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Annual Energy Outlook 2006

With Projections to 2030

February 2006

For Further Information . . .

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AEO2006 will be available on the EIA web site at www.eia.doe.gov/oiaf/aeo/ in early February 2006. Assumptions underlying the projections and tables of regional and other detailed results will also be available in early February 