.11	14.74	13.36	13.81	13.99	14.09	-0.2%
Transportation	**10.58**	**9.91**	**10.50**	**10.53**	**10.54**	**10.69**	**0.3%**
Primary Energy	10.55	9.88	10.48	10.50	10.52	10.67	0.3%
Petroleum Products[2]	10.55	9.88	10.48	10.50	10.52	10.67	0.3%
Distillate Fuel[5]	10.16	9.41	10.12	10.16	10.00	10.03	0.3%
Jet Fuel[6]	6.27	5.97	5.76	5.85	6.06	6.21	0.2%
Motor Gasoline[7]	11.99	11.15	11.87	11.87	11.90	12.06	0.3%
Residual Fuel	3.94	3.77	3.60	3.73	3.88	4.02	0.3%
Liquefied Petroleum Gas[8]	17.12	15.00	14.96	15.39	15.51	15.83	0.2%
Natural Gas[9]	8.69	7.38	8.26	9.07	9.06	9.09	0.9%
Ethanol (E85)[10]	16.56	15.19	17.22	17.79	18.28	18.58	0.9%
Electricity	21.58	21.10	19.57	20.25	20.03	19.92	-0.2%
Average End-Use Energy	**10.95**	**10.10**	**10.23**	**10.61**	**10.76**	**10.96**	**0.4%**
Primary Energy	8.69	7.70	8.22	8.53	8.64	8.82	0.6%
Electricity	21.79	21.20	19.47	19.99	20.10	20.26	-0.2%
Electric Power[11]							
Fossil Fuel Average	2.27	1.89	1.92	2.16	2.18	2.11	0.5%
Petroleum Products	5.00	4.32	4.21	4.54	4.67	4.88	0.5%
Distillate Fuel	6.24	5.58	4.92	5.09	5.47	5.62	0.0%
Residual Fuel	4.55	4.04	3.99	4.14	4.31	4.50	0.5%
Natural Gas	5.30	3.77	4.04	4.78	4.85	4.92	1.2%
Steam Coal	1.25	1.26	1.22	1.22	1.20	1.22	-0.1%

Table A3. Energy Prices by Sector and Source (Continued)
(2002 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Average Price to All Users[12]							
Petroleum Products[2]	9.74	8.94	9.57	9.65	9.81	10.01	0.5%
Distillate Fuel	9.14	8.52	8.93	8.97	9.07	9.18	0.3%
Jet Fuel	6.27	5.97	5.76	5.85	6.06	6.21	0.2%
Liquefied Petroleum Gas	13.00	9.27	10.65	11.21	11.55	11.96	1.1%
Motor Gasoline[7]	11.99	11.15	11.87	11.87	11.90	12.06	0.3%
Residual Fuel	4.16	3.92	3.78	3.93	4.08	4.23	0.3%
Natural Gas	6.63	5.07	5.27	5.93	5.93	6.03	0.8%
Coal	1.27	1.28	1.25	1.24	1.22	1.24	-0.1%
Ethanol (E85)[10]	16.56	15.19	17.22	17.79	18.28	18.58	0.9%
Electricity	21.79	21.20	19.47	19.99	20.10	20.26	-0.2%
Non-Renewable Energy Expenditures by Sector (billion 2002 dollars)							
Residential	168.08	160.37	173.01	189.01	199.98	211.69	1.2%
Commercial	129.31	119.67	132.72	152.16	167.90	184.74	1.9%
Industrial	138.60	120.96	132.71	152.53	169.02	185.61	1.9%
Transportation	275.57	259.11	330.65	363.66	392.36	430.99	2.2%
Total Non-Renewable Expenditures	711.55	660.11	769.08	857.37	929.26	1013.03	1.9%
Transportation Renewable Expenditures	0.01	0.01	0.03	0.05	0.06	0.07	8.6%
Total Expenditures	**711.56**	**660.12**	**769.11**	**857.41**	**929.32**	**1013.10**	**1.9%**

[1]Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Includes combined heat and power, which produces electricity and other useful thermal energy.
[4]Excludes use for lease and plant fuel.
[5]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8]Includes Federal and State taxes while excluding county and local taxes.
[9]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001 and 2002 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2002*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/ current/pdf/pmaall.pdf (August 2003). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Annual 2001*, DOE/EIA-0131(2001) (Washington, DC, February 2003). 2002 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2001 and 2002 electric power sector natural gas prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 and 2002 industrial natural gas delivered prices are based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 and 2002 coal prices based on EIA, *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003) and EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E. 2001 and 2002 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2001 and 2002 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

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

Key Indicators and Consumption	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Key Indicators							
Households (millions)							
Single-Family	73.73	74.77	82.87	87.68	92.09	96.32	1.1%
Multifamily	28.96	29.20	30.71	31.84	33.07	34.36	0.7%
Mobile Homes	6.37	6.31	6.25	6.60	6.88	7.12	0.5%
Total	**109.06**	**110.28**	**119.84**	**126.12**	**132.04**	**137.79**	**1.0%**
Average House Square Footage	**1684**	**1689**	**1731**	**1752**	**1771**	**1788**	**0.2%**
Energy Intensity							
(million Btu per household)							
Delivered Energy Consumption	100.0	102.3	105.0	103.6	103.5	102.8	0.0%
Total Energy Consumption	185.0	189.4	192.4	190.1	190.1	189.5	0.0%
(thousand Btu per square foot)							
Delivered Energy Consumption	59.4	60.6	60.6	59.1	58.4	57.5	-0.2%
Total Energy Consumption	109.9	112.1	111.1	108.5	107.3	106.0	-0.2%
Delivered Energy Consumption by Fuel							
Electricity							
Space Heating	0.38	0.40	0.43	0.44	0.45	0.46	0.6%
Space Cooling	0.63	0.71	0.69	0.72	0.76	0.80	0.5%
Water Heating	0.38	0.37	0.37	0.37	0.36	0.35	-0.3%
Refrigeration	0.43	0.42	0.37	0.36	0.36	0.37	-0.6%
Cooking	0.10	0.10	0.11	0.12	0.12	0.13	0.9%
Clothes Dryers	0.23	0.24	0.25	0.26	0.26	0.27	0.6%
Freezers	0.14	0.13	0.12	0.12	0.12	0.12	-0.4%
Lighting	0.72	0.75	0.87	0.92	0.97	1.02	1.4%
Clothes Washers[1]	0.03	0.03	0.04	0.05	0.06	0.06	3.0%
Dishwashers[1]	0.02	0.02	0.03	0.03	0.03	0.03	1.3%
Color Televisions	0.12	0.12	0.18	0.22	0.26	0.27	3.5%
Personal Computers	0.06	0.06	0.08	0.10	0.11	0.14	3.3%
Furnace Fans	0.07	0.08	0.09	0.10	0.10	0.11	1.7%
Other Uses[2]	0.79	0.88	1.25	1.44	1.63	1.83	3.2%
Delivered Energy	**4.10**	**4.33**	**4.87**	**5.22**	**5.60**	**5.96**	**1.4%**
Natural Gas							
Space Heating	3.39	3.54	4.01	4.13	4.33	4.48	1.0%
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	16.0%
Water Heating	1.16	1.15	1.25	1.25	1.27	1.28	0.5%
Cooking	0.21	0.21	0.23	0.24	0.26	0.27	1.1%
Clothes Dryers	0.07	0.07	0.09	0.10	0.11	0.11	2.3%
Other Uses[3]	0.09	0.10	0.11	0.11	0.12	0.12	1.1%
Delivered Energy	**4.92**	**5.06**	**5.69**	**5.84**	**6.08**	**6.26**	**0.9%**
Distillate							
Space Heating	0.77	0.77	0.81	0.78	0.75	0.71	-0.4%
Water Heating	0.13	0.12	0.12	0.11	0.10	0.09	-1.1%
Other Uses[4]	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Delivered Energy	**0.90**	**0.89**	**0.93**	**0.89**	**0.85**	**0.80**	**-0.5%**
Liquefied Petroleum Gas							
Space Heating	0.29	0.30	0.30	0.31	0.31	0.31	0.1%
Water Heating	0.05	0.05	0.05	0.05	0.05	0.05	-0.1%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.4%
Other Uses[3]	0.14	0.15	0.18	0.20	0.23	0.25	2.3%
Delivered Energy	**0.50**	**0.53**	**0.56**	**0.59**	**0.61**	**0.64**	**0.8%**
Marketed Renewables (wood)[5]	0.36	0.39	0.40	0.41	0.41	0.41	0.1%
Other Fuels[6]	0.12	0.08	0.12	0.12	0.11	0.10	1.1%

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

Key Indicators and Consumption	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Delivered Energy Consumption by End-Use							
Space Heating	5.31	5.48	6.08	6.18	6.35	6.46	0.7%
Space Cooling	0.63	0.71	0.69	0.72	0.76	0.80	0.5%
Water Heating	1.71	1.69	1.79	1.78	1.78	1.77	0.2%
Refrigeration	0.43	0.42	0.37	0.36	0.36	0.37	-0.6%
Cooking	0.34	0.34	0.37	0.39	0.41	0.42	1.0%
Clothes Dryers	0.30	0.31	0.34	0.35	0.37	0.39	1.1%
Freezers	0.14	0.13	0.12	0.12	0.12	0.12	-0.4%
Lighting	0.72	0.75	0.87	0.92	0.97	1.02	1.4%
Clothes Washers	0.03	0.03	0.04	0.05	0.06	0.06	3.0%
Dishwashers	0.02	0.02	0.03	0.03	0.03	0.03	1.3%
Color Televisions	0.12	0.12	0.18	0.22	0.26	0.27	3.5%
Personal Computers	0.06	0.06	0.08	0.10	0.11	0.14	3.3%
Furnace Fans	0.07	0.08	0.09	0.10	0.10	0.11	1.7%
Other Uses[7]	1.02	1.13	1.54	1.75	1.97	2.20	2.9%
Delivered Energy	**10.91**	**11.28**	**12.58**	**13.06**	**13.66**	**14.17**	**1.0%**
Electricity Related Losses	**9.28**	**9.60**	**10.48**	**10.92**	**11.43**	**11.95**	**1.0%**
Total Energy Consumption by End-Use							
Space Heating	6.16	6.36	6.99	7.10	7.27	7.37	0.6%
Space Cooling	2.05	2.29	2.19	2.23	2.32	2.41	0.2%
Water Heating	2.57	2.51	2.58	2.54	2.52	2.46	-0.1%
Refrigeration	1.41	1.37	1.16	1.10	1.09	1.11	-0.9%
Cooking	0.57	0.57	0.61	0.63	0.66	0.68	0.8%
Clothes Dryers	0.83	0.83	0.89	0.89	0.91	0.94	0.5%
Freezers	0.45	0.43	0.37	0.36	0.36	0.37	-0.7%
Lighting	2.34	2.41	2.73	2.84	2.95	3.07	1.1%
Clothes Washers	0.10	0.10	0.12	0.15	0.18	0.19	2.7%
Dishwashers	0.08	0.08	0.08	0.09	0.09	0.10	1.0%
Color Televisions	0.38	0.40	0.58	0.68	0.78	0.82	3.2%
Personal Computers	0.21	0.21	0.25	0.30	0.35	0.41	3.0%
Furnace Fans	0.24	0.25	0.28	0.30	0.32	0.33	1.4%
Other Uses[7]	2.79	3.09	4.22	4.76	5.29	5.87	2.8%
Total	**20.18**	**20.88**	**23.06**	**23.98**	**25.10**	**26.12**	**1.0%**
Non-Marketed Renewables							
Geothermal[8]	0.00	0.00	0.00	0.01	0.01	0.01	9.0%
Solar[9]	0.04	0.02	0.03	0.03	0.04	0.04	2.3%
Total	**0.04**	**0.02**	**0.03**	**0.04**	**0.04**	**0.05**	**3.2%**

[1]Does not include electric water heating portion of load.
[2]Includes small electric devices, heating elements, and motors.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as swimming pool and hot tub heaters.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2001*.
[6]Includes kerosene and coal.
[7]Includes all other uses listed above.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001 and 2002 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections:** EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

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

Key Indicators and Consumption	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Key Indicators							
Total Floorspace (billion square feet)							
Surviving	67.2	68.9	81.1	87.3	93.1	98.8	1.6%
New Additions	3.1	3.2	2.7	2.6	2.8	3.0	-0.3%
Total	**70.2**	**72.1**	**83.8**	**89.9**	**95.9**	**101.8**	**1.5%**
Energy Consumption Intensity (thousand Btu per square foot)							
Delivered Energy Consumption	118.8	114.5	116.2	116.9	118.3	119.7	0.2%
Electricity Related Losses	131.5	126.9	129.6	131.0	132.7	134.6	0.3%
Total Energy Consumption	250.3	241.4	245.8	247.9	251.0	254.3	0.2%
Delivered Energy Consumption by Fuel							
Purchased Electricity							
Space Heating[1]	0.14	0.15	0.16	0.16	0.16	0.16	0.2%
Space Cooling[1]	0.41	0.46	0.45	0.46	0.48	0.49	0.2%
Water Heating[1]	0.14	0.14	0.15	0.15	0.15	0.15	0.3%
Ventilation	0.16	0.16	0.18	0.18	0.18	0.19	0.7%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	-0.7%
Lighting	1.10	1.12	1.30	1.36	1.40	1.43	1.1%
Refrigeration	0.20	0.20	0.22	0.23	0.24	0.25	0.9%
Office Equipment (PC)	0.14	0.14	0.24	0.29	0.34	0.37	4.4%
Office Equipment (non-PC)	0.30	0.31	0.46	0.58	0.71	0.87	4.6%
Other Uses[2]	1.45	1.41	1.86	2.21	2.55	2.91	3.2%
Delivered Energy	**4.09**	**4.12**	**5.05**	**5.64**	**6.24**	**6.83**	**2.2%**
Natural Gas							
Space Heating[1]	1.33	1.42	1.56	1.58	1.64	1.69	0.8%
Space Cooling[1]	0.01	0.01	0.02	0.02	0.03	0.03	3.9%
Water Heating[1]	0.57	0.59	0.70	0.74	0.79	0.84	1.5%
Cooking	0.25	0.26	0.30	0.32	0.34	0.36	1.4%
Other Uses[3]	1.17	0.93	0.99	1.06	1.14	1.24	1.3%
Delivered Energy	**3.33**	**3.21**	**3.57**	**3.72**	**3.94**	**4.16**	**1.1%**
Distillate							
Space Heating[1]	0.17	0.17	0.24	0.27	0.29	0.31	2.6%
Water Heating[1]	0.07	0.07	0.08	0.09	0.09	0.09	1.0%
Other Uses[4]	0.25	0.24	0.30	0.30	0.29	0.29	0.9%
Delivered Energy	**0.49**	**0.49**	**0.62**	**0.65**	**0.67**	**0.70**	**1.6%**
Other Fuels[5]	**0.35**	**0.33**	**0.39**	**0.40**	**0.40**	**0.40**	**0.8%**
Marketed Renewable Fuels							
Biomass	0.09	0.10	0.10	0.10	0.10	0.10	0.0%
Delivered Energy	**0.09**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.0%**
Delivered Energy Consumption by End-Use							
Space Heating[1]	1.64	1.74	1.97	2.01	2.09	2.16	0.9%
Space Cooling[1]	0.43	0.48	0.47	0.48	0.50	0.52	0.4%
Water Heating[1]	0.78	0.80	0.93	0.97	1.03	1.08	1.3%
Ventilation	0.16	0.16	0.18	0.18	0.18	0.19	0.7%
Cooking	0.29	0.29	0.34	0.35	0.37	0.39	1.2%
Lighting	1.10	1.12	1.30	1.36	1.40	1.43	1.1%
Refrigeration	0.20	0.20	0.22	0.23	0.24	0.25	0.9%
Office Equipment (PC)	0.14	0.14	0.24	0.29	0.34	0.37	4.4%
Office Equipment (non-PC)	0.30	0.31	0.46	0.58	0.71	0.87	4.6%
Other Uses[6]	3.31	3.01	3.63	4.06	4.48	4.94	2.2%
Delivered Energy	**8.34**	**8.25**	**9.74**	**10.51**	**11.35**	**12.19**	**1.7%**

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

Key Indicators and Consumption	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Electricity Related Losses	**9.24**	**9.15**	**10.86**	**11.79**	**12.73**	**13.70**	**1.8%**
Total Energy Consumption by End-Use							
Space Heating[1]	1.97	2.07	2.31	2.34	2.41	2.47	0.8%
Space Cooling[1]	1.36	1.51	1.43	1.45	1.48	1.50	-0.0%
Water Heating[1]	1.10	1.11	1.25	1.28	1.33	1.37	0.9%
Ventilation	0.53	0.52	0.56	0.55	0.56	0.57	0.4%
Cooking	0.36	0.36	0.40	0.41	0.43	0.44	0.8%
Lighting	3.58	3.60	4.10	4.20	4.25	4.30	0.8%
Refrigeration	0.65	0.65	0.70	0.71	0.73	0.75	0.6%
Office Equipment (PC)	0.46	0.44	0.76	0.89	1.03	1.10	4.1%
Office Equipment (non-PC)	0.99	1.00	1.46	1.79	2.16	2.61	4.3%
Other Uses[6]	6.59	6.14	7.63	8.67	9.69	10.77	2.5%
Total	**17.58**	**17.40**	**20.60**	**22.30**	**24.07**	**25.89**	**1.7%**
Non-Marketed Renewable Fuels							
Solar[7]	0.02	0.02	0.03	0.03	0.03	0.03	1.5%
Total	**0.02**	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**1.5%**

[1]Includes fuel consumption for district services.
[2]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
[3]Includes miscellaneous uses, such as pumps, emergency electric generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency electric generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency electric generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.
N/A = Not applicable.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001 and 2002 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections:** EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

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

Key Indicators and Consumption	Reference Case 2001	2002	2010	2015	2020	2025	Annual Growth 2002-2025 (percent)
Key Indicators							
Value of Shipments (billion 1996 dollars)							
Manufacturing	4059	4064	5013	5760	6634	7636	2.8%
Nonmanufacturing	1309	1222	1425	1585	1710	1855	1.8%
Total	**5368**	**5285**	**6439**	**7345**	**8344**	**9491**	**2.6%**
Energy Prices (2002 dollars per million Btu)							
Distillate Oil	6.62	6.21	5.68	5.85	6.24	6.40	0.1%
Liquefied Petroleum Gas	12.48	8.28	9.72	10.29	10.66	11.11	1.3%
Residual Oil	3.31	3.89	3.74	3.88	4.03	4.17	0.3%
Motor Gasoline	11.70	11.04	11.84	11.84	11.87	12.03	0.4%
Natural Gas	4.91	3.75	4.05	4.81	4.89	4.99	1.3%
Metallurgical Coal	1.71	1.87	1.96	1.90	1.84	1.77	-0.2%
Steam Coal	1.51	1.52	1.58	1.55	1.53	1.53	0.0%
Electricity	15.11	14.74	13.36	13.81	13.99	14.09	-0.2%
Energy Consumption[1]							
Distillate	1.21	1.16	1.17	1.27	1.34	1.43	0.9%
Liquefied Petroleum Gas	2.10	2.22	2.35	2.53	2.74	2.94	1.2%
Petrochemical Feedstocks	1.16	1.22	1.35	1.43	1.54	1.62	1.2%
Residual Fuel	0.15	0.20	0.21	0.23	0.22	0.23	0.5%
Other Petroleum[2]	4.42	4.19	4.54	4.85	5.12	5.36	1.1%
Petroleum Subtotal	9.04	9.00	9.63	10.31	10.95	11.59	1.1%
Natural Gas	7.56	7.43	8.62	9.12	9.84	10.58	1.5%
Lease and Plant Fuel[3]	1.12	1.35	1.40	1.48	1.65	1.69	1.0%
Natural Gas Subtotal	8.67	8.78	10.02	10.60	11.49	12.27	1.5%
Metallurgical Coal and Coke[4]	0.74	0.65	0.66	0.59	0.52	0.48	-1.3%
Steam Coal	1.51	1.47	1.41	1.43	1.45	1.47	-0.0%
Coal Subtotal	2.25	2.12	2.06	2.01	1.97	1.95	-0.4%
Renewables[5]	1.64	1.66	2.00	2.26	2.48	2.70	2.1%
Purchased Electricity	3.29	3.39	3.82	4.15	4.47	4.85	1.6%
Delivered Energy	**24.89**	**24.94**	**27.53**	**29.32**	**31.36**	**33.35**	**1.3%**
Electricity Related Losses	7.44	7.53	8.22	8.67	9.12	9.72	1.1%
Total	**32.33**	**32.47**	**35.75**	**37.99**	**40.48**	**43.07**	**1.2%**
Energy Consumption per dollar of Shipments[1] (thousand Btu per 1996 dollars)							
Distillate	0.23	0.22	0.18	0.17	0.16	0.15	-1.6%
Liquefied Petroleum Gas	0.39	0.42	0.37	0.34	0.33	0.31	-1.3%
Petrochemical Feedstocks	0.22	0.23	0.21	0.19	0.18	0.17	-1.3%
Residual Fuel	0.03	0.04	0.03	0.03	0.03	0.02	-2.0%
Other Petroleum[2]	0.82	0.79	0.71	0.66	0.61	0.56	-1.5%
Petroleum Subtotal	1.68	1.70	1.50	1.40	1.31	1.22	-1.4%
Natural Gas	1.41	1.41	1.34	1.24	1.18	1.11	-1.0%
Lease and Plant Fuel[3]	0.21	0.26	0.22	0.20	0.20	0.18	-1.6%
Natural Gas Subtotal	1.62	1.66	1.56	1.44	1.38	1.29	-1.1%
Metallurgical Coal and Coke[4]	0.14	0.12	0.10	0.08	0.06	0.05	-3.8%
Steam Coal	0.28	0.28	0.22	0.19	0.17	0.15	-2.5%
Coal Subtotal	0.42	0.40	0.32	0.27	0.24	0.21	-2.9%
Renewables[5]	0.30	0.31	0.31	0.31	0.30	0.28	-0.4%
Purchased Electricity	0.61	0.64	0.59	0.56	0.54	0.51	-1.0%
Delivered Energy	**4.64**	**4.72**	**4.28**	**3.99**	**3.76**	**3.51**	**-1.3%**
Electricity Related Losses	1.39	1.42	1.28	1.18	1.09	1.02	-1.4%
Total	**6.02**	**6.14**	**5.55**	**5.17**	**4.85**	**4.54**	**-1.3%**

[1]Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[3] Represents natural gas used in the field gathering and processing plant machinery.
[4] Includes net coal coke imports.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001 and 2002 prices for motor gasoline and distillate are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2002*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/ current/pdf/pmaall.pdf (August 2003). 2001 and 2002 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003) and EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E. 2001 and 2002 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2001 and 2002 natural gas prices based on: EIA, *Manufacturing Energy Consumption Survey 1998.* 2001 and 2002 consumption values based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2001 and 2002 shipments: Global Insight macroeconomic model T250803. **Projections:** EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	Reference Case 2001	2002	2010	2015	2020	2025	Annual Growth 2002-2025 (percent)
Key Indicators							
Level of Travel (billions)							
Light-Duty Vehicles <8,500 pounds (VMT)	2485	2504	3041	3409	3768	4173	2.2%
Commercial Light Trucks (VMT)[1]	64	65	79	90	101	114	2.5%
Freight Trucks >10,000 pounds (VMT)	201	196	242	276	313	354	2.6%
Air (seat miles available)	953	909	1122	1327	1455	1521	2.3%
Rail (ton miles traveled)	1417	1336	1545	1690	1852	2056	1.9%
Domestic Shipping (ton miles traveled)	774	724	805	857	918	977	1.3%
Energy Efficiency Indicators							
New Light-Duty Vehicle (miles per gallon)[2]	24.0	23.8	25.3	26.0	26.5	26.9	0.5%
New Car (miles per gallon)[2]	28.2	28.2	28.8	29.9	30.4	30.8	0.4%
New Light Truck (miles per gallon)[2]	20.5	20.5	22.8	23.5	24.1	24.7	0.8%
Light-Duty Fleet (miles per gallon)[3]	19.8	19.7	19.6	20.0	20.5	20.9	0.3%
New Commercial Light Truck (MPG)[1]	13.9	13.9	15.1	15.6	16.0	16.4	0.7%
Stock Commercial Light Truck (MPG)[1]	13.7	13.8	14.5	15.0	15.5	15.9	0.6%
Aircraft Efficiency (seat miles per gallon)	55.3	54.8	59.9	63.3	65.4	67.0	0.9%
Freight Truck Efficiency (miles per gallon)	6.0	6.0	6.0	6.1	6.4	6.5	0.4%
Rail Efficiency (ton miles per thousand Btu)	2.8	2.9	3.1	3.3	3.4	3.6	1.0%
(ton miles per thousand Btu)	2.3	2.3	2.3	2.4	2.4	2.4	0.2%
Energy Use by Mode							
(quadrillion Btu)							
Light-Duty Vehicles	15.16	15.58	18.91	20.75	22.34	24.28	1.9%
Commercial Light Trucks[1]	0.58	0.59	0.68	0.75	0.82	0.90	1.9%
Bus Transportation	0.25	0.24	0.25	0.26	0.26	0.26	0.4%
Freight Trucks	4.22	4.09	5.03	5.62	6.15	6.82	2.2%
Rail, Passenger	0.11	0.11	0.13	0.14	0.16	0.17	1.8%
Rail, Freight	0.50	0.47	0.50	0.52	0.54	0.57	0.9%
Shipping, Domestic	0.34	0.32	0.35	0.36	0.39	0.41	1.1%
Shipping, International	0.77	0.64	0.72	0.72	0.73	0.74	0.6%
Recreational Boats	0.30	0.31	0.34	0.35	0.37	0.39	0.9%
Air	2.97	2.84	3.35	3.76	4.09	4.30	1.8%
Military Use	0.62	0.66	0.77	0.79	0.81	0.82	0.9%
Lubricants	0.19	0.20	0.21	0.23	0.25	0.28	1.5%
Pipeline Fuel	0.64	0.65	0.69	0.72	0.83	0.86	1.2%
Total	**26.67**	**26.70**	**31.93**	**35.00**	**37.73**	**40.79**	**1.9%**
(million barrels per day oil equivalent)							
Light-Duty Vehicles	7.98	8.20	9.96	10.92	11.74	12.75	1.9%
Commercial Light Trucks[1]	0.31	0.31	0.36	0.40	0.43	0.47	1.9%
Bus Transportation	0.12	0.11	0.12	0.12	0.12	0.12	0.4%
Freight Trucks	2.00	1.94	2.38	2.66	2.91	3.22	2.2%
Rail, Passenger	0.05	0.05	0.06	0.07	0.07	0.08	1.8%
Rail, Freight	0.24	0.22	0.24	0.24	0.25	0.27	0.9%
Shipping, Domestic	0.16	0.15	0.16	0.17	0.18	0.19	1.1%
Shipping, International	0.34	0.28	0.32	0.32	0.32	0.32	0.6%
Recreational Boats	0.16	0.16	0.18	0.19	0.19	0.20	0.9%
Air	1.44	1.38	1.62	1.82	1.98	2.08	1.8%
Military Use	0.30	0.32	0.37	0.38	0.39	0.39	0.9%
Lubricants	0.09	0.09	0.10	0.11	0.12	0.13	1.5%
Pipeline Fuel	0.32	0.33	0.35	0.36	0.42	0.43	1.2%
Total	**13.50**	**13.54**	**16.20**	**17.75**	**19.13**	**20.68**	**1.9%**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.

Note: Totals may not equal sum of components due to independent rounding. Data for 2000 and 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 and 2002: Energy Information Administration (EIA), *Natural Gas Annual 2001*, DOE/EIA-0131(2001) (Washington, DC, February 2003); Federal Highway Administration, *Highway Statistics 2001* (Washington, DC, November 2002); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 22 and Annual* (Oak Ridge, TN, September 2002) National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997) U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC97TV (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives to Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; EIA, *State Energy Data Report 2000*, DOE/EIA-0214(2000) (Washington, DC, August 2003) U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2002/2001* (Washington, DC, 2002); EIA, *Fuel Oil and Kerosene Sales 2001*, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/fuel_oil_and_kerosene_sales/historical/foks.html; and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

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

Supply, Disposition, and Prices	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Generation by Fuel Type							
Electric Power Sector[1]							
Power Only[2]							
Coal	1852	1875	2201	2318	2560	2975	2.0%
Petroleum	113	77	62	103	82	77	0.0%
Natural Gas[3]	427	450	642	814	972	969	3.4%
Nuclear Power	769	780	794	812	816	816	0.2%
Pumped Storage/Other	-9	-9	-9	-9	-9	-9	0.3%
Renewable Sources[4]	259	304	400	420	442	460	1.8%
Distributed Generation (Natural Gas)	0	0	0	1	3	5	N/A
Non-Utility Generation for Own Use	-20	-34	-37	-37	-37	-37	0.4%
Total	**3391**	**3443**	**4054**	**4423**	**4829**	**5257**	**1.9%**
Combined Heat and Power[5]							
Coal	31	32	33	34	33	33	0.1%
Petroleum	6	6	1	5	2	2	-3.8%
Natural Gas	128	148	174	165	159	149	0.0%
Renewable Sources	4	5	4	4	4	4	-0.7%
Non-Utility Generation for Own Use	-9	-11	-24	-24	-24	-24	3.6%
Total	**160**	**183**	**188**	**183**	**175**	**164**	**-0.5%**
Net Available to the Grid	**3551**	**3626**	**4242**	**4606**	**5004**	**5421**	**1.8%**
End-Use Sector Generation							
Combined Heat and Power[6]							
Coal	21	21	21	21	21	21	-0.0%
Petroleum	6	5	12	15	17	18	5.6%
Natural Gas	83	84	109	129	153	181	3.4%
Other Gaseous Fuels[7]	4	5	9	11	12	13	4.3%
Renewable Sources[4]	29	30	39	45	50	54	2.6%
Other[8]	9	11	11	11	11	11	-0.0%
Total	**151**	**157**	**202**	**231**	**264**	**299**	**2.8%**
Other End-Use Generators[9]	3	4	5	5	5	7	1.9%
Generation for Own Use	-129	-134	-158	-173	-190	-210	2.0%
Total Sales to the Grid	**25**	**27**	**48**	**63**	**80**	**95**	**5.6%**
Total Electricity Generation	**3734**	**3831**	**4510**	**4904**	**5335**	**5787**	**1.8%**
Net Imports	**22**	**22**	**31**	**32**	**21**	**8**	**-4.6%**
Electricity Sales by Sector							
Residential	1203	1268	1428	1531	1641	1747	1.4%
Commercial	1197	1208	1480	1653	1828	2003	2.2%
Industrial	964	994	1120	1216	1310	1422	1.6%
Transportation	22	22	26	29	32	35	2.1%
Total	**3386**	**3492**	**4055**	**4429**	**4811**	**5207**	**1.8%**
End-Use Prices[10] (2002 cents per kilowatthour)							
Residential	8.7	8.4	7.9	8.1	8.1	8.1	-0.2%
Commercial	8.0	7.8	7.0	7.2	7.2	7.3	-0.3%
Industrial	5.2	5.0	4.6	4.7	4.8	4.8	-0.2%
Transportation	7.4	7.2	6.7	6.9	6.8	6.8	-0.2%
All Sectors Average	**7.4**	**7.2**	**6.6**	**6.8**	**6.9**	**6.9**	**-0.2%**
Prices by Service Category[10] (2002 cents per kilowatthour)							
Generation	4.8	4.6	4.1	4.4	4.5	4.5	-0.1%
Transmission	0.6	0.6	0.6	0.7	0.7	0.7	0.9%
Distribution	2.0	2.0	1.9	1.8	1.8	1.7	-0.7%

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

Supply, Disposition, and Prices	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Electric Power Sector Emissions[1]							
Sulfur Dioxide (million tons)	10.63	10.54	9.90	8.95	8.94	8.95	-0.7%
Nitrogen Oxide (million tons)	4.75	4.39	3.50	3.60	3.67	3.75	-0.7%
Mercury (tons)	49.14	50.95	52.20	52.65	53.59	54.37	0.3%

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes plants that only produce electricity.
[3]Includes electricity generation from fuel cells.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[5]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[7]Other gaseous fuels include refinery and still gas.
[8]Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.
[9]Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[10]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001 and 2002 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002), and supporting databases. 2001 and 2002 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2001 and 2002 prices: EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E. **Projections**: EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

Table A9. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Electric Power Sector[2]							
Power Only[3]							
Coal Steam	305.5	305.7	305.1	316.4	348.4	407.2	1.3%
Other Fossil Steam[4]	133.8	132.5	105.0	101.6	100.0	95.4	-1.4%
Combined Cycle	43.0	81.0	127.1	158.8	184.4	202.3	4.1%
Combustion Turbine/Diesel	97.3	123.5	131.1	152.7	163.9	175.0	1.5%
Nuclear Power[5]	98.2	98.7	100.6	102.1	102.6	102.6	0.2%
Pumped Storage	19.9	20.2	20.3	20.3	20.3	20.3	0.0%
Fuel Cells	0.0	0.0	0.1	0.1	0.1	0.1	N/A
Renewable Sources[6]	90.4	91.4	97.1	101.0	105.7	109.9	0.8%
Distributed Generation[7]	0.0	0.0	0.5	2.4	7.6	12.4	N/A
Total	**788.0**	**853.1**	**886.8**	**955.3**	**1032.9**	**1125.1**	**1.2%**
Combined Heat and Power[8]							
Coal Steam	5.2	5.2	5.1	5.1	5.1	5.1	-0.1%
Other Fossil Steam[4]	1.1	1.1	1.1	1.1	1.1	1.1	N/A
Combined Cycle	22.5	29.4	32.9	32.9	32.9	32.9	0.5%
Combustion Turbine/Diesel	4.7	5.4	5.4	5.4	5.4	5.4	0.0%
Renewable Sources[6]	0.3	0.3	0.3	0.3	0.3	0.3	N/A
Total	33.8	41.4	44.8	44.8	44.8	44.8	0.3%
Total Electric Power Industry	**821.8**	**894.5**	**931.7**	**1000.2**	**1077.7**	**1169.9**	**1.2%**
Cumulative Planned Additions[9]							
Coal Steam	0.0	0.0	1.1	1.1	1.1	1.1	N/A
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combined Cycle	0.0	0.0	43.5	43.5	43.5	43.5	N/A
Combustion Turbine/Diesel	0.0	0.0	8.1	8.1	8.1	8.1	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.1	0.1	0.1	0.1	N/A
Renewable Sources[6]	0.0	0.0	4.3	4.6	4.7	4.8	N/A
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Total	**0.0**	**0.0**	**57.1**	**57.4**	**57.5**	**57.6**	**N/A**
Cumulative Unplanned Additions[9]							
Coal Steam	0.0	0.0	5.7	17.5	50.7	110.6	N/A
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combined Cycle	0.0	0.0	6.6	38.3	64.0	81.9	N/A
Combustion Turbine/Diesel	0.0	0.0	10.5	32.8	46.0	59.1	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[6]	0.0	0.0	1.1	4.6	9.3	13.3	N/A
Distributed Generation[7]	0.0	0.0	0.5	2.4	7.6	12.4	N/A
Total	**0.0**	**0.0**	**24.3**	**95.7**	**177.5**	**277.2**	**N/A**
Cumulative Total Additions	**0.0**	**0.0**	**81.4**	**153.0**	**235.0**	**334.8**	**N/A**
Cumulative Retirements[10]							
Coal Steam	0.0	0.0	7.5	8.0	9.3	10.4	N/A
Other Fossil Steam[4]	0.0	0.0	25.6	29.0	30.6	35.2	N/A
Combined Cycle	0.0	0.0	1.1	1.1	1.1	1.1	N/A
Combustion Turbine/Diesel	0.0	0.0	10.2	11.0	13.0	14.9	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[6]	0.0	0.0	0.1	0.1	0.1	0.1	N/A
Total	**0.0**	**0.0**	**44.6**	**49.3**	**54.2**	**61.8**	**N/A**

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

Net Summer Capacity[1]	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
End-Use Sector							
Combined Heat and Power[11]							
Coal	4.1	4.2	4.1	4.1	4.1	4.1	-0.0%
Petroleum	1.0	1.0	1.6	1.9	2.2	2.3	3.8%
Natural Gas	13.9	14.1	17.8	20.4	23.7	27.6	3.0%
Other Gaseous Fuels	1.6	1.8	2.2	2.4	2.6	2.7	1.8%
Renewable Sources[6]	4.0	4.2	5.6	6.7	7.5	8.3	3.0%
Other	0.3	0.3	0.3	0.3	0.3	0.3	N/A
Total	**24.8**	**25.5**	**31.7**	**35.8**	**40.5**	**45.3**	**2.5%**
Other End-Use Generators[12]							
Renewable Sources[13]	1.1	1.1	1.4	1.4	1.6	2.1	3.1%
Cumulative Additions[9]							
Combined Heat and Power[11]	0.0	0.0	6.2	10.4	15.0	19.8	N/A
Other End-Use Generators[12]	0.0	0.0	0.3	0.4	0.5	1.1	N/A

[1]Net summer capacity 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 electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capacity.
[5]Nuclear capacity reflects operating capacity of existing units, including 3.9 gigawatts of uprates through 2025.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[7]Primarily peak load capacity fueled by natural gas.
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[9]Cumulative additions after December 31, 2002.
[10]Cumulative retirements after December 31, 2002.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[12]Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[13]See Table A17 for more detail.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001 and 2002 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections**: EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

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

Electricity Trade	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Interregional Electricity Trade							
Gross Domestic Firm Power Trade	142.7	138.9	107.1	70.7	41.5	41.5	-5.1%
Gross Domestic Economy Trade	182.1	209.9	229.7	221.2	218.4	183.4	-0.6%
Gross Domestic Trade	**324.8**	**348.8**	**336.8**	**291.8**	**259.9**	**224.9**	**-1.9%**
Gross Domestic Firm Power Sales (million 2002 dollars)	7126.8	6932.4	5345.8	3528.2	2074.2	2074.2	-5.1%
Gross Domestic Economy Sales (million 2002 dollars)	8870.2	6809.8	7629.6	8674.0	8663.8	7319.5	0.3%
Gross Domestic Sales (million 2002 dollars)	**15997.0**	**13742.1**	**12975.3**	**12202.2**	**10738.0**	**9393.7**	**-1.6%**
International Electricity Trade							
Firm Power Imports From Canada and Mexico	12.1	9.5	5.8	2.6	0.0	0.0	-21.9%
Economy Imports From Canada and Mexico	26.3	26.8	41.3	40.9	28.9	15.1	-2.5%
Gross Imports From Canada and Mexico	**38.4**	**36.3**	**47.2**	**43.5**	**28.9**	**15.2**	**-3.7%**
Firm Power Exports To Canada and Mexico	6.6	5.6	8.7	3.9	0.0	0.0	N/A
Economy Exports To Canada and Mexico	9.8	8.7	7.7	7.7	7.7	7.7	-0.6%
Gross Exports To Canada and Mexico	**16.4**	**14.3**	**16.4**	**11.5**	**7.7**	**7.7**	**-2.7%**

N/A = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 2001 and 2002 interregional firm electricity trade data: North American Electric Reliability Council (NERC), Electricity Sales and Demand Database 1999. 2001 and 2002 Mexican electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 2001: National Energy Board, *Annual Report 2001*. 2002 Canadian electricity trade data: National Energy Board, Annual Report 2002. **Projections:** Energy Information Administration, AEO2004 National Energy Modeling System run AEO2004.D101703E.

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

Supply and Disposition	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Crude Oil							
Domestic Crude Production[1]	5.74	5.62	5.93	5.53	4.95	4.61	-0.9%
Alaska	0.96	0.98	0.92	0.93	0.72	0.51	-2.8%
Lower 48 States	4.78	4.64	5.01	4.59	4.23	4.11	-0.5%
Net Imports	9.31	9.13	11.21	13.47	14.50	15.74	2.4%
Gross Imports	9.33	9.14	11.29	13.53	14.53	15.76	2.4%
Exports	0.02	0.01	0.08	0.06	0.03	0.02	3.3%
Other Crude Supply[2]	0.02	0.07	0.00	0.00	0.00	0.00	N/A
Total Crude Supply	**15.07**	**14.83**	**17.15**	**19.00**	**19.45**	**20.35**	**1.4%**
Natural Gas Plant Liquids	**1.87**	**1.88**	**2.24**	**2.31**	**2.48**	**2.47**	**1.2%**
Other Inputs[3]	**0.30**	**0.67**	**0.47**	**0.44**	**0.46**	**0.48**	**-1.5%**
Refinery Processing Gain[4]	**0.93**	**0.98**	**0.88**	**0.97**	**1.00**	**1.04**	**0.2%**
Net Product Imports[5]	**1.59**	**1.41**	**1.95**	**2.05**	**2.99**	**3.94**	**4.6%**
Gross Refined Product Imports[6]	2.08	1.92	2.17	2.29	2.82	3.60	2.8%
Unfinished Oil Imports	0.38	0.41	0.72	0.74	1.15	1.34	5.3%
Ether Imports	0.08	0.06	0.00	0.00	0.00	0.00	N/A
Exports	0.95	0.97	0.94	0.98	0.98	1.01	0.1%
Total Primary Supply[7]	**19.75**	**19.77**	**22.69**	**24.77**	**26.38**	**28.27**	**1.6%**
Refined Petroleum Products Supplied							
Motor Gasoline[8]	8.62	8.86	10.59	11.51	12.30	13.30	1.8%
Jet Fuel[9]	1.66	1.61	1.90	2.10	2.27	2.37	1.7%
Distillate Fuel[10]	3.88	3.68	4.38	4.94	5.24	5.71	1.9%
Residual Fuel	0.86	0.74	0.71	0.77	0.77	0.75	0.1%
Other[11]	4.69	4.72	5.13	5.48	5.84	6.16	1.2%
Total	**19.71**	**19.61**	**22.71**	**24.80**	**26.41**	**28.30**	**1.6%**
Refined Petroleum Products Supplied							
Residential and Commercial	1.23	1.22	1.38	1.39	1.40	1.40	0.6%
Industrial[12]	4.79	4.80	5.14	5.50	5.86	6.21	1.1%
Transportation	13.14	13.21	15.91	17.44	18.77	20.32	1.9%
Electric Generators[13]	0.55	0.38	0.29	0.47	0.38	0.36	-0.2%
Total	**19.71**	**19.61**	**22.71**	**24.80**	**26.41**	**28.30**	**1.6%**
Discrepancy[14]	**0.04**	**0.16**	**-0.02**	**-0.03**	**-0.04**	**-0.03**	**N/A**
World Oil Price (2002 dollars per barrel)[15]	**22.25**	**23.68**	**24.17**	**25.07**	**26.02**	**27.00**	**0.6%**
Import Share of Product Supplied	**0.55**	**0.54**	**0.58**	**0.63**	**0.66**	**0.70**	**1.1%**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2002 dollars)	**90.15**	**90.38**	**118.31**	**143.82**	**168.99**	**200.24**	**3.5%**
Domestic Refinery Distillation Capacity[16]	**16.8**	**16.8**	**18.7**	**20.4**	**20.8**	**21.8**	**1.1%**
Capacity Utilization Rate (percent)	**93.0**	**91.0**	**93.1**	**94.7**	**94.8**	**94.8**	**0.2%**

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[6]Includes other hydrocarbons, alcohols, and blending components.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes only kerosene type.
[10]Includes distillate and kerosene.
[11]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[12]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[13]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses, and gains.
[15]Average refiner acquisition cost for imported crude oil.
[16]End-of-year capacity.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001 and 2002 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). Other 2001 data: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2002 data: EIA, *Petroleum Supply Annual 2002,* DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). **Projections:** EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

Table A12. Petroleum Product Prices
(2002 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
World Oil Price (2002 dollars per barrel)	**22.25**	**23.68**	**24.17**	**25.07**	**26.02**	**27.00**	**0.6%**
Delivered Sector Product Prices							
Residential							
Distillate Fuel	126.1	114.2	108.4	111.8	116.4	118.4	0.2%
Liquefied Petroleum Gas	129.1	110.8	119.1	124.1	126.9	130.3	0.7%
Commercial							
Distillate Fuel	88.5	84.1	75.6	78.4	83.3	85.3	0.1%
Residual Fuel	52.5	63.1	61.8	64.0	66.1	68.1	0.3%
Residual Fuel (2002 dollars per barrel)	22.07	26.48	25.97	26.87	27.75	28.59	0.3%
Industrial[1]							
Distillate Fuel	91.8	86.2	78.8	81.1	86.6	88.8	0.1%
Liquefied Petroleum Gas	107.1	71.1	83.4	88.3	91.4	95.3	1.3%
Residual Fuel	49.6	58.3	56.0	58.2	60.3	62.4	0.3%
Residual Fuel (2002 dollars per barrel)	20.82	24.48	23.54	24.42	25.34	26.22	0.3%
Transportation							
Diesel Fuel (distillate)[2]	141.0	130.6	140.3	140.9	138.6	139.0	0.3%
Jet Fuel[3]	84.7	80.6	77.8	79.0	81.8	83.9	0.2%
Motor Gasoline[4]	148.6	138.1	146.9	146.8	147.3	149.2	0.3%
Liquid Petroleum Gas	146.9	128.7	128.3	132.0	133.0	135.8	0.2%
Residual Fuel	59.0	56.5	53.9	55.9	58.0	60.2	0.3%
Residual Fuel (2002 dollars per barrel)	24.80	23.71	22.62	23.48	24.37	25.28	0.3%
Ethanol (E85)[5]	148.1	135.8	153.9	159.1	163.4	166.1	0.9%
Electric Power[6]							
Distillate Fuel	86.5	77.4	68.2	70.5	75.8	77.9	0.0%
Residual Fuel	68.1	60.4	59.7	61.9	64.5	67.4	0.5%
Residual Fuel (2002 dollars per barrel)	28.61	25.38	25.07	26.01	27.07	28.30	0.5%
Refined Petroleum Product Prices[7]							
Distillate Fuel	126.8	118.1	123.8	124.4	125.9	127.3	0.3%
Jet Fuel[3]	84.7	80.6	77.8	79.0	81.8	83.9	0.2%
Liquefied Petroleum Gas	111.5	79.6	91.3	96.1	99.1	102.6	1.1%
Motor Gasoline[4]	148.5	138.1	146.9	146.8	147.3	149.2	0.3%
Residual Fuel	62.2	58.6	56.6	58.8	61.1	63.3	0.3%
Residual Fuel (2002 dollars per barrel)	26.14	24.62	23.76	24.71	25.65	26.60	0.3%
Average	**126.7**	**116.1**	**123.9**	**124.8**	**126.3**	**128.6**	**0.4%**

[1]Includes combined heat and power, which produces electricity and other useful thermal energy.
[2] Diesel fuel containing 500 part per million (ppm) or 15 ppm sulfur. Includes Federal and State taxes while excluding county and local taxes.
[3]Includes only kerosene type.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001 and 2002 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2002*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/ current/pdf/pmaall.pdf (August 2003). 2001 and 2002 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2001 and 2002 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 and 2002 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2001 and 2002 world oil price: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections**: EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

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

Supply and Disposition	Reference Case 2001	2002	2010	2015	2020	2025	Annual Growth 2002-2025 (percent)
Production							
Dry Gas Production[1]	19.70	19.05	20.50	21.62	23.79	23.99	1.0%
Supplemental Natural Gas[2]	0.09	0.08	0.10	0.10	0.10	0.10	0.8%
Net Imports	**3.60**	**3.49**	**5.50**	**6.24**	**6.47**	**7.24**	**3.2%**
Canada	3.56	3.59	3.68	3.17	2.51	2.56	-1.4%
Mexico	-0.13	-0.26	-0.34	-0.15	-0.18	-0.12	-3.2%
Liquefied Natural Gas	0.17	0.17	2.16	3.22	4.14	4.80	15.8%
Total Supply	**23.39**	**22.62**	**26.09**	**27.95**	**30.36**	**31.33**	**1.4%**
Consumption by Sector							
Residential	4.78	4.92	5.53	5.68	5.92	6.09	0.9%
Commercial	3.24	3.12	3.48	3.62	3.83	4.04	1.1%
Industrial[3]	7.35	7.23	8.39	8.87	9.57	10.29	1.5%
Electric Generators[4]	5.38	5.55	6.66	7.64	8.61	8.39	1.8%
Transportation[5]	0.01	0.01	0.06	0.08	0.10	0.11	9.5%
Pipeline Fuel	0.62	0.63	0.67	0.70	0.81	0.84	1.2%
Lease and Plant Fuel[6]	1.09	1.32	1.36	1.44	1.61	1.65	1.0%
Total	**22.48**	**22.78**	**26.15**	**28.03**	**30.44**	**31.41**	**1.4%**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Discrepancy[7]	**0.92**	**-0.16**	**-0.06**	**-0.07**	**-0.08**	**-0.09**	**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 for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as vehicle fuel.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[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, 2000 and 2001 values include net storage injections.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001 supply values: Energy Information Administration (EIA), *Natural Gas Annual 2001*, DOE/EIA-0131(2001) (Washington, DC, February 2003). 2002 supply values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2001 and 2002 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections:** EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

Table A14. Natural Gas Prices, Margins, and Revenues
(2002 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Source Price							
Average Lower 48 Wellhead Price[1]	4.14	2.95	3.40	4.19	4.28	4.40	1.8%
Average Import Price	4.49	3.14	3.78	4.59	4.58	4.67	1.7%
Average[2]	**4.20**	**2.98**	**3.49**	**4.29**	**4.35**	**4.47**	**1.8%**
Delivered Prices							
Residential	9.79	7.86	7.88	8.52	8.47	8.56	0.4%
Commercial	8.67	6.55	6.83	7.52	7.52	7.62	0.7%
Industrial[3]	5.04	3.85	4.16	4.94	5.02	5.13	1.3%
Electric Generators[4]	5.40	3.85	4.12	4.87	4.94	5.01	1.2%
Transportation[5]	8.94	7.58	8.49	9.32	9.32	9.34	0.9%
Average[6]	**6.81**	**5.21**	**5.41**	**6.09**	**6.09**	**6.19**	**0.8%**
Transmission and Distribution Margins[7]							
Residential	5.59	4.88	4.40	4.23	4.11	4.09	-0.8%
Commercial	4.47	3.56	3.34	3.23	3.17	3.15	-0.5%
Industrial[3]	0.84	0.87	0.68	0.65	0.67	0.66	-1.2%
Electric Generators[4]	1.20	0.86	0.63	0.58	0.59	0.54	-2.0%
Transportation[5]	4.74	4.60	5.00	5.03	4.96	4.87	0.2%
Average[6]	**2.61**	**2.23**	**1.92**	**1.80**	**1.74**	**1.72**	**-1.1%**
Transmission and Distribution Revenue (billion 2002 dollars)							
Residential	26.74	24.02	24.33	24.02	24.34	24.89	0.2%
Commercial	14.49	11.12	11.61	11.71	12.13	12.72	0.6%
Industrial[3]	6.20	6.27	5.67	5.78	6.42	6.80	0.3%
Electric Generators[4]	6.46	4.78	4.21	4.46	5.10	4.54	-0.2%
Transportation[5]	0.05	0.06	0.28	0.40	0.48	0.54	9.7%
Total	**53.93**	**46.25**	**46.11**	**46.37**	**48.46**	**49.49**	**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 for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001 residential, commercial, and transportation delivered prices; average lower 48 wellhead price; and average import price: Energy Information Administration (EIA), *Natural Gas Annual 2001*, DOE/EIA-0131(2001) (Washington, DC, February 2003). 2001 and 2002 electric generators delivered price: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 and 2002 industrial delivered prices based on EIA, *Manufacturing Energy Consumption Survey 1998*. 2002 residential, commercial, and transportation delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). Other 2001 and 2002 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

Table A15. Oil and Gas Supply

Production and Supply	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Crude Oil							
Lower 48 Average Wellhead Price[1] (2002 dollars per barrel)	**23.16**	**24.54**	**23.61**	**24.56**	**25.82**	**26.72**	**0.4%**
Production (million barrels per day)[2]							
U.S. Total	**5.74**	**5.62**	**5.93**	**5.53**	**4.95**	**4.61**	**-0.9%**
Lower 48 Onshore	3.14	3.11	2.61	2.38	2.20	2.04	-1.8%
Lower 48 Offshore	1.64	1.53	2.40	2.21	2.03	2.06	1.3%
Alaska	0.96	0.98	0.92	0.93	0.72	0.51	-2.8%
Lower 48 End of Year Reserves (billion barrels)[2]	**19.14**	**19.05**	**18.36**	**17.13**	**16.20**	**14.98**	**-1.0%**
Natural Gas							
Lower 48 Average Wellhead Price[1] (2002 dollars per thousand cubic feet)	**4.14**	**2.95**	**3.40**	**4.19**	**4.28**	**4.40**	**1.8%**
Dry Production (trillion cubic feet)[3]							
U.S. Total	**19.70**	**19.05**	**20.50**	**21.62**	**23.79**	**23.99**	**1.0%**
Lower 48 Onshore	13.90	13.76	14.48	16.11	16.41	16.26	0.7%
Associated-Dissolved[4]	1.63	1.60	1.41	1.31	1.23	1.17	-1.4%
Non-Associated	12.27	12.16	13.08	14.81	15.18	15.09	0.9%
Conventional	6.62	6.23	5.80	6.13	6.07	5.92	-0.2%
Unconventional	5.65	5.93	7.28	8.67	9.11	9.16	1.9%
Lower 48 Offshore	5.37	4.86	5.41	4.87	5.09	5.03	0.1%
Associated-Dissolved[4]	1.15	1.05	1.61	1.33	1.34	1.43	1.4%
Non-Associated	4.21	3.81	3.80	3.54	3.75	3.60	-0.3%
Alaska	0.44	0.43	0.60	0.64	2.29	2.71	8.3%
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**174.66**	**180.03**	**201.20**	**203.74**	**200.97**	**193.51**	**0.3%**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.09**	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.8%**
Total Lower 48 Wells (thousands)	**34.10**	**24.47**	**24.78**	**26.80**	**26.83**	**26.00**	**0.3%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.

Sources: 2001 and 2002 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2002,* DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). 2000 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2001) (Washington, DC, November 2002). 2001 natural gas lower 48 average wellhead price, and total natural gas production: EIA, *Natural Gas Annual 2001,* DOE/EIA-0131(2001) (Washington, DC, February 2003). 2002 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). Other 2001 and 2002 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

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

Supply, Disposition, and Prices	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Production[1]							
Appalachia	443	408	408	395	402	419	0.1%
Interior	147	147	169	162	170	178	0.8%
West	548	550	653	728	805	946	2.4%
East of the Mississippi	539	504	524	505	522	547	0.4%
West of the Mississippi	599	601	706	780	854	996	2.2%
Total	**1138**	**1105**	**1230**	**1285**	**1377**	**1543**	**1.5%**
Net Imports							
Imports	20	17	33	38	42	46	4.4%
Exports	49	40	35	32	27	23	-2.3%
Total	**-29**	**-23**	**-2**	**6**	**14**	**23**	**N/A**
Total Supply[2]	**1109**	**1083**	**1228**	**1291**	**1391**	**1566**	**1.6%**
Consumption by Sector							
Residential and Commercial	4	4	5	5	5	5	0.4%
Industrial[3]	65	63	65	65	66	67	0.3%
of which: Coal to Liquids	0	0	0	0	0	0	N/A
Coke Plants	26	22	23	21	19	17	-1.2%
Electric Generators[4]	964	976	1136	1200	1301	1477	1.8%
Total	**1060**	**1066**	**1229**	**1291**	**1391**	**1567**	**1.7%**
Discrepancy and Stock Change[5]	**49**	**17**	**-0**	**-0**	**-0**	**-1**	**N/A**
Average Minemouth Price							
(2002 dollars per short ton)	17.79	17.90	16.88	16.47	16.32	16.57	-0.3%
(2002 dollars per million Btu)	0.87	0.87	0.82	0.81	0.80	0.82	-0.2%
Delivered Prices (2002 dollars per short ton)[6]							
Industrial	32.96	33.24	34.46	33.83	33.43	33.33	0.0%
Coke Plants	46.94	51.27	53.68	52.13	50.45	48.42	-0.2%
Electric Generators							
(2002 dollars per short ton)	25.13	25.96	24.67	24.34	24.01	24.31	-0.3%
(2002 dollars per million Btu)	1.25	1.26	1.22	1.22	1.20	1.22	-0.1%
Average	**26.15**	**26.93**	**25.74**	**25.28**	**24.83**	**24.96**	**-0.3%**
Exports[7]	37.39	40.44	36.47	35.25	34.13	32.34	-1.0%

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 10.6 million tons in 2001 and 11.1 million tons in 2002.
[2]Production plus net imports plus net storage withdrawals.
[3]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001: Energy Information Administration (EIA), *Annual Coal Report 2002*, DOE/EIA-0584(2002) (Washington, DC, November 2003). 2002 data based on: EIA, *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003); EIA, *Annual Coal Report 2002*, DOE/EIA-0584(2002) (Washington, DC, November 2003); and EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E. **Projections:** EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

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

Capacity and Generation	Reference Case 2001	2002	2010	2015	2020	2025	Annual Growth 2002-2025 (percent)
Electric Power Sector[1]							
Net Summer Capacity							
Conventional Hydropower	78.13	78.29	78.69	78.68	78.68	78.68	0.0%
Geothermal[2]	2.88	2.89	4.01	5.11	6.06	6.84	3.8%
Municipal Solid Waste[3]	3.38	3.49	3.92	3.92	3.95	3.95	0.5%
Wood and Other Biomass[4,5]	1.79	1.83	2.20	2.31	3.04	3.74	3.2%
Solar Thermal	0.33	0.33	0.43	0.47	0.49	0.52	1.9%
Solar Photovoltaic[6]	0.02	0.02	0.15	0.24	0.32	0.41	13.5%
Wind	4.15	4.83	8.01	10.48	13.39	15.99	5.3%
Total	**90.67**	**91.69**	**97.42**	**101.22**	**105.93**	**110.13**	**0.8%**
Generation (billion kilowatthours)							
Conventional Hydropower	213.7	255.78	304.37	304.48	304.63	304.80	0.8%
Geothermal[2]	13.74	13.36	23.25	32.31	40.14	46.66	5.6%
Municipal Solid Waste[3]	19.22	20.02	28.11	28.18	28.44	28.50	1.5%
Wood and Other Biomass[5]	8.56	8.67	23.53	25.07	27.64	29.16	5.4%
Dedicated Plants	7.22	6.32	13.26	14.03	18.47	22.90	5.8%
Cofiring	1.34	2.35	10.26	11.05	9.17	6.25	4.3%
Solar Thermal	0.54	0.54	0.84	0.97	1.04	1.11	3.2%
Solar Photovoltaic[6]	0.00	0.00	0.36	0.57	0.79	1.02	28.8%
Wind	6.74	10.51	24.07	32.95	43.54	53.16	7.3%
Total	**262.5**	**308.87**	**404.52**	**424.54**	**446.22**	**464.40**	**1.8%**
End-Use Sector							
Net Summer Capacity							
Combined Heat and Power[7]							
Municipal Solid Waste	0.21	0.25	0.25	0.25	0.25	0.25	0.0%
Biomass	3.80	3.91	5.36	6.44	7.26	8.03	3.2%
Total	**4.01**	**4.16**	**5.61**	**6.69**	**7.51**	**8.29**	**3.0%**
Other End-Use Generators[8]							
Conventional Hydropower[9]	1.02	1.02	1.02	1.02	1.02	1.02	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Solar Photovoltaic	0.03	0.04	0.39	0.42	0.58	1.13	15.4%
Total	**1.05**	**1.06**	**1.41**	**1.45**	**1.61**	**2.15**	**3.1%**
Generation (billion kilowatthours)							
Combined Heat and Power[7]							
Municipal Solid Waste	1.78	1.84	2.10	2.10	2.10	2.10	0.6%
Biomass	26.91	28.16	36.63	42.96	47.72	52.26	2.7%
Total	**28.68**	**30.00**	**38.73**	**45.06**	**49.82**	**54.36**	**2.6%**
Other End-Use Generators[8]							
Conventional Hydropower[9]	3.21	4.11	4.11	4.11	4.11	4.11	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Solar Photovoltaic	0.06	0.09	0.82	0.91	1.26	2.42	15.4%
Total	**3.27**	**4.20**	**4.93**	**5.02**	**5.37**	**6.53**	**1.9%**

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Includes projections for energy crops after 2010.
[6]Does not include off-grid photovoltaics (PV). See Annual Energy Review 2002 Table 10.6 for estimates of 1989-2001 PV shipments, including exports, for both grid-connected and off-grid applications.
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[8]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[9]Represents own-use industrial hydroelectric power.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001 and 2002 capacity: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2001 and 2002 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections:** EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

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

Sector and Source	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Marketed Renewable Energy[2]							
Residential	**0.36**	**0.39**	**0.40**	**0.41**	**0.41**	**0.41**	**0.1%**
Wood	0.36	0.39	0.40	0.41	0.41	0.41	0.1%
Commercial	**0.09**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.0%**
Biomass	0.09	0.10	0.10	0.10	0.10	0.10	0.0%
Industrial[3]	**1.64**	**1.66**	**2.00**	**2.26**	**2.48**	**2.70**	**2.1%**
Conventional Hydroelectric	0.03	0.04	0.04	0.04	0.04	0.04	N/A
Municipal Solid Waste	0.01	0.01	0.01	0.01	0.01	0.01	N/A
Biomass	1.59	1.60	1.95	2.20	2.43	2.65	2.2%
Transportation	**0.14**	**0.17**	**0.29**	**0.31**	**0.33**	**0.35**	**3.2%**
Ethanol used in E85[4]	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Ethanol used in Gasoline Blending	0.14	0.17	0.29	0.31	0.33	0.35	3.2%
Electric Generators[5]	**3.16**	**3.69**	**4.68**	**5.08**	**5.47**	**5.79**	**2.0%**
Conventional Hydroelectric	2.29	2.75	3.13	3.13	3.13	3.13	0.6%
Geothermal	0.29	0.30	0.61	0.90	1.15	1.36	6.9%
Municipal Solid Waste[6]	0.33	0.34	0.39	0.39	0.39	0.39	0.6%
Biomass	0.15	0.17	0.29	0.30	0.33	0.34	3.1%
Dedicated Plants	0.12	0.11	0.15	0.16	0.21	0.26	3.8%
Cofiring	0.03	0.06	0.14	0.15	0.12	0.08	1.4%
Solar Thermal	0.01	0.01	0.01	0.02	0.02	0.02	6.0%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Wind	0.08	0.13	0.25	0.34	0.45	0.55	6.6%
Total Marketed Renewable Energy	**5.40**	**6.01**	**7.47**	**8.15**	**8.78**	**9.35**	**1.9%**
Sources of Ethanol							
From Corn	0.14	0.17	0.29	0.30	0.31	0.31	2.5%
From Cellulose	0.00	0.00	0.00	0.01	0.02	0.05	N/A
Total	**0.14**	**0.17**	**0.29**	**0.31**	**0.33**	**0.35**	**3.2%**
Non-Marketed Renewable Energy[7]							
Selected Consumption							
Residential	**0.04**	**0.02**	**0.03**	**0.04**	**0.04**	**0.05**	**3.2%**
Solar Hot Water Heating	0.04	0.02	0.03	0.03	0.03	0.04	2.2%
Geothermal Heat Pumps	0.00	0.00	0.00	0.01	0.01	0.01	9.0%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	15.0%
Commercial	**0.02**	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**1.5%**
Solar Thermal	0.02	0.02	0.03	0.03	0.03	0.03	0.6%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.01	15.5%

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table A8.
[3]Includes all electricity production by industrial and other combined heat and power for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Includes landfill gas.
[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001 and 2002 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2001 and 2002 electric generators: EIA, Form EIA-860: "Annual Electric Generator Report" (preliminary). Other 2001 and 2002 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

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

Sector and Source	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Residential							
Petroleum	105.6	104.0	110.4	109.1	107.1	104.5	0.0%
Natural Gas	259.5	267.2	300.4	308.1	321.2	330.7	0.9%
Coal	1.1	1.1	1.2	1.1	1.1	1.1	-0.3%
Electricity	790.8	816.7	905.3	954.0	1019.9	1106.7	1.3%
Total	**1157.**	**1189.0**	**1317.2**	**1372.3**	**1449.2**	**1543.0**	**1.1%**
Commercial							
Petroleum	52.9	52.6	66.2	68.6	70.2	72.2	1.4%
Natural Gas	165.0	169.4	188.7	196.5	207.9	219.4	1.1%
Coal	9.2	9.2	9.3	9.3	9.2	9.2	0.0%
Electricity	787.4	778.0	938.4	1030.1	1135.5	1269.2	2.2%
Total	**1014.**	**1009.1**	**1202.5**	**1304.4**	**1422.9**	**1570.1**	**1.9%**
Industrial[1]							
Petroleum	409.9	412.8	365.4	388.2	408.0	428.4	0.2%
Natural Gas[2]	441.5	432.7	522.1	552.2	598.6	639.4	1.7%
Coal	196.8	185.1	191.9	187.1	183.3	181.1	-0.1%
Electricity	634.1	640.0	710.3	757.4	813.8	900.7	1.5%
Total	**1682.**	**1670.6**	**1789.6**	**1885.0**	**2003.6**	**2149.5**	**1.1%**
Transportation							
Petroleum[3]	1789.	1811.2	2193.2	2406.2	2590.9	2805.8	1.9%
Natural Gas[4]	33.9	35.2	39.5	42.4	49.1	51.3	1.7%
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Electricity	14.2	14.2	16.7	18.1	19.9	22.4	2.0%
Total	**1837.**	**1860.6**	**2249.5**	**2466.7**	**2659.9**	**2879.5**	**1.9%**
Total Carbon Dioxide Emissions by Delivered Fuel							
Petroleum[3]	2358.	2380.5	2735.2	2972.0	3176.2	3410.9	1.6%
Natural Gas	899.9	904.4	1050.7	1099.2	1176.8	1240.8	1.4%
Coal	207.1	195.4	202.4	197.5	193.6	191.4	-0.1%
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Electricity	2226.	2249.0	2570.6	2759.6	2989.0	3299.0	1.7%
Total	**5691.**	**5729.3**	**6558.8**	**7028.4**	**7535.6**	**8142.0**	**1.5%**
Electric Power[6]							
Petroleum	99.6	72.2	51.0	78.6	65.2	61.6	-0.7%
Natural Gas	289.1	299.1	358.5	410.9	463.3	451.6	1.8%
Coal	1838.	1877.8	2161.2	2270.2	2460.5	2785.8	1.7%
Total	**2226.**	**2249.0**	**2570.6**	**2759.6**	**2989.0**	**3299.0**	**1.7%**
Total Carbon Dioxide Emissions by Primary Fuel[7]							
Petroleum[3]	2457.	2452.7	2786.1	3050.6	3241.4	3472.5	1.5%
Natural Gas	1189.	1203.4	1409.2	1510.1	1640.1	1692.4	1.5%
Coal	2045.	2073.2	2363.6	2467.7	2654.1	2977.1	1.6%
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Total	**5691.**	**5729.3**	**6558.8**	**7028.4**	**7535.6**	**8142.0**	**1.5%**
Carbon Dioxide Emissions (ton per person)	**19.9**	**19.8**	**21.2**	**21.8**	**22.5**	**23.4**	**0.7%**

[1]Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2000, international bunker fuels accounted for 24 to 30 million metric tons of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes methanol and liquid hydrogen.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.
[7]Emissions from the electric power sector are distributed to the primary fuels.
N/A = Not applicable
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001 and 2002 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2002,* DOE/EIA-0573(2002) (Washington, DC, October 2003). **Projections:** EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

Table A20. Macroeconomic Indicators
(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	Reference Case 2001	2002	2010	2015	2020	2025	Annual Growth 2002-2025 (percent)
Real Gross Domestic Product	**9215**	**9440**	**12190**	**14101**	**16188**	**18520**	**3.0%**
Real Potential Gross Domestic Product	9433	9726	12313	14144	16186	18520	2.8%
Real Disposable Personal Income	**6748**	**7032**	**8894**	**10330**	**11864**	**13826**	**3.0%**
Components of Real Gross Domestic Product							
Real Consumption	6377	6576	8437	9802	11296	12946	3.0%
Real Investment	1575	1590	2387	3021	3726	4661	4.8%
Real Government Spending	1640	1713	1961	2092	2265	2423	1.5%
Real Exports	1076	1059	1838	2481	3376	4546	6.5%
Real Imports	1492	1547	2436	3265	4433	6015	6.1%
Energy Intensity							
(thousand Btu per 1996 dollar of GDP)							
Delivered Energy	7.69	7.55	6.73	6.26	5.84	5.45	-1.4%
Total Energy	10.53	10.36	9.17	8.50	7.91	7.37	-1.5%
Price Indices							
GDP Chain-Type Price Index (1996=1.000)	1.094	1.107	1.301	1.503	1.774	2.121	2.9%
Consumer Price Index (1982-4=1)	1.77	1.80	2.11	2.44	2.89	3.49	2.9%
Wholesale Price Index (1982=1.00)							
All Commodities	1.34	1.31	1.46	1.57	1.74	1.94	1.7%
Fuel and Power	1.05	0.93	1.06	1.18	1.33	1.52	2.2%
Interest Rates (percent, nominal)							
Federal Funds Rate	3.89	1.67	5.42	5.74	6.30	7.00	N/A
10-Year Treasury Note	5.02	4.61	6.60	6.52	7.07	7.95	N/A
AA Utility Bond Rate	7.57	7.19	7.99	8.19	8.59	9.27	N/A
Unemployment Rate (percent)	**4.77**	**5.78**	**4.93**	**4.53**	**4.41**	**4.44**	**N/A**
Housing Starts (millions)	**1.79**	**1.88**	**1.97**	**1.94**	**1.94**	**1.92**	**0.1%**
Commercial Floorspace, Total							
(billion square feet)	**70.2**	**72.1**	**83.8**	**89.9**	**95.9**	**101.8**	**1.5%**
Unit Sales of Light-Duty Vehicles							
(millions)	**17.11**	**16.78**	**18.01**	**18.71**	**20.25**	**21.32**	**1.0%**
Value of Shipments (billion 1996 dollars)							
Total Industrial	5368	5285	6439	7345	8344	9491	2.6%
Non-manufacturing	1309	1222	1425	1585	1710	1855	1.8%
Manufacturing	4059	4064	5013	5760	6634	7636	2.8%
Energy-Intensive	1085	1120	1273	1393	1500	1610	1.6%
Non-Energy Intensive	2974	2944	3741	4367	5135	6026	3.2%
Population and Employment (millions)							
Population, with Armed Forces Overseas	285.9	288.9	309.3	321.9	334.6	347.5	0.8%
Population, aged 16 and over	221.5	224.3	244.1	254.5	264.3	274.3	0.9%
Employment, Nonfarm	131.6	130.5	145.0	153.4	161.2	168.6	1.1%
Employment, Manufacturing	17.7	16.7	16.1	16.2	16.0	16.2	-0.1%
Labor Force	143.9	145.1	159.8	166.3	171.3	176.8	0.9%

GDP = Gross domestic product.
Btu = British thermal unit.
N/A = Not applicable.
Sources: 2001 and 2002: Global Insight macroeconomic model T250803. **Projections:** Energy Information Administration, AEO2004 National Energy Modeling System run AEO2004.D101703E.

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

Supply and Disposition	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
World Oil Price[1] (2002 dollars per barrel)	**22.25**	**23.68**	**24.17**	**25.07**	**26.02**	**27.00**	**0.6%**
Production[2] (Conventional)							
Industrialized Countries							
U.S. (50 states)	8.84	9.16	9.53	9.25	8.89	8.59	-0.3%
Canada	2.09	2.14	1.83	1.64	1.60	1.57	-1.3%
Mexico	3.62	3.61	4.20	4.53	4.60	4.82	1.3%
Western Europe[3]	6.82	6.76	6.34	5.87	5.48	4.97	-1.3%
Japan	0.08	0.08	0.08	0.07	0.06	0.06	-1.1%
Australia and New Zealand	0.79	0.75	0.96	0.91	0.88	0.86	0.6%
Total Industrialized	**22.24**	**22.51**	**22.93**	**22.28**	**21.52**	**20.87**	**-0.3%**
Eurasia							
Former Soviet Union							
Russia	7.30	7.67	9.92	10.52	10.77	10.93	1.6%
Caspian Area[4]	1.48	1.66	3.12	4.40	5.15	6.11	5.8%
Eastern Europe[5]	0.24	0.23	0.33	0.37	0.41	0.45	3.0%
Total Eurasia	**9.02**	**9.56**	**13.37**	**15.30**	**16.32**	**17.48**	**2.7%**
Developing Countries							
OPEC[6]							
Asia	1.41	1.36	1.26	1.25	1.29	1.33	-0.1%
Middle East	20.99	20.79	24.18	27.51	33.39	40.07	2.9%
North Africa	3.09	2.99	2.95	3.09	3.52	3.90	1.2%
West Africa	2.06	2.02	2.19	2.59	3.01	3.37	2.3%
South America	2.63	2.55	2.65	2.72	3.23	3.88	1.9%
Non-OPEC							
China	3.30	3.39	3.62	3.47	3.45	3.37	-0.0%
Other Asia	2.46	2.50	2.63	2.74	2.67	2.60	0.2%
Middle East[7]	2.02	1.96	2.24	2.46	2.56	2.77	1.5%
Africa	2.77	2.89	3.71	4.68	5.34	6.42	3.5%
South and Central America	3.70	3.79	4.50	5.34	5.86	6.35	2.3%
Total Developing Countries	**44.44**	**44.24**	**49.94**	**55.84**	**64.32**	**74.05**	**2.3%**
Total Production (Conventional)	**75.70**	**76.30**	**86.24**	**93.42**	**102.17**	**112.41**	**1.7%**
Production[8] (Nonconventional)							
U.S. (50 states)	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Other North America	0.72	0.79	1.69	2.97	3.20	3.28	6.4%
Western Europe	0.04	0.04	0.04	0.04	0.04	0.04	0.8%
Asia	0.02	0.03	0.03	0.03	0.03	0.03	1.3%
Middle East[7]	0.01	0.01	0.01	0.02	0.02	0.03	6.8%
Africa.	0.15	0.16	0.19	0.22	0.25	0.28	2.6%
South and Central America	0.49	0.54	0.85	1.27	1.42	1.45	4.4%
Total Production (Nonconventional)	**1.42**	**1.55**	**2.81**	**4.55**	**4.97**	**5.11**	**5.3%**
Total Production	**77.12**	**77.85**	**89.05**	**97.97**	**107.13**	**117.53**	**1.8%**

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

Supply and Disposition	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Consumption[9]							
Industrialized Countries							
U.S. (50 states)	19.71	19.61	22.71	24.80	26.41	28.30	1.6%
U.S. Territories	0.28	0.29	0.38	0.40	0.43	0.47	2.1%
Canada	1.91	1.96	2.23	2.32	2.36	2.44	1.0%
Mexico	1.94	2.01	2.65	3.19	3.62	4.09	3.1%
Western Europe[3]	13.98	14.02	14.36	14.64	14.80	15.26	0.4%
Japan	5.42	5.45	5.79	6.07	6.26	6.54	0.8%
Australia and New Zealand	1.01	1.04	1.28	1.43	1.58	1.75	2.3%
Total Industrialized	**44.25**	**44.39**	**49.41**	**52.86**	**55.47**	**58.85**	**1.2%**
Eurasia							
Former Soviet Union	3.90	4.05	5.10	5.26	5.73	6.25	1.9%
Eastern Europe[5]	1.41	1.44	1.74	1.96	2.21	2.54	2.5%
Total Eurasia	**5.30**	**5.49**	**6.84**	**7.22**	**7.94**	**8.79**	**2.1%**
Developing Countries							
China	4.97	5.11	6.48	7.68	9.39	10.88	3.3%
India	2.13	2.16	2.80	3.53	4.47	5.48	4.1%
South Korea	2.14	2.20	2.75	2.99	3.15	3.32	1.8%
Other Asia	5.53	5.63	6.65	7.81	8.93	10.17	2.6%
Middle East[7]	5.36	5.34	6.19	6.98	7.87	8.88	2.2%
Africa	2.58	2.56	2.68	2.91	3.16	3.50	1.4%
South and Central America	4.87	4.91	5.54	6.28	7.03	7.99	2.1%
Total Developing Countries	27.59	27.91	33.10	38.19	44.00	50.22	2.6%
Total Consumption	**77.14**	**77.79**	**89.35**	**98.27**	**107.40**	**117.8**	**1.8%**
OPEC Production[10]	30.55	30.11	33.89	38.12	45.51	53.67	2.5%
Non-OPEC Production[10]	46.56	47.74	55.16	59.85	61.62	63.86	1.3%
Net Eurasia Exports	3.73	4.08	6.54	8.09	8.40	8.71	3.4%
OPEC Market Share	0.40	0.39	0.38	0.39	0.42	0.46	0.7%

[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 and other sources, and refinery gains.
[3]Western Europe = Austria, Belgium, Bosnia and Herzegovina, Croatia, Denmark, Finland, France, the unified Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Macedonia, Netherlands, Norway, Portugal, Slovenia, Spain, Sweden, Switzerland, United Kingdom, and Yugoslavia.
[4]Caspian area includes Other Former Soviet Union.
[5]Eastern Europe = Albania, Bulgaria, Czech Republic, Hungary, Poland, Romania, and Slovakia.
[6]OPEC = Organization of Petroleum Exporting Countries - Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[7]Non-OPEC Middle East includes Turkey.
[8]Includes liquids produced from energy crops, natural gas, coal, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[9]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[10]Includes both conventional and nonconventional liquids production.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
N/A = Not applicable.
Sources: 2001 data derived from: Energy Information Administration (EIA), *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, March 2003). **2002 and projections:** EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

Economic Growth Case Comparisons

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

Supply, Disposition, and Prices	2002	Projections								
		2010			2020			2025		
		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	11.91	12.52	12.56	12.60	10.49	10.49	10.62	9.29	9.77	9.98
Natural Gas Plant Liquids	2.56	3.05	3.10	3.20	3.25	3.47	3.62	3.30	3.47	3.62
Dry Natural Gas	19.56	20.69	21.05	21.87	22.70	24.43	25.64	23.31	24.64	25.84
Coal	22.70	24.76	25.25	25.52	27.08	27.92	28.20	28.62	31.10	32.26
Nuclear Power	8.15	8.29	8.29	8.29	8.53	8.53	8.53	8.53	8.53	8.53
Renewable Energy[1]	5.84	6.97	7.18	7.39	7.96	8.45	9.18	8.36	9.00	10.14
Other[2]	1.13	0.85	0.88	0.91	0.79	0.81	0.82	0.82	0.84	0.86
Total	**71.85**	**77.13**	**78.30**	**79.79**	**80.81**	**84.09**	**86.62**	**82.23**	**87.33**	**91.22**
Imports										
Crude Oil[3]	19.84	23.66	24.51	25.38	30.65	31.55	33.27	32.65	34.21	35.63
Petroleum Products[4]	4.75	4.96	5.76	6.39	5.41	7.83	9.63	7.20	9.63	12.21
Natural Gas	4.10	5.87	6.54	6.79	6.90	7.56	8.40	7.45	8.29	9.35
Other Imports[5]	0.52	0.93	0.95	0.97	1.10	1.12	1.14	1.17	1.18	1.20
Total	**29.21**	**35.42**	**37.76**	**39.53**	**44.07**	**48.06**	**52.44**	**48.46**	**53.30**	**58.39**
Exports										
Petroleum[6]	2.03	2.14	2.15	2.15	2.16	2.13	2.17	2.14	2.15	2.16
Natural Gas	0.52	0.92	0.91	0.90	1.02	0.93	0.82	1.06	0.88	0.65
Coal	1.03	0.90	0.89	0.89	0.74	0.69	0.66	0.64	0.56	0.52
Total	**3.58**	**3.96**	**3.95**	**3.94**	**3.93**	**3.75**	**3.65**	**3.85**	**3.59**	**3.33**
Discrepancy[7]	**-0.24**	**0.28**	**0.34**	**0.38**	**0.45**	**0.48**	**0.51**	**0.52**	**0.56**	**0.58**
Consumption										
Petroleum Products[8]	38.11	42.46	44.15	45.79	47.82	51.35	55.09	50.41	54.99	59.41
Natural Gas	23.37	25.77	26.82	27.90	28.73	31.21	33.37	29.85	32.21	34.70
Coal	22.18	24.72	25.23	25.49	27.41	28.30	28.64	29.16	31.73	32.90
Nuclear Power	8.15	8.29	8.29	8.29	8.53	8.53	8.53	8.53	8.53	8.53
Renewable Energy[1]	5.84	6.98	7.18	7.39	7.97	8.46	9.18	8.36	9.00	10.14
Other[9]	0.07	0.09	0.11	0.12	0.06	0.07	0.08	0.03	0.03	0.03
Total	**97.72**	**108.32**	**111.77**	**114.99**	**120.51**	**127.92**	**134.89**	**126.33**	**136.48**	**145.70**
Net Imports - Petroleum	**22.56**	**26.48**	**28.13**	**29.62**	**33.90**	**37.25**	**40.72**	**37.70**	**41.69**	**45.69**
Prices (2002 dollars per unit)										
World Oil Price (dollars per barrel)[10]	23.68	23.64	24.17	24.67	24.77	26.02	27.27	25.30	27.00	28.55
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	2.95	3.31	3.40	3.61	3.97	4.28	4.71	4.28	4.40	4.94
Coal Minemouth Price (dollars per ton)	17.90	16.53	16.88	17.47	15.78	16.32	16.92	15.67	16.57	17.95
Average Electricity Price (cents per kilowatthour)	7.2	6.5	6.6	6.9	6.5	6.9	7.3	6.6	6.9	7.3

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table B18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, 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, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[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.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2002 petroleum supply values: EIA, *Petroleum Supply Annual 2002,* DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). Other 2002 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002) and EIA, *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003). **Projections:** EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

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

Sector and Source	2002	Projections								
		2010			2020			2025		
		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	0.89	0.93	0.93	0.93	0.85	0.85	0.85	0.80	0.80	0.80
Kerosene	0.07	0.11	0.11	0.11	0.10	0.10	0.10	0.09	0.09	0.09
Liquefied Petroleum Gas	0.53	0.56	0.56	0.56	0.60	0.61	0.63	0.62	0.64	0.65
Petroleum Subtotal	1.48	1.60	1.60	1.61	1.56	1.56	1.58	1.51	1.53	1.54
Natural Gas	5.06	5.65	5.69	5.74	5.91	6.08	6.18	5.99	6.26	6.43
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.39	0.40	0.40	0.41	0.40	0.41	0.41	0.39	0.41	0.41
Electricity	4.33	4.85	4.87	4.89	5.49	5.60	5.68	5.75	5.96	6.08
Delivered Energy	**11.28**	**12.51**	**12.58**	**12.66**	**13.36**	**13.66**	**13.86**	**13.66**	**14.17**	**14.47**
Electricity Related Losses	9.60	10.48	10.48	10.47	11.41	11.43	11.37	11.77	11.95	11.91
Total	**20.88**	**23.00**	**23.06**	**23.13**	**24.77**	**25.10**	**25.23**	**25.43**	**26.12**	**26.38**
Commercial										
Distillate Fuel	0.49	0.62	0.62	0.63	0.67	0.67	0.69	0.68	0.70	0.72
Residual Fuel	0.08	0.13	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	0.02
Liquefied Petroleum Gas	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Petroleum Subtotal	0.72	0.92	0.92	0.92	0.97	0.97	1.00	0.99	1.00	1.02
Natural Gas	3.21	3.55	3.57	3.59	3.83	3.94	4.02	3.98	4.16	4.30
Coal	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy[3]	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Electricity	4.12	5.02	5.05	5.06	6.10	6.24	6.36	6.59	6.83	7.03
Delivered Energy	**8.25**	**9.68**	**9.74**	**9.77**	**11.09**	**11.35**	**11.57**	**11.75**	**12.19**	**12.54**
Electricity Related Losses	9.15	10.84	10.86	10.83	12.68	12.73	12.73	13.49	13.70	13.77
Total	**17.40**	**20.53**	**20.60**	**20.60**	**23.77**	**24.07**	**24.30**	**25.24**	**25.89**	**26.31**
Industrial[4]										
Distillate Fuel	1.16	1.10	1.17	1.25	1.20	1.34	1.49	1.25	1.43	1.62
Liquefied Petroleum Gas	2.22	2.12	2.35	2.52	2.22	2.74	3.20	2.28	2.94	3.53
Petrochemical Feedstock	1.22	1.21	1.35	1.44	1.24	1.54	1.79	1.25	1.62	1.95
Residual Fuel	0.20	0.20	0.21	0.22	0.21	0.22	0.24	0.21	0.23	0.25
Motor Gasoline[2]	0.16	0.15	0.16	0.17	0.16	0.18	0.20	0.16	0.19	0.22
Other Petroleum[5]	4.03	4.15	4.38	4.63	4.45	4.93	5.38	4.58	5.17	5.67
Petroleum Subtotal	9.00	8.93	9.63	10.23	9.48	10.95	12.30	9.73	11.59	13.25
Natural Gas	7.43	8.08	8.62	9.11	8.69	9.84	10.93	9.02	10.58	12.02
Lease and Plant Fuel[6]	1.35	1.38	1.40	1.44	1.54	1.65	1.72	1.61	1.69	1.75
Natural Gas Subtotal	8.78	9.46	10.02	10.55	10.23	11.49	12.65	10.64	12.27	13.77
Metallurgical Coal	0.62	0.64	0.64	0.64	0.52	0.52	0.52	0.47	0.47	0.46
Steam Coal	1.47	1.36	1.41	1.45	1.37	1.45	1.52	1.38	1.47	1.62
Net Coal Coke Imports	0.03	0.01	0.01	0.02	0.00	0.00	0.02	0.00	0.01	0.03
Coal Subtotal	2.12	2.01	2.06	2.11	1.90	1.97	2.05	1.86	1.95	2.11
Renewable Energy[7]	1.66	1.83	2.00	2.13	2.16	2.48	2.79	2.32	2.70	3.08
Electricity	3.39	3.53	3.82	4.10	3.93	4.47	5.06	4.12	4.85	5.63
Delivered Energy	**24.94**	**25.76**	**27.53**	**29.12**	**27.68**	**31.36**	**34.85**	**28.66**	**33.35**	**37.85**
Electricity Related Losses	7.53	7.62	8.22	8.76	8.17	9.12	10.13	8.43	9.72	11.03
Total	**32.47**	**33.38**	**35.75**	**37.88**	**35.85**	**40.48**	**44.98**	**37.09**	**43.07**	**48.88**

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

Sector and Source	2002	Projections 2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth	2025 Low Economic Growth	2025 Reference	2025 High Economic Growth
Transportation										
Distillate Fuell[8]	5.12	6.00	6.42	6.84	7.16	8.02	8.92	7.83	8.94	10.12
Jet Fuel[9]	3.34	3.87	3.93	4.02	4.57	4.69	4.75	4.72	4.91	5.00
Motor Gasoline[2]	16.62	19.45	19.88	20.33	22.06	23.11	24.14	23.58	24.98	26.33
Residual Fuel	0.71	0.79	0.79	0.80	0.80	0.82	0.83	0.81	0.83	0.84
Liquefied Petroleum Gas	0.02	0.05	0.06	0.06	0.07	0.08	0.08	0.08	0.08	0.09
Other Petroleum[10]	0.24	0.24	0.25	0.27	0.27	0.30	0.32	0.28	0.32	0.36
Petroleum Subtotal	26.06	30.40	31.34	32.32	34.94	37.00	39.05	37.30	40.07	42.74
Pipeline Fuel Natural Gas	0.65	0.68	0.69	0.72	0.75	0.83	0.88	0.80	0.86	0.89
Compressed Natural Gas	0.01	0.05	0.06	0.06	0.09	0.10	0.10	0.10	0.11	0.12
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.09	0.09	0.11	0.11	0.11	0.12	0.12	0.12
Delivered Energy	**26.79**	**31.22**	**32.18**	**33.20**	**35.88**	**38.05**	**40.15**	**38.32**	**41.16**	**43.89**
Electricity Related Losses	0.17	0.19	0.19	0.19	0.22	0.22	0.22	0.24	0.24	0.24
Total	**26.96**	**31.41**	**32.37**	**33.39**	**36.11**	**38.27**	**40.37**	**38.56**	**41.40**	**44.13**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.66	8.65	9.15	9.64	9.89	10.88	11.95	10.56	11.88	13.27
Kerosene	0.09	0.16	0.16	0.16	0.15	0.14	0.14	0.13	0.13	0.13
Jet Fuel[9]	3.34	3.87	3.93	4.02	4.57	4.69	4.75	4.72	4.91	5.00
Liquefied Petroleum Gas	2.86	2.82	3.07	3.24	3.00	3.53	4.00	3.08	3.76	4.37
Motor Gasoline[2]	16.83	19.65	20.09	20.55	22.26	23.34	24.39	23.79	25.22	26.60
Petrochemical Feedstock	1.22	1.21	1.35	1.44	1.24	1.54	1.79	1.25	1.62	1.95
Residual Fuel	1.00	1.12	1.13	1.15	1.14	1.17	1.20	1.15	1.19	1.23
Other Petroleum[12]	4.26	4.37	4.61	4.87	4.70	5.21	5.68	4.84	5.46	6.01
Petroleum Subtotal	37.26	41.84	43.48	45.08	46.94	50.50	53.92	49.53	54.18	58.56
Natural Gas	15.71	17.33	17.94	18.50	18.51	19.95	21.23	19.09	21.11	22.86
Lease and Plant Fuel Plant[6]	1.35	1.38	1.40	1.44	1.54	1.65	1.72	1.61	1.69	1.75
Pipeline Natural Gas	0.65	0.68	0.69	0.72	0.75	0.83	0.88	0.80	0.86	0.89
Natural Gas Subtotal	17.72	19.39	20.03	20.66	20.80	22.43	23.83	21.50	23.66	25.51
Metallurgical Coal	0.62	0.64	0.64	0.64	0.52	0.52	0.52	0.47	0.47	0.46
Steam Coal	1.58	1.47	1.52	1.56	1.48	1.56	1.63	1.49	1.58	1.73
Net Coal Coke Imports	0.03	0.01	0.01	0.02	0.00	0.00	0.02	0.00	0.01	0.03
Coal Subtotal	2.23	2.12	2.17	2.22	2.00	2.08	2.16	1.96	2.06	2.22
Renewable Energy[13]	2.15	2.34	2.50	2.64	2.66	2.99	3.30	2.82	3.21	3.60
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.92	13.49	13.83	14.14	15.61	16.41	17.22	16.58	17.77	18.86
Delivered Energy	**71.27**	**79.18**	**82.03**	**84.74**	**88.01**	**94.42**	**100.44**	**92.39**	**100.87**	**108.75**
Electricity Related Losses	26.45	29.14	29.75	30.25	32.49	33.50	34.46	33.93	35.61	36.95
Total	**97.72**	**108.32**	**111.77**	**114.99**	**120.50**	**127.92**	**134.89**	**126.32**	**136.48**	**145.70**
Electric Power[14]										
Distillate Fuel	0.16	0.15	0.16	0.16	0.32	0.26	0.56	0.31	0.27	0.32
Residual Fuel	0.69	0.47	0.51	0.55	0.56	0.59	0.61	0.57	0.54	0.53
Petroleum Subtotal	0.85	0.62	0.66	0.71	0.88	0.85	1.17	0.89	0.81	0.85
Natural Gas	5.65	6.38	6.79	7.24	7.93	8.78	9.54	8.34	8.55	9.19
Steam Coal	19.96	22.60	23.05	23.27	25.41	26.22	26.48	27.19	29.67	30.68
Nuclear Power	8.15	8.29	8.29	8.29	8.53	8.53	8.53	8.53	8.53	8.53
Renewable Energy[15]	3.69	4.64	4.68	4.75	5.30	5.47	5.88	5.55	5.79	6.54
Electricity Imports	0.07	0.09	0.11	0.12	0.06	0.07	0.08	0.03	0.03	0.03
Total	**38.36**	**42.63**	**43.58**	**44.39**	**48.10**	**49.92**	**51.67**	**50.52**	**53.37**	**55.81**

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

Sector and Source	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Total Energy Consumption										
Distillate Fuel	7.82	8.80	9.31	9.80	10.20	11.14	12.51	10.88	12.15	13.59
Kerosene	0.09	0.16	0.16	0.16	0.15	0.14	0.14	0.13	0.13	0.13
Jet Fuel[9]	3.34	3.87	3.93	4.02	4.57	4.69	4.75	4.72	4.91	5.00
Liquefied Petroleum Gas	2.86	2.82	3.07	3.24	3.00	3.53	4.00	3.08	3.76	4.37
Motor Gasoline[2]	16.83	19.65	20.09	20.55	22.26	23.34	24.39	23.79	25.22	26.60
Petrochemical Feedstock	1.22	1.21	1.35	1.44	1.24	1.54	1.79	1.25	1.62	1.95
Residual Fuel	1.69	1.59	1.64	1.70	1.70	1.76	1.81	1.72	1.72	1.76
Other Petroleum[12]	4.26	4.37	4.61	4.87	4.70	5.21	5.68	4.84	5.46	6.01
Petroleum Subtotal	38.11	42.46	44.15	45.79	47.82	51.35	55.09	50.41	54.99	59.41
Natural Gas	21.36	23.72	24.73	25.74	26.44	28.73	30.77	27.43	29.66	32.05
Lease and Plant Fuel[6]	1.35	1.38	1.40	1.44	1.54	1.65	1.72	1.61	1.69	1.75
Pipeline Natural Gas	0.65	0.68	0.69	0.72	0.75	0.83	0.88	0.80	0.86	0.89
Natural Gas Subtotal	23.37	25.77	26.82	27.90	28.73	31.21	33.37	29.85	32.21	34.70
Metallurgical Coal	0.62	0.64	0.64	0.64	0.52	0.52	0.52	0.47	0.47	0.46
Steam Coal	21.54	24.07	24.57	24.83	26.89	27.78	28.11	28.68	31.25	32.41
Net Coal Coke Imports	0.03	0.01	0.01	0.02	0.00	0.00	0.02	0.00	0.01	0.03
Coal Subtotal	22.18	24.72	25.23	25.49	27.41	28.30	28.64	29.16	31.73	32.90
Nuclear Power	8.15	8.29	8.29	8.29	8.53	8.53	8.53	8.53	8.53	8.53
Renewable Energy[16]	5.84	6.98	7.18	7.39	7.97	8.46	9.18	8.36	9.00	10.14
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.07	0.09	0.11	0.12	0.06	0.07	0.08	0.03	0.03	0.03
Total	**97.72**	**108.32**	**111.77**	**114.99**	**120.51**	**127.92**	**134.89**	**126.33**	**136.48**	**145.70**
Energy Use and Related Statistics										
Delivered Energy Use	71.27	79.18	82.03	84.74	88.01	94.42	100.44	92.39	100.87	108.75
Total Energy Use	97.72	108.32	111.77	114.99	120.50	127.92	134.89	126.32	136.48	145.70
Population (millions)	288.93	304.13	309.28	314.42	322.17	334.61	347.05	331.35	347.53	363.71
Gross Domestic Product (billion 1996 dollars)	9440	11727	12190	12858	14722	16188	17603	16280	18520	20685
Carbon Dioxide Emissions (million metric tons)	5729.3	6367.8	6558.8	6729.6	7136.5	7535.6	7886.3	7537.9	8142.0	8614.9

[1]Includes wood used for residential heating. See Table B18 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table B18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Fuel consumption includes consumption for combined heat and power, which produces electricity, both for sale to the grid and for own use, and other useful thermal energy.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[10]Includes aviation gasoline and lubricants.
[11]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[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 net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2002 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2002 population and gross domestic product: Global Insight macroeconomic model T250803. 2002 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2002,* DOE/EIA-0573(2002) (Washington, DC, October 2003). **Projections:** EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

Table B3. Energy Prices by Sector and Source
(2002 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential	**14.73**	**13.86**	**14.21**	**14.77**	**14.26**	**15.08**	**16.06**	**14.63**	**15.38**	**16.43**
Primary Energy[1]	8.14	8.04	8.15	8.36	8.44	8.76	9.20	8.68	8.89	9.39
Petroleum Products[2]	9.87	9.75	9.90	10.08	10.30	10.86	11.18	10.72	11.26	11.93
Distillate Fuel	8.23	7.73	7.82	7.94	7.94	8.39	8.61	8.19	8.53	9.01
Liquefied Petroleum Gas	12.92	13.64	13.89	14.16	14.16	14.79	15.20	14.49	15.19	16.05
Natural Gas	7.65	7.57	7.67	7.89	7.96	8.24	8.71	8.18	8.32	8.79
Electricity	24.73	22.56	23.30	24.41	22.20	23.73	25.45	22.39	23.88	25.67
Commercial	**14.68**	**13.39**	**13.77**	**14.39**	**14.09**	**14.93**	**15.87**	**14.54**	**15.28**	**16.20**
Primary Energy[1]	6.35	6.37	6.48	6.68	6.78	7.11	7.52	7.01	7.22	7.70
Petroleum Products[2]	6.88	6.22	6.34	6.48	6.39	6.83	7.06	6.61	6.98	7.44
Distillate Fuel	6.07	5.36	5.45	5.57	5.54	6.01	6.23	5.81	6.15	6.62
Residual Fuel	4.21	4.05	4.13	4.21	4.22	4.41	4.60	4.30	4.55	4.78
Natural Gas	6.37	6.53	6.64	6.87	7.02	7.31	7.77	7.25	7.41	7.89
Electricity	22.82	19.77	20.39	21.41	19.95	21.21	22.58	20.31	21.48	22.75
Industrial[3]	**6.31**	**6.19**	**6.44**	**6.74**	**6.65**	**7.21**	**7.73**	**6.94**	**7.42**	**8.08**
Primary Energy	4.77	4.95	5.14	5.33	5.40	5.88	6.27	5.67	6.07	6.64
Petroleum Products[2]	6.35	6.60	6.84	6.99	6.95	7.54	7.86	7.25	7.81	8.41
Distillate Fuel	6.21	5.57	5.68	5.79	5.75	6.24	6.47	6.06	6.40	6.88
Liquefied Petroleum Gas	8.28	9.29	9.72	10.00	9.90	10.66	11.18	10.20	11.11	12.11
Residual Fuel	3.89	3.66	3.74	3.83	3.84	4.03	4.22	3.92	4.17	4.41
Natural Gas[4]	3.75	3.94	4.05	4.28	4.55	4.89	5.34	4.82	4.99	5.54
Metallurgical Coal	1.87	1.92	1.96	2.01	1.79	1.84	1.90	1.70	1.77	1.84
Steam Coal	1.52	1.54	1.58	1.64	1.45	1.53	1.60	1.42	1.53	1.65
Electricity	14.74	12.88	13.36	14.11	13.05	13.99	15.03	13.31	14.09	15.09
Transportation	**9.91**	**10.30**	**10.50**	**10.80**	**10.09**	**10.54**	**10.97**	**10.14**	**10.69**	**11.21**
Primary Energy	9.88	10.28	10.48	10.77	10.06	10.52	10.94	10.11	10.67	11.18
Petroleum Products[2]	9.88	10.28	10.48	10.78	10.07	10.52	10.94	10.11	10.67	11.19
Distillate Fuel[5]	9.41	9.98	10.12	10.52	9.38	10.00	10.45	9.40	10.03	10.58
Jet Fuel[6]	5.97	5.64	5.76	5.92	5.62	6.06	6.33	5.77	6.21	6.67
Motor Gasoline[7]	11.15	11.64	11.87	12.18	11.50	11.90	12.33	11.49	12.06	12.56
Residual Fuel	3.77	3.52	3.60	3.68	3.68	3.88	4.07	3.76	4.02	4.26
Liquefied Petroleum Gas[8]	15.00	14.65	14.96	15.34	14.73	15.51	16.11	14.94	15.83	16.87
Natural Gas[9]	7.38	8.12	8.26	8.56	8.66	9.06	9.63	8.86	9.09	9.68
Ethanol (E85)[10]	15.19	17.12	17.22	17.33	17.47	18.28	18.45	18.41	18.58	18.83
Electricity	21.10	19.07	19.57	20.40	18.96	20.03	21.27	19.00	19.92	21.07
Average End-Use Energy	**10.10**	**10.03**	**10.23**	**10.54**	**10.28**	**10.76**	**11.25**	**10.50**	**10.96**	**11.53**
Primary Energy	7.70	8.07	8.22	8.44	8.26	8.64	9.01	8.44	8.82	9.30
Electricity	21.20	18.97	19.47	20.33	19.00	20.10	21.30	19.28	20.26	21.40
Electric Power[11]										
Fossil Fuel Average	1.89	1.85	1.92	2.03	2.01	2.18	2.41	2.06	2.11	2.33
Petroleum Products	4.32	4.13	4.21	4.28	4.41	4.67	5.09	4.58	4.88	5.27
Distillate Fuel	5.58	4.80	4.92	5.03	4.97	5.47	5.74	5.28	5.62	6.12
Residual Fuel	4.04	3.92	3.99	4.06	4.10	4.31	4.50	4.20	4.50	4.77
Natural Gas	3.77	3.95	4.04	4.28	4.52	4.85	5.32	4.78	4.92	5.47
Steam Coal	1.26	1.19	1.22	1.26	1.15	1.20	1.24	1.14	1.22	1.30

Table B3. Energy Prices by Sector and Source (Continued)
(2002 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2002	Projections								
		2010			2020			2025		
		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[12]										
Petroleum Products[2]	8.94	9.40	9.57	9.80	9.36	9.81	10.14	9.49	10.01	10.51
Distillate Fuel	8.52	8.78	8.93	9.27	8.45	9.07	9.41	8.58	9.18	9.73
Jet Fuel	5.97	5.64	5.76	5.92	5.62	6.06	6.33	5.77	6.21	6.67
Liquefied Petroleum Gas	9.27	10.33	10.65	10.89	10.95	11.55	11.96	11.25	11.96	12.84
Motor Gasoline[7]	11.15	11.64	11.87	12.18	11.50	11.90	12.33	11.49	12.06	12.56
Residual Fuel	3.92	3.70	3.78	3.86	3.88	4.08	4.27	3.96	4.23	4.48
Natural Gas	5.07	5.20	5.27	5.46	5.67	5.93	6.34	5.91	6.03	6.50
Coal	1.28	1.22	1.25	1.29	1.16	1.22	1.26	1.16	1.24	1.33
Ethanol (E85)[10]	15.19	17.12	17.22	17.33	17.47	18.28	18.45	18.41	18.58	18.83
Electricity	21.20	18.97	19.47	20.33	19.00	20.10	21.30	19.28	20.26	21.40
Non-Renewable Energy Expenditures by Sector (billion 2002 dollars)										
Residential	160.37	167.84	173.01	180.96	184.85	199.98	216.04	194.06	211.69	230.97
Commercial	119.67	128.35	132.72	139.12	154.83	167.90	182.08	169.38	184.74	201.55
Industrial	120.96	117.85	132.71	148.55	134.70	169.02	205.02	145.04	185.61	234.80
Transportation	259.11	314.69	330.65	350.71	354.55	392.36	430.65	380.37	430.99	481.97
Total Non-Renewable Expenditures	660.11	728.73	769.08	819.34	828.93	929.26	1033.79	888.85	1013.03	1149.30
Transportation Renewable Expenditures	0.01	0.03	0.03	0.04	0.05	0.06	0.06	0.06	0.07	0.08
Total Expenditures	**660.12**	**728.76**	**769.11**	**819.38**	**828.98**	**929.32**	**1033.86**	**888.91**	**1013.10**	**1149.38**

[1]Weighted average price includes fuels below as well as coal.
[2]This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Includes combined heat and power, which produces electricity and other useful thermal energy.
[4]Excludes use for lease and plant fuel.
[5] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8]Includes Federal and State taxes while excluding county and local taxes.
[9]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2002*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (August 2003). 2002 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2002 electric power sector natural gas prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2002 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998.* 2002 coal prices based on EIA, *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003) and EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E. 2002 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2002 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

Table B4. Residential Sector Key Indicators and End-Use Consumption

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Key Indicators										
Households (millions)										
Single-Family	74.77	82.01	82.87	83.92	88.91	92.09	94.65	91.66	96.32	99.73
Multifamily	29.20	30.50	30.71	31.19	32.34	33.07	34.10	33.30	34.36	35.75
Mobile Homes	6.31	6.21	6.25	6.32	6.68	6.88	6.94	6.81	7.12	7.17
Total	**110.28**	**118.72**	**119.84**	**121.43**	**127.93**	**132.04**	**135.69**	**131.77**	**137.79**	**142.64**
Average House Square Footage	**1689**	**1728**	**1731**	**1733**	**1761**	**1771**	**1776**	**1774**	**1788**	**1794**
Energy Intensity										
(million Btu per household)										
Delivered Energy Consumption	102.3	105.4	105.0	104.2	104.4	103.5	102.2	103.6	102.8	101.5
Total Energy Consumption	189.4	193.7	192.4	190.4	193.6	190.1	186.0	193.0	189.5	184.9
(thousand Btu per square foot)										
Delivered Energy Consumption	60.6	61.0	60.6	60.1	59.3	58.4	57.5	58.4	57.5	56.6
Total Energy Consumption	112.1	112.1	111.1	109.9	109.9	107.3	104.7	108.8	106.0	103.1
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.40	0.43	0.43	0.43	0.44	0.45	0.45	0.44	0.46	0.46
Space Cooling	0.71	0.69	0.69	0.70	0.74	0.76	0.78	0.77	0.80	0.82
Water Heating	0.37	0.37	0.37	0.37	0.36	0.36	0.36	0.34	0.35	0.35
Refrigeration	0.42	0.37	0.37	0.37	0.35	0.36	0.37	0.35	0.37	0.38
Cooking	0.10	0.11	0.11	0.11	0.12	0.12	0.13	0.12	0.13	0.13
Clothes Dryers	0.24	0.25	0.25	0.25	0.26	0.26	0.27	0.27	0.27	0.28
Freezers	0.13	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.13
Lighting	0.75	0.86	0.87	0.87	0.95	0.97	0.98	0.99	1.02	1.03
Clothes Washers[1]	0.03	0.04	0.04	0.04	0.06	0.06	0.06	0.06	0.06	0.07
Dishwashers[1]	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.12	0.18	0.18	0.19	0.25	0.26	0.26	0.26	0.27	0.28
Personal Computers	0.06	0.08	0.08	0.08	0.11	0.11	0.12	0.13	0.14	0.14
Furnace Fans	0.08	0.09	0.09	0.09	0.10	0.10	0.11	0.11	0.11	0.11
Other Uses[2]	0.88	1.24	1.25	1.26	1.59	1.63	1.65	1.77	1.83	1.87
Delivered Energy	**4.33**	**4.85**	**4.87**	**4.89**	**5.49**	**5.60**	**5.68**	**5.75**	**5.96**	**6.08**
Natural Gas										
Space Heating	3.54	3.98	4.01	4.04	4.20	4.33	4.40	4.28	4.48	4.60
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Heating	1.15	1.24	1.25	1.26	1.24	1.27	1.29	1.23	1.28	1.31
Cooking	0.21	0.23	0.23	0.23	0.25	0.26	0.26	0.26	0.27	0.27
Clothes Dryers	0.07	0.09	0.09	0.09	0.10	0.11	0.11	0.11	0.11	0.12
Other Uses[3]	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.13
Delivered Energy	**5.06**	**5.65**	**5.69**	**5.74**	**5.91**	**6.08**	**6.18**	**5.99**	**6.26**	**6.43**
Distillate										
Space Heating	0.77	0.81	0.81	0.81	0.75	0.75	0.75	0.71	0.71	0.71
Water Heating	0.12	0.12	0.12	0.12	0.10	0.10	0.10	0.09	0.09	0.10
Other Uses[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	**0.89**	**0.93**	**0.93**	**0.93**	**0.85**	**0.85**	**0.85**	**0.80**	**0.80**	**0.80**
Liquefied Petroleum Gas										
Space Heating	0.30	0.30	0.30	0.30	0.30	0.31	0.31	0.30	0.31	0.31
Water Heating	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Other Uses[3]	0.15	0.18	0.18	0.18	0.22	0.23	0.23	0.24	0.25	0.26
Delivered Energy	**0.53**	**0.56**	**0.56**	**0.56**	**0.60**	**0.61**	**0.63**	**0.62**	**0.64**	**0.65**
Marketed Renewables (wood)[5]	0.39	0.40	0.40	0.41	0.40	0.41	0.41	0.39	0.41	0.41
Other Fuels[6]	0.08	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10

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

Key Indicators and Consumption	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Delivered Energy Consumption by End-Use										
Space Heating	5.48	6.05	6.08	6.12	6.21	6.35	6.44	6.23	6.46	6.60
Space Cooling	0.71	0.69	0.69	0.70	0.74	0.76	0.78	0.77	0.80	0.82
Water Heating	1.69	1.78	1.79	1.80	1.74	1.78	1.81	1.70	1.77	1.81
Refrigeration	0.42	0.37	0.37	0.37	0.35	0.36	0.37	0.35	0.37	0.38
Cooking	0.34	0.37	0.37	0.37	0.40	0.41	0.42	0.41	0.42	0.44
Clothes Dryers	0.31	0.34	0.34	0.34	0.36	0.37	0.38	0.38	0.39	0.40
Freezers	0.13	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.13
Lighting	0.75	0.86	0.87	0.87	0.95	0.97	0.98	0.99	1.02	1.03
Clothes Washers	0.03	0.04	0.04	0.04	0.06	0.06	0.06	0.06	0.06	0.07
Dishwashers	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.12	0.18	0.18	0.19	0.25	0.26	0.26	0.26	0.27	0.28
Personal Computers	0.06	0.08	0.08	0.08	0.11	0.11	0.12	0.13	0.14	0.14
Furnace Fans	0.08	0.09	0.09	0.09	0.10	0.10	0.11	0.11	0.11	0.11
Other Uses[7]	1.13	1.53	1.54	1.55	1.93	1.97	2.00	2.13	2.20	2.25
Delivered Energy	**11.28**	**12.51**	**12.58**	**12.66**	**13.36**	**13.66**	**13.86**	**13.66**	**14.17**	**14.47**
Electricity Related Losses	**9.60**	**10.48**	**10.48**	**10.47**	**11.41**	**11.43**	**11.37**	**11.77**	**11.95**	**11.91**
Total Energy Consumption by End-Use										
Space Heating	6.36	6.96	6.99	7.03	7.14	7.27	7.35	7.13	7.37	7.50
Space Cooling	2.29	2.18	2.19	2.19	2.29	2.32	2.33	2.34	2.41	2.42
Water Heating	2.51	2.58	2.58	2.59	2.49	2.52	2.54	2.40	2.46	2.49
Refrigeration	1.37	1.15	1.16	1.17	1.08	1.09	1.11	1.08	1.11	1.13
Cooking	0.57	0.60	0.61	0.62	0.64	0.66	0.67	0.65	0.68	0.69
Clothes Dryers	0.83	0.89	0.89	0.89	0.90	0.91	0.91	0.92	0.94	0.94
Freezers	0.43	0.36	0.37	0.37	0.36	0.36	0.37	0.36	0.37	0.37
Lighting	2.41	2.73	2.73	2.72	2.94	2.95	2.94	3.01	3.07	3.05
Clothes Washers	0.10	0.12	0.12	0.13	0.17	0.18	0.18	0.18	0.19	0.19
Dishwashers	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.10
Color Televisions	0.40	0.58	0.58	0.58	0.78	0.78	0.78	0.81	0.82	0.82
Personal Computers	0.21	0.25	0.25	0.25	0.34	0.35	0.35	0.39	0.41	0.42
Furnace Fans	0.25	0.28	0.28	0.28	0.31	0.32	0.32	0.32	0.33	0.34
Other Uses[7]	3.09	4.22	4.22	4.23	5.25	5.29	5.31	5.74	5.87	5.91
Total	**20.88**	**23.00**	**23.06**	**23.13**	**24.77**	**25.10**	**25.23**	**25.43**	**26.12**	**26.38**
Non-Marketed Renewables										
Geothermal[8]	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Solar[9]	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Total	**0.02**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.05**

[1]Does not include electric water heating portion of load.
[2]Includes small electric devices, heating elements, and motors.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as swimming pool and hot tub heaters.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2001*.
[6]Includes kerosene and coal.
[7]Includes all other uses listed above.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections:** EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

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

Key Indicators and Consumption	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Key Indicators										
Total Floorspace (billion square feet)										
Surviving	68.9	80.3	81.1	81.8	90.0	93.1	96.2	94.3	98.8	103.1
New Additions	3.2	2.5	2.7	3.0	2.5	2.8	3.1	2.6	3.0	3.3
Total	**72.1**	**82.8**	**83.8**	**84.8**	**92.5**	**95.9**	**99.3**	**96.9**	**101.8**	**106.4**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	114.5	116.9	116.2	115.3	119.9	118.3	116.5	121.2	119.7	117.9
Electricity Related Losses	126.9	130.9	129.6	127.7	137.1	132.7	128.2	139.2	134.6	129.4
Total Energy Consumption	241.4	247.8	245.8	243.0	256.9	251.0	244.8	260.4	254.3	247.3
Delivered Energy Consumption by Fuel										
Purchased Electricity										
Space Heating[1]	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.15	0.16	0.16
Space Cooling[1]	0.46	0.45	0.45	0.45	0.47	0.48	0.48	0.48	0.49	0.50
Water Heating[1]	0.14	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Ventilation	0.16	0.18	0.18	0.18	0.18	0.18	0.19	0.18	0.19	0.19
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Lighting	1.12	1.30	1.30	1.29	1.39	1.40	1.39	1.41	1.43	1.42
Refrigeration	0.20	0.22	0.22	0.22	0.24	0.24	0.25	0.24	0.25	0.25
Office Equipment (PC)	0.14	0.24	0.24	0.24	0.32	0.34	0.35	0.35	0.37	0.38
Office Equipment (non-PC)	0.31	0.46	0.46	0.47	0.68	0.71	0.74	0.82	0.87	0.91
Other Uses[2]	1.41	1.84	1.86	1.87	2.47	2.55	2.63	2.78	2.91	3.03
Delivered Energy	**4.12**	**5.02**	**5.05**	**5.06**	**6.10**	**6.24**	**6.36**	**6.59**	**6.83**	**7.03**
Natural Gas										
Space Heating[1]	1.42	1.56	1.56	1.57	1.61	1.64	1.66	1.64	1.69	1.72
Space Cooling[1]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Water Heating[1]	0.59	0.69	0.70	0.70	0.77	0.79	0.80	0.81	0.84	0.85
Cooking	0.26	0.30	0.30	0.31	0.34	0.34	0.35	0.35	0.36	0.37
Other Uses[3]	0.93	0.98	0.99	1.00	1.08	1.14	1.19	1.15	1.24	1.33
Delivered Energy	**3.21**	**3.55**	**3.57**	**3.59**	**3.83**	**3.94**	**4.02**	**3.98**	**4.16**	**4.30**
Distillate										
Space Heating[1]	0.17	0.24	0.24	0.25	0.28	0.29	0.31	0.30	0.31	0.33
Water Heating[1]	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.09
Other Uses[4]	0.24	0.30	0.30	0.29	0.30	0.29	0.29	0.30	0.29	0.29
Delivered Energy	**0.49**	**0.62**	**0.62**	**0.63**	**0.67**	**0.67**	**0.69**	**0.68**	**0.70**	**0.72**
Other Fuels[5]	**0.33**	**0.39**	**0.39**	**0.40**	**0.40**	**0.40**	**0.40**	**0.40**	**0.40**	**0.40**
Marketed Renewable Fuels										
Biomass	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Delivered Energy	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Delivered Energy Consumption by End-Use										
Space Heating[1]	1.74	1.96	1.97	1.97	2.05	2.09	2.12	2.09	2.16	2.21
Space Cooling[1]	0.48	0.47	0.47	0.47	0.50	0.50	0.51	0.51	0.52	0.53
Water Heating[1]	0.80	0.92	0.93	0.93	1.01	1.03	1.04	1.05	1.08	1.09
Ventilation	0.16	0.18	0.18	0.18	0.18	0.18	0.19	0.18	0.19	0.19
Cooking	0.29	0.33	0.34	0.34	0.37	0.37	0.38	0.38	0.39	0.39
Lighting	1.12	1.30	1.30	1.29	1.39	1.40	1.39	1.41	1.43	1.42
Refrigeration	0.20	0.22	0.22	0.22	0.24	0.24	0.25	0.24	0.25	0.25
Office Equipment (PC)	0.14	0.24	0.24	0.24	0.32	0.34	0.35	0.35	0.37	0.38
Office Equipment (non-PC)	0.31	0.46	0.46	0.47	0.68	0.71	0.74	0.82	0.87	0.91
Other Uses[6]	3.01	3.60	3.63	3.66	4.35	4.48	4.61	4.72	4.94	5.15
Delivered Energy	**8.25**	**9.68**	**9.74**	**9.77**	**11.09**	**11.35**	**11.57**	**11.75**	**12.19**	**12.54**

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

Key Indicators and Consumption	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Electricity Related Losses	**9.15**	**10.84**	**10.86**	**10.83**	**12.68**	**12.73**	**12.73**	**13.49**	**13.70**	**13.77**
Total Energy Consumption by End-Use										
Space Heating[1]	2.07	2.30	2.31	2.31	2.38	2.41	2.44	2.41	2.47	2.52
Space Cooling[1]	1.51	1.43	1.43	1.42	1.48	1.48	1.48	1.48	1.50	1.51
Water Heating[1]	1.11	1.24	1.25	1.24	1.32	1.33	1.34	1.35	1.37	1.39
Ventilation	0.52	0.56	0.56	0.55	0.56	0.56	0.56	0.56	0.57	0.57
Cooking	0.36	0.40	0.40	0.40	0.43	0.43	0.43	0.43	0.44	0.45
Lighting	3.60	4.12	4.10	4.05	4.30	4.25	4.17	4.29	4.30	4.21
Refrigeration	0.65	0.70	0.70	0.70	0.73	0.73	0.74	0.73	0.75	0.75
Office Equipment (PC)	0.44	0.75	0.76	0.77	1.00	1.03	1.05	1.06	1.10	1.14
Office Equipment (non-PC)	1.00	1.45	1.46	1.47	2.11	2.16	2.21	2.51	2.61	2.69
Other Uses[6]	6.14	7.57	7.63	7.67	9.49	9.69	9.88	10.42	10.77	11.08
Total	**17.40**	**20.53**	**20.60**	**20.60**	**23.77**	**24.07**	**24.30**	**25.24**	**25.89**	**26.31**
Non-Marketed Renewable Fuels										
Solar[7]	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04
Total	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**

[1]Includes fuel consumption for district services.
[2]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
[3]Includes miscellaneous uses, such as pumps, emergency electric generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency electric generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency electric generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections:** EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

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

Key Indicators and Consumption	2002	Projections								
		2010			2020			2025		
		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 Shipments (billion 1996 dollars)										
Manufacturing	4064	4627	5013	5399	5830	6634	7582	6483	7636	8962
Nonmanufacturing	1222	1300	1425	1587	1462	1710	1955	1503	1855	2204
Total	**5285**	**5927**	**6439**	**6986**	**7292**	**8344**	**9537**	**7987**	**9491**	**11166**
Energy Prices (2002 dollars per million Btu)										
Distillate Oil	6.21	5.57	5.68	5.79	5.75	6.24	6.47	6.06	6.40	6.88
Liquefied Petroleum Gas	8.28	9.29	9.72	10.00	9.90	10.66	11.18	10.20	11.11	12.11
Residual Oil	3.89	3.66	3.74	3.83	3.84	4.03	4.22	3.92	4.17	4.41
Motor Gasoline	11.04	11.61	11.84	12.14	11.47	11.87	12.31	11.46	12.03	12.54
Natural Gas	3.75	3.94	4.05	4.28	4.55	4.89	5.34	4.82	4.99	5.54
Metallurgical Coal	1.87	1.92	1.96	2.01	1.79	1.84	1.90	1.70	1.77	1.84
Steam Coal	1.52	1.54	1.58	1.64	1.45	1.53	1.60	1.42	1.53	1.65
Electricity	14.74	12.88	13.36	14.11	13.05	13.99	15.03	13.31	14.09	15.09
Energy Consumption[1]										
Distillate	1.16	1.10	1.17	1.25	1.20	1.34	1.49	1.25	1.43	1.62
Liquefied Petroleum Gas	2.22	2.12	2.35	2.52	2.22	2.74	3.20	2.28	2.94	3.53
Petrochemical Feedstocks	1.22	1.21	1.35	1.44	1.24	1.54	1.79	1.25	1.62	1.95
Residual Fuel	0.20	0.20	0.21	0.22	0.21	0.22	0.24	0.21	0.23	0.25
Other Petroleum[2]	4.19	4.30	4.54	4.80	4.61	5.12	5.58	4.74	5.36	5.89
Petroleum Subtotal	9.00	8.93	9.63	10.23	9.48	10.95	12.30	9.73	11.59	13.25
Natural Gas	7.43	8.08	8.62	9.11	8.69	9.84	10.93	9.02	10.58	12.02
Lease and Plant Fuel[3]	1.35	1.38	1.40	1.44	1.54	1.65	1.72	1.61	1.69	1.75
Natural Gas Subtotal	8.78	9.46	10.02	10.55	10.23	11.49	12.65	10.64	12.27	13.77
Metallurgical Coal and Coke[4]	0.65	0.65	0.66	0.66	0.52	0.52	0.54	0.47	0.48	0.49
Steam Coal	1.47	1.36	1.41	1.45	1.37	1.45	1.52	1.38	1.47	1.62
Coal Subtotal	2.12	2.01	2.06	2.11	1.90	1.97	2.05	1.86	1.95	2.11
Renewables[5]	1.66	1.83	2.00	2.13	2.16	2.48	2.79	2.32	2.70	3.08
Purchased Electricity	3.39	3.53	3.82	4.10	3.93	4.47	5.06	4.12	4.85	5.63
Delivered Energy	**24.94**	**25.76**	**27.53**	**29.12**	**27.69**	**31.36**	**34.85**	**28.67**	**33.35**	**37.85**
Electricity Related Losses	7.53	7.62	8.22	8.76	8.17	9.12	10.13	8.43	9.72	11.03
Total	**32.47**	**33.38**	**35.75**	**37.88**	**35.86**	**40.48**	**44.98**	**37.09**	**43.07**	**48.88**
Energy Consumption per dollar of Shipments[1] (thousand Btu per 1996 dollars)										
Distillate	0.22	0.19	0.18	0.18	0.16	0.16	0.16	0.16	0.15	0.15
Liquefied Petroleum Gas	0.42	0.36	0.37	0.36	0.30	0.33	0.34	0.29	0.31	0.32
Petrochemical Feedstocks	0.23	0.20	0.21	0.21	0.17	0.18	0.19	0.16	0.17	0.17
Residual Fuel	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02
Other Petroleum[2]	0.79	0.73	0.71	0.69	0.63	0.61	0.59	0.59	0.56	0.53
Petroleum Subtotal	1.70	1.51	1.50	1.46	1.30	1.31	1.29	1.22	1.22	1.19
Natural Gas	1.41	1.36	1.34	1.30	1.19	1.18	1.15	1.13	1.11	1.08
Lease and Plant Fuel[3]	0.26	0.23	0.22	0.21	0.21	0.20	0.18	0.20	0.18	0.16
Natural Gas Subtotal	1.66	1.60	1.56	1.51	1.40	1.38	1.33	1.33	1.29	1.23
Metallurgical Coal and Coke[4]	0.12	0.11	0.10	0.09	0.07	0.06	0.06	0.06	0.05	0.04
Steam Coal	0.28	0.23	0.22	0.21	0.19	0.17	0.16	0.17	0.15	0.14
Coal Subtotal	0.40	0.34	0.32	0.30	0.26	0.24	0.22	0.23	0.21	0.19
Renewables[5]	0.31	0.31	0.31	0.30	0.30	0.30	0.29	0.29	0.28	0.28
Purchased Electricity	0.64	0.60	0.59	0.59	0.54	0.54	0.53	0.52	0.51	0.50
Delivered Energy	**4.72**	**4.35**	**4.28**	**4.17**	**3.80**	**3.76**	**3.65**	**3.59**	**3.51**	**3.39**
Electricity Related Losses	1.42	1.29	1.28	1.25	1.12	1.09	1.06	1.06	1.02	0.99
Total	**6.14**	**5.63**	**5.55**	**5.42**	**4.92**	**4.85**	**4.72**	**4.64**	**4.54**	**4.38**

[1]Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Represents natural gas used in the field gathering and processing plant machinery.
[3]Includes net coal coke imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 prices for motor gasoline and distillate are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2002*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (August 2003). 2002 coal prices are based on EIA, *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003) and EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E. 2002 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2002 natural gas prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2002 consumption values based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2002 shipments: Global Insight macroeconomic model T250803. **Projections:** EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

Table B7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Key Indicators										
Level of Travel (billions)										
Light-Duty Vehicles <8,500 pounds (VMT)	2504	2982	3041	3108	3597	3768	3936	3937	4173	4403
Commercial Light Trucks (VMT)[1]	65	75	79	84	91	101	112	100	114	129
Freight Trucks >10,000 pounds (VMT)	196	224	242	259	274	313	353	305	354	410
Air (seat miles available)	909	1103	1122	1148	1455	1455	1455	1521	1521	1521
Rail (ton miles traveled)	1336	1460	1545	1610	1687	1852	1998	1810	2056	2266
Domestic Shipping (ton miles traveled)	724	773	805	848	838	918	999	867	977	1082
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[2]	23.8	25.3	25.3	25.3	26.4	26.5	26.6	26.8	26.9	27.0
New Car (miles per gallon)[2]	28.2	28.8	28.8	28.8	30.3	30.4	30.5	30.6	30.8	31.0
New Light Truck (miles per gallon)[2]	20.5	22.8	22.8	22.8	24.1	24.1	24.2	24.6	24.7	24.8
Light-Duty Fleet (miles per gallon)[3]	19.7	19.6	19.6	19.6	20.5	20.5	20.5	20.8	20.9	21.0
New Commercial Light Truck (MPG)[1]	13.9	15.1	15.1	15.1	16.0	16.0	16.1	16.3	16.4	16.5
Stock Commercial Light Truck (MPG)[1]	13.8	14.5	14.5	14.5	15.4	15.5	15.5	15.8	15.9	16.0
Aircraft Efficiency (seat miles per gallon)	54.8	59.4	59.9	60.3	64.9	65.4	66.9	66.2	67.0	69.3
Freight Truck Efficiency (miles per gallon)	6.0	6.0	6.0	6.0	6.4	6.4	6.4	6.5	6.5	6.5
Rail Efficiency (ton miles per thousand Btu)	2.9	3.1	3.1	3.1	3.4	3.4	3.4	3.6	3.6	3.6
(ton miles per thousand Btu)	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4
Energy Use by Mode										
(quadrillion Btu)										
Light-Duty Vehicles	15.58	18.53	18.91	19.32	21.35	22.34	23.28	22.97	24.28	25.51
Commercial Light Trucks[1]	0.59	0.64	0.68	0.72	0.74	0.82	0.90	0.79	0.90	1.01
Bus Transportation	0.24	0.25	0.25	0.26	0.26	0.26	0.26	0.26	0.26	0.27
Freight Trucks	4.09	4.64	5.03	5.40	5.40	6.15	6.96	5.86	6.82	7.87
Rail, Passenger	0.11	0.13	0.13	0.13	0.15	0.16	0.16	0.17	0.17	0.17
Rail, Freight	0.47	0.47	0.50	0.52	0.49	0.54	0.58	0.50	0.57	0.63
Shipping, Domestic	0.32	0.33	0.35	0.36	0.35	0.39	0.42	0.36	0.41	0.45
Shipping, International	0.64	0.72	0.72	0.72	0.73	0.73	0.73	0.73	0.74	0.74
Recreational Boats	0.31	0.33	0.34	0.34	0.36	0.37	0.38	0.38	0.39	0.40
Air	2.84	3.29	3.35	3.44	3.97	4.09	4.15	4.11	4.30	4.39
Military Use	0.66	0.77	0.77	0.77	0.81	0.81	0.81	0.83	0.82	0.82
Lubricants	0.20	0.20	0.21	0.23	0.23	0.25	0.28	0.24	0.28	0.32
Pipeline Fuel	0.65	0.68	0.69	0.72	0.75	0.83	0.88	0.80	0.86	0.89
Total	**26.70**	**31.00**	**31.93**	**32.94**	**35.59**	**37.73**	**39.81**	**37.99**	**40.79**	**43.47**
(million barrels per day oil equivalent)										
Light-Duty Vehicles	8.20	9.76	9.96	10.17	11.22	11.74	12.24	12.07	12.75	13.40
Commercial Light Trucks[1]	0.31	0.34	0.36	0.38	0.39	0.43	0.48	0.42	0.47	0.53
Bus Transportation	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.13
Freight Trucks	1.94	2.20	2.38	2.55	2.55	2.91	3.29	2.77	3.22	3.72
Rail, Passenger	0.05	0.06	0.06	0.06	0.07	0.07	0.08	0.08	0.08	0.08
Rail, Freight	0.22	0.22	0.24	0.24	0.23	0.25	0.27	0.24	0.27	0.30
Shipping, Domestic	0.15	0.15	0.16	0.17	0.16	0.18	0.19	0.17	0.19	0.21
Shipping, International	0.28	0.31	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32
Recreational Boats	0.16	0.18	0.18	0.18	0.19	0.19	0.20	0.20	0.20	0.21
Air	1.38	1.59	1.62	1.66	1.92	1.98	2.01	1.99	2.08	2.12
Military Use	0.32	0.37	0.37	0.37	0.39	0.39	0.39	0.40	0.39	0.39
Lubricants	0.09	0.09	0.10	0.11	0.11	0.12	0.13	0.11	0.13	0.15
Pipeline Fuel	0.33	0.34	0.35	0.36	0.38	0.42	0.45	0.41	0.43	0.45
Total	**13.54**	**15.74**	**16.20**	**16.71**	**18.06**	**19.13**	**20.17**	**19.28**	**20.68**	**22.02**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002: Energy Information Administration (EIA), *Natural Gas Annual 2001*, DOE/EIA-0131(2001) (Washington, DC, February 2003); Federal Highway Administration, *Highway Statistics 2000* (Washington, DC, November 2001); Oak Ridge National Laboratory, Transportation Energy Data Book: *Edition 22 and Annual* (Oak Ridge, TN, September 2002); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey" EC97TV (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives to Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; EIA, *State Energy Data Report 2000*, DOE/EIA-0214(2000) (Washington, DC, August 2003); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2002/2001* (Washington, DC, 2002); EIA, *Fuel Oil and Kerosene Sales 2001*, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/fuel_oil_and_kerosene_sales/historical/foks.html; and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

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

Supply, Disposition, and Prices	2002	Projections								
		2010			2020			2025		
		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 Power Sector[1]										
Power Only[2]										
Coal	1875	2159	2201	2219	2468	2560	2592	2681	2975	3111
Petroleum	77	58	62	67	85	82	121	86	77	84
Natural Gas[3]	450	594	642	699	847	972	1098	929	969	1081
Nuclear Power	780	794	794	794	816	816	816	816	816	816
Pumped Storage/Other	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9
Renewable Sources[4]	304	398	400	405	429	442	478	440	460	528
Distributed Generation (Natural Gas)	0	0	0	0	2	3	5	4	5	7
Non-Utility Generation for Own Use	-34	-37	-37	-37	-37	-37	-37	-37	-37	-37
Total	**3443**	**3956**	**4054**	**4137**	**4602**	**4829**	**5063**	**4911**	**5257**	**5581**
Combined Heat and Power[5]										
Coal	32	33	33	33	33	33	33	33	33	34
Petroleum	6	1	1	1	3	2	4	3	2	2
Natural Gas	148	171	174	179	160	159	160	153	149	144
Renewable Sources	5	4	4	4	4	4	4	4	4	4
Non-Utility Generation for Own Use	-11	-24	-24	-24	-24	-24	-24	-24	-24	-24
Total	**183**	**184**	**188**	**194**	**176**	**175**	**178**	**169**	**164**	**160**
Net Available to the Grid	**3626**	**4141**	**4242**	**4331**	**4778**	**5004**	**5241**	**5079**	**5421**	**5741**
End-Use Sector Generation										
Combined Heat and Power[6]										
Coal	21	21	21	21	21	21	21	21	21	24
Petroleum	5	12	12	12	13	17	19	14	18	19
Natural Gas	84	106	109	114	134	153	172	151	181	211
Other Gaseous Fuels[7]	5	9	9	9	11	12	12	12	13	13
Renewable Sources[4]	30	35	39	42	43	50	56	46	54	62
Other[8]	11	11	11	11	11	11	11	11	11	11
Total	**157**	**194**	**202**	**209**	**233**	**264**	**291**	**256**	**299**	**342**
Other End-Use Generators[9]	4	5	5	5	5	5	6	6	7	7
Generation for Own Use	-134	-155	-158	-162	-177	-190	-202	-190	-210	-230
Total Sales to the Grid	**27**	**44**	**48**	**52**	**62**	**80**	**95**	**72**	**95**	**120**
Total Electricity Generation	3831	4401	4510	4607	5078	5335	5599	5402	5787	6152
Net Imports	**22**	**28**	**31**	**35**	**18**	**21**	**24**	**7**	**8**	**8**
Electricity Sales by Sector										
Residential	1268	1422	1428	1434	1608	1641	1665	1686	1747	1781
Commercial	1208	1472	1480	1483	1787	1828	1865	1932	2003	2059
Industrial	994	1034	1120	1200	1151	1310	1484	1207	1422	1650
Transportation	22	26	26	27	31	32	33	35	35	36
Total	**3492**	**3954**	**4055**	**4144**	**4576**	**4811**	**5046**	**4861**	**5207**	**5527**
End-Use Prices[10] (2002 cents per kilowatthour)										
Residential	8.4	7.7	7.9	8.3	7.6	8.1	8.7	7.6	8.1	8.8
Commercial	7.8	6.7	7.0	7.3	6.8	7.2	7.7	6.9	7.3	7.8
Industrial	5.0	4.4	4.6	4.8	4.5	4.8	5.1	4.5	4.8	5.1
Transportation	7.2	6.5	6.7	7.0	6.5	6.8	7.3	6.5	6.8	7.2
All Sectors Average	**7.2**	**6.5**	**6.6**	**6.9**	**6.5**	**6.9**	**7.3**	**6.6**	**6.9**	**7.3**
Prices by Service Category[10] (2002 cents per kilowatthour)										
Generation	4.6	4.0	4.1	4.4	4.1	4.5	4.8	4.2	4.5	4.9
Transmission	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Distribution	2.0	1.9	1.9	2.0	1.7	1.8	1.8	1.7	1.7	1.7

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

Supply, Disposition, and Prices	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Electric Power Sector Emissions[1]										
Sulfur Dioxide (million tons)	10.54	9.98	9.90	10.11	8.94	8.94	8.96	8.95	8.95	8.95
Nitrogen Oxide (million tons)	4.39	3.45	3.50	3.54	3.62	3.67	3.68	3.67	3.75	3.75
Mercury (tons)	50.95	52.57	52.20	53.99	53.49	53.59	54.55	53.54	54.37	55.35

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes plants that only produce electricity.
[3]Includes electricity generation from fuel cells.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[5]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[7]Other gaseous fuels include refinery and still gas.
[8]Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.
[9]Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[10]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Source: 2002 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002), and supporting databases. 2002 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2002 prices: EIA, National Energy Modeling System run AEO2004.D101703E. **Projections**: EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

Table B9. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Electric PowerSector[2]										
Power Only[3]										
Coal Steam	305.7	302.6	305.1	305.3	337.7	348.4	350.9	367.4	407.2	422.2
Other Fossil Steam[4]	132.5	100.4	105.0	104.0	93.2	100.0	100.3	90.7	95.4	97.4
Combined Cycle	81.0	124.5	127.1	131.1	169.6	184.4	211.3	191.6	202.3	227.0
Combustion Turbine/Diesel	123.5	128.7	131.1	131.6	164.0	163.9	169.9	176.4	175.0	181.4
Nuclear Power[5]	98.7	100.6	100.6	100.6	102.6	102.6	102.6	102.6	102.6	102.6
Pumped Storage	20.2	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Fuel Cells	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Renewable Sources[6]	91.4	96.8	97.1	97.9	102.4	105.7	114.9	104.6	109.9	125.7
Distributed Generation[7]	0.0	0.4	0.5	0.6	5.5	7.6	11.1	9.4	12.4	15.4
Total	**853.1**	**874.4**	**886.8**	**891.4**	**995.4**	**1032.9**	**1081.4**	**1063.2**	**1125.1**	**1192.1**
Combined Heat and Power[8]										
Coal Steam	5.2	5.0	5.1	5.1	5.0	5.1	5.1	5.0	5.1	5.1
Other Fossil Steam[4]	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Combined Cycle	29.4	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9
Combustion Turbine/Diesel	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Renewable Sources[6]	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**41.4**	**44.7**	**44.8**	**44.8**	**44.7**	**44.8**	**44.8**	**44.7**	**44.8**	**44.8**
Total Electric Power Industry	**894.5**	**919.1**	**931.7**	**936.3**	**1040.1**	**1077.7**	**1126.3**	**1107.9**	**1169.9**	**1236.9**
Cumulative Planned Additions[9]										
Coal Steam	0.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	43.5	43.5	43.5	43.5	43.5	43.5	43.5	43.5	43.5
Combustion Turbine/Diesel	0.0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Renewable Sources[6]	0.0	4.3	4.3	4.3	4.7	4.7	4.7	4.8	4.8	4.8
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**57.1**	**57.1**	**57.1**	**57.5**	**57.5**	**57.5**	**57.6**	**57.6**	**57.6**
Cumulative Unplanned Additions[9]										
Coal Steam	0.0	3.1	5.7	5.8	40.1	50.7	53.3	70.9	110.6	125.7
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	4.6	6.6	10.6	49.7	64.0	90.9	71.7	81.9	106.5
Combustion Turbine/Diesel	0.0	8.7	10.5	10.9	45.6	46.0	53.3	58.0	59.1	66.7
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	0.8	1.1	1.9	6.0	9.3	18.5	8.1	13.3	29.2
Distributed Generation[7]	0.0	0.4	0.5	0.6	5.5	7.6	11.1	9.4	12.4	15.4
Total	**0.0**	**17.6**	**24.3**	**29.9**	**146.8**	**177.5**	**227.1**	**218.1**	**277.2**	**343.3**
Cumulative Total Additions	**0.0**	**74.7**	**81.4**	**86.9**	**204.3**	**235.0**	**284.6**	**275.7**	**334.8**	**400.9**
Cumulative Retirements[10]										
Coal Steam	0.0	7.6	7.5	7.5	9.5	9.3	9.3	10.6	10.4	10.4
Other Fossil Steam[4]	0.0	30.2	25.6	26.6	37.4	30.6	30.3	39.9	35.2	33.2
Combined Cycle	0.0	1.7	1.1	1.1	1.7	1.1	1.1	1.7	1.1	1.1
Combustion Turbine/Diesel	0.0	10.8	10.2	10.2	12.4	13.0	14.3	12.4	14.9	16.1
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**50.5**	**44.6**	**45.5**	**61.1**	**54.2**	**55.2**	**64.7**	**61.8**	**60.9**

Table B9. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
End-Use Sector										
Combined Heat and Power[11]										
Coal	4.2	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.6
Petroleum	1.0	1.6	1.6	1.6	1.8	2.2	2.4	1.9	2.3	2.5
Natural Gas	14.1	17.3	17.8	18.4	21.1	23.7	26.2	23.5	27.6	31.7
Other Gaseous Fuels	1.8	2.2	2.2	2.2	2.5	2.6	2.6	2.5	2.7	2.7
Renewable Sources[6]	4.2	5.0	5.6	6.1	6.3	7.5	8.6	6.9	8.3	9.6
Other	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**25.5**	**30.5**	**31.7**	**32.8**	**36.1**	**40.5**	**44.3**	**39.2**	**45.3**	**51.5**
Other End-Use Generators[12]										
Renewable Sources[13]	1.1	1.4	1.4	1.4	1.5	1.6	1.7	1.9	2.1	2.6
Cumulative Additions[9]										
Combined Heat and Power[11]	0.0	5.1	6.2	7.3	10.6	15.0	18.8	13.7	19.8	26.0
Other End-Use Generators[12]	0.0	0.3	0.3	0.3	0.4	0.5	0.7	0.8	1.1	1.5

[1]Net summer capacity 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 electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capability.
[5]Nuclear capacity reflects operating capacity of existing units, including 3.9 gigawatts of uprates through 2025.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[7]Primarily peak-load capacity fueled by natural gas
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public(i.e., those that report NAICS code 22).
[9]Cumulative additions after December 31, 2002.
[10]Cumulative total retirements after December 31, 2002.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[12]Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[13]See Table B17 for more detail.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model estimates and may differ slightly from official EIA data reports.
Source: 2002 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

Table B10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Interregional Electricity Trade										
Gross Domestic Firm Power Trade	138.9	107.1	107.1	107.1	41.5	41.5	41.5	41.5	41.5	41.5
Gross Domestic Economy Trade	209.9	243.1	229.7	225.1	221.7	218.4	203.5	205.1	183.4	180.0
Gross Domestic Trade	**348.8**	**350.2**	**336.8**	**332.2**	**263.2**	**259.9**	**245.1**	**246.7**	**224.9**	**221.5**
Gross Domestic Firm Power Sales (million 2002 dollars)	6932.4	5345.8	5345.8	5345.8	2074.2	2074.2	2074.2	2074.2	2074.2	2074.2
Gross Domestic Economy Sales (million 2002 dollars)	6809.8	7817.6	7629.6	7994.4	8127.5	8663.8	8812.3	7892.8	7319.5	7568.5
Gross Domestic Sales (million 2002 dollars)	**13742.1**	**13163.3**	**12975.3**	**13340.1**	**10201.7**	**10738.0**	**10886.5**	**9967.0**	**9393.7**	**9642.7**
International Electricity Trade										
Firm Power Imports From Canada and Mexico	9.5	5.8	5.8	5.8	0.0	0.0	0.0	0.0	0.0	0.0
Economy Imports From Canada and Mexico	26.8	38.3	41.3	45.0	25.7	28.9	31.3	15.0	15.1	15.2
Gross Imports From Canada and Mexico	**36.3**	**44.2**	**47.2**	**50.9**	**25.7**	**28.9**	**31.3**	**15.0**	**15.2**	**15.3**
Firm Power Exports To Canada and Mexico	5.6	8.7	8.7	8.7	0.0	0.0	0.0	0.0	0.0	0.0
Economy Exports To Canada and Mexico	8.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**14.3**	**16.4**	**16.4**	**16.4**	**7.7**	**7.7**	**7.7**	**7.7**	**7.7**	**7.7**

Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.
Source: Energy Information Administration, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

Table B11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2002	Projections								
		2010			2020			2025		
		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]	5.62	5.91	5.93	5.95	4.96	4.95	5.02	4.39	4.61	4.72
Alaska	0.98	0.92	0.92	0.92	0.72	0.72	0.73	0.50	0.51	0.52
Lower 48 States	4.64	5.00	5.01	5.03	4.24	4.23	4.28	3.89	4.11	4.20
Net Imports	9.13	10.82	11.21	11.61	14.08	14.50	15.29	15.03	15.74	16.39
Gross Imports	9.14	10.90	11.29	11.69	14.12	14.53	15.32	15.04	15.76	16.41
Exports	0.01	0.08	0.08	0.08	0.03	0.03	0.04	0.01	0.02	0.02
Other Crude Supply[2]	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**14.83**	**16.74**	**17.15**	**17.56**	**19.04**	**19.45**	**20.30**	**19.42**	**20.35**	**21.11**
Natural Gas Plant Liquids	**1.88**	**2.21**	**2.24**	**2.32**	**2.33**	**2.48**	**2.58**	**2.35**	**2.47**	**2.57**
Other Inputs[3]	**0.67**	**0.45**	**0.47**	**0.49**	**0.44**	**0.46**	**0.47**	**0.47**	**0.48**	**0.52**
Refinery Processing Gain[4]	**0.98**	**0.88**	**0.88**	**0.88**	**1.00**	**1.00**	**1.01**	**1.04**	**1.04**	**1.02**
Net Product Imports[5]	**1.41**	**1.53**	**1.95**	**2.28**	**1.71**	**2.99**	**3.96**	**2.58**	**3.94**	**5.37**
Gross Refined Product Imports[6]	1.92	1.85	2.17	2.49	2.01	2.82	3.67	2.69	3.60	4.98
Unfinished Oil Imports	0.41	0.61	0.72	0.74	0.69	1.15	1.30	0.90	1.34	1.40
Ether Imports	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Exports	0.97	0.94	0.94	0.95	0.99	0.98	1.01	1.01	1.01	1.02
Total Primary Supply[7]	**19.77**	**21.81**	**22.69**	**23.53**	**24.52**	**26.38**	**28.32**	**25.85**	**28.27**	**30.58**
Refined Petroleum Products Supplied										
Motor Gasoline[8]	8.86	10.36	10.59	10.84	11.74	12.30	12.86	12.54	13.30	14.02
Jet Fuel[9]	1.61	1.87	1.90	1.94	2.21	2.27	2.30	2.28	2.37	2.41
Distillate Fuel[10]	3.68	4.14	4.38	4.61	4.80	5.24	5.88	5.12	5.71	6.39
Residual Fuel	0.74	0.69	0.71	0.74	0.74	0.77	0.79	0.75	0.75	0.77
Other[11]	4.72	4.77	5.13	5.43	5.06	5.84	6.53	5.19	6.16	7.02
Total	**19.61**	**21.83**	**22.71**	**23.56**	**24.54**	**26.41**	**28.36**	**25.87**	**28.30**	**30.62**
Refined Petroleum Products Supplied										
Residential and Commercial	1.22	1.37	1.38	1.38	1.39	1.40	1.42	1.38	1.40	1.42
Industrial[12]	4.80	4.74	5.14	5.46	5.02	5.86	6.61	5.16	6.21	7.15
Transportation	13.21	15.44	15.91	16.40	17.74	18.77	19.79	18.94	20.32	21.66
Electric Generators[13]	0.38	0.27	0.29	0.32	0.39	0.38	0.53	0.40	0.36	0.38
Total	**19.61**	**21.83**	**22.71**	**23.56**	**24.54**	**26.41**	**28.36**	**25.87**	**28.30**	**30.62**
Discrepancy[14]	**0.16**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.04**	**-0.04**	**-0.02**	**-0.03**	**-0.04**
World Oil Price (2002 dollars per barrel)[15]	**23.68**	**23.64**	**24.17**	**24.67**	**24.77**	**26.02**	**27.27**	**25.30**	**27.00**	**28.55**
Import Share of Product Supplied	**0.54**	**0.57**	**0.58**	**0.59**	**0.64**	**0.66**	**0.68**	**0.68**	**0.70**	**0.71**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2002 dollars)	**90.38**	**108.26**	**118.31**	**128.45**	**144.55**	**168.99**	**195.83**	**166.08**	**200.24**	**236.71**
Domestic Refinery Distillation Capacity[16]	**16.8**	**18.2**	**18.7**	**19.0**	**20.4**	**20.8**	**21.7**	**20.8**	**21.8**	**22.6**
Capacity Utilization Rate (percent)	**91.0**	**93.4**	**93.1**	**93.5**	**94.7**	**94.8**	**94.8**	**94.8**	**94.8**	**94.8**

[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, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[6]Includes other hydrocarbons, alcohols, and blending components.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes only kerosene type.
[10]Includes distillate and kerosene.
[11]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[12]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[13]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses, and gains.
[15]Average refiner acquisition cost for imported crude oil.
[16]End-of-year capacity.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). Other 2002 data: EIA, *Petroleum Supply Annual 2002,* DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). **Projections:** EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

Table B12. Petroleum Product Prices
(2002 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
World Oil Price (2002 dollars per barrel)	**23.68**	**23.64**	**24.17**	**24.67**	**24.77**	**26.02**	**27.27**	**25.30**	**27.00**	**28.55**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	114.2	107.2	108.4	110.1	110.1	116.4	119.4	113.6	118.4	125.0
Liquefied Petroleum Gas	110.8	117.0	119.1	121.4	121.5	126.9	130.4	124.3	130.3	137.7
Commercial										
Distillate Fuel	84.1	74.3	75.6	77.3	76.8	83.3	86.4	80.6	85.3	91.8
Residual Fuel	63.1	60.6	61.8	63.0	63.2	66.1	68.9	64.3	68.1	71.6
Residual Fuel (2002 dollars per barrel)	26.48	25.43	25.97	26.48	26.54	27.75	28.93	27.02	28.59	30.06
Industrial[1]										
Distillate Fuel	86.2	77.2	78.8	80.3	79.8	86.6	89.7	84.0	88.8	95.4
Liquefied Petroleum Gas	71.1	79.7	83.4	85.8	85.0	91.4	95.9	87.5	95.3	103.8
Residual Fuel	58.3	54.8	56.0	57.3	57.4	60.3	63.2	58.6	62.4	66.0
Residual Fuel (2002 dollars per barrel)	24.48	23.01	23.54	24.06	24.12	25.34	26.55	24.62	26.22	27.72
Transportation										
Diesel Fuel (distillate)[2]	130.6	138.4	140.3	145.9	130.1	138.6	145.0	130.3	139.0	146.7
Jet Fuel[3]	80.6	76.1	77.8	80.0	75.9	81.8	85.4	77.9	83.9	90.0
Motor Gasoline[4]	138.1	144.0	146.9	150.7	142.3	147.3	152.6	142.2	149.2	155.5
Liquid Petroleum Gas	128.7	125.7	128.3	131.6	126.4	133.0	138.2	128.2	135.8	144.7
Residual Fuel	56.5	52.6	53.9	55.0	55.1	58.0	60.9	56.3	60.2	63.8
Residual Fuel (2002 dollars per barrel)	23.71	22.11	22.62	23.12	23.15	24.37	25.58	23.63	25.28	26.79
Ethanol (E85)[5]	135.8	153.0	153.9	154.9	156.2	163.4	164.9	164.5	166.1	168.3
Electric Power[6]										
Distillate Fuel	77.4	66.5	68.2	69.8	68.9	75.8	79.6	73.3	77.9	84.8
Residual Fuel	60.4	58.7	59.7	60.8	61.4	64.5	67.3	62.8	67.4	71.3
Residual Fuel (2002 dollars per barrel)	25.38	24.63	25.07	25.54	25.81	27.07	28.27	26.37	28.30	29.96
Refined Petroleum Product Prices[7]										
Distillate Fuel	118.1	121.7	123.8	128.5	117.1	125.9	130.5	119.0	127.3	135.0
Jet Fuel[3]	80.6	76.1	77.8	80.0	75.9	81.8	85.4	77.9	83.9	90.0
Liquefied Petroleum Gas	79.6	88.6	91.3	93.4	94.0	99.1	102.6	96.5	102.6	110.1
Motor Gasoline[4]	138.1	144.0	146.9	150.7	142.3	147.3	152.6	142.2	149.2	155.5
Residual Fuel	58.6	55.3	56.6	57.8	58.1	61.1	64.0	59.3	63.3	67.0
Residual Fuel (2002 dollars per barrel)	24.62	23.24	23.76	24.29	24.40	25.65	26.86	24.92	26.60	28.14
Average	**116.1**	**121.7**	**123.9**	**127.1**	**120.8**	**126.3**	**130.6**	**122.2**	**128.6**	**135.0**

[1]Includes combined heat and power, which produces electricity and other useful thermal energy.
[2]Diesel fuel containing 500 part per million (ppm) or 15 ppm sulfur. Includes Federal and State taxes while excluding county and local taxes.
[3]Kerosene-type jet fuel.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources:. 2002 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2002*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (August 2003). 2002 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A: "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2002 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2002 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2002 world oil price: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections**: EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

Table B13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	2002	Projections								
		2010			2020			2025		
		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]	19.05	20.15	20.50	21.30	22.10	23.79	24.96	22.70	23.99	25.16
Supplemental Natural Gas[2]	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Net Imports	**3.49**	**4.83**	**5.50**	**5.75**	**5.74**	**6.47**	**7.40**	**6.23**	**7.24**	**8.50**
Canada	3.59	3.53	3.68	3.89	2.44	2.51	2.64	2.37	2.56	2.81
Mexico	-0.26	-0.35	-0.34	-0.33	-0.27	-0.18	-0.07	-0.31	-0.12	0.22
Liquefied Natural Gas	0.17	1.64	2.16	2.19	3.56	4.14	4.83	4.17	4.80	5.46
Total Supply	**22.62**	**25.07**	**26.09**	**27.15**	**27.94**	**30.36**	**32.46**	**29.03**	**31.33**	**33.75**
Consumption by Sector										
Residential	4.92	5.50	5.53	5.58	5.75	5.92	6.01	5.83	6.09	6.26
Commercial	3.12	3.45	3.48	3.49	3.72	3.83	3.91	3.87	4.04	4.18
Industrial[3]	7.23	7.86	8.39	8.86	8.45	9.57	10.63	8.78	10.29	11.69
Electric Generators[4]	5.55	6.26	6.66	7.11	7.78	8.61	9.36	8.18	8.39	9.01
Transportation[5]	0.01	0.05	0.06	0.06	0.09	0.10	0.10	0.10	0.11	0.12
Pipeline Fuel	0.63	0.66	0.67	0.70	0.73	0.81	0.86	0.78	0.84	0.87
Lease and Plant Fuel[6]	1.32	1.35	1.36	1.40	1.50	1.61	1.67	1.57	1.65	1.71
Total	**22.78**	**25.13**	**26.15**	**27.21**	**28.01**	**30.44**	**32.55**	**29.11**	**31.41**	**33.84**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**-0.16**	**-0.06**	**-0.06**	**-0.06**	**-0.08**	**-0.08**	**-0.09**	**-0.08**	**-0.09**	**-0.09**

[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 for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as vehicle fuel.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[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, 2002 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2002 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections:** EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

Table B14. Natural Gas Prices, Margins, and Revenue
(2002 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Source Price										
Average Lower 48 Wellhead Price[1]	2.95	3.31	3.40	3.61	3.97	4.28	4.71	4.28	4.40	4.94
Average Import Price	3.14	3.63	3.78	4.00	4.28	4.58	4.98	4.48	4.67	5.13
Average[2]	**2.98**	**3.38**	**3.49**	**3.70**	**4.04**	**4.35**	**4.78**	**4.33**	**4.47**	**4.99**
Delivered Prices										
Residential	7.86	7.78	7.88	8.11	8.18	8.47	8.95	8.41	8.56	9.04
Commercial	6.55	6.72	6.83	7.06	7.21	7.52	7.99	7.45	7.62	8.12
Industrial[3]	3.85	4.05	4.16	4.40	4.68	5.02	5.49	4.95	5.13	5.69
Electric Generators[4]	3.85	4.02	4.12	4.36	4.61	4.94	5.42	4.87	5.01	5.57
Transportation[5]	7.58	8.35	8.49	8.80	8.90	9.32	9.90	9.11	9.34	9.95
Average[6]	**5.21**	**5.34**	**5.41**	**5.60**	**5.83**	**6.09**	**6.51**	**6.07**	**6.19**	**6.68**
Transmission & Distribution Margins[7]										
Residential	4.88	4.40	4.40	4.41	4.14	4.11	4.17	4.08	4.09	4.05
Commercial	3.56	3.33	3.34	3.36	3.17	3.17	3.21	3.12	3.15	3.12
Industrial[3]	0.87	0.67	0.68	0.70	0.63	0.67	0.71	0.63	0.66	0.70
Electric Generators[4]	0.86	0.64	0.63	0.66	0.56	0.59	0.64	0.54	0.54	0.58
Transportation[5]	4.60	4.97	5.00	5.10	4.85	4.96	5.12	4.78	4.87	4.96
Average[6]	**2.23**	**1.96**	**1.92**	**1.90**	**1.78**	**1.74**	**1.73**	**1.74**	**1.72**	**1.69**
Transmission & Distribution Revenue (billion 2002 dollars)										
Residential	24.02	24.18	24.33	24.62	23.78	24.34	25.08	23.80	24.89	25.32
Commercial	11.12	11.51	11.61	11.73	11.81	12.13	12.55	12.08	12.72	13.05
Industrial[3]	6.27	5.23	5.67	6.22	5.35	6.42	7.52	5.51	6.80	8.18
Electric Generators[4]	4.78	4.01	4.21	4.66	4.36	5.10	6.02	4.43	4.54	5.25
Transportation[5]	0.06	0.27	0.28	0.31	0.43	0.48	0.54	0.47	0.54	0.60
Total	**46.25**	**45.19**	**46.11**	**47.54**	**45.73**	**48.46**	**51.70**	**46.30**	**49.49**	**52.41**

[1]Represents lower 48 onshore and offshore supplies.
[2]Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.
[3]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.

Sources: 2002 electric generators delivered price: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2002 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1998*. 2002 residential, commercial, and transportation delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). Other 2002 values**:** EIA, Office of Integrated Analysis and Forecasting. **Projections**: EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

Table B15. Oil and Gas Supply

Production and Supply	2002	Projections								
		2010			2020			2025		
		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] (2002 dollars per barrel)	**24.54**	**23.02**	**23.61**	**24.20**	**24.27**	**25.82**	**26.96**	**24.83**	**26.72**	**28.45**
Production (million barrels per day)[2]										
U.S. Total	**5.62**	**5.91**	**5.93**	**5.95**	**4.96**	**4.95**	**5.02**	**4.39**	**4.61**	**4.72**
Lower 48 Onshore	3.11	2.60	2.61	2.62	2.17	2.20	2.23	2.01	2.04	2.07
Lower 48 Offshore	1.53	2.40	2.40	2.41	2.07	2.03	2.06	1.88	2.06	2.13
Alaska	0.98	0.92	0.92	0.92	0.72	0.72	0.73	0.50	0.51	0.52
Lower 48 End of Year Reserves (billion barrels)[2]	**19.05**	**18.29**	**18.36**	**18.42**	**16.05**	**16.20**	**16.21**	**14.42**	**14.98**	**15.29**
Natural Gas										
Lower 48 Average Wellhead Price[1] (2002 dollars per thousand cubic feet)	**2.95**	**3.31**	**3.40**	**3.61**	**3.97**	**4.28**	**4.71**	**4.28**	**4.40**	**4.94**
Dry Production (trillion cubic feet)[3]										
U.S. Total	**19.05**	**20.15**	**20.50**	**21.30**	**22.10**	**23.79**	**24.97**	**22.70**	**23.99**	**25.16**
Lower 48 Onshore	13.76	14.18	14.48	15.13	15.48	16.41	17.21	15.86	16.26	17.28
Associated-Dissolved[4]	1.60	1.40	1.41	1.41	1.22	1.23	1.24	1.16	1.17	1.18
Non-Associated	12.16	12.78	13.08	13.72	14.26	15.18	15.97	14.71	15.09	16.10
Conventional	6.23	5.72	5.80	6.07	5.70	6.07	6.41	5.70	5.92	6.30
Unconventional	5.93	7.06	7.28	7.65	8.55	9.11	9.55	9.00	9.16	9.80
Lower 48 Offshore	4.86	5.37	5.41	5.57	5.15	5.09	5.09	4.51	5.03	5.17
Associated-Dissolved[4]	1.05	1.61	1.61	1.61	1.34	1.34	1.33	1.23	1.43	1.48
Non-Associated	3.81	3.76	3.80	3.96	3.80	3.75	3.76	3.29	3.60	3.69
Alaska	0.43	0.60	0.60	0.60	1.48	2.29	2.67	2.32	2.71	2.71
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**180.03**	**198.58**	**201.20**	**202.86**	**198.82**	**200.97**	**201.88**	**188.97**	**193.51**	**192.74**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Total Lower 48 Wells (thousands)	**24.47**	**23.94**	**24.78**	**25.99**	**25.79**	**26.83**	**27.68**	**25.40**	**26.00**	**27.45**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2002*, DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). 2002 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). Other 2002 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

Table B16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production[1]										
Appalachia	408	401	408	421	385	402	426	378	419	462
Interior	147	165	169	181	161	170	177	144	178	192
West	550	642	653	640	791	805	779	898	946	931
East of the Mississippi	504	513	524	541	497	522	553	492	547	605
West of the Mississippi	601	694	706	702	840	854	829	929	996	981
Total	**1105**	**1208**	**1230**	**1242**	**1337**	**1377**	**1382**	**1420**	**1543**	**1586**
Net Imports										
Imports	17	33	33	33	42	42	42	46	46	46
Exports	40	36	35	35	29	27	26	26	23	21
Total	**-23**	**-2**	**-2**	**-2**	**12**	**14**	**16**	**20**	**23**	**25**
Total Supply[2]	**1083**	**1205**	**1228**	**1240**	**1349**	**1391**	**1398**	**1440**	**1566**	**1611**
Consumption by Sector										
Residential and Commercial	4	5	5	5	5	5	5	5	5	5
Industrial[3]	63	62	65	67	63	66	70	63	67	79
of which: Coal to Liquids	0	0	0	0	0	0	0	0	0	8
Coke Plants	22	23	23	23	19	19	19	17	17	17
Electric Generators[4]	976	1115	1136	1145	1263	1301	1305	1355	1477	1510
Total	**1066**	**1205**	**1229**	**1240**	**1349**	**1391**	**1399**	**1441**	**1567**	**1612**
Discrepancy and Stock Change[5]	**17**	**-0**	**-0**	**0**	**-0**	**-0**	**-1**	**-1**	**-1**	**-1**
Average Minemouth Price										
(2002 dollars per short ton)	17.90	16.53	16.88	17.47	15.78	16.32	16.92	15.67	16.57	17.95
(2002 dollars per million Btu)	0.87	0.81	0.82	0.85	0.78	0.80	0.83	0.78	0.82	0.88
Delivered Prices (2002 dollars per short ton)[6]										
Industrial	33.24	33.54	34.46	35.76	31.62	33.43	34.96	31.01	33.33	33.61
Coke Plants	51.27	52.75	53.68	55.04	48.98	50.45	52.22	46.67	48.42	50.50
Electric Generators										
(2002 dollars per short ton)	25.96	24.03	24.67	25.52	22.87	24.01	25.03	22.75	24.31	26.29
(2002 dollars per million Btu)	1.26	1.19	1.22	1.26	1.15	1.20	1.24	1.14	1.22	1.30
Average	**26.93**	**25.09**	**25.74**	**26.63**	**23.65**	**24.83**	**25.90**	**23.40**	**24.96**	**26.91**
Exports[7]	40.44	35.68	36.47	37.22	33.43	34.13	35.20	31.67	32.34	33.74

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 11.1 million tons in 2002.
[2]Production plus net imports plus net storage withdrawals.
[3]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003); EIA, *Annual Coal Report 2002*, DOE/EIA-0584(2002) (Washington, DC, November 2003); and EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E. **Projections:** EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

Table B17. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Electric Power Sector[1]										
Net Summer Capacity										
Conventional Hydropower	78.29	78.69	78.69	78.69	78.68	78.68	78.68	78.68	78.68	78.68
Geothermal[2]	2.89	3.94	4.01	4.11	5.91	6.06	6.36	6.63	6.84	7.30
Municipal Solid Waste[3]	3.49	3.89	3.92	3.89	3.92	3.95	4.06	3.92	3.95	4.07
Wood and Other Biomass[4,5]	1.83	2.17	2.20	2.14	2.55	3.04	4.62	2.65	3.74	8.13
Solar Thermal	0.33	0.43	0.43	0.43	0.49	0.49	0.49	0.52	0.52	0.52
Solar Photovoltaic[5]	0.02	0.15	0.15	0.15	0.32	0.32	0.32	0.41	0.41	0.41
Wind	4.83	7.82	8.01	8.74	10.77	13.39	20.65	12.09	15.99	26.84
Total	**91.69**	**97.09**	**97.42**	**98.15**	**102.65**	**105.93**	**115.18**	**104.90**	**110.13**	**125.95**
Generation (billion kilowatthours)										
Conventional Hydropower	255.78	304.35	304.37	304.40	304.57	304.63	304.69	304.72	304.80	304.88
Geothermal[2]	13.36	22.67	23.25	24.03	38.92	40.14	42.51	45.01	46.66	50.32
Municipal Solid Waste[3]	20.02	27.89	28.11	27.94	28.18	28.44	29.32	28.22	28.50	29.49
Wood and Other Biomass[5]	8.67	22.68	23.53	25.40	25.16	27.64	33.30	25.21	29.16	51.55
Dedicated Plants	6.32	13.09	13.26	13.11	15.66	18.47	27.29	16.52	22.90	49.87
Cofiring	2.35	9.59	10.26	12.29	9.50	9.17	6.01	8.68	6.25	1.68
Solar Thermal	0.54	0.84	0.84	0.84	1.04	1.04	1.04	1.11	1.11	1.11
Solar Photovoltaic[6]	0.00	0.36	0.36	0.36	0.79	0.79	0.79	1.02	1.02	1.02
Wind	10.51	23.41	24.07	26.63	34.10	43.54	70.33	38.91	53.16	93.54
Total	**308.87**	**402.20**	**404.52**	**409.59**	**432.77**	**446.22**	**481.98**	**444.18**	**464.40**	**531.90**
End- Use Sector										
Net Summer Capacity										
Combined Heat and Power[7]										
Municipal Solid Waste	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Biomass	3.91	4.71	5.36	5.83	6.02	7.26	8.37	6.60	8.03	9.38
Total	**4.16**	**4.96**	**5.61**	**6.09**	**6.27**	**7.51**	**8.62**	**6.86**	**8.29**	**9.64**
Other End-Use Generators[8]										
Conventional Hydropower[9]	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.04	0.39	0.39	0.39	0.49	0.58	0.70	0.89	1.13	1.55
Total	**1.06**	**1.41**	**1.41**	**1.41**	**1.51**	**1.61**	**1.72**	**1.91**	**2.15**	**2.57**
Generation (billion kilowatthours)										
Combined Heat and Power[7]										
Municipal Solid Waste	1.84	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10
Biomass	28.16	32.85	36.63	39.42	40.51	47.72	54.23	43.92	52.26	60.14
Total	**30.00**	**34.95**	**38.73**	**41.52**	**42.61**	**49.82**	**56.33**	**46.02**	**54.36**	**62.24**
Other End-Use Generators[8]										
Conventional Hydropower[9]	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.09	0.82	0.82	0.82	1.05	1.26	1.50	1.92	2.42	3.31
Total	**4.20**	**4.93**	**4.93**	**4.93**	**5.16**	**5.37**	**5.61**	**6.02**	**6.53**	**7.42**

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Includes projections for energy crops after 2010.
[6]Does not include off-grid photovoltaics (PV). See Annual Energy Review 2002 Table 10.6 for estimates of 1989-2001 PV shipments, including exports, for both grid-connected and off-grid applications.
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[8]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[9]Represents own-use industrial hydroelectric power.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2004. Net summer capacity is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.
Sources: 2002 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2002 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections:** EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

Table B18. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	2002	Projections								
		2010			2020			2025		
		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	**0.39**	**0.40**	**0.40**	**0.41**	**0.40**	**0.41**	**0.41**	**0.39**	**0.41**	**0.41**
Wood	0.39	0.40	0.40	0.41	0.40	0.41	0.41	0.39	0.41	0.41
Commercial	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Biomass	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Industrial[3]	**1.66**	**1.83**	**2.00**	**2.13**	**2.16**	**2.48**	**2.79**	**2.32**	**2.70**	**3.08**
Conventional Hydroelectric	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Municipal Solid Waste	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biomass	1.60	1.78	1.95	2.07	2.11	2.43	2.73	2.27	2.65	3.03
Transportation	**0.17**	**0.28**	**0.29**	**0.30**	**0.32**	**0.33**	**0.35**	**0.34**	**0.35**	**0.38**
Ethanol used in E85[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ethanol used in Gasoline Blending	0.17	0.28	0.29	0.30	0.31	0.33	0.34	0.33	0.35	0.37
Electric Generators[5]	**3.69**	**4.64**	**4.68**	**4.75**	**5.30**	**5.47**	**5.88**	**5.55**	**5.79**	**6.54**
Conventional Hydroelectric	2.75	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13
Geothermal	0.30	0.59	0.61	0.64	1.11	1.15	1.23	1.30	1.36	1.49
Municipal Solid Waste[6]	0.34	0.38	0.39	0.38	0.39	0.39	0.40	0.39	0.39	0.40
Biomass	0.17	0.28	0.29	0.31	0.30	0.33	0.37	0.30	0.34	0.53
Dedicated Plants	0.11	0.15	0.15	0.15	0.18	0.21	0.30	0.19	0.26	0.51
Cofiring	0.06	0.13	0.14	0.17	0.13	0.12	0.07	0.12	0.08	0.02
Solar Thermal	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.13	0.24	0.25	0.27	0.35	0.45	0.72	0.40	0.55	0.96
Total Marketed Renewable Energy	**6.01**	**7.26**	**7.47**	**7.68**	**8.28**	**8.78**	**9.53**	**8.70**	**9.35**	**10.51**
Sources of Ethanol										
From Corn	0.17	0.28	0.29	0.30	0.29	0.31	0.32	0.29	0.31	0.32
From Cellulose	0.00	0.00	0.00	0.00	0.02	0.02	0.03	0.05	0.05	0.05
Total	**0.17**	**0.28**	**0.29**	**0.30**	**0.32**	**0.33**	**0.35**	**0.34**	**0.35**	**0.38**
Non-Marketed Renewable Energy[7]										
Selected Consumption										
Residential	**0.02**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.05**
Solar Hot Water Heating	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04
Geothermal Heat Pumps	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**
Solar Thermal	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table B8.
[3]Includes all electricity production by industrial and other combined heat and power for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Includes landfill gas.
[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2002 electric generators: EIA, Form EIA-860: "Annual Electric Generator Report" (preliminary). Other 2002 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

Table B19. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons)

Sector and Source	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential										
Petroleum	104.0	110.2	110.4	110.7	106.7	107.1	108.0	103.2	104.5	105.1
Natural Gas	267.2	298.3	300.4	302.9	311.9	321.2	326.3	316.3	330.7	339.5
Coal	1.1	1.2	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.1
Electricity	816.7	900.4	905.3	906.1	1008.2	1019.9	1014.6	1062.2	1106.7	1104.4
Total	**1189.0**	**1310.1**	**1317.2**	**1320.9**	**1427.8**	**1449.2**	**1449.9**	**1482.8**	**1543.0**	**1550.1**
Commercial										
Petroleum	52.6	66.0	66.2	66.5	69.8	70.2	71.7	71.0	72.2	73.9
Natural Gas	169.4	187.5	188.7	189.5	202.2	207.9	212.1	210.0	219.4	226.8
Coal	9.2	9.2	9.3	9.3	9.2	9.2	9.3	9.2	9.2	9.3
Electricity	778.0	931.6	938.4	937.0	1120.3	1135.5	1136.1	1217.1	1269.2	1276.7
Total	**1009.1**	**1194.3**	**1202.5**	**1202.3**	**1401.4**	**1422.9**	**1429.2**	**1507.2**	**1570.1**	**1586.6**
Industrial[1]										
Petroleum	412.8	346.2	365.4	381.2	366.9	408.0	446.5	380.0	428.4	471.2
Natural Gas[2]	432.7	493.3	522.1	549.7	533.7	598.6	658.8	554.9	639.4	717.4
Coal	185.1	186.9	191.9	196.6	175.6	183.3	191.1	171.9	181.1	196.4
Electricity	640.0	654.5	710.3	758.2	721.5	813.8	904.1	760.4	900.7	1023.3
Total	**1670.6**	**1680.9**	**1789.6**	**1885.8**	**1797.7**	**2003.6**	**2200.4**	**1867.2**	**2149.5**	**2408.3**
Transportation										
Petroleum[3]	1811.2	2127.3	2193.2	2262.6	2445.6	2590.9	2734.7	2611.2	2805.8	2993.7
Natural Gas[4]	35.2	38.6	39.5	41.3	44.1	49.1	52.2	47.7	51.3	53.8
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	14.2	16.6	16.7	16.8	19.8	19.9	19.9	21.8	22.4	22.4
Total	**1860.6**	**2182.5**	**2249.5**	**2320.6**	**2509.5**	**2659.9**	**2806.8**	**2680.7**	**2879.5**	**3069.9**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	2380.5	2649.7	2735.2	2820.9	2989.0	3176.2	3360.9	3165.4	3410.9	3643.9
Natural Gas	904.4	1017.7	1050.7	1083.5	1091.9	1176.8	1249.3	1128.9	1240.8	1337.6
Coal	195.4	197.3	202.4	207.0	185.9	193.6	201.4	182.1	191.4	206.7
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	2249.0	2503.1	2570.6	2618.1	2869.7	2989.0	3074.6	3061.5	3299.0	3426.7
Total	**5729.3**	**6367.8**	**6558.8**	**6729.6**	**7136.5**	**7535.6**	**7886.3**	**7537.9**	**8142.0**	**8614.9**
Electric Power[6]										
Petroleum	72.2	47.4	51.0	54.8	66.8	65.2	87.9	67.4	61.6	64.8
Natural Gas	299.1	336.9	358.5	382.4	418.5	463.3	503.6	440.3	451.6	485.0
Coal	1877.8	2118.8	2161.2	2181.0	2384.4	2460.5	2483.0	2553.8	2785.8	2877.0
Total	**2249.0**	**2503.1**	**2570.6**	**2618.1**	**2869.7**	**2989.0**	**3074.6**	**3061.5**	**3299.0**	**3426.7**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	2452.7	2697.1	2786.1	2875.7	3055.8	3241.4	3448.9	3232.8	3472.5	3708.7
Natural Gas	1203.4	1354.6	1409.2	1465.9	1510.4	1640.1	1753.0	1569.2	1692.4	1822.6
Coal	2073.2	2316.1	2363.6	2388.0	2570.3	2654.1	2684.5	2735.9	2977.1	3083.7
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**5729.3**	**6367.8**	**6558.8**	**6729.6**	**7136.5**	**7535.6**	**7886.3**	**7537.9**	**8142.0**	**8614.9**
Carbon Dioxide Emissions (tons per person)	**19.8**	**20.9**	**21.2**	**21.4**	**22.2**	**22.5**	**22.7**	**22.7**	**23.4**	**23.7**

[1]Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2000, international bunker fuels accounted for 24 to 30 million metric tons of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes methanol and liquid hydrogen.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.
[7]Emissions from electric power generators are distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2002,* DOE/EIA-0573(2002) (Washington, DC, October 2003). **Projections:** EIA, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

Table B20. Macroeconomic Indicators
(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High.5 Economic Growth
Real Gross Domestic Product	**9440**	**11727**	**12190**	**12858**	**14722**	**16188**	**17603**	**16280**	**18520**	**20685**
Real Potential Gross Domestic Product	**9726**	**12001**	**12313**	**12745**	**15028**	**16186**	**17586**	**16645**	**18520**	**20598**
Real Disposable Personal Income	**7032**	**8619**	**8894**	**9264**	**11030**	**11864**	**12658**	**12643**	**13826**	**14969**
Components of Real Gross Domestic Product										
Real Consumption	6576	8162	8437	8801	10329	11296	12010	11483	12946	14089
Real Investment	1590	2209	2387	2638	3125	3726	4210	3627	4661	5483
Real Government Spending	1713	1879	1961	2009	2072	2265	2387	2172	2423	2599
Real Exports	1059	1751	1838	1974	2969	3376	3857	3773	4546	5347
Real Imports	1547	2278	2436	2529	3713	4433	4676	5058	6015	6492
Energy Intensity										
(thousand Btu per 1996 dollar of GDP										
Delivered Energy	7.55	6.76	6.73	6.60	5.98	5.84	5.71	5.68	5.45	5.26
Total Energy	10.36	9.24	9.17	8.95	8.19	7.91	7.67	7.76	7.37	7.05
Price Indices										
GDP Chain-Type Price Index (1996=1.000)	1.107	1.356	1.301	1.210	2.012	1.774	1.564	2.493	2.121	1.790
Consumer Price Index (1982-4=1)	1.80	2.21	2.11	1.96	3.33	2.89	2.54	4.23	3.49	2.93
Wholesale Price Index (1982=1.00)										
All Commodities	1.31	1.53	1.46	1.36	2.03	1.74	1.52	2.38	1.94	1.62
Fuel and Power	0.93	1.08	1.06	1.04	1.51	1.33	1.19	1.85	1.52	1.27
Interest Rates (percent, nominal)										
Federal Funds Rate	1.67	5.86	5.42	5.04	7.08	6.30	5.59	8.06	7.00	6.04
10-Year Treasury Note	4.61	6.95	6.60	6.27	7.79	7.07	6.42	9.02	7.95	6.95
AA Utility Bond Rate	7.19	8.41	7.99	7.61	9.53	8.59	7.75	10.69	9.27	7.99
Unemployment Rate (percent)	**5.78**	**5.45**	**4.93**	**4.38**	**5.01**	**4.41**	**3.84**	**5.08**	**4.44**	**3.80**
Housing Starts (millions)	**1.88**	**1.74**	**1.97**	**2.24**	**1.57**	**1.94**	**2.16**	**1.49**	**1.92**	**2.20**
Commercial Floorspace, Total										
(billion square feet)	**72.1**	**82.8**	**83.8**	**84.8**	**92.5**	**95.9**	**99.3**	**96.9**	**101.8**	**106.4**
Unit Sales of Light-Duty Vehicles										
(millions)	**16.78**	**17.01**	**18.01**	**19.08**	**18.41**	**20.25**	**22.16**	**18.08**	**21.32**	**24.91**
Value of Shipments (billion 1996 dollars)										
Total Industrial	5285	5927	6439	6986	7292	8344	9537	7987	9491	11166
Non-manufacturing	1222	1300	1425	1587	1462	1710	1955	1503	1855	2204
Manufacturing	4064	4627	5013	5399	5830	6634	7582	6483	7636	8962
Energy-Intensive	1120	1181	1273	1348	1321	1500	1679	1393	1610	1830
Non-Energy Intensive	2944	3446	3741	4051	4508	5135	5903	5090	6026	7132
Population and Employment (millions)										
Population with Armed Forces Overseas	288.9	304.1	309.3	314.4	322.2	334.6	347.1	331.4	347.5	363.7
Population (aged 16 and over)	224.3	240.3	244.1	247.9	255.2	264.3	273.3	262.3	274.3	286.3
Employment,Non-Agriculture	130.5	136.7	145.0	150.9	148.5	161.2	169.2	160.5	168.6	181.1
Employment,Manufacturing	16.7	15.3	16.1	16.9	15.3	16.0	17.0	15.3	16.2	17.3
Labor Force	145.1	156.8	159.8	163.6	164.2	171.3	178.8	167.1	176.8	186.8

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2002: Global Insight macroeconomic model T250803. **Projections:** Energy Information Administration, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

Table B21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2002	Projections								
		2010			2020			2025		
		Low Economic Growth	Reference Case	High Economic Growth	Low Economic Growth	Reference Case	High Economic Growth	Low Economic Growth	Reference Case	High Economic Growth
World Oil Price[1] (2002 dollars per barrel)	**23.68**	**23.64**	**24.17**	**24.67**	**24.77**	**26.02**	**27.27**	**25.30**	**27.00**	**28.55**
Production[2] (Conventional)										
Industrialized Countries										
U.S. (50 states)	9.16	9.46	9.53	9.64	8.73	8.89	9.07	8.24	8.59	8.79
Canada	2.14	1.83	1.83	1.83	1.59	1.60	1.61	1.55	1.57	1.58
Mexico	3.61	4.20	4.20	4.20	4.58	4.60	4.62	4.79	4.82	4.84
Western Europe[3]	6.76	6.33	6.34	6.34	5.47	5.48	5.49	4.96	4.97	4.99
Japan	0.08	0.08	0.08	0.08	0.06	0.06	0.07	0.06	0.06	0.06
Australia and New Zealand	0.75	0.95	0.96	0.96	0.88	0.88	0.89	0.85	0.86	0.86
Total Industrialized	**22.51**	**22.85**	**22.93**	**23.05**	**21.32**	**21.52**	**21.75**	**20.46**	**20.87**	**21.13**
Eurasia										
Former Soviet Union										
Russia	7.67	9.90	9.92	9.93	10.72	10.77	10.80	10.87	10.93	10.98
Caspian Area[4]	1.66	3.11	3.12	3.12	5.13	5.15	5.17	6.08	6.11	6.14
Eastern Europe[5]	0.23	0.33	0.33	0.33	0.41	0.41	0.41	0.45	0.45	0.45
Total Eurasia	**9.56**	**13.35**	**13.37**	**13.38**	**16.26**	**16.32**	**16.38**	**17.39**	**17.48**	**17.57**
Developing Countries	**44.24**	**49.32**	**49.94**	**50.51**	**63.37**	**64.32**	**65.32**	**73.18**	**74.05**	**75.20**
Total Production (Conventional)	**76.30**	**85.52**	**86.24**	**86.95**	**100.94**	**102.17**	**103.45**	**111.03**	**112.41**	**113.89**
Production[6] (Nonconventional)										
U.S. (50 states)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03
Other North America	0.79	1.69	1.69	1.69	3.20	3.20	3.20	3.28	3.28	3.28
Western Europe	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Asia	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Middle East[7]	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.03
Africa	0.16	0.19	0.19	0.19	0.25	0.25	0.25	0.28	0.28	0.28
South and Central America	0.54	0.85	0.85	0.85	1.42	1.42	1.42	1.45	1.45	1.45
Total Production (Nonconventional)	**1.55**	**2.81**	**2.81**	**2.81**	**4.97**	**4.97**	**4.97**	**5.11**	**5.11**	**5.11**
Total Production	**77.85**	**88.33**	**89.05**	**89.76**	**105.91**	**107.13**	**108.41**	**116.14**	**117.53**	**119.03**
Consumption[8]										
Industrialized Countries										
U.S. (50 states)	19.61	21.83	22.71	23.56	24.54	26.41	28.36	25.87	28.30	30.62
U.S. Territories	0.29	0.38	0.38	0.38	0.43	0.43	0.42	0.48	0.47	0.46
Canada	1.96	2.25	2.23	2.23	2.40	2.36	2.33	2.50	2.44	2.40
Mexico	2.01	2.66	2.65	2.65	3.69	3.62	3.57	4.20	4.09	3.99
Western Europe[3]	14.02	14.39	14.36	14.33	14.90	14.80	14.70	15.41	15.26	15.14
Japan	5.45	5.82	5.79	5.77	6.38	6.26	6.15	6.73	6.54	6.38
Australia and New Zealand	1.04	1.28	1.28	1.28	1.59	1.58	1.57	1.76	1.75	1.74
Total Industrialized	**44.39**	**48.61**	**49.41**	**50.18**	**53.94**	**55.47**	**57.11**	**56.95**	**58.85**	**60.73**
Eurasia										
Former Soviet Union	4.05	5.11	5.10	5.09	5.76	5.73	5.70	6.29	6.25	6.21
Eastern Europe[5]	1.44	1.74	1.74	1.74	2.22	2.21	2.21	2.55	2.54	2.53
Total Eurasia	**5.49**	**6.85**	**6.84**	**6.83**	**7.98**	**7.94**	**7.90**	**8.85**	**8.79**	**8.74**
Developing Countries										
China	5.11	6.50	6.48	6.46	9.48	9.39	9.30	11.03	10.88	10.76
India	2.16	2.81	2.80	2.80	4.52	4.47	4.43	5.55	5.48	5.41
South Korea	2.20	2.76	2.75	2.74	3.18	3.15	3.12	3.37	3.32	3.27
Other Asia	5.63	6.66	6.65	6.64	8.97	8.93	8.89	10.24	10.17	10.12
Middle East[7]	5.34	6.20	6.19	6.18	7.89	7.87	7.85	8.92	8.88	8.86
Africa	2.56	2.69	2.68	2.68	3.18	3.16	3.15	3.52	3.50	3.47
South and Central America	4.91	5.54	5.54	5.53	7.06	7.03	7.00	8.03	7.99	7.95
Total Developing Countries	**27.91**	**33.17**	**33.10**	**33.04**	**44.27**	**44.00**	**43.74**	**50.66**	**50.22**	**49.84**
Total Consumption	**77.79**	**88.63**	**89.35**	**90.05**	**106.20**	**107.40**	**108.75**	**116.45**	**117.86**	**119.31**

[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 and other sources.
[3]Western Europe = Austria, Belgium, Bosnia and Herzegovina, Croatia, Denmark, Finland, France, the unified Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Macedonia, Netherlands, Norway, Portugal, Slovenia, Spain, Sweden, Switzerland, United Kingdom, and Yugoslavia.
[4]Caspian area includes Other Former Soviet Union.
[5]Eastern Europe = Albania, Bulgaria, Czech Republic, Hungary, Poland, Romania, and Slovakia.
[6]Includes liquids produced from energy crops, natural gas, coal, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[7]Includes Turkey.
[8]Includes both OPEC and non-OPEC consumers in the regional breakdown.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: Energy Information Administration, AEO2004 National Energy Modeling System runs LM2004.D101703A, AEO2004.D101703E, and HM2004.D101703A.

Table C1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2002	Projections								
		2010			2020			2025		
		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	11.91	12.05	12.56	13.06	9.54	10.49	11.59	8.50	9.77	10.27
Natural Gas Plant Liquids	2.56	2.99	3.10	3.20	3.17	3.47	3.62	3.17	3.47	3.60
Dry Natural Gas	19.56	20.80	21.05	21.87	22.75	24.43	25.62	23.09	24.64	25.69
Coal	22.70	25.38	25.25	25.30	27.44	27.92	29.21	30.10	31.10	31.86
Nuclear Power	8.15	8.29	8.29	8.29	8.53	8.53	8.53	8.53	8.53	8.53
Renewable Energy[1]	5.84	7.34	7.18	7.21	8.51	8.45	8.41	8.95	9.00	8.92
Other[2]	1.13	0.86	0.88	0.84	0.75	0.81	0.77	0.82	0.84	0.79
Total	**71.85**	**77.72**	**78.30**	**79.77**	**80.67**	**84.09**	**87.75**	**83.15**	**87.33**	**89.67**
Imports										
Crude Oil[3]	19.84	26.36	24.51	22.16	35.63	31.55	27.85	39.56	34.21	31.19
Petroleum Products[4]	4.75	6.57	5.76	4.59	9.98	7.83	5.47	12.22	9.63	6.16
Natural Gas	4.10	5.93	6.54	6.34	7.36	7.56	6.92	7.82	8.29	8.05
Other Imports[5]	0.52	0.94	0.95	0.96	1.10	1.12	1.12	1.18	1.18	1.18
Total	**29.21**	**39.80**	**37.76**	**34.04**	**54.08**	**48.06**	**41.36**	**60.78**	**53.30**	**46.58**
Exports										
Petroleum[6]	2.03	2.18	2.15	2.09	2.42	2.13	2.09	2.54	2.15	2.05
Natural Gas	0.52	0.90	0.91	0.92	0.91	0.93	1.01	0.89	0.88	1.00
Coal	1.03	0.90	0.89	0.89	0.73	0.69	0.75	0.60	0.56	0.55
Total	**3.58**	**3.98**	**3.95**	**3.90**	**4.06**	**3.75**	**3.84**	**4.03**	**3.59**	**3.61**
Discrepancy[7]	**-0.24**	**0.38**	**0.34**	**0.30**	**0.54**	**0.48**	**0.62**	**0.64**	**0.56**	**0.72**
Consumption										
Petroleum Products[8]	38.11	46.10	44.15	41.56	55.93	51.35	47.14	60.88	54.99	49.83
Natural Gas	23.37	25.98	26.82	27.22	29.34	31.21	31.17	30.19	32.21	32.39
Coal	22.18	25.34	25.23	25.22	27.78	28.30	29.33	30.68	31.73	32.23
Nuclear Power	8.15	8.29	8.29	8.29	8.53	8.53	8.53	8.53	8.53	8.53
Renewable Energy[1]	5.84	7.34	7.18	7.21	8.51	8.46	8.41	8.95	9.00	8.92
Other[9]	0.07	0.10	0.11	0.11	0.06	0.07	0.07	0.02	0.03	0.03
Total	**97.72**	**113.16**	**111.77**	**109.61**	**130.14**	**127.92**	**124.65**	**139.26**	**136.48**	**131.93**
Net Imports - Petroleum	**22.56**	**30.75**	**28.13**	**24.66**	**43.19**	**37.25**	**31.23**	**49.23**	**41.69**	**35.30**
Prices (2002 dollars per unit)										
World Oil Price (dollars per barrel)[10]	23.68	16.98	24.17	33.27	16.98	26.02	34.63	16.98	27.00	35.03
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	2.95	3.34	3.40	3.50	3.91	4.28	4.18	4.30	4.40	4.66
Coal Minemouth Price (dollars per ton)	17.90	17.01	16.88	17.14	16.08	16.32	16.96	16.35	16.57	16.80
Average Electricity Price (cents per kilowatthour)	7.2	6.5	6.6	6.7	6.6	6.9	6.8	6.7	6.9	6.9

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table C18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, 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, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[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.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 natural gas supply values :EIA, Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2002 petroleum supply values EIA: *Petroleum Supply Annual 2002,* DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). Other 2002 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002) and EIA, *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003). **Projections:** EIA, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2002	Projections								
		2010			2020			2025		
		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	0.89	0.97	0.93	0.88	0.90	0.85	0.80	0.86	0.80	0.75
Kerosene	0.07	0.12	0.11	0.10	0.11	0.10	0.09	0.10	0.09	0.08
Liquefied Petroleum Gas	0.53	0.58	0.56	0.53	0.65	0.61	0.58	0.69	0.64	0.60
Petroleum Subtotal	1.48	1.67	1.60	1.52	1.66	1.56	1.47	1.64	1.53	1.43
Natural Gas	5.06	5.71	5.69	5.68	6.13	6.08	6.10	6.31	6.26	6.26
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.39	0.40	0.40	0.40	0.41	0.41	0.41	0.41	0.41	0.40
Electricity	4.33	4.89	4.87	4.86	5.63	5.60	5.61	5.99	5.96	5.95
Delivered Energy	**11.28**	**12.68**	**12.58**	**12.47**	**13.84**	**13.66**	**13.59**	**14.37**	**14.17**	**14.06**
Electricity Related Losses	9.60	10.56	10.48	10.44	11.55	11.43	11.45	12.01	11.95	11.92
Total	**20.88**	**23.24**	**23.06**	**22.91**	**25.39**	**25.10**	**25.04**	**26.37**	**26.12**	**25.98**
Commercial										
Distillate Fuel	0.49	0.68	0.62	0.56	0.78	0.67	0.57	0.83	0.70	0.57
Residual Fuel	0.08	0.13	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	0.02
Liquefied Petroleum Gas	0.09	0.10	0.10	0.09	0.10	0.10	0.10	0.10	0.10	0.10
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Petroleum Subtotal	0.72	0.98	0.92	0.85	1.09	0.97	0.86	1.14	1.00	0.87
Natural Gas	3.21	3.58	3.57	3.58	3.93	3.94	4.01	4.14	4.16	4.23
Coal	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy[3]	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Electricity	4.12	5.08	5.05	5.02	6.30	6.24	6.22	6.90	6.83	6.82
Delivered Energy	**8.25**	**9.84**	**9.74**	**9.65**	**11.52**	**11.35**	**11.29**	**12.37**	**12.19**	**12.12**
Electricity Related Losses	9.15	10.98	10.86	10.79	12.91	12.73	12.71	13.82	13.70	13.67
Total	**17.40**	**20.82**	**20.60**	**20.44**	**24.42**	**24.07**	**23.99**	**26.19**	**25.89**	**25.78**
Industrial[4]										
Distillate Fuel	1.16	1.21	1.17	1.15	1.38	1.34	1.31	1.48	1.43	1.40
Liquefied Petroleum Gas	2.22	2.40	2.35	2.31	2.84	2.74	2.66	3.09	2.94	2.80
Petrochemical Feedstock	1.22	1.36	1.35	1.33	1.57	1.54	1.51	1.66	1.62	1.58
Residual Fuel	0.20	0.23	0.21	0.18	0.27	0.22	0.20	0.27	0.23	0.21
Motor Gasoline[2]	0.16	0.16	0.16	0.16	0.18	0.18	0.18	0.19	0.19	0.19
Other Petroleum[5]	4.03	4.60	4.38	4.00	5.31	4.93	4.42	5.61	5.17	4.72
Petroleum Subtotal	9.00	9.97	9.63	9.13	11.54	10.95	10.27	12.31	11.59	10.89
Natural Gas	7.43	8.48	8.62	8.87	9.58	9.84	10.06	10.28	10.58	10.65
Lease and Plant Fuel[6]	1.35	1.39	1.40	1.44	1.57	1.65	1.72	1.61	1.69	1.75
Natural Gas Subtotal	8.78	9.86	10.02	10.31	11.14	11.49	11.78	11.89	12.27	12.40
Metallurgical Coal	0.62	0.65	0.64	0.64	0.53	0.52	0.52	0.48	0.47	0.46
Steam Coal	1.47	1.41	1.41	1.46	1.45	1.45	1.66	1.48	1.47	1.74
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.00	0.00	0.01	0.01	0.01	0.01
Coal Subtotal	2.12	2.07	2.06	2.12	1.99	1.97	2.18	1.97	1.95	2.21
Renewable Energy[7]	1.66	2.01	2.00	1.99	2.50	2.48	2.46	2.73	2.70	2.68
Electricity	3.39	3.84	3.82	3.81	4.51	4.47	4.45	4.93	4.85	4.81
Delivered Energy	**24.94**	**27.75**	**27.53**	**27.35**	**31.67**	**31.36**	**31.15**	**33.82**	**33.35**	**32.99**
Electricity Related Losses	7.53	8.30	8.22	8.18	9.24	9.12	9.09	9.87	9.72	9.64
Total	**32.47**	**36.05**	**35.75**	**35.53**	**40.92**	**40.48**	**40.24**	**43.69**	**43.07**	**42.63**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2002	Projections								
		2010			2020			2025		
		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 Fuell[8]	5.12	6.45	6.42	6.36	8.04	8.02	7.84	8.98	8.94	8.65
Jet Fuel[9]	3.34	3.95	3.93	3.90	4.70	4.69	4.53	4.97	4.91	4.70
Motor Gasoline[2]	16.62	20.51	19.88	18.33	24.27	23.11	20.56	26.54	24.98	21.63
Residual Fuel	0.71	0.79	0.79	0.79	0.81	0.82	0.82	0.82	0.83	0.83
Liquefied Petroleum Gas	0.02	0.06	0.06	0.05	0.08	0.08	0.07	0.09	0.08	0.08
Other Petroleum[10]	0.24	0.26	0.25	0.25	0.30	0.30	0.30	0.32	0.32	0.32
Petroleum Subtotal	26.06	32.02	31.34	29.69	38.20	37.00	34.11	41.72	40.07	36.20
Pipeline Fuel Natural Gas	0.65	0.68	0.69	0.71	0.77	0.83	0.84	0.79	0.86	0.87
Compressed Natural Gas	0.01	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.09	0.09	0.11	0.11	0.11	0.12	0.12	0.12
Delivered Energy	**26.79**	**32.85**	**32.18**	**30.54**	**39.19**	**38.05**	**35.15**	**42.75**	**41.16**	**37.30**
Electricity Related Losses	0.17	0.20	0.19	0.19	0.23	0.22	0.21	0.25	0.24	0.23
Total	**26.96**	**33.04**	**32.37**	**30.73**	**39.41**	**38.27**	**35.37**	**43.00**	**41.40**	**37.53**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.66	9.31	9.15	8.95	11.09	10.88	10.51	12.16	11.88	11.36
Kerosene	0.09	0.16	0.16	0.15	0.15	0.14	0.14	0.14	0.13	0.13
Jet Fuel[9]	3.34	3.95	3.93	3.90	4.70	4.69	4.53	4.97	4.91	4.70
Liquefied Petroleum Gas	2.86	3.14	3.07	2.99	3.68	3.53	3.40	3.97	3.76	3.57
Motor Gasoline[2]	16.83	20.72	20.09	18.54	24.50	23.34	20.79	26.78	25.22	21.87
Petrochemical Feedstock	1.22	1.36	1.35	1.33	1.57	1.54	1.51	1.66	1.62	1.58
Residual Fuel	1.00	1.16	1.13	1.11	1.21	1.17	1.14	1.22	1.19	1.16
Other Petroleum[12]	4.26	4.84	4.61	4.23	5.58	5.21	4.69	5.91	5.46	5.02
Petroleum Subtotal	37.26	44.63	43.48	41.18	52.49	50.50	46.71	56.82	54.18	49.39
Natural Gas	15.71	17.82	17.94	18.19	19.74	19.95	20.27	20.84	21.11	21.25
Lease and Plant Fuel[6]	1.35	1.39	1.40	1.44	1.57	1.65	1.72	1.61	1.69	1.75
Pipeline Natural Gas	0.65	0.68	0.69	0.71	0.77	0.83	0.84	0.79	0.86	0.87
Natural Gas Subtotal	17.72	19.88	20.03	20.34	22.07	22.43	22.83	23.24	23.66	23.87
Metallurgical Coal	0.62	0.65	0.64	0.64	0.53	0.52	0.52	0.48	0.47	0.46
Steam Coal	1.58	1.52	1.52	1.57	1.56	1.56	1.76	1.59	1.58	1.85
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.00	0.00	0.01	0.01	0.01	0.01
Coal Subtotal	2.23	2.18	2.17	2.23	2.09	2.08	2.29	2.08	2.06	2.32
Renewable Energy[13]	2.15	2.51	2.50	2.49	3.01	2.99	2.97	3.24	3.21	3.18
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.92	13.91	13.83	13.78	16.55	16.41	16.39	17.94	17.77	17.71
Delivered Energy	**71.27**	**83.12**	**82.03**	**80.02**	**96.22**	**94.42**	**91.19**	**103.31**	**100.87**	**96.47**
Electricity Related Losses	26.45	30.04	29.75	29.59	33.92	33.50	33.46	35.94	35.61	35.46
Total	**97.72**	**113.16**	**111.77**	**109.61**	**130.14**	**127.92**	**124.65**	**139.26**	**136.48**	**131.93**
Electric Power[14]										
Distillate Fuel	0.16	0.61	0.16	0.12	2.37	0.26	0.13	2.96	0.27	0.14
Residual Fuel	0.69	0.86	0.51	0.25	1.08	0.59	0.30	1.11	0.54	0.31
Petroleum Subtotal	0.85	1.47	0.66	0.37	3.44	0.85	0.43	4.07	0.81	0.45
Natural Gas	5.65	6.09	6.79	6.88	7.26	8.78	8.34	6.94	8.55	8.52
Steam Coal	19.96	23.16	23.05	22.99	25.69	26.22	27.05	28.61	29.67	29.91
Nuclear Power	8.15	8.29	8.29	8.29	8.53	8.53	8.53	8.53	8.53	8.53
Renewable Energy[15]	3.69	4.83	4.68	4.72	5.50	5.47	5.43	5.71	5.79	5.74
Electricity Imports	0.07	0.10	0.11	0.11	0.06	0.07	0.07	0.02	0.03	0.03
Total	**38.36**	**43.95**	**43.58**	**43.37**	**50.48**	**49.92**	**49.85**	**53.88**	**53.37**	**53.17**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2002	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Total Energy Consumption										
Distillate Fuel	7.82	9.92	9.31	9.07	13.46	11.14	10.64	15.12	12.15	11.50
Kerosene	0.09	0.16	0.16	0.15	0.15	0.14	0.14	0.14	0.13	0.13
Jet Fuel[9]	3.34	3.95	3.93	3.90	4.70	4.69	4.53	4.97	4.91	4.70
Liquefied Petroleum Gas	2.86	3.14	3.07	2.99	3.68	3.53	3.40	3.97	3.76	3.57
Motor Gasoline[2]	16.83	20.72	20.09	18.54	24.50	23.34	20.79	26.78	25.22	21.87
Petrochemical Feedstock	1.22	1.36	1.35	1.33	1.57	1.54	1.51	1.66	1.62	1.58
Residual Fuel	1.69	2.01	1.64	1.36	2.29	1.76	1.44	2.33	1.72	1.48
Other Petroleum[12]	4.26	4.84	4.61	4.23	5.58	5.21	4.69	5.91	5.46	5.02
Petroleum Subtotal	38.11	46.10	44.15	41.56	55.93	51.35	47.14	60.88	54.99	49.83
Natural Gas	21.36	23.91	24.73	25.06	27.00	28.73	28.61	27.79	29.66	29.77
Lease and Plant Fuel[6]	1.35	1.39	1.40	1.44	1.57	1.65	1.72	1.61	1.69	1.75
Pipeline Natural Gas	0.65	0.68	0.69	0.71	0.77	0.83	0.84	0.79	0.86	0.87
Natural Gas Subtotal	23.37	25.98	26.82	27.22	29.34	31.21	31.17	30.19	32.21	32.39
Metallurgical Coal	0.62	0.65	0.64	0.64	0.53	0.52	0.52	0.48	0.47	0.46
Steam Coal	21.54	24.69	24.57	24.57	27.25	27.78	28.81	30.20	31.25	31.76
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.00	0.00	0.01	0.01	0.01	0.01
Coal Subtotal	22.18	25.34	25.23	25.22	27.78	28.30	29.33	30.68	31.73	32.23
Nuclear Power	8.15	8.29	8.29	8.29	8.53	8.53	8.53	8.53	8.53	8.53
Renewable Energy[16]	5.84	7.34	7.18	7.21	8.51	8.46	8.41	8.95	9.00	8.92
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.07	0.10	0.11	0.11	0.06	0.07	0.07	0.02	0.03	0.03
Total	**97.72**	**113.16**	**111.77**	**109.61**	**130.14**	**127.92**	**124.65**	**139.26**	**136.48**	**131.93**
Energy Use and Related Statistics										
Delivered Energy Use	71.27	83.12	82.03	80.02	96.22	94.42	91.19	103.31	100.87	96.47
Total Energy Use	97.72	113.16	111.77	109.61	130.14	127.92	124.65	139.26	136.48	131.93
Population (millions)	288.93	309.28	309.28	309.28	334.61	334.61	334.61	347.53	347.53	347.53
Gross Domestic Product (billion 1996 dollars)	9440	12234	12190	12147	16226	16188	16155	18588	18520	18456
Carbon Dioxide Emissions (million metric tons)	5729.3	6661.3	6558.8	6400.5	7711.7	7535.6	7340.5	8350.9	8142.0	7849.1

[1]Includes wood used for residential heating. See Table C18 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table C18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Fuel consumption includes consumption for combined heat and power, which produces electricity, both for sale to the grid and for own use, and other useful thermal energy.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[10]Includes aviation gasoline and lubricants.
[11]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[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 net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2002 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2002 population and gross domestic product: Global Insight macroeconomic model T250803. 2002 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2002,* DOE/EIA-0573(2002) (Washington, DC, October 2003). **Projections:** EIA, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C3. Energy Prices by Sector and Source
(2002 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2002	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price	2025 Low World Oil Price	2025 Reference	2025 High World Oil Price
Residential	**14.73**	**13.89**	**14.21**	**14.61**	**14.43**	**15.08**	**15.20**	**14.84**	**15.38**	**15.68**
Primary Energy[1]	8.14	7.80	8.15	8.60	8.10	8.76	9.03	8.40	8.89	9.33
Petroleum Products[2]	9.87	8.63	9.90	11.68	9.13	10.86	12.47	9.31	11.26	12.89
Distillate Fuel	8.23	6.75	7.82	9.33	7.08	8.39	9.66	7.13	8.53	9.86
Liquefied Petroleum Gas	12.92	12.27	13.89	16.14	12.42	14.79	16.90	12.44	15.19	17.20
Natural Gas	7.65	7.57	7.67	7.79	7.84	8.24	8.22	8.17	8.32	8.53
Electricity	24.73	23.10	23.30	23.53	23.20	23.73	23.55	23.40	23.88	23.91
Commercial	**14.68**	**13.35**	**13.77**	**14.19**	**14.17**	**14.93**	**15.02**	**14.57**	**15.28**	**15.56**
Primary Energy[1]	6.35	6.14	6.48	6.87	6.48	7.11	7.34	6.74	7.22	7.65
Petroleum Products[2]	6.88	5.13	6.34	7.97	5.30	6.83	8.30	5.28	6.98	8.48
Distillate Fuel	6.07	4.36	5.45	6.96	4.68	6.01	7.25	4.70	6.15	7.45
Residual Fuel	4.21	3.04	4.13	5.52	3.04	4.41	5.72	3.03	4.55	5.78
Natural Gas	6.37	6.54	6.64	6.76	6.92	7.31	7.27	7.27	7.41	7.62
Electricity	22.82	19.96	20.39	20.78	20.43	21.21	21.15	20.68	21.48	21.59
Industrial[3]	**6.31**	**5.80**	**6.44**	**7.19**	**6.22**	**7.21**	**7.70**	**6.39**	**7.42**	**8.05**
Primary Energy	4.77	4.43	5.14	5.97	4.80	5.88	6.49	4.95	6.07	6.80
Petroleum Products[2]	6.35	5.39	6.84	8.72	5.60	7.54	9.19	5.58	7.81	9.37
Distillate Fuel	6.21	4.55	5.68	7.16	4.91	6.24	7.44	4.91	6.40	7.63
Liquefied Petroleum Gas	8.28	7.82	9.72	12.24	8.02	10.66	13.14	8.03	11.11	13.39
Residual Fuel	3.89	2.66	3.74	5.13	2.65	4.03	5.34	2.65	4.17	5.40
Natural Gas[4]	3.75	3.97	4.05	4.15	4.51	4.89	4.78	4.86	4.99	5.24
Metallurgical Coal	1.87	1.94	1.96	1.97	1.83	1.84	1.84	1.76	1.77	1.77
Steam Coal	1.52	1.56	1.58	1.60	1.51	1.53	1.57	1.50	1.53	1.54
Electricity	14.74	13.13	13.36	13.59	13.46	13.99	13.86	13.57	14.09	14.20
Transportation	**9.91**	**9.21**	**10.50**	**11.80**	**8.98**	**10.54**	**11.79**	**8.85**	**10.69**	**11.91**
Primary Energy	9.88	9.18	10.48	11.77	8.95	10.52	11.76	8.82	10.67	11.88
Petroleum Products[2]	9.88	9.18	10.48	11.78	8.95	10.52	11.77	8.82	10.67	11.89
Distillate Fuel[5]	9.41	8.99	10.12	11.51	8.70	10.00	11.19	8.46	10.03	11.19
Jet Fuel[6]	5.97	4.59	5.76	7.30	4.69	6.06	7.35	4.65	6.21	7.48
Motor Gasoline[7]	11.15	10.45	11.87	13.19	10.13	11.90	13.29	9.98	12.06	13.45
Residual Fuel	3.77	2.46	3.60	5.05	2.45	3.88	5.25	2.44	4.02	5.30
Liquefied Petroleum Gas[8]	15.00	13.39	14.96	17.21	13.17	15.51	17.50	13.08	15.83	17.71
Natural Gas[9]	7.38	8.10	8.26	8.33	8.54	9.06	8.92	8.76	9.09	9.19
Ethanol (E85)[10]	15.19	15.48	17.22	18.65	16.35	18.28	19.78	16.57	18.58	20.15
Electricity	21.10	19.33	19.57	19.84	19.48	20.03	19.94	19.39	19.92	20.06
Average End-Use Energy	**10.10**	**9.40**	**10.23**	**11.09**	**9.60**	**10.76**	**11.45**	**9.68**	**10.96**	**11.75**
Primary Energy	7.70	7.29	8.22	9.15	7.40	8.64	9.43	7.45	8.82	9.66
Electricity	21.20	19.17	19.47	19.75	19.47	20.10	19.98	19.63	20.26	20.35
Electric Power[11]										
Fossil Fuel Average	1.89	1.85	1.92	1.96	2.07	2.18	2.11	2.09	2.11	2.16
Petroleum Products	4.32	3.25	4.21	5.90	3.77	4.67	6.14	3.87	4.88	6.26
Distillate Fuel	5.58	3.79	4.92	6.39	4.19	5.47	6.68	4.25	5.62	6.88
Residual Fuel	4.04	2.86	3.99	5.67	2.86	4.31	5.90	2.86	4.50	5.99
Natural Gas	3.77	3.91	4.04	4.17	4.42	4.85	4.72	4.74	4.92	5.16
Steam Coal	1.26	1.21	1.22	1.24	1.17	1.20	1.23	1.19	1.22	1.24

Table C3. Energy Prices by Sector and Source (Continued)
(2002 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2002	Projections								
		2010			2020			2025		
		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[12]										
Petroleum Products[2]	8.94	8.15	9.57	11.05	7.95	9.81	11.19	7.86	10.01	11.33
Distillate Fuel	8.52	7.59	8.93	10.40	7.18	9.07	10.35	7.00	9.18	10.43
Jet Fuel	5.97	4.59	5.76	7.30	4.69	6.06	7.35	4.65	6.21	7.48
Liquefied Petroleum Gas	9.27	8.82	10.65	13.09	8.98	11.55	13.93	8.97	11.96	14.18
Motor Gasoline[7]	11.15	10.45	11.87	13.19	10.13	11.90	13.29	9.98	12.06	13.45
Residual Fuel	3.92	2.69	3.78	5.22	2.70	4.08	5.44	2.70	4.23	5.51
Natural Gas	5.07	5.21	5.27	5.36	5.61	5.93	5.86	5.96	6.03	6.26
Coal	1.28	1.23	1.25	1.27	1.19	1.22	1.27	1.20	1.24	1.27
Ethanol (E85)[13]	15.19	15.48	17.22	18.65	16.35	18.28	19.78	16.57	18.58	20.15
Electricity	21.20	19.17	19.47	19.75	19.47	20.10	19.98	19.63	20.26	20.35
Non-Renewable Energy Expenditures by Sector (billion 2002 dollars)										
Residential	160.37	170.53	173.01	176.32	193.91	199.98	200.47	207.13	211.69	214.19
Commercial	119.67	130.07	132.72	135.53	161.82	167.90	168.10	178.82	184.74	187.06
Industrial	120.96	121.63	132.71	146.74	148.67	169.02	179.28	164.53	185.61	198.70
Transportation	259.11	296.17	330.65	351.89	344.91	392.36	404.44	371.41	430.99	433.72
Total Non-Renewable Expenditures	660.11	718.40	769.08	810.48	849.31	929.26	952.29	921.89	1013.03	1033.67
Transportation Renewable Expenditures	0.01	0.03	0.03	0.03	0.05	0.06	0.06	0.06	0.07	0.07
Total Expenditures	**660.12**	**718.43**	**769.11**	**810.51**	**849.36**	**929.32**	**952.34**	**921.95**	**1013.10**	**1033.73**

[1]Weighted average price includes fuels below as well as coal.
[2]This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Includes combined heat and power, which produces electricity and other useful thermal energy.
[4]Excludes use for lease and plant fuel.
[5] Diesel fuel containing 500 parts per million (ppm) or 15 pm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8]Includes Federal and State taxes while excluding county and local taxes.
[9]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2002*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (August 2003). 2002 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2002 electric power sector natural gas prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2002 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2002 coal prices based on EIA, *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003) and EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E. 2002 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2002 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C4. Residential Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2002	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Key Indicators										
Households (millions)										
Single-Family	74.77	82.94	82.87	82.80	92.23	92.09	91.96	96.50	96.32	96.16
Multifamily	29.20	30.73	30.71	30.70	33.06	33.07	33.09	34.34	34.36	34.38
Mobile Homes	6.31	6.26	6.25	6.25	6.87	6.88	6.90	7.10	7.12	7.14
Total	**110.28**	**119.93**	**119.84**	**119.75**	**132.15**	**132.04**	**131.96**	**137.94**	**137.79**	**137.68**
Average House Square Footage	**1689**	**1731**	**1731**	**1731**	**1772**	**1771**	**1770**	**1789**	**1788**	**1787**
Energy Intensity										
(million Btu per household)										
Delivered Energy Consumption	102.3	105.7	105.0	104.2	104.7	103.5	103.0	104.1	102.8	102.1
Total Energy Consumption	189.4	193.8	192.4	191.3	192.1	190.1	189.7	191.2	189.5	188.7
(thousand Btu per square foot)										
Delivered Energy Consumption	60.6	61.1	60.6	60.2	59.1	58.4	58.2	58.2	57.5	57.1
Total Energy Consumption	112.1	111.9	111.1	110.5	108.4	107.3	107.2	106.9	106.0	105.6
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.40	0.43	0.43	0.42	0.45	0.45	0.45	0.46	0.46	0.46
Space Cooling	0.71	0.70	0.69	0.69	0.77	0.76	0.76	0.81	0.80	0.80
Water Heating	0.37	0.37	0.37	0.37	0.36	0.36	0.36	0.35	0.35	0.35
Refrigeration	0.42	0.37	0.37	0.37	0.36	0.36	0.36	0.37	0.37	0.37
Cooking	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.13
Clothes Dryers	0.24	0.25	0.25	0.25	0.27	0.26	0.26	0.28	0.27	0.27
Freezers	0.13	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Lighting	0.75	0.87	0.87	0.86	0.98	0.97	0.97	1.03	1.02	1.02
Clothes Washers[1]	0.03	0.04	0.04	0.04	0.06	0.06	0.06	0.06	0.06	0.06
Dishwashers[1]	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.12	0.19	0.18	0.18	0.26	0.26	0.26	0.27	0.27	0.27
Personal Computers	0.06	0.08	0.08	0.08	0.11	0.11	0.11	0.14	0.14	0.14
Furnace Fans	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11
Other Uses[2]	0.88	1.25	1.25	1.24	1.64	1.63	1.63	1.84	1.83	1.83
Delivered Energy	**4.33**	**4.89**	**4.87**	**4.86**	**5.63**	**5.60**	**5.61**	**5.99**	**5.96**	**5.95**
Natural Gas										
Space Heating	3.54	4.02	4.01	4.00	4.36	4.33	4.34	4.52	4.48	4.48
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Heating	1.15	1.25	1.25	1.25	1.28	1.27	1.27	1.29	1.28	1.28
Cooking	0.21	0.23	0.23	0.23	0.26	0.26	0.26	0.27	0.27	0.27
Clothes Dryers	0.07	0.09	0.09	0.09	0.11	0.11	0.11	0.12	0.11	0.11
Other Uses[3]	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.12
Delivered Energy	**5.06**	**5.71**	**5.69**	**5.68**	**6.13**	**6.08**	**6.10**	**6.31**	**6.26**	**6.26**
Distillate										
Space Heating	0.77	0.85	0.81	0.77	0.79	0.75	0.70	0.76	0.71	0.66
Water Heating	0.12	0.12	0.12	0.11	0.11	0.10	0.10	0.10	0.09	0.09
Other Uses[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	**0.89**	**0.97**	**0.93**	**0.88**	**0.90**	**0.85**	**0.80**	**0.86**	**0.80**	**0.75**
Liquefied Petroleum Gas										
Space Heating	0.30	0.32	0.30	0.28	0.33	0.31	0.28	0.34	0.31	0.28
Water Heating	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.04
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Other Uses[3]	0.15	0.19	0.18	0.17	0.24	0.23	0.22	0.26	0.25	0.24
Delivered Energy	**0.53**	**0.58**	**0.56**	**0.53**	**0.65**	**0.61**	**0.58**	**0.69**	**0.64**	**0.60**
Marketed Renewables (wood)[5]	0.39	0.40	0.40	0.40	0.41	0.41	0.41	0.41	0.41	0.40
Other Fuels[6]	0.08	0.13	0.12	0.12	0.12	0.11	0.10	0.11	0.10	0.09

Table C4. Residential Sector Key Indicators and End-Use Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2002	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Delivered Energy Consumption by End-Use										
Space Heating	5.48	6.15	6.08	6.00	6.47	6.35	6.29	6.59	6.46	6.38
Space Cooling	0.71	0.70	0.69	0.69	0.77	0.76	0.76	0.81	0.80	0.80
Water Heating	1.69	1.80	1.79	1.78	1.81	1.78	1.78	1.79	1.77	1.75
Refrigeration	0.42	0.37	0.37	0.37	0.36	0.36	0.36	0.37	0.37	0.37
Cooking	0.34	0.37	0.37	0.37	0.41	0.41	0.41	0.42	0.42	0.42
Clothes Dryers	0.31	0.34	0.34	0.34	0.37	0.37	0.37	0.39	0.39	0.39
Freezers	0.13	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Lighting	0.75	0.87	0.87	0.86	0.98	0.97	0.97	1.03	1.02	1.02
Clothes Washers	0.03	0.04	0.04	0.04	0.06	0.06	0.06	0.06	0.06	0.06
Dishwashers	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.12	0.19	0.18	0.18	0.26	0.26	0.26	0.27	0.27	0.27
Personal Computers	0.06	0.08	0.08	0.08	0.11	0.11	0.11	0.14	0.14	0.14
Furnace Fans	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11
Other Uses[7]	1.13	1.55	1.54	1.53	1.99	1.97	1.97	2.23	2.20	2.19
Delivered Energy	**11.28**	**12.68**	**12.58**	**12.47**	**13.84**	**13.66**	**13.59**	**14.37**	**14.17**	**14.06**
Electricity Related Losses	**9.60**	**10.56**	**10.48**	**10.44**	**11.55**	**11.43**	**11.45**	**12.01**	**11.95**	**11.92**
Total Energy Consumption by End-Use										
Space Heating	6.36	7.07	6.99	6.91	7.39	7.27	7.22	7.50	7.37	7.29
Space Cooling	2.29	2.20	2.19	2.18	2.34	2.32	2.32	2.42	2.41	2.40
Water Heating	2.51	2.60	2.58	2.57	2.55	2.52	2.52	2.49	2.46	2.45
Refrigeration	1.37	1.16	1.16	1.16	1.10	1.09	1.09	1.11	1.11	1.11
Cooking	0.57	0.61	0.61	0.61	0.66	0.66	0.66	0.68	0.68	0.68
Clothes Dryers	0.83	0.89	0.89	0.88	0.92	0.91	0.91	0.95	0.94	0.94
Freezers	0.43	0.37	0.37	0.37	0.36	0.36	0.36	0.37	0.37	0.37
Lighting	2.41	2.75	2.73	2.72	2.99	2.95	2.96	3.09	3.07	3.06
Clothes Washers	0.10	0.12	0.12	0.12	0.18	0.18	0.18	0.19	0.19	0.19
Dishwashers	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10
Color Televisions	0.40	0.59	0.58	0.58	0.79	0.78	0.78	0.82	0.82	0.82
Personal Computers	0.21	0.25	0.25	0.25	0.35	0.35	0.35	0.41	0.41	0.41
Furnace Fans	0.25	0.28	0.28	0.28	0.32	0.32	0.32	0.34	0.33	0.33
Other Uses[7]	3.09	4.26	4.22	4.20	5.35	5.29	5.29	5.91	5.87	5.85
Total	**20.88**	**23.24**	**23.06**	**22.91**	**25.39**	**25.10**	**25.04**	**26.37**	**26.12**	**25.98**
Non-Marketed Renewables										
Geothermal[8]	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Solar[9]	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Total	**0.02**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**

[1]Does not include electric water heating portion of load.
[2]Includes small electric devices, heating elements, and motors.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as swimming pool and hot tub heaters.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2001*.
[6]Includes kerosene and coal.
[7]Includes all other uses listed above.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections:** EIA, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C5. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2002	Projections								
		2010			2020			2025		
		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 Floorspace (billion square feet)										
Surviving	68.9	81.3	81.1	80.9	93.4	93.1	92.8	99.1	98.8	98.6
New Additions	3.2	2.7	2.7	2.6	2.8	2.8	2.8	3.0	3.0	3.0
Total	**72.1**	**84.0**	**83.8**	**83.6**	**96.2**	**95.9**	**95.6**	**102.1**	**101.8**	**101.6**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	114.5	117.1	116.2	115.5	119.7	118.3	118.1	121.2	119.7	119.2
Electricity Related Losses	126.9	130.7	129.6	129.1	134.2	132.7	132.9	135.3	134.6	134.5
Total Energy Consumption	241.4	247.8	245.8	244.6	253.9	251.0	250.9	256.5	254.3	253.7
Delivered Energy Consumption by Fuel										
Purchased Electricity										
Space Heating[1]	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Space Cooling[1]	0.46	0.45	0.45	0.45	0.48	0.48	0.48	0.50	0.49	0.49
Water Heating[1]	0.14	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Ventilation	0.16	0.18	0.18	0.18	0.19	0.18	0.18	0.19	0.19	0.19
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Lighting	1.12	1.32	1.30	1.29	1.43	1.40	1.40	1.46	1.43	1.43
Refrigeration	0.20	0.22	0.22	0.22	0.24	0.24	0.24	0.25	0.25	0.25
Office Equipment (PC)	0.14	0.24	0.24	0.24	0.34	0.34	0.34	0.37	0.37	0.37
Office Equipment (non-PC)	0.31	0.47	0.46	0.46	0.71	0.71	0.71	0.87	0.87	0.87
Other Uses[2]	1.41	1.86	1.86	1.85	2.56	2.55	2.55	2.92	2.91	2.90
Delivered Energy	**4.12**	**5.08**	**5.05**	**5.02**	**6.30**	**6.24**	**6.22**	**6.90**	**6.83**	**6.82**
Natural Gas										
Space Heating[1]	1.42	1.56	1.56	1.58	1.62	1.64	1.71	1.66	1.69	1.77
Space Cooling[1]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Water Heating[1]	0.59	0.69	0.70	0.69	0.78	0.79	0.80	0.82	0.84	0.84
Cooking	0.26	0.31	0.30	0.30	0.35	0.34	0.34	0.36	0.36	0.36
Other Uses[3]	0.93	1.00	0.99	0.98	1.15	1.14	1.13	1.25	1.24	1.23
Delivered Energy	**3.21**	**3.58**	**3.57**	**3.58**	**3.93**	**3.94**	**4.01**	**4.14**	**4.16**	**4.23**
Distillate										
Space Heating[1]	0.17	0.27	0.24	0.20	0.35	0.29	0.21	0.39	0.31	0.21
Water Heating[1]	0.07	0.10	0.08	0.07	0.12	0.09	0.08	0.13	0.09	0.08
Other Uses[4]	0.24	0.31	0.30	0.28	0.31	0.29	0.28	0.31	0.29	0.28
Delivered Energy	**0.49**	**0.68**	**0.62**	**0.56**	**0.78**	**0.67**	**0.57**	**0.83**	**0.70**	**0.57**
Other Fuels[5]	**0.33**	**0.40**	**0.39**	**0.39**	**0.40**	**0.40**	**0.40**	**0.41**	**0.40**	**0.40**
Marketed Renewable Fuels										
Biomass	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Delivered Energy	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Delivered Energy Consumption by End-Use										
Space Heating[1]	1.74	2.00	1.97	1.94	2.14	2.09	2.07	2.22	2.16	2.14
Space Cooling[1]	0.48	0.47	0.47	0.46	0.51	0.50	0.50	0.53	0.52	0.52
Water Heating[1]	0.80	0.94	0.93	0.92	1.05	1.03	1.02	1.10	1.08	1.07
Ventilation	0.16	0.18	0.18	0.18	0.19	0.18	0.18	0.19	0.19	0.19
Cooking	0.29	0.34	0.34	0.33	0.38	0.37	0.37	0.39	0.39	0.38
Lighting	1.12	1.32	1.30	1.29	1.43	1.40	1.40	1.46	1.43	1.43
Refrigeration	0.20	0.22	0.22	0.22	0.24	0.24	0.24	0.25	0.25	0.25
Office Equipment (PC)	0.14	0.24	0.24	0.24	0.34	0.34	0.34	0.37	0.37	0.37
Office Equipment (non-PC)	0.31	0.47	0.46	0.46	0.71	0.71	0.71	0.87	0.87	0.87
Other Uses[6]	3.01	3.67	3.63	3.60	4.53	4.48	4.46	4.99	4.94	4.91
Delivered Energy	**8.25**	**9.84**	**9.74**	**9.65**	**11.52**	**11.35**	**11.29**	**12.37**	**12.19**	**12.12**

Table C5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2002	Projections								
		2010			2020			2025		
		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	**9.15**	**10.98**	**10.86**	**10.79**	**12.91**	**12.73**	**12.71**	**13.82**	**13.70**	**13.67**
Total Energy Consumption by End-Use										
Space Heating[1]	2.07	2.34	2.31	2.28	2.47	2.41	2.39	2.53	2.47	2.45
Space Cooling[1]	1.51	1.45	1.43	1.42	1.50	1.48	1.48	1.52	1.50	1.50
Water Heating[1]	1.11	1.26	1.25	1.23	1.36	1.33	1.33	1.40	1.37	1.36
Ventilation	0.52	0.56	0.56	0.55	0.57	0.56	0.56	0.57	0.57	0.57
Cooking	0.36	0.41	0.40	0.40	0.44	0.43	0.43	0.45	0.44	0.44
Lighting	3.60	4.17	4.10	4.07	4.35	4.25	4.25	4.38	4.30	4.30
Refrigeration	0.65	0.71	0.70	0.70	0.74	0.73	0.73	0.75	0.75	0.74
Office Equipment (PC)	0.44	0.77	0.76	0.76	1.03	1.03	1.02	1.11	1.10	1.10
Office Equipment (non-PC)	1.00	1.47	1.46	1.45	2.17	2.16	2.15	2.62	2.61	2.60
Other Uses[6]	6.14	7.69	7.63	7.58	9.78	9.69	9.65	10.85	10.77	10.73
Total	**17.40**	**20.82**	**20.60**	**20.44**	**24.42**	**24.07**	**23.99**	**26.19**	**25.89**	**25.78**
Non-Marketed Renewable Fuels										
Solar[7]	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

[1]Includes fuel consumption for district services.
[2]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
[3]Includes miscellaneous uses, such as pumps, emergency electric generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency electric generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency electric generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections:** EIA, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2002	Projections								
		2010			2020			2025		
		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 Shipments (billion 1996 dollars)										
Manufacturing	4,064	5023	5013	5,005	6679	6634	6595	7730	7636	7554
Nonmanufacturing	1222	1433	1425	1422	1704	1710	1714	1854	1855	1853
Total	**5285**	**6456**	**6439**	**6427**	**8383**	**8344**	**8309**	**9584**	**9491**	**9407**
Energy Prices (2002 dollars per million Btu)										
Distillate Oil	6.21	4.55	5.68	7.16	4.91	6.24	7.44	4.91	6.40	7.63
Liquefied Petroleum Gas	8.28	7.82	9.72	12.24	8.02	10.66	13.14	8.03	11.11	13.39
Residual Oil	3.89	2.66	3.74	5.13	2.65	4.03	5.34	2.65	4.17	5.40
Motor Gasoline	11.04	10.42	11.84	13.16	10.11	11.87	13.27	9.96	12.03	13.43
Natural Gas	3.75	3.97	4.05	4.15	4.51	4.89	4.78	4.86	4.99	5.24
Metallurgical Coal	1.87	1.94	1.96	1.97	1.83	1.84	1.84	1.76	1.77	1.77
Steam Coal	1.52	1.56	1.58	1.60	1.51	1.53	1.57	1.50	1.53	1.54
Electricity	14.74	13.13	13.36	13.59	13.46	13.99	13.86	13.57	14.09	14.20
Energy Consumption[1]										
Distillate	1.16	1.21	1.17	1.15	1.38	1.34	1.31	1.48	1.43	1.40
Liquefied Petroleum Gas	2.22	2.40	2.35	2.31	2.84	2.74	2.66	3.09	2.94	2.80
Petrochemical Feedstocks	1.22	1.36	1.35	1.33	1.57	1.54	1.51	1.66	1.62	1.58
Residual Fuel	0.20	0.23	0.21	0.18	0.27	0.22	0.20	0.27	0.23	0.21
Other Petroleum[2]	4.19	4.77	4.54	4.16	5.49	5.12	4.60	5.81	5.36	4.91
Petroleum Subtotal	9.00	9.97	9.63	9.13	11.54	10.95	10.27	12.31	11.59	10.89
Natural Gas	7.43	8.48	8.62	8.87	9.58	9.84	10.06	10.28	10.58	10.65
Lease and Plant Fuel[3]	1.35	1.39	1.40	1.44	1.57	1.65	1.72	1.61	1.69	1.75
Natural Gas Subtotal	8.78	9.86	10.02	10.31	11.14	11.49	11.78	11.89	12.27	12.40
Metallurgical Coal and Coke[4]	0.65	0.66	0.66	0.65	0.53	0.52	0.52	0.49	0.48	0.47
Steam Coal	1.47	1.41	1.41	1.46	1.45	1.45	1.66	1.48	1.47	1.74
Coal Subtotal	2.12	2.07	2.06	2.12	1.99	1.97	2.18	1.97	1.95	2.21
Renewables[5]	1.66	2.01	2.00	1.99	2.50	2.48	2.46	2.73	2.70	2.68
Purchased Electricity	3.39	3.84	3.82	3.81	4.51	4.47	4.45	4.93	4.85	4.81
Delivered Energy	**24.94**	**27.75**	**27.53**	**27.35**	**31.67**	**31.36**	**31.15**	**33.82**	**33.35**	**32.99**
Electricity Related Losses	7.53	8.30	8.22	8.18	9.24	9.12	9.09	9.87	9.72	9.64
Total	**32.47**	**36.05**	**35.75**	**35.53**	**40.92**	**40.48**	**40.24**	**43.69**	**43.07**	**42.63**
Energy Consumption per dollar of Shipment[1] (thousand Btu per 1996 dollars)										
Distillate	0.22	0.19	0.18	0.18	0.16	0.16	0.16	0.15	0.15	0.15
Liquefied Petroleum Gas	0.42	0.37	0.37	0.36	0.34	0.33	0.32	0.32	0.31	0.30
Petrochemical Feedstocks	0.23	0.21	0.21	0.21	0.19	0.18	0.18	0.17	0.17	0.17
Residual Fuel	0.04	0.04	0.03	0.03	0.03	0.03	0.02	0.03	0.02	0.02
Other Petroleum[2]	0.79	0.74	0.71	0.65	0.65	0.61	0.55	0.61	0.56	0.52
Petroleum Subtotal	1.70	1.54	1.50	1.42	1.38	1.31	1.24	1.28	1.22	1.16
Natural Gas	1.41	1.31	1.34	1.38	1.14	1.18	1.21	1.07	1.11	1.13
Lease and Plant Fuel[3]	0.26	0.21	0.22	0.22	0.19	0.20	0.21	0.17	0.18	0.19
Natural Gas Subtotal	1.66	1.53	1.56	1.60	1.33	1.38	1.42	1.24	1.29	1.32
Metallurgical Coal and Coke[4]	0.12	0.10	0.10	0.10	0.06	0.06	0.06	0.05	0.05	0.05
Steam Coal	0.28	0.22	0.22	0.23	0.17	0.17	0.20	0.15	0.15	0.18
Coal Subtotal	0.40	0.32	0.32	0.33	0.24	0.24	0.26	0.21	0.21	0.24
Renewables[5]	0.31	0.31	0.31	0.31	0.30	0.30	0.30	0.28	0.28	0.28
Purchased Electricity	0.64	0.60	0.59	0.59	0.54	0.54	0.54	0.51	0.51	0.51
Delivered Energy	**4.72**	**4.30**	**4.28**	**4.26**	**3.78**	**3.76**	**3.75**	**3.53**	**3.51**	**3.51**
Electricity Related Losses	1.42	1.29	1.28	1.27	1.10	1.09	1.09	1.03	1.02	1.02
Total	**6.14**	**5.58**	**5.55**	**5.53**	**4.88**	**4.85**	**4.84**	**4.56**	**4.54**	**4.53**

[1]Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Represents natural gas used in the field gathering and processing plant machinery.
[3]Includes net coke coal imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 prices for motor gasoline and distillate are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2002*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (August 2003). 2002 coal prices are based on EIA, *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003) and EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E. 2002 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2002 natural gas prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2002 consumption values based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2002 shipments: Global Insight macroeconomic model T250803. **Projections:** EIA, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	2002	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Key Indicators										
Level of Travel (billions)										
Light-Duty Vehicles <8,500 pounds (VMT)	2504	3129	3041	2802	3891	3768	3396	4330	4173	3675
Commercial Light Trucks (VMT)[1]	65	80	79	77	103	101	97	116	114	108
Freight Trucks >10,000 pounds (VMT)	196	243	242	241	314	313	311	358	354	352
Air (seat miles available)	909	1131	1122	1112	1455	1455	1455	1521	1521	1521
Rail (ton miles traveled)	1336	1547	1545	1542	1843	1852	1878	2037	2056	2069
Domestic Shipping (ton miles traveled)	724	803	805	810	899	918	934	959	977	982
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[2]	23.8	25.0	25.3	25.7	25.9	26.5	27.1	26.1	26.9	27.6
New Car (miles per gallon)[2]	28.2	28.5	28.8	29.3	29.7	30.4	31.2	30.0	30.8	31.7
New Light Truck (miles per gallon)[2]	20.5	22.6	22.8	23.1	23.6	24.1	24.6	24.1	24.7	25.3
Light-Duty Fleet (miles per gallon)[3]	19.7	19.5	19.6	19.7	20.2	20.5	20.9	20.4	20.9	21.3
New Commercial Light Truck (MPG)[1]	13.9	15.1	15.1	15.3	15.7	16.0	16.3	16.0	16.4	16.8
Stock Commercial Light Truck (MPG)[1]	13.8	14.4	14.5	14.5	15.3	15.5	15.7	15.6	15.9	16.2
Aircraft Efficiency (seat miles per gallon)	54.8	60.0	59.9	59.8	65.4	65.4	68.0	66.5	67.0	70.3
Freight Truck Efficiency (miles per gallon)	6.0	6.0	6.0	6.0	6.3	6.4	6.4	6.5	6.5	6.6
Rail Efficiency (ton miles per thousand Btu)	2.9	3.1	3.1	3.1	3.4	3.4	3.4	3.6	3.6	3.6
(ton miles per thousand Btu)	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4
Energy Use by Mode										
(quadrillion Btu)										
Light-Duty Vehicles	15.58	19.52	18.91	17.36	23.43	22.34	19.77	25.73	24.28	20.89
Commercial Light Trucks[1]	0.59	0.69	0.68	0.66	0.84	0.82	0.77	0.93	0.90	0.84
Bus Transportation	0.24	0.26	0.25	0.25	0.26	0.26	0.25	0.27	0.26	0.25
Freight Trucks	4.09	5.05	5.03	5.00	6.20	6.15	6.04	6.91	6.82	6.65
Rail, Passenger	0.11	0.13	0.13	0.13	0.16	0.16	0.15	0.17	0.17	0.16
Rail, Freight	0.47	0.50	0.50	0.50	0.54	0.54	0.55	0.57	0.57	0.58
Shipping, Domestic	0.32	0.34	0.35	0.35	0.38	0.39	0.39	0.40	0.41	0.41
Shipping, International	0.64	0.72	0.72	0.72	0.73	0.73	0.73	0.74	0.74	0.74
Recreational Boats	0.31	0.34	0.34	0.33	0.37	0.37	0.37	0.39	0.39	0.39
Air	2.84	3.37	3.35	3.32	4.10	4.09	3.92	4.36	4.30	4.09
Military Use	0.66	0.77	0.77	0.77	0.81	0.81	0.81	0.82	0.82	0.82
Lubricants	0.20	0.21	0.21	0.21	0.25	0.25	0.25	0.28	0.28	0.28
Pipeline Fuel	0.65	0.68	0.69	0.71	0.77	0.83	0.84	0.79	0.86	0.87
Total	**26.70**	**32.60**	**31.93**	**30.31**	**38.85**	**37.73**	**34.86**	**42.36**	**40.79**	**36.96**
(million barrels per day oil equivalent)										
Light-Duty Vehicles	8.20	10.28	9.96	9.14	12.32	11.74	10.39	13.53	12.75	10.97
Commercial Light Trucks[1]	0.31	0.37	0.36	0.35	0.44	0.43	0.41	0.49	0.47	0.44
Bus Transportation	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.13	0.12	0.12
Freight Trucks	1.94	2.39	2.38	2.37	2.93	2.91	2.86	3.26	3.22	3.14
Rail, Passenger	0.05	0.06	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08
Rail, Freight	0.22	0.24	0.24	0.23	0.25	0.25	0.26	0.27	0.27	0.27
Shipping, Domestic	0.15	0.16	0.16	0.16	0.17	0.18	0.18	0.18	0.19	0.19
Shipping, International	0.28	0.32	0.32	0.31	0.32	0.32	0.32	0.32	0.32	0.32
Recreational Boats	0.16	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20
Air	1.38	1.63	1.62	1.61	1.98	1.98	1.90	2.11	2.08	1.98
Military Use	0.32	0.37	0.37	0.37	0.39	0.39	0.39	0.39	0.39	0.39
Lubricants	0.09	0.10	0.10	0.10	0.12	0.12	0.12	0.13	0.13	0.13
Pipeline Fuel	0.33	0.34	0.35	0.36	0.39	0.42	0.43	0.40	0.43	0.44
Total	**13.54**	**16.55**	**16.20**	**15.35**	**19.72**	**19.13**	**17.63**	**21.50**	**20.68**	**18.68**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.

Sources: 2002: Energy Information Administration (EIA), *Natural Gas Annual 2001*, DOE/EIA-0131(2001) (Washington, DC, February 2003); Federal Highway Administration, *Highway Statistics 2000* (Washington, DC, November 2001); Oak Ridge National Laboratory, Transportation Energy Data Book: *Edition 22 and Annual* (Oak Ridge, TN, September 2002); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey" EC97TV (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives to Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; EIA,*State Energy Data Report 2000*, DOE/EIA-0214(2000) (Washington, DC, August 2003); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2002/2001* (Washington, DC, 2002); EIA, *Fuel Oil and Kerosene Sales 2001*, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/fuel_oil_and_kerosene_sales/historical/foks.html; and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C8. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2002	Projections								
		2010			2020			2025		
		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 Power Sector[1]										
Power Only[2]										
Coal	1875	2214	2201	2196	2495	2560	2661	2848	2975	3002
Petroleum	77	143	62	34	421	82	39	478	77	40
Natural Gas[3]	450	560	642	647	740	972	902	750	969	955
Nuclear Power	780	794	794	794	816	816	816	816	816	816
Pumped Storage/Other	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9
Renewable Sources[4]	304	412	400	405	444	442	440	456	460	456
Distributed Generation (Natural Gas)	0	0	0	0	4	3	3	7	5	5
Non-Utility Generation for Own Use	-34	-37	-37	-37	-37	-37	-37	-37	-37	-37
Total	**3443**	**4078**	**4054**	**4030**	**4874**	**4829**	**4814**	**5308**	**5257**	**5228**
Combined Heat and Power[5]										
Coal	32	33	33	33	33	33	33	34	33	33
Petroleum	6	8	1	0	16	2	0	15	2	1
Natural Gas	148	167	174	178	147	159	160	137	149	151
Renewable Sources	5	4	4	4	4	4	4	4	4	4
Non-Utility Generation for Own Use	-11	-24	-24	-24	-24	-24	-24	-24	-24	-24
Total	**183**	**187**	**188**	**191**	**176**	**175**	**173**	**165**	**164**	**165**
Net Available to the Grid	**3626**	**4265**	**4242**	**4221**	**5050**	**5004**	**4988**	**5473**	**5421**	**5394**
End-Use Sector Generation										
Combined Heat and Power[6]										
Coal	21	21	21	24	21	21	33	21	21	37
Petroleum	5	11	12	11	17	17	14	17	18	14
Natural Gas	84	109	109	109	154	153	149	183	181	174
Other Gaseous Fuels[7]	5	9	9	9	12	12	11	13	13	12
Renewable Sources[4]	30	39	39	38	50	50	49	55	54	54
Other[8]	11	11	11	11	11	11	11	11	11	11
Total	157	201	202	203	265	264	268	301	299	302
Other End-Use Generators[9]	4	5	5	5	5	5	5	6	7	6
Generation for Own Use	-134	-158	-158	-157	-190	-190	-186	-210	-210	-204
Total Sales to the Grid	**27**	**48**	**48**	**51**	**80**	**80**	**87**	**97**	**95**	**105**
Total Electricity Generation	**3831**	**4533**	**4510**	**4491**	**5382**	**5335**	**5323**	**5842**	**5787**	**5763**
Net Imports	**22**	**30**	**31**	**33**	**17**	**21**	**22**	**7**	**8**	**8**
Electricity Sales by Sector										
Residential	1268	1433	1428	1424	1651	1641	1643	1756	1747	1745
Commercial	1208	1490	1480	1472	1846	1828	1824	2021	2003	2000
Industrial	994	1126	1120	1116	1322	1310	1306	1444	1422	1411
Transportation	22	27	26	26	32	32	31	36	35	34
Total	**3492**	**4075**	**4055**	**4039**	**4852**	**4811**	**4803**	**5257**	**5207**	**5190**
End-Use Prices[10] (2002 cents per kilowatthour)										
Residential	8.4	7.9	7.9	8.0	7.9	8.1	8.0	8.0	8.1	8.2
Commercial	7.8	6.8	7.0	7.1	7.0	7.2	7.2	7.1	7.3	7.4
Industrial	5.0	4.5	4.6	4.6	4.6	4.8	4.7	4.6	4.8	4.8
Transportation	7.2	6.6	6.7	6.8	6.6	6.8	6.8	6.6	6.8	6.8
All Sectors Average	**7.2**	**6.5**	**6.6**	**6.7**	**6.6**	**6.9**	**6.8**	**6.7**	**6.9**	**6.9**
Prices by Service Category[10] (2002 cents per kilowatthour)										
Generation	4.6	4.0	4.1	4.2	4.2	4.5	4.4	4.3	4.5	4.6
Transmission	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Distribution	2.0	1.9	1.9	1.9	1.8	1.8	1.7	1.7	1.7	1.7

Table C8. Electricity Supply, Disposition, Prices, and Emissions (Continued)
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2002	Projections								
		2010			2020			2025		
		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 Power Sector Emissions[1]										
Sulfur Dioxide (million tons)	10.54	9.56	9.90	9.93	8.94	8.94	8.95	8.94	8.95	8.95
Nitrogen Oxide (million tons)	4.39	3.52	3.50	3.48	3.72	3.67	3.65	3.80	3.75	3.73
Mercury (tons)	50.95	51.09	52.20	52.19	53.41	53.59	53.76	54.69	54.37	54.05

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes plants that only produce electricity.
[3]Includes electricity generation from fuel cells.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[5]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[7]Other gaseous fuels include refinery and still gas.
[8]Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.
[9]Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[10]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Source: 2002 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002), and supporting databases. 2002 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2002 prices: EIA, National Energy Modeling System run AEO2004.D101703E. **Projections:** AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C9. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	2002	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price	2025 Low World Oil Price	2025 Reference	2025 High World Oil Price
Electric Power Sector[2]										
Power Only[3]										
Coal Steam	305.7	306.8	305.1	304.4	338.2	348.4	364.3	386.3	407.2	412.9
Other Fossil Steam[4]	132.5	108.8	105.0	103.7	102.4	100.0	96.7	99.8	95.4	94.8
Combined Cycle	81.0	126.4	127.1	126.0	190.4	184.4	173.1	218.8	202.3	195.2
Combustion Turbine/Diesel	123.5	131.6	131.1	129.6	174.4	163.9	161.8	186.0	175.0	176.6
Nuclear Power[5]	98.7	100.6	100.6	100.6	102.6	102.6	102.6	102.6	102.6	102.6
Pumped Storage	20.2	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Fuel Cells	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Renewable Sources[6]	91.4	100.5	97.1	98.6	106.5	105.7	105.5	109.3	109.9	108.5
Distributed Generation[7]	0.0	0.6	0.5	0.5	9.8	7.6	6.6	15.5	12.4	11.8
Total	**853.1**	**895.7**	**886.8**	**883.7**	**1044.7**	**1032.9**	**1031.0**	**1138.7**	**1125.1**	**1122.7**
Combined Heat and Power[8]										
Coal Steam	5.2	5.2	5.1	5.2	5.2	5.1	5.2	5.2	5.1	5.2
Other Fossil Steam[4]	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Combined Cycle	29.4	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9
Combustion Turbine/Diesel	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Renewable Sources[6]	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**41.4**	**44.9**	**44.8**	**44.9**	**44.9**	**44.8**	**44.9**	**44.9**	**44.8**	**44.9**
Total Electric Power Industry	**894.5**	**940.5**	**931.7**	**928.6**	**1089.5**	**1077.7**	**1075.9**	**1183.5**	**1169.9**	**1167.6**
Cumulative Planned Additions[9]										
Coal Steam	0.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	43.5	43.5	43.5	43.5	43.5	43.5	43.5	43.5	43.5
Combustion Turbine/Diesel	0.0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Renewable Sources[6]	0.0	4.3	4.3	4.3	4.7	4.7	4.7	4.8	4.8	4.8
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**57.1**	**57.1**	**57.1**	**57.5**	**57.5**	**57.5**	**57.6**	**57.6**	**57.6**
Cumulative Unplanned Additions[9]										
Coal Steam	0.0	8.1	5.7	5.6	41.3	50.7	67.3	90.5	110.6	117.0
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	6.4	6.6	5.5	70.4	64.0	52.7	98.9	81.9	74.7
Combustion Turbine/Diesel	0.0	10.4	10.5	9.9	56.7	46.0	42.8	69.5	59.1	58.8
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	4.5	1.1	2.6	10.1	9.3	9.1	12.8	13.3	12.0
Distributed Generation[7]	0.0	0.6	0.5	0.5	9.8	7.6	6.6	15.5	12.4	11.8
Total	**0.0**	**30.0**	**24.3**	**24.1**	**188.4**	**177.5**	**178.5**	**287.2**	**277.2**	**274.3**
Cumulative Total Additions	**0.0**	**87.0**	**81.4**	**81.1**	**245.8**	**235.0**	**236.0**	**344.8**	**334.8**	**331.9**
Cumulative Retirements[10]										
Coal Steam	0.0	8.2	7.5	8.1	10.0	9.3	10.0	11.1	10.4	11.1
Other Fossil Steam[4]	0.0	21.8	25.6	26.9	28.2	30.6	33.9	30.8	35.2	35.8
Combined Cycle	0.0	1.7	1.1	1.1	1.7	1.1	1.1	1.7	1.1	1.1
Combustion Turbine/Diesel	0.0	9.6	10.2	11.1	13.1	13.0	11.9	14.3	14.9	13.1
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**41.4**	**44.6**	**47.4**	**53.2**	**54.2**	**57.0**	**58.1**	**61.8**	**61.2**

Table C9. Electricity Generating Capcity (Continued)
(Gigawatts)

Net Summer Capacity[1]	2002	2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price	2025 Low World Oil Price	2025 Reference	2025 High World Oil Price
End-Use Sector										
Combined Heat and Power[11]										
Coal	4.2	4.1	4.1	4.6	4.1	4.1	5.7	4.1	4.1	6.2
Petroleum	1.0	1.5	1.6	1.5	2.2	2.2	1.8	2.2	2.3	1.8
Natural Gas	14.1	17.8	17.8	17.7	23.8	23.7	23.2	27.8	27.6	26.6
Other Gaseous Fuels	1.8	2.2	2.2	2.2	2.6	2.6	2.4	2.7	2.7	2.5
Renewable Sources[6]	4.2	5.7	5.6	5.5	7.6	7.5	7.4	8.4	8.3	8.2
Other	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**25.5**	**31.6**	**31.7**	**31.8**	**40.6**	**40.5**	**40.9**	**45.6**	**45.3**	**45.6**
Other End-Use Generators[12]										
Renewable Sources[13]	1.1	1.4	1.4	1.4	1.6	1.6	1.6	2.1	2.1	2.1
Cumulative Additions[9]										
Combined Heat and Power[11]	0.0	6.2	6.2	6.3	15.1	15.0	15.4	20.1	19.8	20.1
Other End-Use Generators[12]	0.0	0.3	0.3	0.3	0.5	0.5	0.5	1.0	1.1	1.1

[1]Net summer capacity 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 electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capability.
[5]Nuclear capacity reflects operating capacity of existing units, including 3.9 gigawatts of uprates through 2025.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[7]Primarily peak-load capacity fueled by natural gas.
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[9]Cumulative additions after December 31, 2002.
[10]Cumulative total retirements after December 31, 2002.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[12]Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[13]See Table C17 for more detail.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model estimates and may differ slightly from official EIA data reports.
Source: 2002 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	2002	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Interregional Electricity Trade										
Gross Domestic Firm Power Trade	138.9	107.1	107.1	107.1	41.5	41.5	41.5	41.5	41.5	41.5
Gross Domestic Economy Trade	209.9	207.9	229.7	239.6	188.2	218.4	210.6	169.0	183.4	198.2
Gross Domestic Trade	**348.8**	**315.0**	**336.8**	**346.7**	**229.7**	**259.9**	**252.1**	**210.6**	**224.9**	**239.8**
Gross Domestic Firm Power Sales (million 2002 dollars)	6932.4	5345.8	5345.8	5345.8	2074.2	2074.2	2074.2	2074.2	2074.2	2074.2
Gross Domestic Economy Sales (million 2002 dollars)	6809.8	6551.0	7629.6	8387.5	6892.5	8663.8	8340.6	6251.4	7319.5	8162.0
Gross Domestic Sales (million 2002 dollars)	**13742.1**	**11896.8**	**12975.3**	**13733.2**	**8966.7**	**10738.0**	**10414.8**	**8325.6**	**9393.7**	**10236.2**
International Electricity Trade										
Firm Power Imports From Canada & Mexico	9.5	5.8	5.8	5.8	0.0	0.0	0.0	0.0	0.0	0.0
Economy Imports From Canada and Mexico	26.8	40.0	41.3	43.0	25.0	28.9	29.5	14.8	15.1	15.7
Gross Imports From Canada and Mexico	**36.3**	**45.9**	**47.2**	**48.9**	**25.0**	**28.9**	**29.5**	**14.8**	**15.2**	**15.7**
Firm Power Exports To Canada and Mexico	5.6	8.7	8.7	8.7	0.0	0.0	0.0	0.0	0.0	0.0
Economy Exports To Canada and Mexico	8.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**14.3**	**16.4**	**16.4**	**16.4**	**7.7**	**7.7**	**7.7**	**7.7**	**7.7**	**7.7**

Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Source: Energy Information Administration, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C11. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2002	Projections: 2010			Projections: 2020			Projections: 2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Crude Oil										
Domestic Crude Production[1]	5.62	5.69	5.93	6.17	4.51	4.95	5.48	4.02	4.61	4.85
Alaska	0.98	0.89	0.92	0.97	0.66	0.72	0.78	0.46	0.51	0.55
Lower 48 States	4.64	4.81	5.01	5.20	3.84	4.23	4.69	3.55	4.11	4.31
Net Imports	9.13	12.08	11.21	10.12	16.40	14.50	12.77	18.21	15.74	14.34
Gross Imports	9.14	12.14	11.29	10.21	16.41	14.53	12.83	18.22	15.76	14.37
Exports	0.01	0.07	0.08	0.09	0.01	0.03	0.06	0.01	0.02	0.03
Other Crude Supply[2]	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**14.83**	**17.77**	**17.15**	**16.29**	**20.90**	**19.45**	**18.25**	**22.23**	**20.35**	**19.19**
Natural Gas Plant Liquids	**1.88**	**2.15**	**2.24**	**2.31**	**2.25**	**2.48**	**2.58**	**2.24**	**2.47**	**2.55**
Other Inputs[3]	**0.67**	**0.46**	**0.47**	**0.53**	**0.44**	**0.46**	**0.67**	**0.48**	**0.48**	**0.71**
Refinery Processing Gain[4]	**0.98**	**0.91**	**0.88**	**0.84**	**1.09**	**1.00**	**0.90**	**1.13**	**1.04**	**0.94**
Net Product Imports[5]	**1.41**	**2.35**	**1.95**	**1.42**	**3.93**	**2.99**	**1.85**	**5.07**	**3.94**	**2.22**
Gross Refined Product Imports[6]	1.92	2.57	2.17	1.89	3.60	2.82	2.17	4.60	3.60	2.47
Unfinished Oil Imports	0.41	0.75	0.72	0.43	1.47	1.15	0.61	1.68	1.34	0.70
Ether Imports	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Exports	0.97	0.97	0.94	0.90	1.14	0.98	0.94	1.21	1.01	0.95
Total Primary Supply[7]	**19.77**	**23.65**	**22.69**	**21.39**	**28.61**	**26.38**	**24.25**	**31.14**	**28.27**	**25.62**
Refined Petroleum Products Supplied										
Motor Gasoline[8]	8.86	10.92	10.59	9.77	12.92	12.30	10.96	14.12	13.30	11.53
Jet Fuel[9]	1.61	1.91	1.90	1.88	2.27	2.27	2.19	2.40	2.37	2.27
Distillate Fuel[10]	3.68	4.67	4.38	4.27	6.33	5.24	5.00	7.11	5.71	5.41
Residual Fuel	0.74	0.88	0.71	0.59	1.00	0.77	0.63	1.02	0.75	0.64
Other[11]	4.72	5.30	5.13	4.88	6.14	5.84	5.48	6.55	6.16	5.79
Total	**19.61**	**23.68**	**22.71**	**21.39**	**28.66**	**26.41**	**24.26**	**31.20**	**28.30**	**25.63**
Refined Petroleum Products Supplied										
Residential and Commercial	1.22	1.44	1.38	1.30	1.51	1.40	1.29	1.54	1.40	1.28
Industrial[12]	4.80	5.31	5.14	4.89	6.16	5.86	5.52	6.59	6.21	5.85
Transportation	13.21	16.27	15.91	15.04	19.40	18.77	17.26	21.19	20.32	18.31
Electric Generators[13]	0.38	0.66	0.29	0.17	1.58	0.38	0.19	1.88	0.36	0.20
Total	**19.61**	**23.68**	**22.71**	**21.39**	**28.66**	**26.41**	**24.26**	**31.20**	**28.30**	**25.63**
Discrepancy[14]	**0.16**	**-0.03**	**-0.02**	**-0.00**	**-0.05**	**-0.04**	**-0.01**	**-0.06**	**-0.03**	**-0.01**
World Oil Price (2002 dollars per barrel)[15]	**23.68**	**16.98**	**24.17**	**33.27**	**16.98**	**26.02**	**34.63**	**16.98**	**27.00**	**35.03**
Import Share of Product Supplied	**0.54**	**0.61**	**0.58**	**0.54**	**0.71**	**0.66**	**0.60**	**0.75**	**0.70**	**0.65**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2002 dollars)	**90.38**	**92.51**	**118.31**	**140.96**	**130.58**	**168.99**	**186.21**	**152.32**	**200.24**	**213.44**
Domestic Refinery Distillation Capacity[16]	**16.8**	**19.0**	**18.7**	**18.0**	**22.4**	**20.8**	**19.8**	**23.8**	**21.8**	**20.6**
Capacity Utilization Rate (percent)	**91.0**	**94.6**	**93.1**	**91.7**	**94.7**	**94.8**	**93.3**	**94.8**	**94.8**	**94.3**

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.
[3]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[6]Includes other hydrocarbons, alcohols, and blending components.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes only kerosene type.
[10]Includes distillate and kerosene.
[11]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[12]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[13]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses and gains.
[15]Average refiner acquisition cost for imported crude oil.
[16]End-of-year capacity.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). Other 2002 data: EIA, *Petroleum Supply Annual 2002,* DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). **Projections:** EIA, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C12. Petroleum Product Prices
(2002 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2002	Projections: 2010			2020			2025		
		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 (2002 dollars per barrel)	**23.68**	**16.98**	**24.17**	**33.27**	**16.98**	**26.02**	**34.63**	**16.98**	**27.00**	**35.03**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	114.2	93.6	108.4	129.4	98.2	116.4	133.9	98.9	118.4	136.7
Liquefied Petroleum Gas	110.8	105.2	119.1	138.5	106.5	126.9	144.9	106.7	130.3	147.6
Commercial										
Distillate Fuel	84.1	60.4	75.6	96.5	64.9	83.3	100.6	65.1	85.3	103.3
Residual Fuel	63.1	45.5	61.8	82.6	45.4	66.1	85.7	45.3	68.1	86.5
Residual Fuel (2002 dollars per barrel)	26.48	19.12	25.97	34.70	19.09	27.75	35.97	19.03	28.59	36.34
Industrial[1]										
Distillate Fuel	86.2	63.1	78.8	99.3	68.0	86.6	103.1	68.1	88.8	105.8
Liquefied Petroleum Gas	71.1	67.1	83.4	105.0	68.8	91.4	112.7	68.8	95.3	114.9
Residual Fuel	58.3	39.9	56.0	76.8	39.7	60.3	80.0	39.7	62.4	80.9
Residual Fuel (2002 dollars per barrel)	24.48	16.75	23.54	32.27	16.68	25.34	33.58	16.68	26.22	33.97
Transportation										
Diesel Fuel (distillate)[2]	130.6	124.7	140.3	159.7	120.6	138.6	155.2	117.3	139.0	155.2
Jet Fuel[3]	80.6	62.0	77.8	98.5	63.3	81.8	99.2	62.8	83.9	101.0
Motor Gasoline[4]	138.1	129.3	146.9	163.2	125.4	147.3	164.5	123.5	149.2	166.4
Liquid Petroleum Gas	128.7	114.9	128.3	147.6	113.0	133.0	150.1	112.2	135.8	152.0
Residual Fuel	56.5	36.9	53.9	75.5	36.6	58.0	78.5	36.5	60.2	79.4
Residual Fuel (2002 dollars per barrel)	23.71	15.49	22.62	31.72	15.38	24.37	32.99	15.31	25.28	33.35
Ethanol (E85)[5]	135.8	138.4	153.9	166.7	146.1	163.4	176.8	148.1	166.1	180.1
Electric Power[6]										
Distillate Fuel	77.4	52.6	68.2	88.6	58.1	75.8	92.6	58.9	77.9	95.4
Residual Fuel	60.4	42.8	59.7	84.9	42.8	64.5	88.4	42.8	67.4	89.7
Residual Fuel (2002 dollars per barrel)	25.38	17.96	25.07	35.66	17.97	27.07	37.12	17.99	28.30	37.66
Refined Petroleum Product Prices[7]										
Distillate Fuel	118.1	105.3	123.8	144.3	99.5	125.9	143.6	97.1	127.3	144.7
Jet Fuel[3]	80.6	62.0	77.8	98.5	63.3	81.8	99.2	62.8	83.9	101.0
Liquefied Petroleum Gas	79.6	75.7	91.3	112.3	77.0	99.1	119.5	76.9	102.6	121.7
Motor Gasoline[4]	138.1	129.3	146.9	163.2	125.4	147.3	164.5	123.5	149.2	166.4
Residual Fuel	58.6	40.3	56.6	78.1	40.4	61.1	81.4	40.4	63.3	82.4
Residual Fuel (2002 dollars per barrel)	24.62	16.92	23.76	32.81	16.96	25.65	34.19	16.95	26.60	34.62
Average	**116.1**	**106.3**	**123.9**	**142.0**	**103.4**	**126.3**	**143.5**	**102.1**	**128.6**	**145.4**

[1]Includes combined heat and power, which produces electricity and other useful thermal energy.
[2]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Includes Federal and State taxes while excluding county and local taxes.
[3]Includes only Kerosene type.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2002*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (August 2003). 2002 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A: “Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report.” 2002 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.” 2002 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2002 world oil price: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections**: EIA, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C13. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	2002	Projections								
		2010			2020			2025		
		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]	19.05	20.26	20.50	21.30	22.15	23.79	24.95	22.48	23.99	25.02
Supplemental Natural Gas[2]	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Net Imports	**3.49**	**4.91**	**5.50**	**5.29**	**6.29**	**6.47**	**5.77**	**6.77**	**7.24**	**6.88**
Canada	3.59	3.70	3.68	3.53	2.88	2.51	2.02	2.87	2.56	2.22
Mexico	-0.26	-0.45	-0.34	-0.35	-0.16	-0.18	-0.25	-0.13	-0.12	-0.25
Liquefied Natural Gas	0.17	1.66	2.16	2.12	3.58	4.14	4.00	4.03	4.80	4.91
Total Supply	**22.62**	**25.26**	**26.09**	**26.68**	**28.54**	**30.36**	**30.82**	**29.35**	**31.33**	**32.00**
Consumption by Sector										
Residential	4.92	5.55	5.53	5.52	5.96	5.92	5.93	6.14	6.09	6.09
Commercial	3.12	3.48	3.48	3.48	3.83	3.83	3.90	4.02	4.04	4.11
Industrial[3]	7.23	8.24	8.39	8.63	9.32	9.57	9.79	10.00	10.29	10.36
Electric Generators[4]	5.55	5.98	6.66	6.75	7.12	8.61	8.19	6.81	8.39	8.36
Transportation[5]	0.01	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Pipeline Fuel	0.63	0.66	0.67	0.69	0.75	0.81	0.82	0.77	0.84	0.85
Lease and Plant Fuel[6]	1.32	1.35	1.36	1.41	1.52	1.61	1.67	1.56	1.65	1.71
Total	**22.78**	**25.32**	**26.15**	**26.54**	**28.60**	**30.44**	**30.40**	**29.43**	**31.41**	**31.59**
Natural Gas to Liquids	**0.00**	**0.00**	**0.00**	**0.21**	**0.00**	**0.00**	**0.50**	**0.00**	**0.00**	**0.50**
Discrepancy[7]	**-0.16**	**-0.06**	**-0.06**	**-0.06**	**-0.06**	**-0.08**	**-0.08**	**-0.08**	**-0.09**	**-0.09**

[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 for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as vehicle fuel.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[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, 2002 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2002 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections:** EIA, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C14. Natural Gas Prices, Margins, and Revenue

(2002 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	2002	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Source Price										
Average Lower 48 Wellhead Price[1]	2.95	3.34	3.40	3.50	3.91	4.28	4.18	4.30	4.40	4.66
Average Import Price	3.14	3.57	3.78	3.94	4.15	4.58	4.50	4.47	4.67	4.92
Average[2]	**2.98**	**3.39**	**3.49**	**3.60**	**3.97**	**4.35**	**4.25**	**4.34**	**4.47**	**4.73**
Delivered Prices										
Residential	7.86	7.79	7.88	8.00	8.06	8.47	8.45	8.40	8.56	8.77
Commercial	6.55	6.72	6.83	6.95	7.12	7.52	7.48	7.47	7.62	7.83
Industrial[3]	3.85	4.08	4.16	4.27	4.64	5.02	4.91	4.99	5.13	5.39
Electric Generators[4]	3.85	3.99	4.12	4.25	4.50	4.94	4.81	4.83	5.01	5.26
Transportation[5]	7.58	8.33	8.49	8.57	8.78	9.32	9.17	9.01	9.34	9.45
Average[6]	**5.21**	**5.35**	**5.41**	**5.51**	**5.76**	**6.09**	**6.02**	**6.12**	**6.19**	**6.43**
Transmission and Distribution Margins[7]										
Residential	4.88	4.39	4.40	4.41	4.09	4.11	4.20	4.06	4.09	4.04
Commercial	3.56	3.33	3.34	3.35	3.15	3.17	3.23	3.13	3.15	3.11
Industrial[3]	0.87	0.69	0.68	0.67	0.67	0.67	0.66	0.65	0.66	0.66
Electric Generators[4]	0.86	0.60	0.63	0.65	0.54	0.59	0.56	0.49	0.54	0.54
Transportation[5]	4.60	4.94	5.00	4.97	4.82	4.96	4.92	4.66	4.87	4.72
Average[6]	**2.23**	**1.96**	**1.92**	**1.91**	**1.79**	**1.74**	**1.77**	**1.77**	**1.72**	**1.71**
Transmission and Distribution Revenue (billion 2002 dollars)										
Residential	24.02	24.40	24.33	24.33	24.38	24.34	24.90	24.91	24.89	24.64
Commercial	11.12	11.60	11.61	11.66	12.07	12.13	12.58	12.57	12.72	12.78
Industrial[3]	6.27	5.66	5.67	5.79	6.23	6.42	6.47	6.47	6.80	6.85
Electric Generators[4]	4.78	3.57	4.21	4.40	3.82	5.10	4.61	3.32	4.54	4.47
Transportation[5]	0.06	0.28	0.28	0.28	0.46	0.48	0.47	0.52	0.54	0.51
Total	**46.25**	**45.51**	**46.11**	**46.47**	**46.96**	**48.46**	**49.03**	**47.79**	**49.49**	**49.25**

[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 for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, “transmission and distribution” margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term “transmission and distribution” margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.

Sources: 2002 electric generators delivered price: Federal Energy Regulatory Commission, FERC Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.” 2002 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1998.* 2002 residential, commercial, and transportation delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). Other 2002 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, Office of Integrated Analysis and Forecasting AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C15. Oil and Gas Supply

Production and Supply	2002	Projections								
		2010			2020			2025		
		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] (2002 dollars per barrel)	**24.54**	**16.36**	**23.61**	**32.80**	**16.82**	**25.82**	**34.33**	**16.49**	**26.72**	**34.90**
Production (million barrels per day)[2]										
U.S. Total	**5.62**	**5.69**	**5.93**	**6.17**	**4.51**	**4.95**	**5.48**	**4.02**	**4.61**	**4.85**
Lower 48 Onshore	3.11	2.45	2.61	2.76	2.03	2.20	2.32	1.87	2.04	2.13
Lower 48 Offshore	1.53	2.35	2.40	2.44	1.82	2.03	2.37	1.68	2.06	2.17
Alaska	0.98	0.89	0.92	0.97	0.66	0.72	0.78	0.46	0.51	0.55
Lower 48 End of Year Reserves (billion barrels)[2]	**19.05**	**17.43**	**18.36**	**19.21**	**14.98**	**16.20**	**17.43**	**13.64**	**14.98**	**15.63**
Natural Gas										
Lower 48 Average Wellhead Price[1] (2002 dollars per thousand cubic feet)	**2.95**	**3.34**	**3.40**	**3.50**	**3.91**	**4.28**	**4.18**	**4.30**	**4.40**	**4.66**
Dry Production (trillion cubic feet)[3]										
U.S. Total	**19.05**	**20.26**	**20.50**	**21.30**	**22.15**	**23.79**	**24.95**	**22.48**	**23.99**	**25.02**
Lower 48 Onshore	13.76	14.21	14.48	14.98	15.18	16.41	16.62	15.56	16.26	16.89
Associated-Dissolved[4]	1.60	1.35	1.41	1.45	1.18	1.23	1.27	1.11	1.17	1.20
Non-Associated	12.16	12.86	13.08	13.52	14.00	15.18	15.35	14.45	15.09	15.69
Conventional	6.23	5.70	5.80	6.09	5.57	6.07	6.17	5.60	5.92	6.12
Unconventional	5.93	7.16	7.28	7.43	8.43	9.11	9.19	8.85	9.16	9.58
Lower 48 Offshore	4.86	5.44	5.41	5.50	4.68	5.09	5.50	4.59	5.03	4.89
Associated-Dissolved[4]	1.05	1.61	1.61	1.62	1.28	1.34	1.59	1.16	1.43	1.43
Non-Associated	3.81	3.84	3.80	3.89	3.40	3.75	3.91	3.43	3.60	3.46
Alaska	0.43	0.60	0.60	0.82	2.29	2.29	2.83	2.33	2.71	3.24
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**180.03**	**196.17**	**201.20**	**204.63**	**194.25**	**200.97**	**206.11**	**186.21**	**193.51**	**194.51**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Total Lower 48 Wells (thousands)	**24.47**	**22.80**	**24.78**	**27.26**	**24.56**	**26.83**	**27.77**	**24.60**	**26.00**	**27.16**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2002,* DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). 2002 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). Other 2002 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C16. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2002	Projections 2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price	2025 Low World Oil Price	2025 Reference	2025 High World Oil Price
Production[1]										
Appalachia	408	421	408	412	403	402	427	420	419	422
Interior	147	169	169	170	165	170	177	171	178	181
West	550	641	653	651	780	805	837	894	946	985
East of the Mississippi	504	541	524	529	523	522	554	547	547	554
West of the Mississippi	601	690	706	703	826	854	887	939	996	1034
Total	**1105**	**1231**	**1230**	**1233**	**1349**	**1377**	**1441**	**1486**	**1543**	**1588**
Net Imports										
Imports	17	33	33	33	42	42	42	46	46	46
Exports	40	36	35	35	29	27	30	24	23	22
Total	**-23**	**-2**	**-2**	**-2**	**13**	**14**	**12**	**21**	**23**	**23**
Total Supply[2]	**1083**	**1228**	**1228**	**1231**	**1362**	**1391**	**1453**	**1507**	**1566**	**1612**
Consumption by Sector										
Residential and Commercial	4	5	5	5	5	5	5	5	5	5
Industrial[3]	63	65	65	72	67	66	94	68	67	103
of which: Coal to Liquids	0	0	0	8	0	0	28	0	0	36
Coke Plants	22	24	23	23	19	19	19	18	17	17
Electric Generators[4]	976	1135	1136	1131	1272	1301	1336	1418	1477	1487
Total	**1066**	**1229**	**1229**	**1231**	**1363**	**1391**	**1454**	**1508**	**1567**	**1612**
Discrepancy and Stock Change[5]	**17**	**-0**	**-0**	**-0**	**-1**	**-0**	**-0**	**-1**	**-1**	**-0**
Average Minemouth Price										
(2002 dollars per short ton)	17.90	17.01	16.88	17.14	16.08	16.32	16.96	16.35	16.57	16.80
(2002 dollars per million Btu)	0.87	0.82	0.82	0.84	0.79	0.80	0.84	0.81	0.82	0.84
Delivered Prices (2002 dollars per short ton)[6]										
Industrial	33.24	34.12	34.46	32.35	32.93	33.43	27.66	32.64	33.33	26.17
Coke Plants	51.27	53.28	53.68	53.96	50.18	50.45	50.51	48.22	48.42	48.53
Electric Generators										
(2002 dollars per short ton)	25.96	24.57	24.67	25.04	23.49	24.01	24.81	23.79	24.31	24.74
(2002 dollars per million Btu)	1.26	1.21	1.22	1.24	1.17	1.20	1.23	1.19	1.22	1.24
Average	**26.93**	**25.63**	**25.74**	**26.02**	**24.34**	**24.83**	**25.33**	**24.47**	**24.96**	**25.08**
Exports[7]	40.44	35.95	36.47	36.63	34.15	34.13	34.44	32.07	32.34	32.47

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 11.1 million tons in 2002.
[2]Production plus net imports and net storage withdrawals.
[3]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003); EIA, *Annual Coal Report 2002*, DOE/EIA-0584(2002) (Washington, DC, November 2003); and EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E. **Projections:** EIA, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C17. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2002	Projections 2010 Low World Oil Price	2010 Reference	2010 High World Oil Price	2020 Low World Oil Price	2020 Reference	2020 High World Oil Price	2025 Low World Oil Price	2025 Reference	2025 High World Oil Price
Electric Power Sector[1]										
Net Summer Capacity										
Conventional Hydropower	78.29	78.69	78.69	78.69	78.68	78.68	78.68	78.68	78.68	78.68
Geothermal[2]	2.89	4.13	4.01	3.95	6.11	6.06	5.98	6.69	6.84	6.81
Municipal Solid Waste[3]	3.49	3.99	3.92	3.89	3.99	3.95	3.92	3.99	3.95	3.92
Wood and Other Biomass[4,5]	1.83	2.26	2.20	2.19	3.04	3.04	2.76	4.20	3.74	3.34
Solar Thermal	0.33	0.43	0.43	0.43	0.49	0.49	0.49	0.52	0.52	0.52
Solar Photovoltaic[6]	0.02	0.15	0.15	0.15	0.32	0.32	0.32	0.41	0.41	0.41
Wind	4.83	11.14	8.01	9.55	14.11	13.39	13.58	15.12	15.99	15.10
Total	**91.69**	**100.80**	**97.42**	**98.86**	**106.75**	**105.93**	**105.73**	**109.61**	**110.13**	**108.78**
Generation (billion kilowatthours)										
Conventional Hydropower	255.78	304.38	304.37	304.37	304.64	304.63	304.63	304.81	304.80	304.80
Geothermal[2]	13.36	24.18	23.25	22.77	40.55	40.14	39.46	45.35	46.66	46.46
Municipal Solid Waste[3]	20.02	28.68	28.11	27.90	28.78	28.44	28.22	28.84	28.50	28.28
Wood and Other Biomass[5]	8.67	22.71	23.53	23.75	26.12	27.64	26.14	28.94	29.16	28.33
Dedicated Plants	6.32	12.89	13.26	13.18	18.19	18.47	17.03	24.78	22.90	21.02
Cofiring	2.35	9.82	10.26	10.56	7.93	9.17	9.11	4.16	6.25	7.32
Solar Thermal	0.54	0.84	0.84	0.84	1.04	1.04	1.04	1.11	1.11	1.11
Solar Photovoltaic[5]	0.00	0.36	0.36	0.36	0.79	0.79	0.79	1.02	1.02	1.02
Wind	10.51	35.11	24.07	29.53	46.02	43.54	44.16	49.76	53.16	49.82
Total	**308.87**	**416.26**	**404.52**	**409.52**	**447.94**	**446.22**	**444.44**	**459.83**	**464.40**	**459.82**
End-Use Sector										
Net Summer Capacity										
Combined Heat and Power[7]										
Municipal Solid Waste	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Biomass	3.91	5.41	5.36	5.29	7.35	7.26	7.17	8.17	8.03	7.93
Total	**4.16**	**5.66**	**5.61**	**5.54**	**7.60**	**7.51**	**7.42**	**8.42**	**8.29**	**8.18**
Other End-Use Generators[8]										
Contentional Hydropower[9]	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.04	0.39	0.39	0.39	0.55	0.58	0.57	1.04	1.13	1.11
Total	**1.06**	**1.41**	**1.41**	**1.41**	**1.57**	**1.61**	**1.59**	**2.06**	**2.15**	**2.14**
Generation (billion kilowatthours)										
Combined Heat and Power[7]										
Municipal Solid Waste	1.84	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10
Biomass	28.16	36.95	36.63	36.26	48.24	47.72	47.23	53.05	52.26	51.67
Total	**30.00**	**39.05**	**38.73**	**38.36**	**50.34**	**49.82**	**49.33**	**55.16**	**54.36**	**53.77**
Other End-Use Generators[8]										
Conventional Hydropower[9]	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.09	0.82	0.82	0.82	1.18	1.26	1.22	2.23	2.42	2.38
Total	**4.20**	**4.93**	**4.93**	**4.93**	**5.29**	**5.37**	**5.33**	**6.34**	**6.53**	**6.49**

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Includes projections for energy crops after 2010.
[6]Does not include off-grid photovoltaics (PV). See Annual Energy Review 2002 Table 10.6 for estimates of 1989-2001 PV shipments, including exports, for both grid-connected and off-grid applications.
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[8]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[9]Represents own-use industrial hydroelectric power.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2002 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections:** EIA, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C18. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	2002	Projections								
		2010			2020			2025		
		Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price	Low World Oil Price	Reference	High World Oil Price
Marketed Renewable Energy[2]										
Residential	**0.39**	**0.40**	**0.40**	**0.40**	**0.41**	**0.41**	**0.41**	**0.41**	**0.41**	**0.40**
Wood	0.39	0.40	0.40	0.40	0.41	0.41	0.41	0.41	0.41	0.40
Commercial	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Biomass	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Industrial[3]	**1.66**	**2.01**	**2.00**	**1.99**	**2.50**	**2.48**	**2.46**	**2.73**	**2.70**	**2.68**
Conventional Hydroelectric	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Municipal Solid Waste	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biomass	1.60	1.96	1.95	1.93	2.45	2.43	2.41	2.68	2.65	2.62
Transportation	**0.17**	**0.30**	**0.29**	**0.27**	**0.35**	**0.33**	**0.30**	**0.38**	**0.35**	**0.31**
Ethanol used in E85[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ethanol used in Gasoline Blending	0.17	0.30	0.29	0.27	0.34	0.33	0.30	0.37	0.35	0.31
Electric Generators[5]	**3.69**	**4.83**	**4.68**	**4.72**	**5.50**	**5.47**	**5.43**	**5.71**	**5.79**	**5.74**
Conventional Hydroelectric	2.75	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13
Geothermal	0.30	0.64	0.61	0.59	1.16	1.15	1.13	1.32	1.36	1.36
Municipal Solid Waste[6]	0.34	0.39	0.39	0.38	0.40	0.39	0.39	0.40	0.39	0.39
Biomass	0.17	0.29	0.29	0.29	0.32	0.33	0.31	0.33	0.34	0.33
Dedicated Plants	0.11	0.15	0.15	0.15	0.21	0.21	0.19	0.28	0.26	0.24
Cofiring	0.06	0.14	0.14	0.14	0.10	0.12	0.12	0.05	0.08	0.09
Solar Thermal	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.13	0.36	0.25	0.30	0.47	0.45	0.45	0.51	0.55	0.51
Total Marketed Renewable Energy	**6.01**	**7.64**	**7.47**	**7.48**	**8.85**	**8.78**	**8.70**	**9.32**	**9.35**	**9.23**
Sources of Ethanol										
From Corn	0.17	0.30	0.29	0.27	0.32	0.31	0.27	0.33	0.31	0.26
From Cellulose	0.00	0.00	0.00	0.00	0.02	0.02	0.03	0.05	0.05	0.05
Total	**0.17**	**0.30**	**0.29**	**0.27**	**0.35**	**0.33**	**0.30**	**0.38**	**0.35**	**0.31**
Non-Marketed Renewable Energy[7]										
Selected Consumption										
Residential	**0.02**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**
Solar Hot Water Heating	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04
Geothermal Heat Pumps	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table C8.
[3]Includes all electricity production by industrial and other combined heat and power for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Includes landfill gas.
[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2002 electric generators: EIA, Form EIA-860: "Annual Electric Generator Report" (preliminary). Other 2002 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C19. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons)

Sector and Source	2002	Projections								
		2010			2020			2025		
		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	104.0	115.0	110.4	104.8	113.8	107.1	100.6	112.1	104.5	97.5
Natural Gas	267.2	301.4	300.4	299.8	323.6	321.2	322.1	333.4	330.7	330.7
Coal	1.1	1.2	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.1
Electricity	816.7	915.1	905.3	898.3	1037.9	1019.9	1029.6	1119.7	1106.7	1106.8
Total	**1189.0**	**1332.7**	**1317.2**	**1304.0**	**1476.4**	**1449.2**	**1453.3**	**1566.3**	**1543.0**	**1536.0**
Commercial										
Petroleum	52.6	70.7	66.2	61.3	78.3	70.2	62.2	82.4	72.2	62.5
Natural Gas	169.4	188.9	188.7	189.1	207.8	207.9	211.5	218.3	219.4	223.3
Coal	9.2	9.2	9.3	9.3	9.2	9.2	9.3	9.2	9.2	9.2
Electricity	778.0	951.8	938.4	928.5	1160.2	1135.5	1142.9	1288.7	1269.2	1268.7
Total	**1009.1**	**1220.7**	**1202.5**	**1188.2**	**1455.5**	**1422.9**	**1425.8**	**1598.7**	**1570.1**	**1563.7**
Industrial[1]										
Petroleum	412.8	385.9	365.4	334.2	443.7	408.0	367.9	472.0	428.4	392.5
Natural Gas[2]	432.7	513.7	522.1	537.7	580.1	598.6	614.5	619.2	639.4	646.5
Coal	185.1	192.5	191.9	197.0	184.6	183.3	202.3	183.0	181.1	205.6
Electricity	640.0	719.5	710.3	704.0	830.9	813.8	818.1	920.5	900.7	894.9
Total	**1670.6**	**1811.6**	**1789.6**	**1772.8**	**2039.3**	**2003.6**	**2002.8**	**2194.7**	**2149.5**	**2139.5**
Transportation										
Petroleum[3]	1811.2	2240.6	2193.2	2078.9	2673.9	2590.9	2389.5	2920.4	2805.8	2536.5
Natural Gas[4]	35.2	38.8	39.5	40.5	46.1	49.1	49.6	47.9	51.3	52.0
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	14.2	17.0	16.7	16.1	20.4	19.9	19.3	22.9	22.4	21.4
Total	**1860.6**	**2296.4**	**2249.5**	**2135.5**	**2740.5**	**2659.9**	**2458.5**	**2991.2**	**2879.5**	**2609.8**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	2380.5	2812.3	2735.2	2579.3	3309.7	3176.2	2920.1	3586.9	3410.9	3088.9
Natural Gas	904.4	1042.8	1050.7	1067.0	1157.5	1176.8	1197.8	1218.9	1240.8	1252.5
Coal	195.4	202.9	202.4	207.4	194.9	193.6	212.7	193.2	191.4	215.9
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	2249.0	2603.4	2570.6	2546.9	3049.5	2989.0	3009.9	3351.8	3299.0	3291.9
Total	**5729.3**	**6661.3**	**6558.8**	**6400.5**	**7711.7**	**7535.6**	**7340.5**	**8350.9**	**8142.0**	**7849.1**
Electric Power[6]										
Petroleum	72.2	111.1	51.0	28.4	255.5	65.2	32.5	300.9	61.6	34.2
Natural Gas	299.1	321.7	358.5	363.2	384.3	463.3	440.5	366.4	451.6	449.7
Coal	1877.8	2170.5	2161.2	2155.3	2409.7	2460.5	2536.9	2684.6	2785.8	2807.9
Total	**2249.0**	**2603.4**	**2570.6**	**2546.9**	**3049.5**	**2989.0**	**3009.9**	**3351.8**	**3299.0**	**3291.9**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	2452.7	2923.4	2786.1	2607.7	3565.2	3241.4	2952.7	3887.7	3472.5	3123.2
Natural Gas	1203.4	1364.5	1409.2	1430.2	1541.8	1640.1	1638.3	1585.3	1692.4	1702.2
Coal	2073.2	2373.4	2363.6	2362.7	2604.6	2654.1	2749.6	2877.8	2977.1	3023.8
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**5729.3**	**6661.3**	**6558.8**	**6400.5**	**7711.7**	**7535.6**	**7340.5**	**8350.9**	**8142.0**	**7849.1**
Carbon Dioxide Emissions (tons per person)	**19.8**	**21.5**	**21.2**	**20.7**	**23.0**	**22.5**	**21.9**	**24.0**	**23.4**	**22.6**

[1]Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2000, international bunker fuels accounted for 24 to 30 million metric tons of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes methanol and liquid hydrogen.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.
[7]Emissions from electric power generators are distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2002,* DOE/EIA-0573(2002) (Washington, DC, October 2003). **Projections:** EIA, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C20. Macroeconomic Indicators
(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2002	Projections								
		2010			2020			2025		
		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
Real Gross Domestic Product	**9440**	**12234**	**12190**	**12147**	**16226**	**16188**	**16155**	**18588**	**18520**	**18456**
Real Potential Gross Domestic Product	**9726**	**12352**	**12313**	**12275**	**16238**	**16186**	**16140**	**18594**	**18520**	**18456**
Real Disposable Personal Income	**7032**	**8964**	**8894**	**8813**	**11897**	**11864**	**11844**	**13859**	**13826**	**13815**
Components of Real Gross Domestic										
Real Consumption	6576	8488	8437	8374	11333	11296	11252	12989	12946	12899
Real Investment	1590	2413	2387	2363	3753	3726	3698	4698	4661	4627
Real Government Spending	1713	1961	1961	1962	2260	2265	2271	2418	2423	2429
Real Exports	1059	1840	1838	1837	3395	3376	3360	4588	4546	4511
Real Imports	1547	2483	2436	2378	4511	4433	4343	6120	6015	5920
Energy Intensity										
(thousand Btu per 1996 dollar of GDP										
Delivered Energy	7.55	6.80	6.73	6.59	5.93	5.84	5.65	5.56	5.45	5.23
Total Energy	10.36	9.25	9.17	9.03	8.03	7.91	7.72	7.50	7.37	7.15
Price Indices										
GDP Chain-Type Price Index (1996=1.000)	1.107	1.293	1.301	1.308	1.741	1.774	1.805	2.067	2.121	2.168
Consumer Price Index (1982-4=1)	1.80	2.09	2.11	2.14	2.82	2.89	2.96	3.37	3.49	3.59
Wholesale Price Index (1982=1.00)										
All Commodities	1.31	1.42	1.46	1.50	1.66	1.74	1.81	1.84	1.94	2.02
Fuel and Power	0.93	0.98	1.06	1.17	1.17	1.33	1.45	1.31	1.52	1.68
Interest Rates (percent, nominal)										
Federal Funds Rate	1.67	5.28	5.42	5.58	6.02	6.30	6.56	6.68	7.00	7.24
10-Year Treasury Note	4.61	6.46	6.60	6.74	6.86	7.07	7.28	7.70	7.95	8.14
AA Utility Bond Rate	7.19	7.88	7.99	8.07	8.36	8.59	8.75	8.96	9.27	9.49
Unemployment Rate (percent)	**5.78**	**4.91**	**4.93**	**4.95**	**4.46**	**4.41**	**4.36**	**4.45**	**4.44**	**4.43**
Housing Starts (millions)	**1.88**	**1.98**	**1.97**	**1.96**	**1.95**	**1.94**	**1.94**	**1.92**	**1.92**	**1.91**
Commercial Floorspace, Total										
(billion square feet)	**72.1**	**84.0**	**83.8**	**83.6**	**96.2**	**95.9**	**95.6**	**102.1**	**101.8**	**101.6**
Unit Sales of Light-Duty Vehicles										
(millions)	**16.78**	**18.10**	**18.01**	**17.95**	**20.27**	**20.25**	**20.27**	**21.37**	**21.32**	**21.33**
Value of Shipments (billion 1996 dollars)										
Total Industrial	5285	6456	6439	6427	8383	8344	8309	9584	9491	9407
Nonmanufacturing	1222	1433	1425	1422	1704	1710	1714	1854	1855	1853
Manufacturing	4064	5023	5013	5005	6679	6634	6595	7730	7636	7554
Energy-Intensive	1120	1284	1273	1256	1524	1500	1476	1646	1610	1583
Non-Energy-Intensive	2944	3739	3741	3749	5155	5135	5119	6084	6026	5971
Population (millions)										
Population with Armed Forces Overseas)	288.9	309.3	309.3	309.3	334.6	334.6	334.6	347.5	347.5	347.5
Population (aged 16 and over)	224.3	244.1	244.1	244.1	264.3	264.3	264.3	274.3	274.3	274.3
Employment, Non-Agriculture	130.5	145.0	145.0	145.1	160.9	161.2	161.7	168.5	168.6	168.9
Employment, Manufacturing	16.7	16.1	16.1	16.2	16.0	16.0	16.1	16.3	16.2	16.2
Labor Force	145.1	159.8	159.8	159.8	171.3	171.3	171.4	176.8	176.8	176.8

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2002: Global Insight macroeconomic model T250803. **Projections:** Energy Information Administration, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Table C21. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2002	Projections								
		2010			2020			2025		
		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[1] (2002 dollars per barrel)	**23.68**	**16.98**	**24.17**	**33.27**	**16.98**	**26.02**	**34.63**	**16.98**	**27.00**	**35.03**
Production[2] (Conventional)										
Industrialized Countries										
U.S. (50 states)	9.16	9.22	9.53	9.76	8.28	8.89	9.39	7.86	8.59	8.79
Canada	2.14	1.80	1.83	1.92	1.54	1.60	1.77	1.45	1.57	1.79
Mexico	3.61	4.09	4.20	4.46	4.42	4.60	4.96	4.62	4.82	5.20
Western Europe[3]	6.76	6.25	6.34	6.64	5.39	5.48	5.82	4.88	4.97	5.28
Japan	0.08	0.07	0.08	0.10	0.05	0.06	0.09	0.05	0.06	0.09
Australia and New Zealand	0.75	0.93	0.96	1.01	0.85	0.88	0.95	0.82	0.86	0.92
Total Industrialized	**22.51**	**22.37**	**22.93**	**23.89**	**20.53**	**21.52**	**22.99**	**19.67**	**20.87**	**22.07**
Eurasia										
Former Soviet Union										
Russia	7.67	9.65	9.92	10.62	10.36	10.77	11.75	10.47	10.93	11.94
Caspian Area[4]	1.66	3.03	3.12	3.34	4.95	5.15	5.62	5.85	6.11	6.68
Eastern Europe[5]	0.23	0.33	0.33	0.35	0.40	0.41	0.44	0.43	0.45	0.48
Total Eurasia	**9.56**	**13.01**	**13.37**	**14.30**	**15.70**	**16.32**	**17.82**	**16.75**	**17.48**	**19.09**
Developing Countries	**44.24**	**55.83**	**49.94**	**43.20**	**76.04**	**64.32**	**53.23**	**89.14**	**74.05**	**61.99**
Total Production (Conventional)	**76.30**	**91.21**	**86.24**	**81.39**	**112.27**	**102.17**	**94.03**	**125.56**	**112.41**	**103.16**
Production[6] (Nonconventional)										
U.S. (50 states)	0.00	0.00	0.00	0.09	0.00	0.00	0.24	0.00	0.00	0.27
Other North America	0.79	1.61	1.69	1.77	2.86	3.20	3.55	2.83	3.28	3.73
Western Europe	0.04	0.04	0.04	0.05	0.03	0.04	0.06	0.03	0.04	0.06
Asia	0.03	0.02	0.03	0.04	0.02	0.03	0.05	0.02	0.03	0.05
Middle East[7]	0.01	0.01	0.01	0.01	0.01	0.02	0.03	0.01	0.03	0.04
Africa	0.16	0.16	0.19	0.23	0.16	0.25	0.34	0.15	0.28	0.41
South and Central America	0.54	0.78	0.85	1.02	1.16	1.42	1.94	1.11	1.45	2.13
Total Production[3] (Nonconventional)	**1.55**	**2.62**	**2.81**	**3.21**	**4.25**	**4.97**	**6.20**	**4.16**	**5.11**	**6.70**
Total Production	**77.8**	**93.84**	**89.05**	**84.59**	**116.52**	**107.13**	**100.24**	**129.72**	**117.53**	**109.86**
Consumption[8]										
Industrialized Countries										
U.S. (50 states)	19.61	23.68	22.71	21.39	28.66	26.41	24.26	31.20	28.30	25.63
U.S. Territories	0.29	0.43	0.38	0.34	0.50	0.43	0.38	0.56	0.47	0.42
Canada	1.96	2.48	2.23	2.03	2.74	2.36	2.12	2.88	2.44	2.20
Mexico	2.01	2.93	2.65	2.43	4.53	3.62	3.02	5.44	4.09	3.31
Western Europe[3]	14.02	15.09	14.36	13.72	15.82	14.80	14.09	16.42	15.26	14.59
Japan	5.45	6.52	5.79	5.21	7.81	6.26	5.26	8.48	6.54	5.45
Australia and New Zealand	1.04	1.33	1.28	1.23	1.68	1.58	1.52	1.86	1.75	1.68
Total Industrialized	**44.39**	**52.46**	**49.41**	**46.36**	**61.74**	**55.47**	**50.65**	**66.84**	**58.85**	**53.28**
Eurasia										
Former Soviet Union	4.05	5.31	5.10	4.92	6.04	5.73	5.51	6.62	6.25	6.03
Eastern Europe[5]	1.44	1.79	1.74	1.70	2.29	2.21	2.16	2.63	2.54	2.49
Total Eurasia	**5.49**	**7.10**	**6.84**	**6.62**	**8.32**	**7.94**	**7.67**	**9.25**	**8.79**	**8.52**
Developing Countries										
China	5.11	6.95	6.48	6.09	10.28	9.39	8.79	12.02	10.88	10.24
India	2.16	2.98	2.80	2.65	4.97	4.47	4.12	6.18	5.48	5.05
South Korea	2.20	2.97	2.75	2.57	3.53	3.15	2.89	3.77	3.32	3.05
Other Asia	5.63	6.88	6.65	6.45	9.35	8.93	8.63	10.70	10.17	9.86
Middle East[7]	5.34	6.32	6.19	6.08	8.08	7.87	7.73	9.14	8.88	8.74
Africa	2.56	2.77	2.68	2.61	3.33	3.16	3.04	3.71	3.50	3.36
South and Central America	4.91	5.71	5.54	5.39	7.30	7.03	6.84	8.33	7.99	7.79
Total Developing Countries	**27.91**	**34.57**	**33.10**	**31.83**	**46.84**	**44.00**	**42.03**	**53.85**	**50.22**	**48.08**
Total Consumption	**77.79**	**94.13**	**89.35**	**84.81**	**116.91**	**107.40**	**100.35**	**129.94**	**117.86**	**109.89**

[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 and other sources, and refinery gains.
[3]Western Europe = Austria, Belgium, Bosnia and Herzegovina, Croatia, Denmark, Finland, France, the unified Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Macedonia, Netherlands, Norway, Portugal, Slovenia, Spain, Sweden, Switzerland, United Kingdom, and Yugoslavia.
[4]Caspian area includes Other Former Soviet Union.
[5]Eastern Europe = Albania, Bulgaria, Czech Republic, Hungary, Poland, Romania, and Slovakia.
[6]Includes liquids produced from energy crops, natural gas, coal, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[7]Iincludes Turkey.
[8]Includes both OPEC and non-OPEC consumers in the regional breakdown.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: Energy Information Administration, AEO2004 National Energy Modeling System runs LW2004.D101703B, AEO2004.D101703E, and HW2004.D101703B.

Crude Oil Equivalency Summary

Table D1. Total Energy Supply and Disposition Summary
(Million Barrels per Day Oil Equivalent, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Production							
Crude Oil and Lease Condensate	5.74	5.62	5.93	5.53	4.95	4.61	-0.9%
Natural Gas Plant Liquids	1.20	1.21	1.46	1.51	1.64	1.64	1.3%
Dry Natural Gas	9.56	9.24	9.94	10.49	11.51	11.64	1.0%
Coal	11.32	10.72	11.93	12.35	13.15	14.69	1.4%
Nuclear Power	3.79	3.85	3.92	4.01	4.02	4.03	0.2%
Renewable Energy[1]	2.48	2.76	3.39	3.70	3.98	4.25	1.9%
Other[2]	0.25	0.54	0.41	0.37	0.38	0.39	-1.3%
Total	**34.35**	**33.94**	**36.99**	**37.96**	**39.63**	**41.25**	**0.9%**
Imports							
Crude Oil [3]	9.33	9.14	11.29	13.53	14.53	15.76	2.4%
Petroleum Products[4]	2.38	2.24	2.72	2.84	3.70	4.55	3.1%
Natural Gas	1.92	1.93	3.09	3.44	3.56	3.92	3.1%
Other Imports[5]	0.28	0.25	0.45	0.50	0.53	0.56	3.6%
Total	**13.91**	**13.57**	**17.55**	**20.31**	**22.32**	**24.78**	**2.7%**
Exports							
Petroleum[6]	0.95	0.96	1.01	1.03	1.00	1.01	0.2%
Natural Gas	0.18	0.25	0.43	0.43	0.44	0.41	2.3%
Coal	0.60	0.49	0.42	0.38	0.33	0.27	-2.6%
Total	**1.72**	**1.69**	**1.86**	**1.83**	**1.77**	**1.69**	**0.0%**
Discrepancy[7]	**-0.76**	**0.33**	**0.12**	**0.13**	**0.07**	**0.13**	**N/A**
Consumption							
Petroleum Products[8]	18.18	18.00	20.85	22.80	24.19	25.98	1.6%
Natural Gas	10.89	11.04	12.67	13.58	14.70	15.22	1.4%
Coal	10.40	10.47	11.91	12.43	13.33	14.98	1.6%
Nuclear Power	3.79	3.85	3.92	4.01	4.02	4.03	0.2%
Renewable Energy[1]	2.48	2.76	3.39	3.70	3.98	4.25	1.9%
Other[9]	0.04	0.04	0.05	0.05	0.03	0.01	-4.6%
Total	**45.78**	**46.15**	**52.79**	**56.56**	**60.26**	**64.47**	**1.5%**
Net Imports - Petroleum	**11.00**	**10.66**	**13.29**	**15.68**	**17.55**	**19.69**	**2.7%**
Prices (2002 dollars per unit)							
World Oil Price (dollars per barrel)[10]	22.25	23.68	24.17	25.07	26.02	27.00	0.6%
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.14	2.95	3.40	4.19	4.28	4.40	1.8%
Coal Minemouth Price (dollars per ton)	17.79	17.90	16.88	16.47	16.32	16.57	-0.3%
Average Electricity Price (cents per kilowatthour)	7.4	7.2	6.6	6.8	6.9	6.9	-0.2%

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[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.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Annual 2001*, DOE/EIA-0131(2001) (Washington, DC, February 2003). 2002 natural gas supply values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2001 coal minemouth prices: EIA, *Annual Coal Report 2002*, DOE/EIA-0584(2002) (Washington, DC, November 2003). 2001 petroleum supply values: EIA *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). 2002 petroleum supply values: EIA, *Petroleum Supply Annual 2002,* DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). Other 2001 and 2002 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002) and EIA, *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003).
Projections: EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

Table D2. Total Energy Supply and Disposition Summary
(Million Tons of Oil Equivalent, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case						Annual Growth 2002-2025 (percent)
	2001	2002	2010	2015	2020	2025	
Production							
Crude Oil and Lease Condensate	306.38	300.06	316.51	295.00	264.29	246.16	-0.9%
Natural Gas Plant Liquids	64.17	64.55	78.01	80.71	87.35	87.45	1.3%
Dry Natural Gas	509.91	492.97	530.43	559.54	615.72	620.86	1.0%
Coal	604.04	572.04	636.20	658.80	703.48	783.64	1.4%
Nuclear Power	202.31	205.26	209.02	213.66	214.85	214.85	0.2%
Renewable Energy[1]	132.33	147.07	180.90	197.50	213.05	226.72	1.9%
Other[2]	13.46	28.59	22.11	19.89	20.33	21.05	-1.3%
Total	**1832.60**	**1810.54**	**1973.19**	**2025.11**	**2119.08**	**2200.73**	**0.9%**
Imports							
Crude Oil[3]	510.44	500.05	617.72	740.12	795.03	861.97	2.4%
Petroleum Products[4]	127.02	119.73	145.14	151.30	197.31	242.60	3.1%
Natural Gas	102.42	103.21	164.87	183.71	190.52	208.93	3.1%
Other Imports[5]	14.97	13.20	23.91	26.66	28.21	29.69	3.6%
Total	**754.85**	**736.19**	**951.63**	**1101.79**	**1211.07**	**1343.19**	**2.6%**
Exports							
Petroleum[6]	50.55	51.16	54.06	54.85	53.58	54.08	0.2%
Natural Gas	9.46	13.09	22.91	22.76	23.44	22.11	2.3%
Coal	31.88	26.01	22.52	20.16	17.40	14.23	-2.6%
Total	**91.89**	**90.25**	**99.49**	**97.77**	**94.42**	**90.42**	**0.0%**
Discrepancy[7]	**52.60**	**-5.99**	**8.65**	**11.51**	**12.16**	**14.11**	**N/A**
Consumption							
Petroleum Products[8]	970.06	960.37	1112.48	1216.12	1294.03	1385.85	1.6%
Natural Gas	580.98	588.84	675.90	724.23	786.55	811.77	1.4%
Coal	555.38	559.03	635.72	663.34	713.24	799.53	1.6%
Nuclear Power	202.31	205.26	209.02	213.66	214.85	214.85	0.2%
Renewable Energy[1]	132.34	147.08	180.92	197.52	213.08	226.75	1.9%
Other[9]	1.89	1.89	2.65	2.75	1.83	0.65	-4.6%
Total	**2442.96**	**2462.47**	**2816.69**	**3017.61**	**3223.57**	**3439.39**	**1.5%**
Net Imports - Petroleum	**586.91**	**568.62**	**708.80**	**836.56**	**938.76**	**1050.49**	**2.7%**
Prices (2002 dollars per unit)							
World Oil Price (dollars per barrel)[10]	22.25	23.68	24.17	25.07	26.02	27.00	0.6%
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.14	2.95	3.40	4.19	4.28	4.40	1.8%
Coal Minemouth Price (dollars per ton)	17.79	17.90	16.88	16.47	16.32	16.57	-0.3%
Average Electricity Price (cents per kilowatthour)	7.4	7.2	6.6	6.8	6.9	6.9	-0.2%

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[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.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 and 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2001 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Annual 2001*, DOE/EIA-0131(2001) (Washington, DC, February 2003). 2002 natural gas supply values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2001 coal minemouth prices: EIA, *Annual Coal Report 2002*, DOE/EIA-0584(2002) (Washington, DC, November 2003). 2001 petroleum supply values: EIA *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). 2002 petroleum supply values: EIA, *Petroleum Supply Annual 2002,* DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). Other 2001 and 2002 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002) and EIA, *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003).
Projections: EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

Household Expenditures

Table E1. 2001 Average Household Expenditures for Energy by Household Characteristic
(2002 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**2983.60**	**1446.69**	**943.05**	**444.01**	**59.63**	**1536.91**
Households by Income Quintile						
1st	1707.27	1032.59	664.12	333.93	34.54	674.68
2nd	2531.28	1245.82	799.73	395.54	50.54	1285.46
3rd	3033.91	1404.40	930.92	409.01	64.47	1629.51
4th	3523.42	1639.12	1079.75	482.43	76.93	1884.30
5th	4257.70	2007.68	1296.00	641.71	69.96	2250.02
Households by Census Division						
New England	3304.63	1756.35	868.36	438.90	449.09	1548.28
Middle Atlantic	2878.05	1681.53	913.87	577.43	190.23	1196.52
South Atlantic	3159.31	1474.98	767.34	691.20	16.44	1684.34
East North Central	3284.35	1436.65	842.55	564.40	29.71	1847.70
East South Central	2934.45	1438.30	1136.18	277.61	24.51	1496.16
West North Central	2832.80	1324.87	1042.11	280.06	2.71	1507.92
West South Central	3035.74	1612.84	1244.90	367.72	0.22	1422.90
Mountain	2774.65	1210.87	794.26	414.83	1.79	1563.78
Pacific	2827.90	1148.61	787.98	354.91	5.73	1679.30

Source: Energy Information Administration, AEO2004 National Energy Modeling System run AEO2004.D101703E.

Table E2. 2010 Average Household Expenditures for Energy by Household Characteristic
(2002 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**3051.77**	**1351.91**	**926.70**	**377.52**	**47.69**	**1699.86**
Households by Income Quintile						
1st	1732.66	972.69	666.07	278.88	27.74	759.97
2nd	2605.59	1161.48	784.50	336.25	40.72	1444.12
3rd	3115.23	1313.34	914.92	347.01	51.41	1801.89
4th	3587.59	1528.51	1057.04	410.43	61.05	2059.07
5th	4305.44	1858.69	1254.84	548.18	55.67	2446.75
Households by Census Division						
New England	3310.18	1578.25	808.05	391.75	378.44	1731.93
Middle Atlantic	2847.41	1477.55	805.67	508.20	163.67	1369.86
South Atlantic	3070.96	1359.94	750.78	596.70	12.46	1711.02
East North Central	3343.35	1353.74	868.43	462.03	23.28	1989.61
East South Central	3097.20	1449.60	1188.49	243.20	17.92	1647.60
West North Central	3011.58	1337.08	1104.67	230.12	2.29	1674.51
West South Central	3099.37	1468.09	1180.03	287.95	0.11	1631.28
Mountain	3044.89	1210.07	810.18	398.49	1.40	1834.81
Pacific	2921.85	1024.64	728.63	291.45	4.56	1897.21

Source: Energy Information Administration, AEO2004 National Energy Modeling System run AEO2004.D101703E.

Table E3. 2015 Average Household Expenditures for Energy by Household Characteristic
(2002 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**3159.07**	**1404.66**	**961.86**	**398.01**	**44.79**	**1754.41**
Households by Income Quintile						
1st	1799.40	1010.64	692.57	291.92	26.15	788.75
2nd	2705.19	1208.35	816.16	353.89	38.30	1496.83
3rd	3223.04	1362.45	948.45	365.74	48.26	1860.59
4th	3707.51	1587.62	1097.24	433.13	57.25	2119.89
5th	4442.85	1930.71	1298.60	579.92	52.19	2512.14
Households by Census Division						
New England	3436.82	1643.05	865.88	411.09	366.08	1793.77
Middle Atlantic	2981.44	1560.11	874.84	526.04	159.22	1421.34
South Atlantic	3179.85	1438.63	794.82	632.13	11.68	1741.22
East North Central	3423.80	1384.43	883.67	479.04	21.72	2039.36
East South Central	3211.53	1501.06	1223.58	261.57	15.91	1710.47
West North Central	3077.58	1366.84	1116.57	248.12	2.15	1710.75
West South Central	3261.57	1568.16	1266.32	301.72	0.12	1693.41
Mountain	3216.87	1283.36	843.33	438.81	1.22	1933.51
Pacific	2946.14	1004.04	689.25	310.46	4.33	1942.11

Source: Energy Information Administration, AEO2004 National Energy Modeling System run AEO2004.D101703E.

Table E4. 2020 Average Household Expenditures for Energy by Household Characteristic
(2002 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**3214.81**	**1418.52**	**982.39**	**393.80**	**42.33**	**1796.29**
Households by Income Quintile						
1st	1831.14	1019.96	708.24	286.92	24.79	811.18
2nd	2759.03	1220.16	834.32	349.60	36.24	1538.88
3rd	3280.44	1374.39	967.38	361.41	45.60	1906.06
4th	3769.17	1603.66	1120.57	429.05	54.05	2165.52
5th	4513.41	1951.40	1325.77	576.43	49.20	2562.01
Households by Census Division						
New England	3489.08	1653.63	887.82	409.68	356.13	1835.45
Middle Atlantic	3017.77	1565.64	896.36	513.91	155.37	1452.13
South Atlantic	3197.58	1446.27	815.47	619.83	10.97	1751.31
East North Central	3464.53	1391.57	908.05	463.12	20.39	2072.96
East South Central	3281.69	1519.67	1241.51	264.20	13.96	1762.01
West North Central	3108.92	1374.35	1123.30	248.99	2.06	1734.57
West South Central	3341.49	1605.99	1311.56	294.29	0.14	1735.50
Mountain	3338.70	1304.34	851.73	451.53	1.08	2034.36
Pacific	3001.53	1014.18	693.55	316.51	4.12	1987.35

Source: Energy Information Administration, AEO2004 National Energy Modeling System run AEO2004.D101703E.

Table E5. 2025 Average Household Expenditures for Energy by Household Characteristic
(2002 Dollars)

Household Characteristics	Fuels					
	Total Energy	Total Home	Electricity	Natural Gas	Fuel Oil and Kerosene	Motor Gasoline
Average U.S. Household	**3323.87**	**1438.67**	**1007.04**	**392.62**	**39.01**	**1885.21**
Households by Income Quintile						
1st	1888.77	1033.23	726.19	284.14	22.90	855.54
2nd	2859.85	1237.51	855.78	348.33	33.40	1622.33
3rd	3394.12	1392.26	990.31	359.92	42.04	2001.85
4th	3891.76	1626.75	1148.66	428.30	49.80	2265.01
5th	4662.57	1981.95	1359.82	576.90	45.23	2680.62
Households by Census Division						
New England	3569.40	1667.51	914.70	413.85	338.97	1901.88
Middle Atlantic	3074.95	1571.60	916.50	506.78	148.32	1503.35
South Atlantic	3274.54	1461.77	839.23	612.86	9.68	1812.76
East North Central	3561.59	1411.02	936.51	456.50	18.02	2150.57
East South Central	3384.60	1539.61	1262.24	265.89	11.48	1844.99
West North Central	3166.30	1377.54	1127.50	248.12	1.92	1788.76
West South Central	3465.01	1656.66	1370.49	286.02	0.15	1808.35
Mountain	3563.66	1337.07	868.61	467.52	0.94	2226.59
Pacific	3154.51	1034.15	704.10	326.22	3.83	2120.36

Source: Energy Information Administration, AEO2004 National Energy Modeling System run AEO2004.D101703E.

Results from Side Cases

Table F1. Key Results for Residential and Commercial Sector Technology Cases

Energy Consumption	2002	2010				2015			
		2004 Technology	Reference Case	High Technology	Best Available Technology	2004 Technology	Reference Case	High Technology	Best Available Technology
Residential									
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.89	0.94	0.93	0.92	0.89	0.91	0.89	0.88	0.83
Kerosene	0.07	0.11	0.11	0.11	0.10	0.11	0.11	0.11	0.10
Liquefied Petroleum Gas	0.53	0.56	0.56	0.55	0.52	0.60	0.59	0.57	0.51
Petroleum Subtotal	1.48	1.62	1.60	1.59	1.51	1.62	1.59	1.55	1.44
Natural Gas	5.06	5.72	5.69	5.67	5.07	5.90	5.84	5.74	4.78
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy	0.39	0.41	0.40	0.40	0.40	0.41	0.41	0.40	0.39
Electricity	4.33	4.90	4.87	4.80	4.53	5.28	5.22	5.06	4.56
Delivered Energy	**11.28**	**12.66**	**12.58**	**12.48**	**11.52**	**13.22**	**13.06**	**12.76**	**11.18**
Electricity Related Losses	9.60	10.54	10.48	10.33	9.74	11.03	10.91	10.56	9.53
Total	**20.88**	**23.21**	**23.05**	**22.80**	**21.26**	**24.25**	**23.98**	**23.32**	**20.71**
Delivered Energy Consumption per Household (million Btu per household)	**102.3**	**105.7**	**105.0**	**104.1**	**96.1**	**104.8**	**103.6**	**101.2**	**88.7**
Non-Marketed Renewables Consumption (quadrillion Btu)	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**0.03**
Commercial									
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.49	0.63	0.62	0.62	0.61	0.66	0.65	0.65	0.64
Residual Fuel	0.08	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	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Motor Gasoline	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Petroleum Subtotal	0.72	0.92	0.92	0.91	0.91	0.96	0.95	0.94	0.94
Natural Gas	3.21	3.59	3.57	3.56	3.48	3.74	3.72	3.71	3.60
Coal	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Electricity	4.12	5.10	5.05	4.97	4.53	5.76	5.64	5.48	4.84
Delivered Energy	**8.25**	**9.81**	**9.74**	**9.64**	**9.12**	**10.66**	**10.51**	**10.32**	**9.57**
Electricity Related Losses	9.15	10.98	10.86	10.69	9.74	12.03	11.78	11.44	10.12
Total	**17.40**	**20.79**	**20.60**	**20.33**	**18.86**	**22.69**	**22.29**	**21.76**	**19.69**
Delivered Energy Consumption per Square Foot (thousand Btu per square foot)	**114.5**	**117.1**	**116.2**	**115.0**	**108.8**	**118.5**	**116.9**	**114.8**	**106.4**
Net Summer Generation Capacity (megawatts)									
Natural Gas	617	703	765	774	786	758	967	1038	1147
Solar Photovoltaic	35	258	258	285	297	284	284	452	650
Generation (billion kilowatthours)									
Natural Gas	4.45	5.06	5.51	5.58	5.66	5.46	6.98	7.50	8.29
Solar Photovoltaic	0.07	0.55	0.55	0.60	0.63	0.60	0.60	0.97	1.39
Non-Marketed Renewables (quadrillion Btu)	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all feedbacks are captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.

Source: Energy Information Administration, AEO2004 National Energy Modeling System, runs BLDFRZN.D102303D, BLDDEF.D102303A, BLDHIGH.D102303D, and BLDBEST.D102303D

2020				2025				Annual Growth 2002-2025			
2004 Technology	Reference Case	High Technology	Best Available Technology	2004 Technology	Reference Case	High Technology	Best Available Technology	2004 Technology	Reference Case	High Technology	Best Available Technology
0.88	0.85	0.83	0.76	0.84	0.80	0.78	0.70	-0.3%	-0.5%	-0.6%	-1.1%
0.10	0.10	0.10	0.08	0.09	0.09	0.09	0.07	1.4%	1.3%	1.2%	0.3%
0.63	0.61	0.58	0.52	0.66	0.64	0.60	0.54	1.0%	0.8%	0.6%	0.1%
1.61	1.56	1.51	1.37	1.59	1.53	1.46	1.31	0.3%	0.1%	-0.1%	-0.5%
6.17	6.08	5.92	4.81	6.37	6.27	6.04	4.87	1.0%	0.9%	0.8%	-0.2%
0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.1%	-0.3%	-0.4%	-0.5%
0.42	0.41	0.39	0.39	0.42	0.41	0.39	0.38	0.3%	0.1%	-0.1%	-0.2%
5.66	5.60	5.34	4.66	6.06	5.96	5.64	4.85	1.5%	1.4%	1.2%	0.5%
13.87	**13.66**	**13.18**	**11.23**	**14.45**	**14.17**	**13.54**	**11.42**	**1.1%**	**1.0%**	**0.8%**	**0.1%**
11.56	11.43	10.91	9.51	12.15	11.94	11.31	9.73	1.0%	1.0%	0.7%	0.1%
25.43	**25.10**	**24.09**	**20.74**	**26.60**	**26.11**	**24.85**	**21.15**	**1.1%**	**1.0%**	**0.8%**	**0.1%**
105.0	**103.5**	**99.8**	**85.1**	**104.9**	**102.8**	**98.3**	**82.9**	**0.1%**	**0.0%**	**-0.2%**	**-0.9%**
0.04	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.05**	**0.08**	**2.9%**	**3.2%**	**3.5%**	**5.2%**
0.69	0.67	0.66	0.65	0.72	0.70	0.68	0.67	1.7%	1.6%	1.5%	1.4%
0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	2.2%	2.2%	2.2%	2.2%
0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	1.4%	1.4%	1.4%	1.4%
0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.3%	0.3%	0.3%	0.3%
0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.2%	0.2%	0.2%	0.2%
0.99	0.97	0.96	0.95	1.02	1.00	0.99	0.98	1.5%	1.4%	1.4%	1.3%
3.95	3.94	3.92	3.79	4.16	4.16	4.15	4.05	1.1%	1.1%	1.1%	1.0%
0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.0%	0.0%	0.0%	0.0%
0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.0%	0.0%	0.0%	0.0%
6.45	6.24	5.96	5.20	7.17	6.83	6.44	5.56	2.4%	2.2%	2.0%	1.3%
11.59	**11.34**	**11.05**	**10.15**	**12.54**	**12.19**	**11.78**	**10.79**	**1.8%**	**1.7%**	**1.6%**	**1.2%**
13.17	12.73	12.17	10.62	14.36	13.70	12.91	11.15	2.0%	1.8%	1.5%	0.9%
24.76	**24.08**	**23.22**	**20.77**	**26.90**	**25.89**	**24.69**	**21.94**	**1.9%**	**1.7%**	**1.5%**	**1.0%**
120.8	**118.3**	**115.2**	**105.8**	**123.2**	**119.7**	**115.7**	**106.0**	**0.3%**	**0.2%**	**0.0%**	**-0.3%**
806	1309	1521	1841	867	1919	2409	3822	1.5%	5.1%	6.1%	8.2%
311	434	890	1715	337	953	1800	3267	10.3%	15.4%	18.7%	21.8%
5.81	9.47	11.01	13.34	6.25	13.90	17.47	27.75	1.5%	5.1%	6.1%	8.3%
0.66	0.93	1.91	3.57	0.72	2.04	3.80	6.73	10.4%	15.5%	18.6%	21.6%
0.03	**0.03**	**0.03**	**0.04**	**0.03**	**0.03**	**0.04**	**0.05**	**1.1%**	**1.5%**	**2.1%**	**3.1%**

Table F2. Key Results for Industrial Sector Technology Cases

Consumption	2002	2010			2020			2025		
		2004 Technology	Reference Case	High Technology	2004 Technology	Reference Case	High Technology	2004 Technology	Reference Case	High Technology
Energy Consumption (quadrillion Btu)										
Distillate Fuel	1.16	1.19	1.17	1.16	1.39	1.34	1.29	1.49	1.43	1.37
Liquefied Petroleum Gas	2.22	2.40	2.35	2.32	2.85	2.74	2.64	3.07	2.94	2.83
Petrochemical Feedstocks	1.22	1.37	1.35	1.33	1.60	1.54	1.49	1.69	1.62	1.57
Residual Fuel	0.20	0.22	0.21	0.20	0.24	0.22	0.20	0.25	0.23	0.21
Motor Gasoline	0.16	0.16	0.16	0.16	0.19	0.18	0.18	0.20	0.19	0.19
Other Petroleum	4.03	4.42	4.38	4.34	5.04	4.93	4.82	5.30	5.17	5.03
Petroleum Subtotal	9.00	9.77	9.63	9.52	11.30	10.95	10.63	11.99	11.59	11.19
Natural Gas	7.43	8.94	8.62	8.47	10.57	9.84	9.20	11.42	10.58	9.74
Lease and Plant Fuel	1.35	1.40	1.40	1.40	1.65	1.65	1.65	1.69	1.69	1.69
Natural Gas Subtotal	8.78	10.34	10.02	9.88	12.22	11.49	10.85	13.11	12.27	11.43
Metallurgical Coal[1]	0.65	0.72	0.66	0.58	0.67	0.52	0.38	0.65	0.48	0.32
Steam Coal	1.47	1.43	1.41	1.39	1.50	1.45	1.39	1.53	1.47	1.40
Coal Subtotal	2.12	2.14	2.06	1.97	2.16	1.97	1.78	2.18	1.95	1.72
Renewable Energy	1.66	1.98	2.00	2.10	2.43	2.48	2.86	2.63	2.70	3.25
Electricity	3.39	3.89	3.82	3.64	4.69	4.47	4.11	5.16	4.85	4.41
Delivered Energy	**24.94**	**28.12**	**27.53**	**27.11**	**32.80**	**31.36**	**30.22**	**35.08**	**33.35**	**32.00**
Electricity Related Losses	7.53	8.37	8.22	7.83	9.57	9.12	8.39	10.34	9.72	8.84
Total	**32.47**	**36.49**	**35.75**	**34.94**	**42.37**	**40.48**	**38.61**	**45.42**	**43.07**	**40.84**
Delivered Energy Use per Dollar of Shipments (thousand Btu per 1996 dollar)	**4.72**	**4.37**	**4.28**	**4.21**	**3.93**	**3.76**	**3.62**	**3.70**	**3.51**	**3.37**
Onsite Industrial Combined Heat and Power										
Capacity (gigawatts)	19.91	24.20	24.28	26.85	29.87	30.68	36.20	32.56	34.45	40.80
Generation (billion kilowatthours)	119.26	148.84	149.23	166.76	187.92	193.26	228.93	206.59	219.49	259.07

[1]Includes net coal coke imports.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2004 National Energy Modeling System runs INDFRZN.D102303A, AEO2004.D101703E, and INDHIGH.D102303A.

Table F3. Key Results for Transportation Sector Technology Cases

Consumption and Indicators	2002	2010			2020			2025		
		2004 Technology	Reference Case	High Technology	2004 Technology	Reference Case	High Technology	2004 Technology	Reference Case	High Technology
Energy Consumption (quadrillion Btu)										
Distillate Fuel	5.12	6.48	6.42	6.36	8.49	8.02	7.73	9.63	8.94	8.49
Jet Fuel	3.34	3.97	3.93	3.90	5.06	4.69	4.38	5.44	4.91	4.45
Motor Gasoline	16.62	19.91	19.88	19.76	23.76	23.11	22.52	26.14	24.98	24.14
Residual Fuel	0.71	0.80	0.79	0.79	0.82	0.82	0.81	0.84	0.83	0.81
Liquefied Petroleum Gas	0.02	0.06	0.06	0.06	0.08	0.08	0.07	0.09	0.08	0.08
Other Petroleum	0.24	0.25	0.25	0.25	0.30	0.30	0.30	0.32	0.32	0.32
Petroleum Subtotal	26.06	31.47	31.34	31.12	38.50	37.00	35.81	42.46	40.07	38.30
Pipeline Fuel Natural Gas	0.65	0.69	0.69	0.69	0.83	0.83	0.83	0.86	0.86	0.86
Compressed Natural Gas	0.01	0.06	0.06	0.06	0.10	0.10	0.09	0.11	0.11	0.10
Renewables (E85)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.08	0.09	0.09	0.09	0.11	0.12	0.10	0.12	0.14
Delivered Energy	**26.79**	**32.30**	**32.18**	**31.97**	**39.53**	**38.05**	**36.86**	**43.53**	**41.16**	**39.40**
Electricity Related Losses	0.17	0.18	0.19	0.20	0.19	0.22	0.24	0.20	0.24	0.27
Total	**26.96**	**32.49**	**32.37**	**32.17**	**39.72**	**38.27**	**37.10**	**43.73**	**41.41**	**39.68**
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[1]	23.8	25.0	25.3	25.9	24.9	26.5	27.9	24.8	26.9	28.5
New Car (miles per gallon)[1]	28.2	28.3	28.8	29.9	28.6	30.4	32.1	28.5	30.8	32.7
New Light Truck (miles per gallon)[1]	20.5	22.6	22.8	23.1	22.7	24.1	25.4	22.7	24.7	26.1
Light-Duty Fleet (miles per gallon)[2]	19.7	19.6	19.6	19.7	19.9	20.5	21.2	19.8	20.9	21.8
New Commercial Light Truck (MPG)[3]	13.9	15.0	15.1	15.4	14.9	16.0	17.0	14.9	16.4	17.4
Stock Commercial Light Truck (MPG)[3]	13.8	14.4	14.5	14.5	14.9	15.5	16.0	14.9	15.9	16.7
Aircraft Efficiency (seat miles per gallon)	54.8	59.1	59.9	60.4	60.0	65.4	70.8	59.6	67.0	75.2
Freight Truck Efficiency (miles per gallon)	6.0	6.0	6.0	6.1	6.0	6.4	6.6	6.0	6.5	6.8
Rail Efficiency (ton miles per thousand Btu)	2.9	2.9	3.1	3.2	2.9	3.4	3.8	2.9	3.6	4.1
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.3	2.3	2.4	2.3	2.4	2.5	2.3	2.4	2.6
Light-Duty Vehicles Less Than 8500 Pounds (vehicle miles traveled)	**2504**	**3041**	**3041**	**3044**	**3748**	**3768**	**3792**	**4132**	**4173**	**4210**

[1]Environmental Protection Agency rated miles per gallon.
[2]Combined car and light truck "on-the-road" estimate.
[3]Commercial trucks 8,500 to 10,000 pounds.
Btu = British thermal unit.
MPG = Miles per gallon.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2004 National Energy Modeling System runs TRNFRZN.D102403A, AEO2004.D101703E, and TRNHIGH.D102403A

Table F4. Key Results for Integrated Technology Cases

Consumption and Emissions	2002	2010			2020			2025		
		2004 Technology	Reference Case	High Technology	2004 Technology	Reference Case	High Technology	2004 Technology	Reference Case	High Technology
Consumption by Sector (quadrillion Btu)										
Residential	20.9	23.1	23.1	22.8	25.4	25.1	24.1	26.6	26.1	24.7
Commercial	17.4	20.7	20.6	20.4	24.7	24.1	23.3	26.9	25.9	24.5
Industrial	32.5	36.5	35.7	34.9	42.6	40.5	38.4	45.8	43.1	40.3
Transportation	27.0	32.5	32.4	32.2	39.8	38.3	37.1	43.8	41.4	39.7
Total	**97.7**	**112.9**	**111.8**	**110.3**	**132.5**	**127.9**	**122.9**	**143.0**	**136.5**	**129.2**
Consumption by Fuel (quadrillion Btu)										
Petroleum Products	38.1	44.5	44.1	43.7	53.5	51.4	49.6	58.0	55.0	52.7
Natural Gas	23.4	27.4	26.8	26.3	32.6	31.2	30.1	33.3	32.2	31.6
Coal	22.2	25.4	25.2	24.5	29.4	28.3	25.5	34.4	31.7	26.5
Nuclear Power	8.1	8.3	8.3	8.3	8.5	8.5	8.5	8.5	8.5	8.5
Renewable Energy	5.8	7.1	7.2	7.4	8.3	8.5	9.2	8.7	9.0	9.9
Other	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0
Total	**97.7**	**112.9**	**111.8**	**110.3**	**132.5**	**127.9**	**122.9**	**143.0**	**136.5**	**129.2**
Energy Intensity (thousand Btu per 1996 dollar of GDP)	**10.4**	**9.3**	**9.2**	**9.1**	**8.2**	**7.9**	**7.6**	**7.7**	**7.4**	**7.0**
Carbon Dioxide Emissions by Sector (million metric tons)										
Residential	1189.0	1324.4	1317.2	1295.3	1478.1	1449.2	1354.5	1601.7	1543.0	1393.0
Commercial	1009.1	1212.8	1202.5	1179.2	1476.6	1422.9	1332.4	1669.5	1570.1	1412.3
Industrial	1670.6	1834.3	1789.6	1729.5	2137.1	2003.6	1836.0	2335.7	2149.5	1908.9
Transportation	1860.6	2258.5	2249.5	2234.3	2764.6	2659.9	2574.8	3046.7	2879.5	2758.3
Total	**5729.3**	**6630.0**	**6558.8**	**6438.3**	**7856.4**	**7535.6**	**7097.6**	**8653.6**	**8142.0**	**7472.5**
Carbon Dioxide Emissions by End-Use Fuel (million metric tons)										
Petroleum	2380.5	2750.7	2735.2	2714.0	3301.3	3176.2	3070.3	3603.9	3410.9	3264.3
Natural Gas	904.4	1069.5	1050.7	1041.8	1223.3	1176.8	1131.1	1293.5	1240.8	1171.6
Coal	195.4	209.7	202.4	194.2	211.4	193.6	176.4	213.6	191.4	171.1
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	2249.0	2600.2	2570.6	2488.2	3120.4	2989.0	2719.8	3542.5	3299.0	2865.4
Total	**5729.3**	**6630.0**	**6558.8**	**6438.3**	**7856.4**	**7535.6**	**7097.6**	**8653.6**	**8142.0**	**7472.5**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)										
Petroleum	72.2	58.3	51.0	45.2	81.9	65.2	55.7	66.6	61.6	60.4
Natural Gas	299.1	370.6	358.5	337.6	490.1	463.3	449.5	456.4	451.6	487.4
Coal	1877.8	2171.2	2161.2	2105.4	2548.4	2460.5	2214.6	3019.6	2785.8	2317.7
Total	**2249.0**	**2600.2**	**2570.6**	**2488.2**	**3120.4**	**2989.0**	**2719.8**	**3542.5**	**3299.0**	**2865.4**
Carbon Dioxide Emissions by Primary Fuel (million metric tons)										
Petroleum	2452.7	2809.0	2786.1	2759.3	3383.2	3241.4	3126.0	3670.5	3472.5	3324.7
Natural Gas	1203.4	1440.1	1409.2	1379.4	1713.4	1640.1	1580.6	1749.9	1692.4	1659.0
Coal	2073.2	2380.9	2363.6	2299.6	2759.8	2654.1	2391.1	3233.2	2977.1	2488.8
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**5729.4**	**6630.0**	**6558.8**	**6438.3**	**7856.4**	**7535.6**	**7097.6**	**8653.6**	**8142.0**	**7472.5**

Btu = British thermal unit.
GDP = Gross domestic product.
Note: Includes end-use, fossil electricity, and renewable technology assumptions. Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2004 National Energy Modeling System runs LTRKITEN.D102303A, AEO2004.D101703E, and HTRKITEN.D103103A.

Table F5. Key Results for Advanced Nuclear Cost Case
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation, Emissions, and Fuel Prices	2002	2010			2020			2025		
		Reference Case	Vendor Estimates	AP1000	Reference Case	Vendor Estimates	AP1000	Reference Case	Vendor Estimates	AP 1000
Capacity										
Coal Steam	310.9	310.3	310.3	310.2	353.5	354.0	354.1	412.3	402.9	393.5
Other Fossil Steam	133.6	106.1	106.0	106.0	101.1	100.2	100.3	96.5	96.5	96.0
Combined Cycle	110.5	160.0	159.9	160.0	217.3	215.6	213.7	235.2	232.6	232.0
Combustion Turbine/Diesel	128.8	136.5	136.6	136.6	169.2	166.6	167.4	180.4	182.0	181.3
Nuclear Power	98.7	100.6	100.6	100.6	102.6	106.9	106.9	102.6	115.4	128.4
Pumped Storage	20.2	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Fuel Cells	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Renewable Sources	91.7	97.4	97.4	97.4	105.9	103.9	104.7	110.1	106.5	106.1
Distributed Generation (Natural Gas)	0.0	0.5	0.4	0.4	7.6	7.6	7.5	12.4	13.3	13.1
Combined Heat and Power[1]	26.6	33.1	33.1	33.1	42.1	42.0	41.9	47.4	47.2	47.2
Total	**921.1**	**964.7**	**964.6**	**964.7**	**1119.7**	**1117.1**	**1116.9**	**1217.3**	**1216.8**	**1217.9**
Cumulative Additions										
Coal Steam	0.0	6.8	6.8	6.8	51.9	52.3	52.4	111.8	102.3	93.0
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	50.1	50.0	50.1	107.4	105.7	103.8	125.3	122.7	122.1
Combustion Turbine/Diesel	0.0	18.5	18.6	18.6	54.1	51.3	52.1	67.1	69.5	68.8
Nuclear Power	0.0	0.0	0.0	0.0	0.0	4.3	4.3	0.0	12.8	25.8
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Renewable Sources	0.0	5.5	5.4	5.5	14.0	11.9	12.8	18.2	14.6	14.1
Distributed Generation	0.0	0.5	0.4	0.4	7.6	7.6	7.5	12.4	13.3	13.1
Combined Heat and Power[1]	0.0	6.5	6.5	6.5	15.5	15.4	15.4	20.9	20.7	20.7
Total	**0.0**	**87.9**	**87.8**	**87.9**	**250.5**	**248.6**	**248.3**	**355.7**	**355.9**	**357.6**
Cumulative Retirements	**0.0**	**44.6**	**44.7**	**44.6**	**54.2**	**54.9**	**54.8**	**61.8**	**62.5**	**63.1**
Generation by Fuel (billion kilowatthours)										
Coal	1907	2235	2234	2234	2593	2592	2592	3008	2935	2862
Petroleum	83	63	64	63	85	84	84	80	76	76
Natural Gas	598	816	816	816	1131	1112	1110	1117	1115	1104
Nuclear Power	780	794	794	794	816	848	848	816	913	1002
Pumped Storage	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9
Renewable Sources	309	405	405	405	446	439	442	464	450	448
Distributed Generation	0	0	0	0	3	3	3	5	6	6
Combined Heat and Power[1]	161	207	207	206	270	269	269	305	304	304
Total	**3829**	**4510**	**4510**	**4510**	**5335**	**5337**	**5337**	**5787**	**5789**	**5792**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Petroleum	72.2	51.0	51.4	51.0	65.2	64.7	64.6	61.6	59.5	59.1
Natural Gas	299.1	358.5	358.3	358.5	463.3	456.8	456.5	451.6	451.9	447.7
Coal	1877.8	2161.2	2160.8	2160.4	2460.5	2458.5	2458.1	2785.8	2727.5	2669.1
Total	**2249.0**	**2570.6**	**2570.5**	**2569.9**	**2989.0**	**2980.0**	**2979.3**	**3299.0**	**3238.9**	**3176.0**
Prices to the Electric Power Sector[2] (2002 dollars per million Btu)										
Petroleum	4.32	4.21	4.20	4.21	4.67	4.66	4.67	4.88	4.83	4.87
Natural Gas	3.77	4.04	4.04	4.04	4.85	4.79	4.78	4.92	4.95	4.93
Coal	1.26	1.22	1.23	1.22	1.20	1.20	1.19	1.22	1.20	1.18

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.

[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.

Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.

Source: Energy Information Administration, AEO2004 National Energy Modeling System runs AEO2004.D101703E, ADVNUC3A.D102803A, and ADVNUC5A.D102803A.

Table F6. Key Results for High Electricity Demand Case

Net Summer Capacity, Generation, Consumption, Emissions, and Prices	2002	2010		2020		2025		Annual Growth 2002-2025	
		Reference Case	High Demand	Reference Case	High Demand	Reference Case	High Demand	Reference Case	High Demand
Electricity Sales (billion kilowatthours)	**3492**	**4055**	**4296**	**4811**	**5480**	**5207**	**6149**	**1.8%**	**2.5%**
Electricity Prices									
(2002 cents per kilowatthour)	**7.2**	**6.6**	**6.8**	**6.9**	**7.1**	**6.9**	**7.1**	**-0.2%**	**-0.1%**
Capacity (gigawatts)									
Coal Steam	310.9	310.3	314.9	353.5	405.7	412.3	498.1	1.2%	2.1%
Other Fossil Steam	133.6	106.1	116.0	101.1	112.0	96.5	110.5	-1.4%	-0.8%
Combined Cycle	110.5	160.0	181.0	217.3	274.1	235.2	293.5	3.3%	4.3%
Combustion Turbine/Diesel	128.8	136.5	149.0	169.2	192.3	180.4	219.5	1.5%	2.3%
Nuclear Power	98.7	100.6	100.6	102.6	102.6	102.6	102.6	0.2%	0.2%
Fuel Cells	0.0	0.1	0.1	0.1	0.1	0.1	0.1	N/A	N/A
Renewable Sources/Pumped Storage	111.9	117.7	121.4	126.3	134.7	130.5	144.1	0.7%	1.1%
Distributed Generation	0.0	0.5	1.0	7.6	14.3	12.4	23.0	N/A	N/A
Combined Heat and Power[1]	26.6	33.1	33.1	42.1	42.2	47.4	47.7	2.6%	2.6%
Total	**921.1**	**964.7**	**1017.0**	**1119.7**	**1277.8**	**1217.3**	**1438.9**	**1.2%**	**2.0%**
Cumulative Additions (gigawatts)									
Coal Steam	0.0	6.8	11.4	51.9	104.0	111.8	197.5	N/A	N/A
Other Fossil Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A	N/A
Combined Cycle	0.0	50.1	70.7	107.4	163.8	125.3	183.5	N/A	N/A
Combustion Turbine/Diesel	0.0	18.5	29.8	54.1	77.3	67.1	105.1	N/A	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A	N/A
Fuel Cells	0.0	0.1	0.1	0.1	0.1	0.1	0.1	N/A	N/A
Renewable Sources/Pumped Storage	0.0	5.5	9.1	14.0	22.4	18.2	31.8	N/A	N/A
Distributed Generation	0.0	0.5	1.0	7.6	14.3	12.4	23.0	N/A	N/A
Combined Heat and Power[1]	0.0	6.5	6.6	15.5	15.6	20.9	21.1	N/A	N/A
Total	**0.0**	**87.9**	**128.5**	**250.5**	**397.4**	**355.7**	**562.1**	**N/A**	**N/A**
Generation by Fuel (billion kilowatthours)									
Coal	1907	2235	2295	2593	2987	3008	3644	2.0%	2.9%
Petroleum	83	63	82	85	121	80	125	-0.2%	1.8%
Natural Gas	598	816	974	1131	1372	1117	1362	2.8%	3.6%
Nuclear Power	780	794	794	816	816	816	816	0.2%	0.2%
Renewable Sources/Pumped Storage	300	395	409	437	469	455	519	1.8%	2.4%
Distributed Generation	0	0	0	3	6	5	10	N/A	N/A
Combined Heat and Power[1]	161	207	207	270	271	305	307	2.8%	2.8%
Total	**3829**	**4510**	**4762**	**5335**	**6042**	**5787**	**6784**	**1.8%**	**2.5%**
Fossil Fuel Consumption by the Electric Power Sector (quadrillion Btu)[2]									
Petroleum	0.85	0.66	0.84	0.85	1.15	0.81	1.18	-0.2%	1.4%
Natural Gas	5.65	6.79	7.93	8.78	10.27	8.55	10.12	1.8%	2.6%
Coal	19.96	23.05	23.67	26.22	29.49	29.67	34.71	1.7%	2.4%
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]									
Petroleum	72.2	51.0	63.9	65.2	86.6	61.6	88.7	-0.7%	0.9%
Natural Gas	299.1	358.5	418.5	463.3	542.1	451.6	534.6	1.8%	2.6%
Coal	1877.8	2161.2	2218.4	2460.5	2768.0	2785.8	3260.7	1.7%	2.4%
Total	**2249.0**	**2570.6**	**2700.8**	**2989.0**	**3396.7**	**3299.0**	**3883.9**	**1.7%**	**2.4%**
Prices to the Electric Power Sector[2] (2002 dollars per million Btu)									
Petroleum	4.32	4.21	4.26	4.67	4.86	4.88	5.11	0.5%	0.7%
Natural Gas	3.77	4.04	4.26	4.85	5.08	4.92	5.30	1.2%	1.5%
Coal	1.26	1.22	1.24	1.20	1.26	1.22	1.29	-0.1%	0.1%

[1]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.

[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.

Btu = British thermal unit.

N/A = not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports. Other includes non-coal fossil steam, pumped storage, methane, propane and blast furnace gas. Side case was run without the fully integrated modeling system, so not all potential feedbacks were captured.

Source: Energy Information Administration, AEO2004 National Energy Modeling System runs AEO2004.D101703E and HDEM04.D101903A

Table F7. Key Results for Electric Power Sector Fossil Technology Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation Consumption, and Emissions	2002	2010				2025			
		Low Fossil	Reference Case	High Fossil	DOE Fossil Goals	Low Fossil	Reference Case	High Fossil	DOE Fossil Goals
Capacity									
Pulverized Coal	310.4	309.8	309.8	307.4	307.5	425.5	405.5	328.5	304.6
Coal Gasification Combined-Cycle	0.5	0.5	0.5	0.5	2.0	0.9	6.8	26.2	90.3
Conventional Natural Gas Combined-Cycle	110.5	154.4	153.6	153.4	153.4	191.9	154.6	153.4	153.2
Advanced Natural Gas Combined-Cycle	0.0	2.6	6.4	13.4	12.6	9.0	80.6	189.6	162.7
Conventional Combustion Turbine	128.8	134.4	133.4	130.7	131.3	185.5	153.3	128.2	129.2
Advanced Combustion Turbine	0.0	3.3	3.1	2.0	2.4	10.7	27.1	18.2	15.1
Fuel Cells	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Nuclear	98.7	100.6	100.6	100.6	100.6	102.6	102.6	102.6	102.6
Oil and Gas Steam	133.6	108.0	106.1	104.2	104.3	98.9	96.5	92.4	85.2
Renewable Sources/Pumped Storage	111.9	119.4	117.7	117.8	117.9	135.7	130.5	125.6	121.0
Distributed Generation	0.0	0.5	0.5	0.4	0.4	15.6	12.4	5.6	4.4
Combined Heat and Power[1]	26.6	33.1	33.1	33.1	33.1	47.5	47.4	47.3	46.8
Total	**921.1**	**966.5**	**964.7**	**963.5**	**965.4**	**1223.7**	**1217.3**	**1217.7**	**1215.4**
Cumulative Additions									
Pulverized Coal	0.0	6.8	6.8	4.5	4.6	125.4	105.5	28.5	4.6
Coal Gasification Combined-Cycle	0.0	0.0	0.0	0.0	1.5	0.4	6.3	25.7	89.8
Conventional Natural Gas Combined-Cycle	0.0	44.5	43.7	43.5	43.5	82.0	44.7	43.5	43.5
Advanced Natural Gas Combined-Cycle	0.0	2.6	6.4	13.4	12.6	9.0	80.6	189.6	162.7
Conventional Combustion Turbine	0.0	16.4	15.5	13.1	13.6	72.6	40.0	16.7	18.3
Advanced Combustion Turbine	0.0	3.3	3.1	2.0	2.4	10.7	27.1	18.2	15.1
Fuel Cells	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil and Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	7.1	5.5	5.5	5.6	23.4	18.2	13.4	8.8
Distributed Generation	0.0	0.5	0.5	0.4	0.4	15.6	12.4	5.6	4.4
Combined Heat and Power[1]	0.0	6.5	6.5	6.5	6.5	20.9	20.9	20.7	20.3
Total	**0.0**	**87.7**	**87.9**	**88.9**	**90.6**	**360.0**	**355.7**	**361.8**	**367.5**
Cumulative Retirements	**0.0**	**42.6**	**44.6**	**46.8**	**46.6**	**59.8**	**61.8**	**67.6**	**75.6**
Generation by Fuel (billion kilowatthours)									
Coal	1906.9	2234.8	2234.5	2217.4	2228.6	3100.2	3007.9	2614.6	2896.5
Petroleum	83.1	64.8	63.4	60.1	60.4	73.8	79.9	113.4	69.0
Natural Gas	598.1	808.7	816.4	836.8	825.2	1009.1	1117.5	1499.4	1287.6
Nuclear Power	780.1	794.3	794.3	794.3	794.3	816.5	816.5	816.5	816.5
Renewable Sources/Pumped Storage	300.1	400.7	395.1	395.6	395.5	476.7	455.0	437.0	414.1
Distributed Generation	0.0	0.2	0.2	0.2	0.2	6.8	5.4	2.4	1.9
Combined Heat and Power[1]	161.1	206.5	206.5	206.4	206.4	305.6	305.1	303.4	300.3
Total	**3829.4**	**4510.2**	**4510.5**	**4510.8**	**4510.7**	**5788.7**	**5787.3**	**5786.7**	**5785.9**
Fuel Consumption by the Electric Power Sector (quadrillion Btu)[2]									
Coal	19.96	23.06	23.05	22.90	22.98	30.51	29.67	26.02	26.99
Petroleum	0.85	0.68	0.66	0.63	0.64	0.78	0.81	0.99	0.66
Natural Gas	5.65	6.79	6.79	6.82	6.74	8.25	8.55	9.96	8.17
Nuclear Power	8.15	8.29	8.29	8.29	8.29	8.53	8.53	8.53	8.53
Renewable Sources	3.69	4.73	4.68	4.70	4.68	6.04	5.79	5.57	5.17
Total	**38.29**	**43.55**	**43.48**	**43.35**	**43.34**	**54.10**	**53.35**	**51.05**	**49.52**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]									
Petroleum	72.2	52.1	51.0	48.4	48.8	59.5	61.6	74.2	50.0
Natural Gas	299.1	358.3	358.5	360.1	356.1	435.4	451.6	525.8	431.5
Coal	1877.8	2161.7	2161.2	2146.9	2154.3	2865.0	2785.8	2440.7	2532.7
Total	**2249.0**	**2572.1**	**2570.6**	**2555.5**	**2559.1**	**3359.9**	**3299.0**	**3040.8**	**3014.2**

[1]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured.
Source: Energy Information Administration, AEO2004 National Energy Modeling System runs LFOSS04.D101903A, AEO2004.D101703E, HFOSS10.D102103A, and HFOSS04.D101903A.

Table F8. Key Results for High Renewable Energy Case

Capacity, Generation, and Emissions	2002	2010 Low Renewables	2010 Reference Case	2010 High Renewables	2010 DOE Renewable Goals	2025 Low Renewables	2025 Reference Case	2025 High Renewables	2025 DOE Renewable Goals
Renewable Capacity (gigawatts)									
Net Summer Capacity									
Electric Power Sector[1]									
Conventional Hydropower	78.29	78.69	78.69	78.69	78.69	78.68	78.68	78.68	78.68
Geothermal[2]	2.89	3.82	4.01	3.69	3.71	5.89	6.84	8.62	12.48
Municipal Solid Waste[3]	3.49	3.92	3.92	3.89	3.89	3.95	3.95	3.95	3.95
Wood and Other Biomass[4]	1.83	2.14	2.20	2.14	2.14	2.14	3.74	5.90	2.54
Solar Thermal	0.33	0.43	0.43	0.43	0.43	0.52	0.52	0.52	0.52
Solar Photovoltaic	0.02	0.15	0.15	0.15	0.15	0.41	0.41	0.41	0.41
Wind	4.83	7.89	8.01	7.83	9.79	10.79	15.99	35.35	80.83
Total	**91.69**	**97.04**	**97.42**	**96.82**	**98.80**	**102.38**	**110.13**	**133.43**	**179.41**
Combined Heat and Power[5]									
Municipal Solid Waste	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Wood and Other Biomass	3.91	5.31	5.36	5.81	5.81	7.81	8.03	10.31	10.31
Total	**4.16**	**5.56**	**5.61**	**6.06**	**6.06**	**8.06**	**8.29**	**10.57**	**10.57**
Other End-Use Generators[6]									
Conventional Hydropower	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.04	0.39	0.39	0.41	0.42	0.50	1.13	2.28	8.52
Total	**1.06**	**1.41**	**1.41**	**1.44**	**1.45**	**1.52**	**2.15**	**3.31**	**9.55**
Generation (billion kilowatthours)									
Electric Power Sector[1]									
Coal	1875	2197	2201	2153	2154	2990	2975	2907	2702
Petroleum	77	62	62	73	74	76	77	78	71
Natural Gas	450	648	642	668	659	987	969	927	941
Total Fossil	**2401**	**2908**	**2906**	**2895**	**2887**	**4053**	**4021**	**3912**	**3715**
Conventional Hydropower	255.78	304.38	304.37	304.37	304.37	304.80	304.80	304.80	304.81
Geothermal	13.36	21.69	23.25	20.79	20.93	38.84	46.66	61.10	90.33
Municipal Solid Waste[3]	20.02	28.11	28.11	27.90	27.88	28.50	28.50	28.49	28.50
Wood and Other Biomass[4]	8.67	23.40	23.53	24.21	24.30	22.19	29.16	39.33	25.52
Dedicated Plants	6.32	13.01	13.26	12.99	13.04	12.99	22.90	35.62	15.61
Cofiring	2.35	10.39	10.26	11.21	11.25	9.20	6.25	3.71	9.92
Solar Thermal	0.54	0.84	0.84	0.84	0.93	1.11	1.11	1.11	1.41
Solar Photovoltaic	0.00	0.36	0.36	0.36	0.36	1.02	1.02	1.02	1.02
Wind	10.51	23.62	24.07	23.43	30.95	33.66	53.16	130.11	330.98
Total Renewable	**308.87**	**402.39**	**404.52**	**401.90**	**409.72**	**430.12**	**464.40**	**565.95**	**782.56**
Combined Heat and Power[5]									
Total Fossil	**111**	**142**	**142**	**143**	**143**	**221**	**220**	**217**	**207**
Municipal Solid Waste	1.84	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10
Wood and Other Biomass	28.16	36.34	36.63	39.28	39.27	50.93	52.26	65.57	65.57
Total Renewables	**30.00**	**38.44**	**38.73**	**41.38**	**41.37**	**53.03**	**54.36**	**67.67**	**67.67**
Other End-Use Generators[6]									
Conventional Hydropower[7]	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.09	0.82	0.82	0.88	0.91	1.07	2.42	4.86	17.47
Total	**4.20**	**4.93**	**4.93**	**4.99**	**5.02**	**5.18**	**6.53**	**8.97**	**21.58**
Sources of Ethanol									
From Corn	0.17	0.29	0.29	0.28	0.28	0.31	0.31	0.27	0.27
From Cellulose	0.00	0.00	0.00	0.01	0.01	0.05	0.05	0.09	0.09
Total	**0.17**	**0.29**	**0.29**	**0.29**	**0.29**	**0.35**	**0.35**	**0.36**	**0.36**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[1]									
Petroleum	72.2	50.8	51.0	59.5	59.7	60.7	61.6	61.9	57.9
Natural Gas	299.1	360.5	358.5	386.6	382.7	459.5	451.6	438.3	437.7
Coal	1877.8	2157.8	2161.2	2118.0	2118.6	2798.0	2785.8	2709.5	2564.5
Total	**2249.0**	**2569.1**	**2570.6**	**2564.2**	**2560.9**	**3318.2**	**3299.0**	**3209.8**	**3060.1**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[6]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[7]Represents own-use industrial hydroelectric power.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2004 National Energy Modeling System runs LORENEW04.D102703B, AEO2004.D101703E, HIREN1004.D103103A, and EERE04.D103103A.

Table F9. Total Energy Supply and Disposition Summary, Oil and Gas Technological Progress Cases

(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2002	2010			2020			2025		
		Slow Technology Progress	Reference Case	Rapid Technology Progress	Slow Technology Progress	Reference Case	Rapid Technology Progress	Slow Technology Progress	Reference Case	Rapid Technology Progress
Production										
Crude Oil and Lease Condensate	11.91	12.46	12.56	12.67	10.02	10.49	11.07	8.99	9.77	10.28
Natural Gas Plant Liquids	2.56	3.06	3.10	3.19	3.29	3.47	3.79	3.23	3.47	3.88
Dry Natural Gas	19.56	20.76	21.05	21.75	23.10	24.43	27.10	22.79	24.64	28.21
Coal	22.70	25.28	25.25	25.13	28.47	27.92	27.21	31.97	31.10	29.51
Nuclear Power	8.15	8.29	8.29	8.29	8.53	8.53	8.53	8.53	8.53	8.53
Renewable Energy[1]	5.84	7.23	7.18	7.23	8.46	8.45	8.32	9.00	9.00	8.82
Other[2]	1.13	0.87	0.88	0.89	0.81	0.81	0.81	0.84	0.84	0.84
Total	**71.85**	**77.95**	**78.30**	**79.16**	**82.68**	**84.09**	**86.82**	**85.35**	**87.33**	**90.06**
Imports										
Crude Oil[3]	19.84	24.68	24.51	24.37	32.06	31.55	30.68	35.23	34.21	33.29
Petroleum Products[4]	4.75	5.83	5.76	5.61	8.20	7.83	7.43	10.19	9.63	9.21
Natural Gas	4.10	6.47	6.54	6.22	7.69	7.56	6.94	8.01	8.29	7.90
Other Imports[5]	0.52	0.95	0.95	0.95	1.11	1.12	1.11	1.17	1.18	1.18
Total	**29.21**	**37.93**	**37.76**	**37.14**	**49.06**	**48.06**	**46.16**	**54.60**	**53.30**	**51.59**
Exports										
Petroleum[6]	2.03	2.14	2.15	2.14	2.12	2.13	2.16	2.17	2.15	2.17
Natural Gas	0.52	0.89	0.91	0.93	0.83	0.93	1.08	0.66	0.88	1.24
Coal	1.03	0.89	0.89	0.89	0.69	0.69	0.74	0.64	0.56	0.58
Total	**3.58**	**3.93**	**3.95**	**3.96**	**3.64**	**3.75**	**3.97**	**3.47**	**3.59**	**3.98**
Consumption										
Petroleum Products[7]	38.11	44.24	44.15	44.08	51.56	51.35	50.99	55.51	54.99	54.63
Natural Gas	23.37	26.47	26.82	27.18	30.11	31.21	33.10	30.26	32.21	35.01
Coal	22.18	25.26	25.23	25.11	28.86	28.30	27.56	32.52	31.73	30.13
Nuclear Power	8.15	8.29	8.29	8.29	8.53	8.53	8.53	8.53	8.53	8.53
Renewable Energy[1]	5.84	7.23	7.18	7.23	8.46	8.46	8.32	9.00	9.00	8.82
Other[8]	0.07	0.11	0.11	0.11	0.07	0.07	0.06	0.02	0.03	0.03
Total	**97.72**	**111.60**	**111.77**	**112.00**	**127.59**	**127.92**	**128.54**	**135.84**	**136.48**	**137.14**
Net Imports - Petroleum	**22.56**	**28.38**	**28.13**	**27.83**	**38.14**	**37.25**	**35.95**	**43.26**	**41.69**	**40.34**
Prices (2002 dollars per unit)										
World Oil Price (dollars per barrel)[9]	23.68	24.17	24.17	24.17	26.02	26.02	26.02	27.00	27.00	27.00
Natural Gas Wellhead Price (dollars per thousand cubic feet)[10]	2.95	3.58	3.40	3.25	4.54	4.28	3.56	5.10	4.40	3.80
Coal Minemouth Price (dollars per ton)	17.90	16.95	16.88	16.81	16.55	16.32	16.12	16.80	16.57	16.39
Average Electricity Price (cents per kilowatthour)	7.2	6.7	6.6	6.6	7.0	6.9	6.6	7.1	6.9	6.6
Carbon Dioxide Emissions (million metric tons)	**5729.4**	**6550.3**	**6558.8**	**6560.6**	**7546.5**	**7535.6**	**7536.4**	**8152.2**	**8142.0**	**8110.5**

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[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, unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[8]Includes net electricity imports, methanol, and liquid hydrogen.
[9]Average refiner acquisition cost for imported crude oil.
[10]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2002 petroleum supply values: *EIA, Petroleum Supply Annual 2002*, DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). 2002 carbon dioxide emission values: EIA, *Emissions of Greenhouse Gases in the United States 2002,* DOE/EIA-0573(2002) (Washington, DC, October 2003). Other 2002 values: *EIA,Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002) and *EIA,Quarterly Coal Report*, October-December 2002, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003). **Projections:** EIA, AEO2004 National Energy Modeling System runs OGLTEC04.D102103A, AEO2004.D101703E, and OGHTEC04.D102003B.

Table F10. Natural Gas Supply and Disposition, Oil and Gas Technological Progress Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2002	2010			2020			2025		
		Slow Technology Progress	Reference Case	Rapid Technology Progress	Slow Technology Progress	Reference Case	Rapid Technology Progress	Slow Technology Progress	Reference Case	Rapid Technology Progress
Lower 48 Average Wellhead Price (2002 dollars per thousand cubic feet)	**2.95**	**3.58**	**3.40**	**3.25**	**4.54**	**4.28**	**3.56**	**5.10**	**4.40**	**3.80**
Dry Gas Production[1]										
U.S. Total	**19.05**	**20.21**	**20.50**	**21.18**	**22.49**	**23.79**	**26.39**	**22.19**	**23.99**	**27.46**
Lower 48 Onshore	13.76	14.34	14.48	14.89	15.62	16.41	18.68	15.20	16.26	19.98
Associated-Dissolved	1.60	1.42	1.41	1.39	1.22	1.23	1.25	1.14	1.17	1.20
Non-Associated	12.16	12.92	13.08	13.50	14.41	15.18	17.43	14.06	15.09	18.78
Conventional	6.23	5.89	5.80	5.92	5.83	6.07	5.96	5.65	5.92	5.84
Unconventional	5.93	7.03	7.28	7.58	8.58	9.11	11.47	8.41	9.16	12.94
Lower 48 Offshore	4.86	5.28	5.41	5.69	4.58	5.09	5.42	4.29	5.03	5.16
Associated-Dissolved	1.05	1.56	1.61	1.66	1.25	1.34	1.49	1.12	1.43	1.54
Non-Associated	3.81	3.72	3.80	4.03	3.33	3.75	3.93	3.16	3.60	3.62
Alaska	0.43	0.60	0.60	0.60	2.29	2.29	2.29	2.71	2.71	2.33
Supplemental Natural Gas[2]	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Net Imports	**3.49**	**5.44**	**5.50**	**5.17**	**6.70**	**6.47**	**5.72**	**7.18**	**7.24**	**6.50**
Canada	3.59	3.47	3.68	3.89	2.03	2.51	2.84	1.56	2.56	3.24
Mexico	-0.26	-0.32	-0.34	-0.36	-0.08	-0.18	-0.32	0.15	-0.12	-0.48
Liquefied Natural Gas	0.17	2.29	2.16	1.63	4.74	4.14	3.20	5.46	4.80	3.75
Total Supply	**22.62**	**25.75**	**26.09**	**26.44**	**29.29**	**30.36**	**32.20**	**29.46**	**31.33**	**34.06**
Consumption by Sector										
Residential	4.92	5.50	5.53	5.57	5.86	5.92	6.03	6.00	6.09	6.27
Commercial	3.12	3.45	3.48	3.51	3.77	3.83	3.94	3.94	4.04	4.22
Industrial[3]	7.23	8.32	8.39	8.44	9.46	9.57	9.88	10.02	10.29	10.64
Electric Generators[4]	5.55	6.46	6.66	6.84	7.86	8.61	9.74	7.09	8.39	10.20
Transportation[5]	0.01	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Pipeline Fuel	0.63	0.66	0.67	0.69	0.77	0.81	0.88	0.77	0.84	0.92
Lease and Plant Fuel[6]	1.32	1.35	1.36	1.39	1.54	1.61	1.71	1.56	1.65	1.78
Total	**22.78**	**25.81**	**26.15**	**26.51**	**29.36**	**30.44**	**32.28**	**29.50**	**31.41**	**34.15**
Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**-0.16**	**-0.06**	**-0.06**	**-0.06**	**-0.08**	**-0.08**	**-0.08**	**-0.04**	**-0.09**	**-0.09**
Lower 48 End of Year Reserves	**180.03**	**193.63**	**201.20**	**212.12**	**185.12**	**200.97**	**239.47**	**171.76**	**193.51**	**238.82**

[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 for combined heat and power, which produces electricity and other useful thermal energy.
[4]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as vehicle fuel.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[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, 2001 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2002 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections:** EIA, AEO2004 National Energy Modeling System runs OGLTEC04.D102103A, AEO2004.D101703E, and OGHTEC04.D102003B.

Table F11. Crude Oil Supply and Disposition, Oil and Gas Technological Progress Cases
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2002	2010			2020			2025		
		Slow Technology Progress	Reference Case	Rapid Technology Progress	Slow Technology Progress	Reference Case	Rapid Technology Progress	Slow Technology Progress	Reference Case	Rapid Technology Progress
World Oil Price										
(2002 dollars per barrel)	**23.68**	**24.17**	**24.17**	**24.17**	**26.02**	**26.02**	**26.02**	**27.00**	**27.00**	**27.00**
Production[1]										
U.S. Total	**5.62**	**5.88**	**5.93**	**5.98**	**4.73**	**4.95**	**5.23**	**4.25**	**4.61**	**4.85**
Lower 48 Onshore	3.11	2.65	2.61	2.57	2.18	2.20	2.22	2.00	2.04	2.09
Lower 48 Offshore	1.53	2.32	2.40	2.49	1.86	2.03	2.28	1.75	2.06	2.25
Alaska	0.98	0.92	0.92	0.93	0.69	0.72	0.73	0.50	0.51	0.51
Net Crude Imports	**9.13**	**11.30**	**11.21**	**11.15**	**14.74**	**14.50**	**14.08**	**16.22**	**15.74**	**15.31**
Other Crude Supply	**0.07**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Total Crude Supply	**14.83**	**17.18**	**17.15**	**17.13**	**19.48**	**19.45**	**19.31**	**20.47**	**20.35**	**20.16**
Natural Gas Plant Liquids	**1.88**	**2.22**	**2.24**	**2.31**	**2.35**	**2.48**	**2.69**	**2.30**	**2.47**	**2.74**
Other Inputs[2]	**0.67**	**0.47**	**0.47**	**0.48**	**0.46**	**0.46**	**0.46**	**0.47**	**0.48**	**0.48**
Refinery Processing Gain[3]	**0.98**	**0.88**	**0.88**	**0.88**	**1.01**	**1.00**	**1.00**	**1.04**	**1.04**	**1.03**
Net Product Imports[4]	**1.41**	**1.99**	**1.95**	**1.88**	**3.19**	**2.99**	**2.76**	**4.22**	**3.94**	**3.70**
Total Primary Supply[5]	**19.77**	**22.73**	**22.69**	**22.66**	**26.47**	**26.38**	**26.22**	**28.50**	**28.27**	**28.11**
Refined Petroleum Products Supplied										
Residential and Commercial	1.22	1.38	1.38	1.37	1.41	1.40	1.39	1.41	1.40	1.38
Industrial[6]	4.80	5.14	5.14	5.13	5.86	5.86	5.79	6.23	6.21	6.15
Transportation	13.21	15.90	15.91	15.92	18.76	18.77	18.80	20.31	20.32	20.36
Electric Generators[7]	0.38	0.34	0.29	0.26	0.48	0.38	0.27	0.59	0.36	0.24
Total	**19.61**	**22.75**	**22.71**	**22.68**	**26.51**	**26.41**	**26.25**	**28.54**	**28.30**	**28.13**
Discrepancy[8]	**0.16**	**-0.02**	**-0.02**	**-0.02**	**-0.04**	**-0.04**	**-0.02**	**-0.04**	**-0.03**	**-0.03**
Lower 48 End of Year Reserves										
(billion barrels)[1]	**19.05**	**18.73**	**18.36**	**18.03**	**16.19**	**16.20**	**16.23**	**14.84**	**14.98**	**15.04**

[1]Includes lease condensate.
[2]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.
[3]Represents volumetric gain in refinery distillation and cracking processes.
[4]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[5]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[6]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[7]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Balancing item. Includes unaccounted for supply, losses and gains.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 product supplied data based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). Other 2002 data: EIA, *Petroleum Supply Annual 2002,* DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). **Projections:** EIA, AEO2004 National Energy Modeling System runs OGLTEC04.D102103A, AEO2004.D101703E, and OGHTEC04.D102003B.

Table F12. Key Results for Coal Mining Cost Cases

Prices, Productivity, Wages, and Emissions	2002	2010			2020			2025		
		Low Cost	Reference Case	High Cost	Low Cost	Reference Case	High Cost	Low Cost	Reference Case	High Cost
Minemouth Price										
(2002 dollars per short ton)	**17.90**	**15.68**	**16.88**	**18.28**	**13.87**	**16.32**	**19.67**	**13.27**	**16.57**	**21.45**
Delivered Price to Electric Generators										
(2002 dollars per million Btu)	**1.26**	**1.16**	**1.22**	**1.29**	**1.07**	**1.20**	**1.36**	**1.04**	**1.22**	**1.44**
Labor Productivity										
(short tons per miner per hour)	**6.80**	**8.54**	**7.59**	**6.75**	**11.30**	**8.57**	**6.27**	**13.10**	**9.19**	**5.94**
Labor Productivity										
(average annual growth from 2002)	**0.00**	**2.89**	**1.38**	**-0.09**	**2.86**	**1.29**	**-0.45**	**2.89**	**1.32**	**-0.59**
Average Coal Miner Wage										
(2002 dollars per hour)	**19.64**	**18.87**	**19.64**	**20.44**	**17.95**	**19.64**	**21.48**	**17.50**	**19.64**	**22.03**
Average Coal Miner Wage										
(average annual growth from 2002)	**0.00**	**-0.50**	**0.00**	**0.50**	**-0.50**	**0.00**	**0.50**	**-0.50**	**0.00**	**0.50**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[1]										
Petroleum	72.2	50.5	51.0	50.9	55.7	65.2	76.7	60.0	61.6	79.2
Natural Gas	299.1	359.3	358.5	365.2	425.3	463.3	503.3	419.9	451.6	509.8
Coal	1877.8	2165.1	2161.2	2134.6	2592.7	2460.5	2304.2	2901.8	2785.8	2520.1
Total	**2249.0**	**2574.8**	**2570.6**	**2550.7**	**3073.7**	**2989.0**	**2884.2**	**3381.8**	**3299.0**	**3109.1**
Electric Power Sector Capacity [1] (gigawatts)										
Coal	310.9	310.5	310.3	306.8	378.2	353.5	326.3	434.0	412.3	364.7
Other	583.6	618.6	621.4	621.9	699.8	724.2	750.4	741.5	757.6	813.8
Total	**894.5**	**929.1**	**931.7**	**928.7**	**1078.0**	**1077.7**	**1076.7**	**1175.6**	**1169.9**	**1178.5**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2004 National Energy Modeling System runs LMCST04.D102303A, AEO2004.D101703E, and HMCST04.D102303A.

Major Assumptions for the Forecasts

The National Energy Modeling System

The projections in the *Annual Energy Outlook 2004* (*AEO2004*) are generated from the National Energy Modeling System (NEMS), developed and maintained by the Office of Integrated Analysis and Forecasting (OIAF) of the Energy Information Administration (EIA). In addition to its use in the development of the *AEO* projections, NEMS is also used in analytical studies for the U.S. Congress and other offices within the Department of Energy. The *AEO* forecasts are also used by analysts and planners in other government agencies and outside organizations.

The projections in NEMS are developed with the use of a market-based approach to energy analysis. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. The time horizon of NEMS is the midterm period, approximately 20 years into the future. In order to represent the regional differences in energy markets, the component modules of NEMS function at the regional level: the nine Census divisions for the end-use demand modules; production regions specific to oil, gas, and coal supply and distribution; the North American Electric Reliability Council (NERC) regions and subregions for electricity; and aggregations of the Petroleum Administration for Defense Districts (PADDs) 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, and international petroleum supply availability.

The integrating module controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data file. This modular design provides the capability to execute modules individually, thus allowing decentralized development of the system and independent analysis and testing of individual modules, permitting the use of the methodology and level of detail most appropriate for each energy sector. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Solution is reached annually through the midterm horizon. Other variables are also evaluated for convergence, such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

Each NEMS component also represents the impacts and costs of legislation and environmental regulations that affect that sector and reports key emissions. NEMS represents current legislation and environmental regulations as of September 1, 2003, such as the Clean Air Act Amendments of 1990 (CAAA90), and the costs of compliance with other regulations, such as the new Corporate Average Fuel Economy rule for light-duty trucks, which was formally announced on April 1, 2003, and published in the *Federal Register* on April 7, 2003.

In general, the historical data used for the *AEO2004* projections were based on EIA's *Annual Energy Review 2002*, published in October 2003 [*1*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2002. Carbon dioxide emissions were calculated by using carbon dioxide coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 2002*, published in October 2003 [*2*].

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 *AEO2004* includes electricity used by railroads, which is included in the commercial sector in EIA's consumption data publications. Footnotes in the appendix tables of this report indicate the definitions and sources of all historical data.

The *AEO2004* projections for 2003 and 2004 incorporate short-term projections from EIA's September and October 2003 *Short-Term Energy Outlook* (*STEO*). For short-term energy projections, readers are referred to the monthly updates of the *STEO* [*3*].

Component Modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing the prices of energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module provides a set of essential macroeconomic drivers to the energy modules and a macroeconomic feedback mechanism within NEMS. Key macroeconomic variables include gross domestic product (GDP), industrial output, interest rates, disposable income, prices, and employment. This module uses the following Global Insight models: Macroeconomic Model of the U.S. Economy, National Industrial Shipments Model, National Employment Model, and the Regional Disaggregation Model for macroeconomic drivers. In addition, EIA has constructed a Commercial Floorspace Model to forecast 13 floorspace types in 9 Census divisions.

International Energy Module

The International Energy Module represents the world oil markets, calculating the average world oil price and computing supply curves for five categories of imported crude oil for the Petroleum Market Module (PMM) of NEMS, in response to changes in U.S. import requirements. Fourteen international petroleum product supply curves, including curves for oxygenates, are also calculated and provided to the PMM.

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 changes in the efficiency of energy use for residential end uses and in light-duty vehicle fuel efficiency. Estimates of average expenditures for households are provided 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, based on delivered energy prices, the menu of equipment available, the 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, based on 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. The commercial module incorporates combined heat and power (CHP) technology. Both modules include a forecast of distributed generation.

Industrial Demand Module

The Industrial Demand Module forecasts the consumption of energy for heat and power and for feedstocks and raw materials in each of 16 industry groups, subject to the delivered prices of energy and macroeconomic variables representing employment and the value of shipments for each industry. The industries are classified into three groups—energy-intensive, non-energy-intensive, and nonmanufacturing. Of the eight energy-intensive industries, seven are modeled in the Industrial Demand Module, with components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. A representation of cogeneration and a recycling component are also included. The use of energy for petroleum refining is modeled in the Petroleum Market Module, and the projected consumption is included in the industrial totals.

Transportation Demand Module

The Transportation Demand Module forecasts consumption of transportation sector fuels, including petroleum products, electricity, methanol, ethanol, compressed natural gas, and hydrogen by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and the value of output for industries in the freight sector. Fleet vehicles are represented separately to allow analysis of CAAA90 and other legislative proposals, and the module includes a component to explicitly assess the penetration of alternative-fuel vehicles. The air transportation module was substantially revamped for *AEO2004*. The model represents the industry practice of parking aircraft to reduce operating costs and the movement of aircraft from the passenger to cargo markets as aircraft age [*4*]. For air freight shipments, the model employs narrow-body and wide-body aircraft only. The model also uses an infrastructure constraint that limits air travel growth to levels commensurate with industry-projected infrastructure expansion and capacity growth.

Electricity Market Module

The Electricity Market Module models generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, natural gas, and biofuels; costs of generation by all generation plants, including capital costs; macroeconomic variables for costs of capital and domestic investment; enforced environmental emissions laws and regulations; and electricity load shapes and demand. There are three primary submodules—capacity planning, fuel dispatching, and finance and pricing. Nonutility generation, distributed generation, and transmission and trade are modeled 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 specifically identified CAAA90 compliance options that have been promulgated by the U.S. Environmental Protection Agency (EPA) are explicitly represented in the capacity expansion and dispatch decisions; those that have not been promulgated are not incorporated (e.g., fine particulate proposal). Several States, primarily in the Northeast, have recently enacted air emission regulations that affect the electricity generation sector. Where firm State compliance plans have been announced, regulations are represented in *AEO2004*.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing natural resource supply and technology input information for central-station, grid-connected electricity generation technologies, including biomass (wood, energy crops, and biomass co-firing), geothermal, landfill gas, solar thermal, solar photovoltaics, and wind energy. The RFM contains natural resource supply estimates representing the regional opportunities for renewable energy development. Conventional hydroelectricity is represented in the Electricity Market Module (EMM). Investment tax credits for renewable fuels are incorporated, as currently legislated in the Energy Policy Act of 1992 [*5*]. They provide a 10-percent tax credit for business investment in solar energy (thermal nonpower uses as well as power uses) and geothermal power. The credits have no expiration date.

Oil and Gas Supply Module

The Oil and Gas Supply Module models 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 gas recovery from coalbeds and low-permeability formations of sandstone and shale. This framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, based on the prices for crude oil and natural gas, the domestic recoverable resource base, and the state of 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 to Canada and Mexico, and liquefied natural gas (LNG) imports and exports.

Crude oil production quantities are input to the PMM in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are input to the Natural Gas Transmission and Distribution Module for use in determining natural gas prices and quantities. International LNG supply sources and options for regional expansions of domestic regasification capacity are represented, based on the projected regional costs associated with gas supply, liquefaction, transportation, regasification, and natural gas market conditions.

Natural Gas Transmission and Distribution Module

The Natural Gas Transmission and Distribution Module represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module tracks the flows of natural gas in an aggregate, domestic pipeline network, connecting the domestic and foreign supply regions with 12 demand regions. This capability allows the analysis of impacts of regional capacity constraints in the interstate natural gas pipeline network and the identification of pipeline and storage capacity expansion requirements. Peak and off-peak periods are represented for natural gas transmission, and core and noncore markets are represented at the burner tip. Key components of pipeline and distributor tariffs are included in the pricing algorithms.

Petroleum Market Module

The Petroleum Market Module (PMM) 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, the availability and price of imported petroleum, and the domestic production of crude oil, natural gas liquids, and alcohol fuels. The module represents refining activities for five regions—Petroleum Administration for Defense Districts (PADD) 1 through 5. The module uses the same crude oil types as the International Energy Module. It explicitly models the requirements of CAAA90 and the costs of automotive fuels, such as oxygenated and reformulated gasoline, and includes oxygenate production and blending for reformulated gasoline. *AEO2004* reflects legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in the next several years in California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, New York, Ohio, South Dakota, Washington, and Wisconsin [*6*].

The Federal oxygen requirement for reformulated gasoline in Federal nonattainment areas is assumed to remain intact. The "Tier 2" regulation that requires the nationwide phase-in of gasoline with a greatly reduced annual average sulfur content between 2004 and 2007 and the diesel regulation that significantly limits the sulfur content of all highway diesel fuel produced after June 1, 2006, are represented in *AEO2004*. Costs of the regulation include capacity expansion for refinery-processing units based on a 10-percent hurdle rate and a 10-percent after-tax return on investment [*7*]. End-use prices are based on the marginal costs of production, plus markups representing product and distribution costs, and State and Federal taxes. Refinery capacity expansion at existing sites may occur in all five refining regions modeled.

Coal Market Module

The Coal Market Module (CMM) simulates mining, transportation, and pricing of coal, subject to the end-use demand for coal differentiated by heat and sulfur content. The coal supply curves include a response to capacity utilization of mines, mining capacity, fuel costs, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Twelve coal types are represented—differentiated by coal rank, sulfur content, and mining process. Production and distribution are computed for 11 supply and 14 demand regions, using imputed coal transportation costs and trends in factor input costs. The CMM also forecasts the requirements for U.S. coal exports and imports. The international coal market component of the module computes trade in 3 types of coal for 16 export and 20 import regions. Both the domestic and international coal markets are simulated in a linear program.

Major Assumptions for the *Annual Energy Outlook 2004*

Table G1 provides a summary of the cases used to derive the *AEO2004* 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 NEMS (either fully integrated, partially integrated, or standalone), and a reference to the pages in the body of the report and in this appendix where the case is discussed.

Assumptions for domestic macroeconomic activity are presented in the "Market Trends" section. The resulting GDP growth rates between 2002 and 2025 in the three macroeconomic growth cases are 2.4, 3.0, and 3.5 percent per year in the low economic growth, reference and high economic growth cases, respectively. The following section describes the key regulatory, programmatic, and resource assumptions that factor into the projections. More detailed assumptions for each sector are available at web site www.eia.doe.gov/oiaf/aeo/assumption/. Regional results and other details of the projections are available at web site www.eia.doe.gov/ oiaf/aeo/ supplement/.

World Oil Market Assumptions

World oil price. The world oil price is the annual average U.S. refiner's acquisition cost of imported crude oil. Three distinct world oil price scenarios are represented in *AEO2004*, reaching $17, $27, and $35 per barrel in 2025, respectively, in the low world oil price, reference, and high world oil price cases in 2002 dollars. The reference case represents EIA's current judgment regarding the expected behavior of the

Table G1. Summary of the *AEO2004* cases

Case name	Description	Integration mode	Reference in text	Reference in Appendix G
Reference	Baseline economic growth, world oil price, and technology assumptions.	Fully integrated	—	—
Low Economic Growth	Gross domestic product grows at an average annual rate of 2.4 percent from 2002 through 2025, compared to the reference case growth of 3.0 percent.	Fully integrated	p. 67	—
High Economic Growth	Gross domestic product grows at an average annual rate of 3.5 percent from 2002 through 2025, compared to the reference case growth of 3.0 percent.	Fully integrated	p. 67	—
Low World Oil Price	World oil prices are $19.04 per barrel in 2025, compared to $26.57 per barrel in the reference case.	Fully integrated	p. 68	—
High World Oil Price	World oil prices are $33.05 per barrel in 2025, compared to $26.57 per barrel in the reference case.	Fully integrated	p. 68	—
Residential: 2004 Technology	Future equipment purchases based on equipment available in 2004. Existing building shell efficiencies fixed at 2004 levels.	With commercial	p. 77	p. 244
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Heating shell efficiency increases by 13 percent from 2001 values by 2025.	With commercial	p. 77	p. 244
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available. Heating shell efficiency increases by 18 percent from 2001 values by 2025.	With commercial	p. 77	p. 244
Commercial: 2004 Technology	Future equipment purchases based on equipment available in 2004. Building shell efficiencies fixed at 2004 levels.	With residential	p. 78	p. 245
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Heating shell efficiencies for new and existing buildings increase by 8.75 and 6.25 percent, respectively, from 1999 values by 2025.	With residential	p. 78	p. 245
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available. Heating shell efficiencies for new and existing buildings increase by 10.5 and 7.5 percent, respectively, from 1999 values by 2025.	With residential	p. 78	p. 245
Industrial: 2004 Technology	Efficiency of plant and equipment fixed at 2004 levels.	Standalone	p. 79	p. 246
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone	p. 79	p. 246
Transportation: 2004 Technology	Efficiencies for new equipment in all modes of travel are fixed at 2004 levels.	Standalone	p. 79	p. 248
Transportation: High Technology	Reduced costs and improved efficiencies are assumed for advanced technologies.	Standalone	p. 79	p. 248
Integrated 2004 Technology	Combination of the residential, commercial, industrial, and transportation 2004 technology cases, electricity low fossil technology case, and assumption of renewable technologies fixed at 2004 levels.	Fully integrated	p. 104	—
Integrated High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases, electricity high fossil technology case, high renewables case, and advanced nuclear cost case.	Fully integrated	p. 104	—

Table G1. Summary of the *AEO2004* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix G
Electricity: Advanced Nuclear Cost	New nuclear capacity is assumed to have 10 percent lower capital and operating costs in 2025 than in the reference case.	Fully integrated	p. 87	p. 250
Electricity: Nuclear AP1000 Case	New nuclear capacity is assumed to have lower capital costs, based on vendor goals for the AP1000 reactor.	Fully integrated	p. 87	p. 250
Electricity: Nuclear Vendor Estimate Case	New nuclear capacity is assumed to have lower capital costs, based on vendor goals for the AP1000 and CANDU reactors.	Fully integrated	p. 58	p. 250
Electricity: High Demand	Electricity demand increases at an annual rate of 2.5 percent, compared to 1.8 percent in the reference case.	Partially integrated	p. 88	p. 251
Electricity: Low Fossil Technology	New advanced fossil generating technologies are assumed not to improve over time from 2004.	Partially integrated	p. 87	p. 251
Electricity: High Fossil Technology	Costs and efficiencies for advanced fossil-fired generating technologies improve by 10 percent in 2025 from reference case values.	Partially integrated	p. 87	p. 251
Electricity: DOE Fossil Goals	Costs and/or efficiencies for advanced fossil-fired generating technologies improve from reference case values, based on Department goals.	Partially integrated	p. 87	p. 252
Renewables: Low Renewables	New renewable generating technologies are assumed not to improve over time from 2004.	Fully Integrated	p. 86	p. 254
Renewables: High Renewables	Levelized cost of energy for nonhydropower renewable generating technologies declines by 10 percent in 2025 from reference case values.	Fully Integrated	p. 86	p. 253
Renewables: DOE Goals	Lower costs and higher efficiencies for central-station renewable generating technologies and for distributed photovoltaics, approximating U.S. Department of Energy goals for 2025. Includes greater improvements in residential and commercial photovoltaic systems, more rapid improvement in recovery of industrial biomass byproducts, and more rapid improvement in cellulosic ethanol production technology.	Fully integrated	p. 86	p. 254
Oil and Gas: Slow Technology	Cost, finding rate, and success rate parameters adjusted for 50-percent slower improvement than in the reference case.	Fully integrated	p. 91	p. 254
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate parameters adjusted for 50-percent more rapid improvement than in the reference case.	Fully integrated	p. 91	p. 254
Coal: Low Mining Cost	Productivity increases at an annual rate of 2.9 percent, compared to the reference case growth of 1.3 percent. Real wages and real mine equipment costs decrease by 0.5 percent annually, compared to constant real wages and equipment costs in the reference case.	Fully integrated	p. 100	p. 258
Coal: High Mining Cost	Productivity decreases at an annual rate of 0.6 percent, compared to the reference case growth of 1.3 percent. Real wages and real mine equipment costs increase by 0.5 percent annually, compared to constant real wages and equipment costs in the reference case.	Fully integrated	p. 100	p. 258

Organization of Petroleum Exporting Countries (OPEC) in the mid-term, where production is adjusted to keep world oil prices in the $22 to $28 per barrel range. Since OPEC, particularly the Persian Gulf nations, is expected to be the dominant supplier of oil in the international market over the mid-term, the organization's production choices will significantly affect world oil prices. The low world oil price case could result from a future market where all oil production becomes more competitive and plentiful. The high price case could result from a more cohesive and market-assertive OPEC with lower production goals and other nonfinancial (geopolitical) considerations.

World oil demand. Demand outside the United States is assumed to be for total petroleum with no specificity as to individual refined products or sectors of the economy. The forecast of petroleum demand within a region uses a Koyck-lag formulation and is a function of world oil price and GDP. Estimates of regional GDPs are from EIA's *International Energy Outlook 2003*.

World oil supply. Supply outside the United States is assumed to be total liquids and includes production of crude oils (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, refinery gains, alcohol, and liquids produced from coal and other sources. The forecast of oil supply is a function of the world oil price, estimates of proved oil reserves, estimates of ultimately recoverable oil resources, and technological improvements that affect exploration, recovery, and cost. Estimates of proved oil reserves are provided by the *Oil & Gas Journal* [*8*] and represent country-level assessments as of January 1, 2003. Estimates of ultimately recoverable oil resources are provided by the United States Geological Survey (USGS) [*9*] and are part of its "Worldwide Petroleum Assessment 2000." Technology factors are derived from the DESTINY forecast software [*10*] and are a part of the International Energy Services of Petroconsultants, Inc.

Buildings sector assumptions

The buildings sector includes both residential and commercial structures and commercial nonbuilding applications. The National Appliance Energy Conservation Act of 1987 (NAECA) and the Energy Policy Act of 1992 (EPACT), both of which are incorporated in *AEO2004*, contain provisions that affect future buildings sector energy use. The most significant are minimum equipment efficiency standards, which require that new heating, cooling, and other specified energy-using equipment meet minimum energy efficiency levels, which change over time. The manufacture of equipment that does not meet the standards is prohibited. Federal mandates, such as Executive Order 13123, "Greening the Government Through Efficient Energy Management" (signed in June 1999) and Executive Order 13221, "Energy-Efficient Standby Power Devices" (signed in July 2001), are expected to affect future energy use in Federal buildings.

Residential sector assumptions. The NAECA minimum standards [*11*] for the major types of equipment in the residential sector are:

- Central air conditioners and heat pumps—a 10.0 minimum seasonal energy efficiency ratio for 1992, increasing to 12.0 in 2006
- Room air conditioners—an 8.7 energy efficiency ratio in 1990, raised to 9.7 in 2003
- Gas/oil furnaces—a 0.78 annual fuel utilization efficiency in 1992
- Refrigerators—a standard of 976 kilowatthours per year in 1990, 691 kilowatthours per year in 1993, and 483 kilowatthours per year in 2002
- Electric water heaters—a 0.88 energy factor in 1990, increasing to 0.90 in 2004
- Natural gas water heaters—a 0.54 energy factor in 1990, raised to 0.59 in 2004.

The *AEO2004* version of the NEMS Residential Demand Module is based on EIA's 2001 Residential Energy Consumption Survey (RECS) [*12*]. This survey provides most of the housing stock characteristics, appliance stock information (equipment type and fuel), and energy consumption estimates used to initialize the residential module. The projected effects of equipment turnover and the choice of various levels of equipment energy efficiency are based on tradeoffs between higher equipment costs for the more efficient equipment versus lower annual energy costs. Equipment characterizations range from minimum efficiency standards to the best available equipment with the highest energy efficiency. These characterizations include equipment made available through various green programs, such as the EPA's Energy Star Programs [*13*].

A combined heating, ventilation, and air conditioning (HVAC)/shell module is used to model building shells in new construction. The module combines specific heating and cooling equipment with appropriate levels of shell efficiency to represent the least expensive ways to meet selected overall efficiency levels. The levels include:

- The current average new house, defined by the post-1990 housing stock in RECS 2001 and data obtained from results of the 2002 McGraw-Hill Dodge Survey of New Home Builders
- The International Energy Conservation Code (IECC 2000)
- Energy Star Homes using upgraded HVAC equipment and/or shell integrity (combined energy requirements for HVAC must be 30 percent lower than IECC 2000)
- The PATH home (Partnership for Advancing Technology in Housing) [*14*]
- A shell intermediate to Energy Star and PATH set to save 40 percent of HVAC energy.

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

In addition to the *AEO2004* reference case, three cases using the Residential and Commercial Demand Modules of NEMS were developed to examine the effects of equipment and building shell efficiencies. For the residential sector:

- The *2004 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2004. Existing building shell efficiencies are assumed to be fixed at 2004 levels.
- The *high technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [*15*]. Heating shell efficiency is projected to increase by 13 percent over 2001 levels by 2025.
- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. Heating shell efficiency is projected to increase by 18 percent over 2001 levels by 2025.

Commercial sector assumptions. The definition of the commercial sector for *AEO2004* is based on building characteristics and energy consumption data from the 1999 Commercial Buildings Energy Consumption Survey (CBECS) [*16*]. Minimum equipment efficiency standards for the commercial sector are mandated in the EPACT legislation [*17*]. Minimum standards for representative equipment types are:

- Small central air conditioning heat pumps—a 9.7 seasonal energy efficiency rating (January 1994)
- Natural-gas-fired forced-air furnaces—a 0.8 thermal efficiency standard (January 1994)
- Natural-gas-fired storage water heaters—a 0.80 thermal efficiency standard (October 2003)
- Fluorescent lamps—a 75.0 lumens per watt lighting efficacy standard for 4-foot F40T12 lamps (November 1995) and an 80.0 lumens per watt efficacy standard for 8-foot F96T12 lamps (May 1994) [*18*]
- Fluorescent lamp ballasts—a standard mandating electronic ballasts with a 1.17 ballast efficacy factor for 4-foot ballasts holding two F40T12 lamps and a 0.63 ballast efficacy for 8-foot ballasts holding two F96T12 lamps (April 2005 for new lighting systems, June 2010 for replacement ballasts).

Improvements to existing building shells are based on assumed annual efficiency increases. New building shell efficiencies relative to the efficiencies of existing construction vary for each of the 11 building types. The effects of shell improvements are modeled differentially for heating and cooling. For space heating, existing and new shells improve by 5 percent and 7 percent, respectively, by 2025 relative to the 1999 averages.

Among the energy efficiency programs recognized in the *AEO2004* reference case are the expansion of the EPA Energy Star Buildings program and improvements to building shells from advanced insulation methods and technologies. The EPA green programs are designed to facilitate cost-effective retrofitting of equipment by providing participants with information and analysis as well as participation recognition. Retrofitting behavior is captured in the commercial module through discount parameters for controlling cost-based equipment retrofit decisions in various market segments. To model programs that target particular end uses, the *AEO2004* version of the commercial module includes end-use-specific segmentation of discount rates. Federal buildings are assumed to participate in energy efficiency programs and to use the 10-year Treasury Bond rate as a discount rate in making equipment purchase decisions, pursuant to the directives in Executive Order 13123.

In addition to the *AEO2004* reference case, three cases using the Residential and Commercial Demand Modules of NEMS were developed to examine the effects of equipment and building shell efficiencies. For the commercial sector:

- The *2004 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2004. Building shell efficiencies are assumed to be fixed at 2004 levels.
- The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than the reference case [*19*]. Heating shell efficiencies for new and existing buildings are assumed to increase by 8.75 and 6.25 percent, respectively, from 1999 values by 2025—a 25-percent improvement relative to the reference case.
- The *best available technology* case assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year in the high technology case, regardless of cost. Heating shell efficiencies for new and existing buildings are assumed to increase by 10.5 and 7.5 percent, respectively, from 1999 values by 2025—a 50-percent improvement relative to the reference case.

Buildings renewable energy. The forecast for wood consumption in the residential sector is based on the RECS. The RECS data provide a benchmark for British thermal units (Btu) of wood energy use in 2001. Wood consumption is then computed by multiplying the number of homes that use wood for main and secondary space heating by the amount of wood used. Ground source (geothermal) heat pump energy consumption is also based on the latest RECS; however, the measure of geothermal energy consumption is represented by the amount of primary energy displaced by using a geothermal heat pump in place of an electric resistance furnace. Residential and commercial solar thermal energy consumption for water heating is represented by displaced primary energy relative to an electric water heater. Residential and commercial solar photovoltaic systems are discussed in the distributed generation section that follows.

Buildings distributed generation. Distributed generation includes photovoltaics and fuel cells for both the residential and commercial sectors, as well as microturbines and conventional combined heat and power technologies for the commercial sector. The forecast of distributed generation is developed on the basis of economic returns projected for investments in distributed generation technologies. The model uses a detailed cash-flow approach for each technology to estimate the number of years required to achieve a cumulative positive cash flow (although some technologies may never achieve a cumulative positive cash flow). Penetration rates are estimated by Census division and building type and vary by building vintage (newly constructed versus existing floorspace).

For purchases not related to specific programs, penetration rates are determined by the number of years required for an investment to show a positive economic return: the more quickly costs are recovered, the higher the technology penetration rate. Solar photovoltaic technology specifications for the residential and commercial sectors are based on a study published in June 2003 [*20*]. Program-driven installations of photovoltaic systems are based on information from DOE's Photovoltaic and Million Solar Roofs programs, as well as DOE and industry news releases and the National Renewable Energy Laboratory's Renewable Electric Plant Information System [*21*]. The program-driven installations incorporate some of the non-economic considerations and local incentives that are not captured in the cash flow model.

The *high renewables case* assumes greater improvements in residential and commercial photovoltaic systems than in the reference case. The high renewables assumptions result in capital cost estimates for 2025 that are approximately 10 percent lower than reference case costs for distributed photovoltaic technologies, and these costs are used in the integrated high renewables case, which focuses on electricity generation. A second, alternative high renewables case, the *DOE goals case*, was completed using assumptions that result in capital cost estimates for 2020 that approximate DOE's Office of Energy Efficiency and Renewable Energy technology characterizations for distributed photovoltaic technologies [*22*]. Like the high renewables case, the DOE goals case focuses on electricity generation.

Industrial Sector Assumptions

The manufacturing portion of the Industrial Demand Module is calibrated to EIA's 1998 Manufacturing

Energy Consumption Survey [*23*]. The nonmanufacturing portion of the module is based on information from EIA, the U.S. Department of Agriculture, and the U.S. Census Bureau [*24*]. EPACT sets efficiency standards for coke ovens and for boilers, furnaces, and electric motors. CAAA90 sets emissions limits for criteria air pollutants. The electric motor standards in EPACT set minimum efficiency levels for all motors up to 200 horsepower purchased after 1998 [*25*]. It has been estimated that electric motors account for about 60 percent of industrial process electricity use [*26*].

The industrial model includes a motor stock model for the Food, Bulk Chemicals, Metal-Based Durables, and Balance of Manufacturing sectors. When new motors are purchased, either an EPACT minimum efficiency motor or a premium efficiency motor is installed, depending on prevailing electricity prices. For *AEO2004*, the motor stock model was modified to include an explicit economic choice on whether to replace or repair motors when they fail. The cost and performance characteristics of the motor options have been updated based on the Motor Master + 4.0 database [*27*]. Combined heat and power (CHP), the simultaneous generation of electricity and useful steam, has been a standard practice in the industrial sector for many years. A separate model within NEMS evaluates additions to natural-gas-fired CHP, based on technical potential and prevailing electricity and natural gas prices. The cost and performance characteristics for CHP systems have also been updated for *AEO2004*.

High technology, 2004 technology, and high renewables cases. The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*28*]. The high technology case also assumes a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes, at 1.0 percent per year as compared with 0.1 percent per year in the reference case. The same assumption is also incorporated in the integrated high renewable case, which focuses on electricity generation. While the choice of 1 percent recovery is an assumption of the high technology case, it is based on the expectation that there would be higher recovery rates and substantially increased use of CHP in that case. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changing composition of industrial output. Because the composition of industrial output remains the same as in the reference case, primary energy intensity falls by 1.5 percent annually in the high technology case. In the reference case, primary energy intensity falls by 1.3 percent annually between 2002 and 2025.

The *2004 technology case* holds the energy efficiency of plant and equipment constant at the 2004 level over the forecast. In this case, primary energy intensity falls by 1.1 percent annually. Because the level and composition of industrial output are the same in the reference, high technology, and 2004 technology cases, any change in primary energy intensity in the two technology cases is attributable to efficiency changes. Both cases were run with only the Industrial Demand Module rather than as fully integrated NEMS runs. Consequently, no potential feedback effects from energy market interactions were captured.

Transportation Sector Assumptions

The transportation sector accounts for two-thirds of the Nation's oil use and has been subject to regulations for many years. The Corporate Average Fuel Economy (CAFE) standards, which mandate average miles-per-gallon standards for manufacturers, continue to be widely debated. The *AEO2004* projections assume that there will be no further increase in the CAFE standard from the current 27.5 miles per gallon standard for automobiles. The CAFE standard for light trucks was increased in *AEO2004* from 20.7 miles per gallon to 21.0 miles per gallon in 2005, 21.6 miles per gallon in 2006, and 22.2 miles per gallon in 2007, where it remains constant through the projection period. This is consistent with the new Federal CAFE standard for light trucks promulgated in April 2003 and the overall policy that only current legislation is assumed in the *AEO*.

EPACT requires that centrally fueled light-duty fleet operators—Federal and State governments and fuel providers (e.g., natural gas and electric utilities)—purchase a minimum fraction of alternative-fuel vehicles [*29*]. The legislation requires that alternative-fuel vehicles make up 75 percent of Federal and State fleet purchases in 2002. *AEO2004* assumes that they remain at that level through 2005. The municipal and private business fleet mandates, which were proposed to begin in 2003 at 20 percent and scale up to 70 percent by 2005 but were never adopted, are not included in *AEO2004*.

In addition to the EPACT requirements, the sale of zero-emission vehicles (ZEVs) required by the State of California's Low Emission Vehicle Program (LEVP) is also included in the forecast. In 1998, California modified those requirements so that 60 percent of the ZEV mandate could be met by credits earned from the sales of advanced technology vehicles, depending on their degree of similarity to electric vehicles. The remaining 40 percent of the ZEV mandate was to be achieved through the sales of "true ZEVs," which include only electric and hydrogen fuel cell vehicles [*30*]. In December 2001, further modifications were enacted that maintained progress toward the 2003 goal while recognizing technology and cost limitations on ZEV product offerings. Those modifications removed ZEV sales requirements before 2003 but maintained the 2003 required sales goal of 10 percent and required a gradual increase in ZEV sales to 16 percent by 2018.

Additional sales credits were given for the sale of true ZEVs, and partial credits were allowed for advanced technology vehicles and certain alternative-fuel vehicles. The number of vehicles included in the estimation of required ZEV sales was also increased to include light-duty and medium-duty trucks. Auto manufacturers filed a Federal suit in California in 2002 arguing that the revisions to the ZEV program are preempted by the Federal fuel economy statute of the Energy Policy and Conservation Act of 1975. In June 2002, a Federal judge granted a preliminary injunction preventing the California Air Resources Board from enforcing the ZEV regulations for model year 2003 and 2004 vehicles.

In April 2003, the California Air Resources Board proposed amendments to the LEVP in response to the Federal suit filed by auto manufacturers [*31*]. As a result of the proposed amendments, the auto manufacturers agreed to settle litigation with the California Air Resources Board and have indicated initial agreement with the proposed amendments. The amendments place a greater emphasis on emissions reductions from partial zero emission vehicles (PZEVs) and advanced technology partial emission vehicles (AT-PZEVs), and require that manufacturers produce a minimum number of electric and fuel cell vehicles. Credits earned from the sales of PZEVs can be used to meet up to 60 percent of the ZEV sales requirement and credits earned from AT-PZEVs can be used to meet up to 20 percent of the requirement. PZEVs and AT-PZEVs are allowed 0.2 credits per vehicle. The *AEO2004* projections assume that California, Massachusetts, New York, Maine, and Vermont will formally begin implementing the LEVP mandates in 2005.

Technology choice. Conventional light-duty (less than 8,500 pounds gross vehicle weight) vehicle technologies are chosen by consumers and penetrate the market based on the assumption of cost-effectiveness, which compares the capital cost to the discounted stream of fuel savings from the technology. There are approximately 63 fuel-saving technologies, which vary by capital cost, date of availability, marginal fuel efficiency improvement, and marginal horsepower effect [*32*]. The projections assume that the regulations for alternative-fuel and advanced technology vehicles represent minimum requirements for alternative-fuel vehicle sales; in the model, consumers are allowed to purchase more of the vehicles if their cost, fuel efficiency, range, and performance characteristics make them desirable. Technology choice captures the manufacturers' response to the market.

Many consumers do not place a significant value on high-efficiency vehicles. This is reflected in the model by assuming a 3-year payback period, with the real discount rate remaining steady at 15 percent. Expected future fuel prices are calculated based on extrapolation of the growth rate between a 5-year moving average of fuel prices 3 years and 4 years before the present year. This assumption is based on a lead time of 3 to 4 years for significant modification of the vehicles offered by a manufacturer.

For freight trucks, technology choice is based on several technology characteristics, including capital cost, marginal improvement in fuel efficiency, payback period, and discount rate, which are used to calculate a fuel price at which the technologies become cost-effective [*33*]. When technologies are mutually exclusive, the more cost-effective technology will gain market share relative to the less cost-effective technology. Efficiency improvements for both rail and ship are based on recent historical trends [*34*].

As in the case of freight trucks, fuel efficiency improvements for new aircraft are also determined by a trigger fuel price, the time the technology becomes commercially available, and the projected marginal fuel efficiency improvement. The advanced technologies are ultra-high bypass, propfan, thermodynamics, hybrid laminar flow, advanced aerodynamics, and weight-reducing materials [*35*].

Travel. Projections of vehicle-miles traveled for personal travel [*36*] and ton-miles traveled for freight travel [*37*] are based on the assumption that modal shares (for example, personal automobile travel versus mass transit) remain stable over the forecast and follow recent historical patterns. Important factors affecting the forecast of vehicle-miles traveled for light-duty vehicles are personal disposable income per capita and the cost of driving. Travel by freight truck, rail, and ship is based on the growth in industrial output by sector and the historical relationship between freight travel and industrial output [*38*]. Both rail and ship travel are also based on projected coal production and distribution.

Air travel is estimated for domestic travel, international travel, and dedicated air freight shipments by U.S. carriers. Depending on the market segment, the demand for air travel is based on projected disposable personal income, GDP, merchandise exports, and ticket price as a function of jet fuel prices. Load factors, which represent the percentage of seats occupied per plane and are used to convert air travel (expressed in revenue-passenger miles and revenue-ton miles) to seat-miles of demand, increase slightly over the forecast period. For passenger travel, domestic and international air travel is modeled specific to aircraft type (regional, narrow body and wide body) such that regional aircraft are used exclusively for domestic travel, while narrow body aircraft serve both domestic and international markets, and wide body aircraft primarily serve the international market. In addition, the model captures the industry practice of parking aircraft to reduce operating costs and moving aircraft from the passenger to cargo markets as aircraft age. For air freight shipments, the model employs narrow body and wide body aircraft only. The model also utilizes an infrastructure constraint that limits air travel growth to levels commensurate with industry-projected infrastructure expansion and capacity growth.

2004 technology case. The *2004 technology case* assumes that new fuel efficiency levels are held constant at 2004 levels through the forecast horizon for all modes of travel.

High technology case. For the *high technology case*, light-duty conventional and alternative-fuel vehicle characteristics reflect more optimistic assumptions for incremental fuel economy improvements and costs [*39*]. In the air travel sector, the high technology case reflects lower costs for improved thermodynamics, advanced aerodynamics, and weight reduction materials, which provides a 25-percent improvement in new aircraft efficiency compared to the reference case by 2025. In the freight truck sector, the high technology case assumes more optimistic incremental fuel efficiency improvements for engine and emission control technologies [*40*]. More optimistic assumptions for fuel efficiency improvements are also made for the rail and shipping sectors.

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

Electricity Assumptions

Characteristics of generating technologies. The costs (including capital costs and operating and maintenance costs) and performance (efficiency) of new generating technologies are important factors in determining the future mix of capacity. Fossil fuel, renewable, and nuclear technologies are represented and include those currently available as well as those that are expected to be commercially available within the horizon of the forecast. It is assumed that the selection of new plants to be built is based on least cost, subject to environmental constraints. The incremental costs associated with each option are evaluated and used as the basis for selecting plants to be built. Details about each of the generating plant options are described in the detailed assumptions, which are available at web site www.eia.doe.gov/oiaf/aeo/assumption/.

Regulation of electricity markets. It is assumed that electricity producers comply with CAAA90, which mandates a limit of 9.48 million short tons of sulfur dioxide (SO_2) emissions per year from 2001 through 2009 and 8.95 million tons per year by 2010. Electricity producers are assumed to comply with the limits on sulfur dioxide emissions by retrofitting units with flue gas desulfurization (FGD) equipment, transferring or purchasing sulfur emission allowances, operating high-sulfur coal units at a lower capacity utilization rate, or switching to low-sulfur fuels. Electricity producers are assumed to comply with the limits on nitrogen oxides (NO_x) by installing selective catalytic reduction (SCR) equipment. FGD units are assumed to remove 95 percent of the SO_2 and SCR units are assumed to remove 90 percent of the NO_x. The costs per kilowatt to add FGD or SCR equipment decline as the capacity of the coal plant increases. Capital costs for retrofitting with FGD equipment are estimated to decline from $270 per kilowatt (2002 dollars) for a 300-megawatt plant to $206 per kilowatt for a 500-megawatt plant and $171 per kilowatt for a 700-megawatt plant. Capital costs for installing SCR equipment are estimated to decline from $111 per kilowatt for a 300-megawatt plant to $97 per kilowatt for a 500-megawatt plant and $88 per kilowatt for a 700-megawatt plant [*41*].

In the reference, high, and low economic growth, and high and low world oil price cases, generators are projected to meet the annual SO_2 caps based on additions of 23 gigawatts of planned retrofits and 2 to 10 gigawatts of unplanned retrofits of FGD equipment at existing coal-fired power plants, combined with the drawdown of banked SO_2 emission allowances amounting to 9.2 million tons at the end of 2001. Announced retrofits by Duke Power and Progress Energy in response to North Carolina's Clean Smokestacks Bill account for nearly one-half of the planned retrofits included. The remaining are based on other factors, including compliance strategies developed by generators in response to CAAA90, agreements that generators have reached with the U.S. Department of Justice in litigation related to New Source Review, and other State and local environmental issues.

The EPA has issued rules to limit emissions of NO_x, specifically calling for capping emissions during the summer season in 22 eastern and midwestern States. After an initial challenge, the rules have been upheld, and emissions limits have been finalized for 19 States and the District of Columbia, starting in 2004. *AEO2004* assumes that electricity generators in those 19 States and the District of Columbia comply with the limits either by reducing their own emissions or by purchasing allowances from others. *AEO2004* also assumes that generators comply with the NO_x limits through a combination of combustion and post-combustion controls. In the reference case, installed and planned post-combustion control equipment amounts to 42 gigawatts of SCR equipment and 5 gigawatts of selective noncatalytic reduction (SNCR) equipment. The facilities in which the equipment is installed are located in 12 States, and their actions are in response to the EPA rules. Additional unplanned retrofits are projected in the reference case—52 gigawatts of SCR and 25 gigawatts of SNCR—between 2002 and 2025.

The reference case assumes a transition to full competitive pricing in New York, New England, the Mid-Atlantic Area Council, and Texas. In addition, electricity prices in the East Central Area Reliability Council, the Mid-America Interconnected Network, the Southeastern Electric Reliability Council, the Southwest Power Pool, the Northwest Power Pool, and the Rocky Mountain Power Area/Arizona (Arizona, New Mexico, Colorado, and eastern Wyoming) regions are assumed to be partially competitive. Some of the States in each of these regions have not taken action to deregulate their pricing of electricity, and in those States prices are assumed to continue to be based on traditional cost-of-service pricing. In California, a return to almost total cost-of-service regulation is now assumed.

In many deregulated States the legislation has mandated price freezes or reductions over a specified transition period. *AEO2004* includes such agreements in the electricity price forecast. In general, the transition period is assumed to be a 10-year period from the beginning of restructuring in each region, during which time prices gradually shift to competitive prices. The transition period reflects the time needed for the establishment of competitive market institutions and recovery of stranded costs as permitted by regulators. *AEO2004* assumes that the competitive price in deregulated regions is the marginal cost of generation.

Competitive cost of capital. The cost of capital is calculated as a weighted average of the costs of debt and equity. The cost of equity is an implied investor's opportunity cost, or the required rate of return on any risky investment. *AEO2004* assumes a ratio of 45 percent debt and 55 percent equity. The yield on debt represents that of a BBB corporate bond, calculated by applying a 1.25-percent premium to the annual AA utility bond rate projected by the Macroeconomic Activity Module. The cost of equity is calculated to be representative of unregulated industries similar to the electricity generation sector. It is assumed that the capital invested in a new plant must be recovered over a 20-year plant life rather than the traditional 30-year life.

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

To the degree possible, each of the participation agreements was examined to determine whether the commitments made were addressed in the normal reference case assumptions or whether they should be addressed separately. Programs such as tree planting and emissions offset purchasing are not addressed, but the other programs are, for the most part, captured in *AEO2004*. For example, electricity generators annually report to EIA their plans (over the next 10 years) to bring a plant back on line, repower a plant, extend a plant's life, cancel a previously planned plant, build a new plant, or switch fuel at a plant. Data for these programs are included in the *AEO2004* 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.

Fossil steam and nuclear plant retirement assumptions. Fossil steam plants and nuclear plants are retired when it is no longer economical to run them. In each forecast year the model determines whether the market price of electricity is sufficient to support the continued operation of existing plants. If the revenue a plant receives is not sufficient to cover its forward costs (including fuel, operations and maintenance costs, and assumed annual capital additions) the plant is retired. Beyond age 30, the forward costs also include capital expenditures assumed to be needed to address aging-related issues. For fossil plants the aging-related costs are assumed to be $5 per kilowatt, in year 2002 dollars. For nuclear plants the aging-related costs are assumed to be $37 per kilowatt. Aging-related cost increases result from increased capital costs, decreases in performance, and/or increased maintenance expenditures to mitigate the effects of aging.

Nuclear power. There are no nuclear units actively under construction in the United States. In NEMS, new nuclear plants are competed against other options when new capacity is needed. The cost assumptions for new nuclear units are based on an analysis of the realized costs of nuclear plants recently constructed overseas, since no advanced reactors have been built yet in the United States.

The capital cost assumptions in the reference case are meant to represent the expense of building a new single-unit nuclear plant of approximately 1,000 megawatts. Because no new nuclear plants have been built in the United States in many years, there is a great deal of uncertainty about the true costs of a new unit. The estimate used for *AEO2004* is an average of the actual costs incurred in completed advanced reactor builds in Asia, adjusting for expected learning from other units still under construction. The average nuclear capacity factor in 2002 was 90 percent, the highest annual average ever in the United States. The average annual capacity factor reaches a national average of 91 percent by 2011. Capacity factor assumptions are developed at the unit level, and improvements or decrements are based on the age of the reactor.

The *AEO2004* nuclear power forecast assumes capacity increases at existing units. The U.S. Nuclear Regulatory Commission (NRC) approved 18 applications for power uprates in 2002, and another 9 were approved or pending in 2003. *AEO2004* assumes that all of those uprates will be implemented, as well as others expected by the NRC over the next 15 years, for a capacity increase of 3.9 gigawatts between 2003 and 2025.

For nuclear power plants, several advanced nuclear cases analyze the sensitivity of the projections to lower costs for new plants. The cost assumptions for the *advanced nuclear cost case* reflect a 10-percent reduction in the capital and operating costs for the advanced nuclear technology in 2025, relative to the reference case. Since the reference case assumes some learning occurs regardless of new orders and construction, the reference case already projects a 10-percent reduction in capital costs between 2005 and 2025. The advanced nuclear cost case therefore assumes a 19-percent reduction between 2005 and 2025. The *nuclear AP1000 case* assumptions are consistent with estimates from British Nuclear Fuel Limited (BNFL) for the manufacture of its Advanced Pressurized Water Reactor (AP1000), as provided to the Near-Term Deployment Working Group of DOE's Office of Nuclear Energy, Science, and Technology. In this case, the overnight capital cost of a new advanced nuclear unit is assumed initially to be $1,580 per kilowatt, declining to $1,081 per kilowatt for plants coming on line in 2025 (in year 2002 dollars)—18 percent lower than assumed in the reference case in 2002 and 38 percent lower in 2025. A final case, the *nuclear vendor estimate case* (discussed in "Issues in Focus"), uses cost assumptions based on the average of estimates for the AP1000 and Atomic Energy Canada Limited's CANDU reactor, now being marketed to the United States. In this case, the overnight cost is $1,555 per kilowatt initially, falling to $1,149 per kilowatt for plants coming online in 2025. Cost and performance characteristics for all other technologies are as assumed in the reference case.

Biomass co-firing. Coal-fired power plants are allowed to co-fire with biomass fuel if it is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. This expenditure ranges from about $100 to $240 per kilowatt of biomass capacity, depending on the type and size of the boiler. A coal-fired unit modified to allow co-firing can generate up to 15 percent of its total output using biomass fuel, assuming sufficient fuel supplies are available. Larger units are required to pay additional transportation costs as the level of co-firing increases, due to the concentrated use of the regional biomass supply.

Distributed generation. *AEO2004* assumes the availability of two generic technologies for distributed electricity generation. To determine the levels of capacity and generation for distributed technologies projected to be used in the forecast, the model compares their costs with the "avoided costs" of electricity producers. The avoided costs are the costs electricity producers would incur if they added the least expensive conventional central-station generators rather than distributed generators, as well as the costs of additional transmission and distribution equipment that would be required if the distributed generators were not added. Because there are currently no reliable estimates of the transmission and distribution costs that can be avoided by adding distributed generators, regional estimates were developed for the transmission and distribution investments that would be needed for each kilowatt of central-station generating capacity added. It was then assumed that 75 percent of such "growth-related" transmission and distribution costs could be avoided by adding distributed generators.

International learning. Capital costs for all new electricity generating technologies are assumed to decrease in response to domestic as well as foreign experience, to the extent that the new foreign plants reflect technologies and firms competing in the United States. In its learning function, *AEO2004* includes 1,938 megawatts of advanced coal gasification combined-cycle capacity (including the 127-megawatt Fife plant that entered service in Scotland in 2001) and 5,244 megawatts of advanced combined-cycle natural gas capacity operating or under construction outside the United States from 2000 through 2003. A small amount of international biomass integrated gasification combined cycle and wind capacity is also assumed to be on line in that time period. The learning function also includes 7,200 megawatts of advanced nuclear capacity, representing two completed units and four additional units under construction in Asia. Experience indicates that the small amount of learning attributed to international renewable energy installations is already adequately incorporated in U.S. domestic learning functions, and that because installations taking place in the United States are lowering projected capital costs, no additional accounting for new international renewable energy capacity is required.

High electricity demand case. The *high electricity demand case* assumes that the demand for electricity grows by 2.5 percent annually between 2002 and 2025, compared with 1.8 percent in the reference case. No attempt was made to determine changes in the end-use sectors that would result in the stronger demand growth. The high electricity demand case is partially integrated, with no feedback from the Macroeconomic Activity, International, or end-use demand modules. Rapid growth in electricity demand also leads to higher prices. The price of electricity in 2025 is 7.1 cents per kilowatthour in the high demand case, as compared with 6.9 cents in the reference case. Higher fuel prices, especially for natural gas, and higher capital costs for alternative technologies are the key factors leading to higher electricity prices.

High and low fossil technology cases. The high and low fossil technology cases are partially integrated cases, with no feedback from the Macroeconomic Activity, International, or end-use demand modules. In the *high fossil technology case*, capital costs, heat rates and operating costs for the advanced coal and gas technologies are assumed to be 10-percent lower than reference case levels in 2025. Since learning occurs in the reference case, costs and performance in the high case are reduced from initial levels by more than 10 percent. Heat rates in the high fossil case fall to roughly 20 percent below initial levels, while capital costs are reduced by 20 to 25 percent between 2003 and 2025. In the *low fossil technology case*, capital costs and heat rates for coal gasification combined-cycle units and advanced combustion turbine and combined-cycle units do not decline during the forecast period and remain fixed at the 2004 values assumed in the reference case.

In the *DOE fossil goals case*, capital costs and heat rates for the advanced coal and gas technologies are assumed to be lower and decline faster than in the reference case, and in most instances are lower than the high fossil technology case. The values used in the DOE goals case for capital costs and heat rates were based on the DOE's Vision 21 program. The capital costs and heat rates for renewable, nuclear, and other fossil technologies are assumed to be the same as in the reference case. Details about annual capital costs, operating and maintenance costs, plant efficiencies, and other factors used in the high fossil technology, low fossil technology, and DOE goals cases are described in the detailed assumptions, which are available at web site www.eia.doe.gov/oiaf/aeo/assumption/.

Renewable Fuels Assumptions

Energy Policy Act of 1992. The EPACT 10-year renewable electricity production tax credit (PTC) of 1.5 cents per kilowatthour (now adjusted for inflation to 1.8 cents) for new wind and some biomass plants originally expired on June 30, 1999. It was first extended through December 31, 2001, and then retroactively extended from December 31, 2001 through December 31, 2003, by the Job Creation and Worker Assistance Act of 2002 (P.L. 107-147). *AEO2004* applies the credit to all wind plants built through 2003. ("Closed loop" biomass plants are assumed to be commercially available beginning in 2010 and thus are not available to take advantage of the credit until 2010.) *AEO2004* assumes that the 10-percent investment tax credit for solar and geothermal technologies that generate electric power will be continued through 2025.

Renewable capacity additions. In addition to new unplanned generation capacity using renewable resources as determined by NEMS, *AEO2004* includes 4,362 megawatts of new "planned" central-station generating capacity using renewable resources as announced by utilities and independent power producers or identified by EIA to be built from 2003 through 2015. No planned builds were assumed after 2015. Of the total planned capacity builds, 3,132 megawatts result from State mandates, State renewable portfolio standards (RPS), State goals and other objectives or requirements, and 1,229 megawatts result from commercial builds and voluntary programs, such as green power programs and utility testing and demonstration projects using renewable technologies.

Because of demand and regulatory uncertainties, *AEO2004* does not assume that all new renewable capacity implied by State RPS and other mandates will be built; the assumptions for planned renewable capacity include primarily the near-term requirements about which the States and utilities are relatively certain. States and utilities are sometimes unable to quantify the amount of new capacity that will result from the RPS. Further, actual RPS implementation for some States is proceeding more slowly than initially expected, suggesting caution in expectations for the near term. Moreover, RPS implementation itself is often uncertain, because many of the RPS programs are set to be reevaluated, often by 2007. Given the legal alternatives (such as fines and exemptions) and technology choices (including conservation), the prospect of RPS reevaluation and redirection after 2007 may slow or inhibit compliance. Finally, even if the new capacity is eventually built, the specific technologies that will be chosen, the years in which they will be built, and their sizes and locations are uncertain.

Estimating supplemental additions of new renewable capacity for *AEO2004* is further complicated by reported transmission constraints thwarting wind development, by uncertainty about post-2003 extension of the PTC, by uncertain financial positions of utilities in the West that serve California markets, by uncertain demand for renewables in light of potential overbuilding of natural gas capacity, and by uncertainty about States' adherence to RPS mandates when economic growth is slow. As a result, the State RPS estimates should be considered relatively certain estimates of new capacity likely to be built in the near term and not as measure of the full potential consequences of the RPS over the entire forecast period. Using publicly available information and working with State agencies, EIA confirms projections of mandated renewable energy capacity; however, limited resources preclude confirming the status of every new renewable energy plant.

In addition to supplemental additions based on known plans, the projection includes minimum expectations for new central-station solar energy capacity assumed to be installed for reasons other than least-cost electricity supply, based on historical rates of addition of new capacity. *AEO2004* estimates include 75.5 megawatts of central-station solar thermal-electric and 332.5 megawatts of central-station photovoltaic (PV) generating capacity to be installed from 2003 through 2025.

Renewable resources. All central-station electricity generating technologies, including those using renewable energy resources, compete in NEMS based on their relative costs. Intermittent renewables (solar and wind) compete during time periods when they are assumed to be available but decrease in value as they contribute increasing shares of a region's total electricity supply, because they can contribute less additionally to meeting a region's reliability needs. As wind power provides increasing shares of a region's total generation, new wind plants alone cannot provide significant additional reliable capacity and therefore either must be used as fuel-saving nonfirm substitutes for the operation of existing capacity or must have backup capacity to ensure firm power delivery.

The delivered cost of electricity from renewables depends both on the availability of adequate renewable resources and on the capital costs of the technologies using them. Costs of renewable energy resources tend to increase as more of them are used and the best sites are exhausted; at the same time, costs of renewable energy technologies are assumed to decline with experience and mass production. As a result, depending upon the assumed rates of resource cost increases and the assumed rate of decline in capital costs, a region's delivered electricity cost from renewable energy resources may decrease or increase as a function of the changing cost of each input.

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

Solar energy (direct normal insolation) for thermal applications is considered economical only in drier regions west of the Mississippi River. Photovoltaics can be economical in all regions, although conditions are also superior in the West. Wind energy resource potential, while large, is constrained by wind quality differences, distance from markets, power transmission costs, alternative land uses, and environmental objections. The geographic distribution of available wind resources is based on work by the Pacific Northwest Laboratory and the National Renewable Energy Laboratory [*42*], enumerating winds among average annual wind-power classes. Geothermal energy is limited geographically to regions in the western United States with hydrothermal resources of hot water and steam. Although the potential for biomass is large, transportation costs limit the amount of the resource that is economically productive, because biomass fuels have a low Btu content per weight of fuel.

The *AEO2004* reference case incorporates upward-sloping supply curves for geothermal and wind technologies, in recognition of the higher costs of consuming increasing proportions of a region's resources. Capital costs are assumed to increase in response to (1) declining natural resource quality, such as rough or steep terrain or turbulent winds, (2) increasing costs of upgrading the existing transmission and distribution network, and (3) market conditions that increase wind power costs in competition with other land uses, such as for crops, recreation, or environmental or cultural preferences.

AEO2004 includes a revision to the treatment of wind energy for capacity planning and dispatch. This change reflects the additional costs imposed on the power grid by increasing levels of wind penetration. For *AEO2004*, the marginal capacity credit for wind decreases toward zero with increasing penetration, which ensures the availability of adequate firm capacity within a region to satisfy reliability requirements. In addition, surplus wind generation (such as during low-load periods) is assumed to be curtailed and does not contribute to cost-recovery for wind operations during curtailed periods. Penetration of wind and other intermittent generation resources is initially limited to 20 percent of a region's total generation but is allowed to increase over time to 40 percent. These limits reflect the need for a system with large intermittent generation to adjust to new and significantly different operational requirements and recognizes the uncertainties associated with operating a system that has high intermittency.

High renewables case. For the *high renewables case*, the levelized costs of energy for nonhydroelectric generating technologies using renewable resources are assumed to decline, to 10 percent below the reference case costs for the same technologies in 2025. For most renewable resources, lower costs are accomplished by reducing the capital costs of new plant construction. To reflect recent trends in wind energy cost reductions, however, it is assumed that wind plants ultimately achieve the 10-percent cost reduction through performance improvement (an increased capacity factor) rather than capital cost reductions. Biomass supplies are also assumed to be 10-percent greater for each supply step.

The *DOE goals case*, like the high renewables case, assumes improved performance and lower capital costs than the reference case for central-station nonhydroelectric generating technologies using renewable resources (other than landfill gas), in order to approximate published projections of cost and performance targets from DOE's Office of Energy Efficiency and Renewable Energy [*43*]. Differences from the reference case are not uniform, but instead reflect differences existing between the two cases in 2025. The DOE goals case also incorporates reduced operations and maintenance costs, improvements in capacity factors for wind technologies, increased biomass supplies, and lower capital costs for residential and commercial photovoltaic systems.

Annual limits are placed on the development of geothermal sites for both high renewable cases, because they require incremental development to assure that the resource is viable. The annual limits on capacity additions at geothermal sites were raised from 25 megawatts per year through 2015 to 50 megawatts per year for all forecast years. All other cases are assumed to retain the 25-megawatt limit through 2015. Other generating technologies and forecast assumptions remain unchanged from those in the reference case. In both the high renewables case and the DOE goals case, the rate of improvement in the recovery of biomass byproducts from industrial processes is also increased. More rapid improvement in cellulosic ethanol production technology is also assumed in both the high renewables case and the DOE goals case, and cellulosic ethanol production is assumed to capture a higher share of the renewable transportation fuels market, resulting in increased cellulosic ethanol supply compared with the reference case.

Low renewables case. In the *low renewables case*, capital costs, operations and maintenance costs, and performance levels for wind, solar, biomass, and geothermal resources are assumed to remain constant at 2004 levels through 2025.

Oil and Gas Supply Assumptions

Domestic oil and gas technically recoverable resources. The levels of available oil and gas resources assumed for *AEO2004* are based on estimates of the technically recoverable resource base from the U.S. Geological Survey (USGS) and the Minerals Management Service (MMS) of the Department of the Interior [*44*], with supplemental adjustments to the USGS nonconventional resources by Advanced Resources International (ARI), an independent consulting firm.

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

For conventional oil and gas, drilling, operating, and lease equipment costs are expected to decline due exclusively to technological progress, at econometrically estimated rates that vary somewhat by cost and fuel categories, ranging roughly from 0.3 to 1.9 percent. The technological impacts work against increases in costs associated with drilling to greater depths, higher drilling activity levels, and rig availability. As a direct result of technological progress, success rates are assumed to improve by 0.5 percent per year, and finding rates are expected to improve by 2.8 percent per year. For nonconventional gas, these costs are expected to remain at current 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, conventional oil and natural gas reference case parameters for the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates were adjusted by plus or minus 50 percent. For unconventional gas, a number of key exploration and production technologies were also adjusted by plus or minus 50 percent in the rapid and slow technology cases. Key Canadian supply parameters were also adjusted to simulate the assumed impacts of rapid and slow oil and gas technology penetration on Canadian supply potential.

All other parameters in the model were kept at the reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of liquefied natural gas and natural gas trade between the United States and Mexico. Specific detail by region and fuel category is presented in *Assumptions to the Annual Energy Outlook 2004*, which is available at web site www.eia.doe.gov/oiaf/aeo/assumption/.

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 require 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, MacKenzie Delta, and LNG imports. Due to the relative economics, the assumption in the model is that a pipeline from the MacKenzie Delta to Alberta would be constructed first, followed by one from Alaska, with potential expansions following thereafter. The timing of both systems is based on estimates of the cost to bring the gas to market in the United States, relative to the average lower 48 wellhead price.

A natural gas pipeline from Alaska into Alberta, Canada, is assumed to carry an initial capitalization of $13.2 billion (2002 dollars) and be depreciated over 15 years. The initial capitalization includes an expected cost of $ 11.6 billion plus an additional 20 percent to account for the uncertainty in realized capital costs. The expected cost for a pipeline from the MacKenzie Delta into Alberta is $3.6 billion. It is assumed that the Alaska pipeline will require 4 years to construct (3 years for the MacKenzie pipeline), will not be completed before 2013 (2009 for MacKenzie), will deliver 3.9 billion cubic feet of dry natural gas per day once fully operational (1.5 billion for MacKenzie), and can be expanded by 23 percent, if economical. The wellhead price of natural gas from Alaska to be delivered through the pipeline is assumed to be $0.81 per thousand cubic feet in 2002 dollars ($1.00 for MacKenzie). Gas treatment and pipeline fuel costs are accounted for as well.

A market price risk premium totaling $0.34 per thousand cubic feet is assumed, above and beyond the expected cost of delivery into Alberta and on to the lower 48 States. For MacKenzie, a capital cost and market price risk premium totaling $0.39 per thousand cubic feet is assumed. Those assumptions imply that an average price in the lower 48 States of around $3.69 (2002 dollars) per thousand cubic feet ($3.41 for MacKenzie) would need to be maintained on average over a 5-year (2-year for MacKenzie) planning period for construction to commence. Falling prices during the planning period can delay the construction period, depending on the severity of the decline.

The four existing liquefied natural gas (LNG) receiving facilities in Massachusetts, Maryland, Louisiana, and Georgia are in operation and have a combined design capacity of about 1.2 trillion cubic feet per year. All four facilities are in the process of expanding, and additional capacity of approximately 650 billion cubic feet per year is expected to be in place by 2006. This will bring the total U.S. design capacity to approximately 1.8 trillion cubic feet per year. Assumed maximum load factors effectively reduce the total available LNG from existing facilities to a maximum of 1.4 trillion cubic feet per year over the forecast period. It is assumed that existing facilities will not expand beyond current plans.

The model has a provision for the construction of new facilities in all U.S. coastal regions and in Baja California, Mexico. Construction in a region is triggered when the regional price of natural gas meets or exceeds the cost (per thousand cubic feet) of producing, liquefying, transporting, and regasifying the LNG, plus a risk premium of $0.45 (in 2002 dollars) per thousand cubic feet. The risk premium is applied only in making the decision to go ahead with a project, and is not reflected in subsequent costs of LNG to the consumer. The regasification component is based on the assumed cost of constructing a generic terminal in the region with adjustments to account for region-specific parameters such as cost of land and labor costs. New facilities are assumed to range in size from 250 million cubic feet per day to 1 billion cubic feet per day, depending on location. Regional prices at the LNG tailgate (including relevant transportation charges), which trigger construction range from $3.62 (2002 dollars) per thousand cubic feet along the Gulf Coast in Texas and Louisiana to $4.57 per thousand cubic feet in California. The effect of technological progress on reducing some of the component costs is assumed to be offset by increases in other components, such as production costs.

An LNG facility in Baja California, Mexico, with a capacity of 1 billion cubic feet per day and expansion potential of an additional 1 billion cubic feet per day, is assumed to be constructed at a tailgate price of $3.10 (in 2002 dollars) per thousand cubic feet, with half of its capacity available for export to the United States and the other half reserved for use within Mexico. A liquefaction plant in Kenai, Alaska, has been producing and exporting LNG to Japan for the past 30 years, and this is expected to continue throughout the forecast at a level of approximately 65 billion cubic feet per year. Exports to Mexico are determined based on projected production and consumption within Mexico. Consumption in Mexico is projected to grow at an average annual rate of 6.1 percent per year over the forecast period. Production is expected to grow at a slower rate, with the shortfall met by a combination of pipeline imports from the United States and LNG imports.

Natural gas transmission and distribution assumptions. Transportation rates for pipeline services are calculated with the assumption that the costs of new pipeline capacity will be rolled into the existing ratebase. The rates based on cost of service are adjusted according to pipeline utilization, to reflect a more market-based approach. In determining interstate pipeline tariffs, potential future expenditures for pipeline safety necessary to comply with the Pipeline Safety Improvement Act of 2002 are not considered.

Distribution markups to core customers (not including electricity generators) change over the forecast in response to changes in consumption levels and in the costs of capital and labor. Markups to electricity generators are a direct function of changes in consumption levels alone. The natural gas vehicle sector is divided into fleet and nonfleet vehicles. The distributor tariffs for natural gas to fleet vehicles are based on historical differences between end-use and citygate prices from EIA's *Natural Gas Annual* plus Federal and State taxes on natural gas used by vehicles. The price to nonfleet vehicles is based on the industrial sector firm price plus an assumed dispensing charge of $4.29 (2002 dollars) per thousand cubic feet plus taxes.

Petroleum Market Assumptions

Gasoline demand. Demands for conventional, reformulated, and oxygenated gasolines are disaggregated from composite gasoline consumption on the basis of their 2002 market shares in each Census division. Reformulated gasoline (RFG) is consumed in the 10 serious ozone nonattainment areas required by CAAA90 and in areas that voluntarily opted into the program [*45*]. RFG projections also reflect a Statewide requirement in California and State law in Phoenix, Arizona. In total, RFG is assumed to account for about 33 percent of annual gasoline sales throughout the *AEO2004* forecast. The estimated market shares for oxygenated gasoline assume continued wintertime participation of carbon monoxide nonattainment areas and statewide participation in Minnesota. Oxygenated gasoline represents about 4.6 percent of gasoline demand in the forecast. Conventional gasoline makes up the balance (62.4 percent) of gasoline demand.

RFG specifications. RFG must meet the EPA's "Complex Model 2" requirements beginning in 2000. Gasoline currently sold in the United States slightly exceeds the quality implied in the Complex Model 2 specifications (i.e., "over-compliance"). In addition to assuming Complex Model 2 compliance for the RFG, *AEO2004* also reflects the over-compliance nature of gasoline in general by adopting the EPA survey of RFG properties in 2002 [*46*]. The RFG specifications used for the West Coast represent the California Air Resources Board (CARB) statewide gasoline requirements, first implemented in 1996, which will be tightened in 2004 [*47*]. The U.S. 9th Circuit Court of Appeals recently ruled that the EPA must reconsider a request by California to waive the Federal oxygen requirement in Federal nonattainment areas, including Los Angeles, San Diego, Sacramento, and San Joaquin Valley. Because those areas contain about 80 percent of California's population and EPA is appealing the Court's ruling, *AEO2004* assumes that 80 percent of RFG in the State will continue to require 2.0 percent oxygen by weight after MTBE is banned.

State MTBE bans. *AEO2004* includes constraints that model legislation banning or limiting the use of the gasoline blending component MTBE in the next few years in 17 States: California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, New York, Ohio, South Dakota, Washington, and Wisconsin [*48*]. Of the 17 States, only California, New York, Connecticut, Missouri, and Kentucky still sold MTBE-blended RFG in 2003. *AEO2004* assumes that ethanol will replace MTBE as the oxygenate for RFG in those five States, blending at 5.7 percent per volume ethanol in California's RFG (due to stricter CARB gasoline specifications), and 10 percent per volume ethanol in RFG in all other States where MTBE will soon be banned.

Low-sulfur fuel requirements. *AEO2004* reflects "Tier 2" Motor Vehicle Emissions Standards and

Gasoline Sulfur Control Requirements finalized by the EPA in February 2000. The regional assumptions for phasing down the sulfur content of conventional gasoline include less stringent sulfur requirements for small refineries and refineries in the Rocky Mountain region as allowed by EPA. The 30-ppm annual average standard is not fully realized in conventional gasoline until 2008 due to allowances for small refineries.

AEO2004 also incorporates the "ultra-low-sulfur diesel" (ULSD) regulation finalized in December 2000. By definition, ULSD is highway diesel that contains no more than 15 ppm sulfur at the pump; however, there is general consensus that refiners will need to produce ULSD somewhat below 10 ppm in order to allow for contamination during the distribution process. *AEO2004* assumes that ULSD at the refinery gate will contain a maximum of 7 ppm sulfur. The new regulation contains the "80/20" rule, which requires the production of 80 percent ULSD and 20 percent 500 ppm highway diesel between June 2006 and June 2010, and a 100-percent requirement for ULSD thereafter. Because NEMS is an annual average model, the full impact of the 80/20 rule cannot be seen until 2007, and the impact of the 100-percent requirement cannot be seen until 2011. No change in the sulfur level of nonroad diesel fuel is assumed, because the EPA has not yet formally adopted nonroad diesel standards.

Gas-to-liquids. If prices for lower sulfur distillates reach a high level, it is assumed that gas-to-liquids (GTL) facilities will be built on the North Slope of Alaska to convert stranded natural gas into distillates, to be transported on the Trans-Alaskan Pipeline System (TAPS) to Valdez and shipped to markets in the lower 48 States. The facilities are assumed to be built incrementally, no earlier than 2005, with output volumes of 50,000 barrels per day, at a cost of $21,750 per barrel of daily capacity (2002 dollars). Operating costs are assumed to be $4.04 per barrel. Transportation costs to ship the GTL product from the North Slope to Valdez along the TAPS range from $2.78 to $4.50 per barrel, depending on total oil flow on the pipeline and the potential need for GTL to maintain the viability of the TAPS line if Alaskan oil production declines. Initially, the natural gas feedstock is assumed to cost $0.83 per thousand cubic feet (2002 dollars).

Coal-to-liquids. It is also assumed that coal-to-liquids (CTL) facilities will be built when low-sulfur distillate prices are high. One CTL facility is capable of processing 16,400 tons of bituminous coal per day, with a production capacity of 33,200 barrels of synthetic petroleum fuel per day and 696 megawatts of capacity for electricity cogeneration sold to the grid [*49*]. The CTL yields are assumed to be similar to those from a GTL facility, because both involve the Fischer-Tropsch process to convert syngas ($CO + H_2$) to liquid hydrocarbons. The primary yields would be distillate and kerosene, with additional yields of naphthas and liquefied petroleum gases. Petroleum products from CTL facilities are assumed to be competitive when distillate prices rise above the cost of CTL production (adjusted for credits from the sale of cogenerated electricity). CTL capacity is projected to be built only in the *AEO2004* high world oil price case.

Petroleum coke gasification. Gasification of petroleum coke (petcoke) and heavy oil (asphalt, vacuum residual, etc.) are represented in *AEO2004* [*50*]. The primary feedstock for gasification is assumed to be petcoke. Petcoke can be used for combined heat and power (CHP) electric and steam generation or for hydrogen production, based on the particular refinery economics. A typical gasification facility is assumed to have a capacity of 2,000 tons per day, which includes the main gasifier and other integrated units in the refinery such as an air separation unit (ASU), syngas clean-up, a sulfur recovery unit (SRU), and two downstream process options—CHP or hydrogen production. Currently, more than 5,000 tons per day of gasification capacity operates in the United States, producing combined heat and power (CHP) and hydrogen. Additional gasification capacity is projected in the *AEO2004* forecast, primarily for CHP production.

Ethanol and biodiesel. Fuel ethanol production is modeled in the Petroleum Market Module (PMM). Ethanol is produced in dedicated plants from corn or cellulose feedstocks. Most ethanol is produced from corn in the Midwest (Census divisions 3 and 4). Commercial cellulosic ethanol production from corn stover is assumed to be producible in the Midwest. Cellulosic ethanol may be produced from wood products in Census divisions 2, 3, 4, 7, and 9. Ethanol is blended into gasoline at up to 10 percent by volume to provide oxygen, octane, and gasoline volume. Ethanol is also sold as E85, a blend of up to 85 percent ethanol and at least 15 percent gasoline by volume. The historical annual average of the ethanol content in E85 is about 74 percent, due to the lower blending ratios for E85 in the fall and winter months for drivability purposes [*51*]. Ethanol can also be used to make ethyl-tertiary-butyl ether (ETBE), another potential gasoline oxygenate. The PMM is capable of modeling ETBE, but it is expected to cause water contamination problems similar to those caused by MTBE and is therefore not in widespread use.

Biodiesel production is also modeled in the PMM. Biodiesel is the collective name for methyl esters of vegetable oil or animal fat, which are suitable for fueling diesel engines. Payments are offered by the Department of Agriculture's Commodity Credit Corporation for production of biodiesel. Based on data through the third quarter of 2002, biodiesel output is projected to grow by 8.9 million gallons per year until 2006 (biodiesel output was 15.3 million gallons in 2002), when the payments will no longer be offered. Thereafter, biodiesel output is projected to grow at 1.8 percent per year.

Transportation fuel taxes. State taxes on gasoline, diesel, jet fuel, and E85 are assumed to increase with inflation, as has occurred historically. Federal taxes, which have increased sporadically in the past, are assumed to stay at 2002 nominal levels (a decline in real terms). Extension of the excise tax exemption for blending corn-based ethanol with gasoline, passed in the Federal Highway Bill of 1998, is incorporated in the projections. The bill extends the tax exemption through 2007 but reduces the current exemption of 52 cents per gallon by 1 cent per gallon in 2005. It is assumed that the tax exemption will be extended beyond 2007 through 2025 at the nominal level of 51 cents per gallon (a decline in real terms).

High renewables case. The *high renewables case* uses more optimistic assumptions about the availability of renewable energy sources. The supply curve for cellulosic ethanol is shifted in each forecast year relative to the reference case, making larger quantities available at any given price earlier than are available in the reference case. Commercialization of cellulosic ethanol follows the same path from year to year but begins in 2006 rather than 2010.

Coal Market Assumptions

Productivity. Technological advances in the coal industry, such as improvements in coal haulage systems at underground mines, contribute to increases in productivity, as measured in average tons of coal per miner per hour. Productivity improvements are assumed to continue at a reduced rate over the forecast horizon. Rates of improvement are developed based on econometric estimates using historical data by region and by mine type (surface and underground). On a national basis, labor productivity is assumed to improve on average at a rate of 1.3 percent per year over the *AEO2004* forecast period, decreasing from an estimated annual improvement rate of 1.4 percent between 2002 and 2010 to a rate of 1.3 percent between 2010 and 2025. By comparison, productivity in the U.S. coal industry improved at an average rate of 5.9 percent per year between 1980 and 2002. Some reasons why future productivity improvements are expected to be lower than historical levels include increasing strip ratios, thinner coal seams and lower coal yields, longer trucking hauls, and tougher permitting standards. Sulfur dioxide emissions limits from electricity generators, as mandated in CAAA90, are explicitly modeled in the Coal Market Module.

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

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

Coal imports. Projections of annual U.S. coal imports, specified by demand region and economic sector, are developed exogenously. The forecast is based primarily on the capability and plans of existing coal-fired generating plants to import coal and announced plans to expand coal import infrastructure. Projections of coal imports do not vary across the alternative *AEO2004* cases. Total sulfur dioxide emissions from imports and domestically produced coal are subject to the restrictions on emissions specified in CAAA90.

High and low mining cost cases. Two alternative mining cost cases examine the impacts of different labor productivity, labor cost, and equipment cost assumptions. The annual growth rates for productivity were increased and decreased by region and mine type, based on historical variations in labor productivity.

The high and low mining cost cases were developed by adjusting the *AEO2004* reference case productivity path by one standard deviation, corresponding to an adjustment of 1.9 percent in the annual growth rates of coal mine labor productivity which are specified by region and mine type. The resulting national average productivities in 2025 (in short tons per hour) were 13.1 in the *high mining cost case* and 5.94 in the *low mining cost case*, compared with 9.19 in the reference case. These are fully integrated cases, with feedback from the Macroeconomic Activity, International, supply, conversion, and end-use demand modules.

In the reference case, labor wage rates for coal mine production workers and equipment costs are assumed to remain constant in real terms over the forecast period. In the low and high mining cost cases, wages and equipment costs are assumed to decline and increase by 0.5 percent per year in real terms, respectively.

Notes

[*1*] Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384(2001) (Washington, DC, October 2003).

[*2*] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2002*, DOE/EIA-0573(2001) (Washington, DC, October 2003).

[*3*] Energy Information Administration, *Short-Term Energy Outlook*, web site www.eia.doe.gov/emeu/steo/pub/contents.html. Portions of the preliminary information were also used to initialize the PMM projection.

[*4*] Jet Information Services, Inc., *World Jet Inventory Year-End 2002* (Woodinville, WA, March 2003), and personal communications with Bill Francoins at Jet Information Services and Thomas C. Hoang at Boeing.

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

[*6*] Maine has passed legislation that provides a goal of phasing out MTBE, although at this time no MTBE is used in Maine.

[*7*] The hurdle rate for petroleum coke gasification is assumed to be 15 percent because of the higher economic risk involved in this technology.

[*8*] “Worldwide Look at Reserves and Production,” *Oil & Gas Journal* (December 23, 2002), pp. 114-115.

[*9*] U.S. Geological Survey, *World Petroleum Assessment 2000: Description and Results*, Data Series DDS-60, Version 1.1 (Washington, DC, June 2000).

[*10*] Petroconsultants, Inc., “DESTINY: International Forecast Software, Petroleum Exploration and Production Database” (Houston, TX, 1996).

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

[*12*] Energy Information Administration, 2001 *Residential Energy Consumption Survey*, web site www.eia.doe.gov/emeu/recs/contents.html.

[*13*] For additional information on green programs see web site www.energystar.gov.

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

[*15*] High technology assumptions are based on Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Arthur D. Little, Inc., October 2001).

[*16*] Energy Information Administration, 1999 CBECS Public Use Data Files (October 2002), web site www.eia.doe.gov/emeu/cbecs/.

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

[*18*] Efficiency typically refers to the ratio of energy delivered to energy consumed. In the case of lighting, the measure used is efficacy, which is the ratio of light delivered (in lumens) to energy consumed.

[*19*] High technology assumptions are based on Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Arthur D. Little, Inc., October 2001).

[*20*] Navigant Consulting, Inc., *The Changing Face of Renewable Energy* (June 2003).

[*21*] The National Renewable Energy Laboratory’s Renewable Electric Plant Information System is available at web site www.eere.energy.gov/repis/.

[*22*] For current DOE technology characterizations for photovoltaic systems see web site www.eren.doe.gov/power/pdfs/techchar.pdf.

[*23*] Energy Information Administration, *1998 Manufacturing Energy Consumption Survey*, web site www.eia.doe.gov/emeu/mecs/mecs98/datatables/contents.html.

[*24*] The data sources and methodology used to develop the nonmanufacturing portion of the Industrial Demand Module are described in Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M064(2002) (Washington, DC, December 2001).

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

[*26*] S.R. Nadal et al., *Energy-Efficient Motor Systems: A Handbook on Technology, Program, and Policy Opportunities*, 2nd Edition (Washington, DC: American Council for an Energy-Efficient Economy, 2002).

[*27*] U.S. Department of Energy, Motor Master+ 4.0 software database (2003), web site http://mm3.energy.wsu.edu/mmplus/default.stm.

[*28*] These assumptions are based in part on Energy Information Administration, *Industrial Model—Updates on*

Energy Use and Industrial Characteristics (Arthur D. Little, Inc., September 2001).

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

[*30*] California Air Resources Board, Resolution 01-1 (January 25, 2001).

[*31*] California Air Resources Board, Resolution 03-4 (April 24, 2003).

[*32*] Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (Energy and Environmental Analysis, September 2002).

[*33*] A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001).

[*34*] S. Davis, *Transportation Energy Databook No. 22*, prepared for the Office of Transportation Technologies, U.S. Department of Energy (Oak Ridge, TN: Oak Ridge National Laboratory, September 2002).

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

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

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

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

[*39*] Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (Energy and Environmental Analysis, September 2002).

[*40*] A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001).

[*41*] The source of the cost data is the CUECOST3.xls model, as updated February 9, 2000, which was developed for the U.S. Environmental Protection Agency by Raytheon Engineers and Constructors, Inc., EPA Contract Number 68-D7-0001. The EPA model estimates costs for adding SCRs, FGDs, and SNCRs for plants based on a number of design parameters. For retrofits, a retrofit factor is assigned to reflect the additional costs of retrofitting an existing plant rather than adding it as part of a Greenfield plant. The EPA model was run for each individual plant assuming a 1.3 retrofit factor for FGDs and 1.6 for SCRs, based on historical evidence.

[*42*] Pacific Northwest Laboratory, *An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States*, PNL-7789, prepared for the U.S. Department of Energy under Contract DE-AC06-76RLO 1830 (August 1991); and M.N. Schwartz, O.L. Elliott, and G.L. Gower, *Gridded State Maps of Wind Electric Potential. Proceedings, Wind Power 1992* (Seattle, WA, October 19-23, 1992). Also, National Renewable Energy Laboratory, "Subtask A: Incorporation of Existing Validated Wind Data into NEMS," draft final report to EIA (November 2003).

[*43*] Based on technology characterizations from National Renewable Energy Laboratory, *2003 Power Technologies Databook*, web site www.nrel.gov/analysis/power_databook/. Cost and performance projections in the Databook are sourced to U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, publications and documents.

[*44*] D.L. Goutier et al., *1995 National Assessment of the United States Oil and Gas Resources* (Washington, DC: U.S. Department of the Interior, U.S. Geological Survey, 1995); U.S. Department of the Interior, Minerals Management Service, *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf*, OCS Report MMS 96-0034 (Washington, DC, June 1997); U.S. Department of the Interior, Minerals Management Service, *2000 Assessment of the Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf, as of January 1, 1999*, OCS Report MMS 2001-087 (New Orleans, LA, October 2001); National Petroleum Council, *Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand* (Washington, DC, December 1999).

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

[*46*] U.S. Environmental Protection Agency, Office of Transportation and Air Quality, *Information on Reformulated Gasoline (RFG) Properties and Emissions Performance by Area and Season*, web site www.epa.gov/otaq/regs/fuels/rfg/properf/rfgperf.htm.

[*47*] California Air Resource Board, "California Phase 3 Reformulated Gasoline," web site www.arb.ca.gov/fuels/gasoline/carfg3/carfg3.htm.

[*48*] The State of Maine has passed legislation that provides a goal of phasing out MTBE.

[*49*] Based on the methodology described in D. Gray and G. Tomlinson, *Coproduction: A Green Coal Technology*, Technical Report MP 2001-28 (Mitretek, March 2001).

[*50*] National Energy Technology Laboratory, *Refinery Technology Profiles—Gasification and Supporting Technologies* (June 2003).

[*51*] National Ethanol Vehicles Coalition, *E85 Blending, Tax Incentives, and Pump Pricing*. A copy of the report may be obtained by calling (877) 485-8595.

Appendix H
Conversion Factors

Table H1. Heat Rates

Fuel	Units	Approximate Heat Content
Coal[1]		
Production	million Btu per short ton	20.620
Consumption	million Btu per short ton	20.814
Coke Plants	million Btu per short ton	27.426
Industrial	million Btu per short ton	23.361
Residential and Commercial	million Btu per short ton	24.836
Electric Power Sector	million Btu per short ton	20.479
Imports	million Btu per short ton	25.000
Exports	million Btu per short ton	26.062
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	5.325
Motor Gasoline[2]	million Btu per barrel	5.198
Jet Fuel	million Btu per barrel	5.670
Distillate Fuel Oil	million Btu per barrel	5.825
Residual Fuel Oil	million Btu per barrel	6.287
Liquefied Petroleum Gas[2]	million Btu per barrel	3.603
Kerosene	million Btu per barrel	5.670
Petrochemical Feedstocks[2]	million Btu per barrel	5.545
Unfinished Oils	million Btu per barrel	5.825
Imports[2]	million Btu per barrel	5.345
Exports[2]	million Btu per barrel	5.767
Natural Gas Plant Liquids		
Production[2]	million Btu per barrel	3.782
Natural Gas		
Production, Dry	Btu per cubic foot	1,027
Consumption	Btu per cubic foot	1,027
End-Use Sectors	Btu per cubic foot	1,028
Electric Power Sector	Btu per cubic foot	1,019
Imports	Btu per cubic foot	1,022
Exports	Btu per cubic foot	1,006
Electricity Consumption	Btu per kilowatthour	3,412

Btu = British thermal unit.

[1]Coal conversion factors vary from year to year. Values correspond to those published by EIA for 2002 and may differ slightly from model results.

[2]Conversion factors vary from year to year. 2010 values are reported.

Sources: Energy Information Administration (EIA), *Annual Energy Review 2002*, DOE/EIA-0384(2002) (Washington, DC, October 2003), and EIA, AEO2004 National Energy Modeling System run AEO2004.D101703E.

Table H2. Metric Conversion Factors

United States Unit	multiplied by	Conversion Factor	equals	Metric Unit
Mass				
Pounds (lb)	X	0.453 592 37	=	kilograms (kg)
Short Tons (2000 lb)	X	0.907 184 7	=	metric tons (t)
Length				
Miles	X	1.609 344	=	kilometers (km)
Energy				
British Thermal Unit (Btu)	X	1055.056[a]	=	joules(J)
Quadrillion Btu	X	25.2	=	million tons of oil equivalent (Mtoe)
Kilowatthours (kWh)	X	3.6	=	megajoules(MJ)
Volume				
Barrels of Oil (bbl)	X	0.158 987 3	=	cubic meters (m^3)
Cubic Feet (ft^3)	X	0.028 316 85	=	cubic meters (m^3)
U.S. Gallons (gal)	X	3.785 412	=	liters (L)
Area				
Square feet (ft^2)	X	0.092 903 04	=	square meters (m^2)

Note: Spaces have been inserted after every third digit to the right of the decimal for ease of reading.
[a]The Btu used in this table is the International Table Btu adopted by the Fifth International Conference on Properties of Steam, London, 1956.
Source: Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002).

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 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002), Table B2.

The Energy Information Administration
National Energy Modeling System/Annual Energy Outlook Conference

Renaissance Hotel, Washington, DC ***March 23, 2004***

Morning Program

8:30 a.m. - 8:45	**Opening Remarks - *Guy F. Caruso*,** *Administrator*, Energy Information Administration
8:45 a.m. - 9:15	**Overview of the *Annual Energy Outlook 2004* - *Mary J. Hutzler,*** *Director*, Office of Integrated Analysis and Forecasting, Energy Information Administration
9:00 a.m. - 9:45	**Keynote Address: North American Natural Gas Resources: Yesterday, Today, and Tomorrow - *Dr. John B. Curtis*,** *Director*, Potential Gas Committee
10:30 a.m. - 12:00	**Concurrent Sessions A** **1. Electricity Reliability in the Changing Markets of the 21st Century** **2. The Expanding Role of Liquefied Natural Gas in Natural Gas Markets** **3. Industrial Natural Gas Demand Response to Higher Natural Gas Prices**
1:15 p.m. - 2:45	**Concurrent Sessions B** **1. International Nuclear Markets** **2. Lower 48 Natural Gas Production and Prices** **3. Market Power and Transmission**
3:00 p.m. - 4:30	**Concurrent Sessions C** **1. End-Use Energy Efficiency: Sources, Projections, and Impacts** **2. The Coming Decline of Canadian Natural Gas Imports** **3. Future Capacity Needs: When New Capacity Is Needed, What Will Be Built?**

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The conference will be held at the *Renaissance Hotel*, (202) 898-9000. The *Renaissance Hotel* is located at 999 Ninth Street, NW, Washington, DC 20001, near the Gallery Place Metro station. A block of rooms has been reserved at the *Renaissance Hotel*, (202) 898-9000, in the name of the NEMS Conference. Please make reservations quickly; only a limited number of rooms were held.

Information

For information, contact Peggy Wells, Energy Information Administration, at (202) 586-0109, peggy.wells@eia.doe.gov.

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❒ Market Power and Transmission

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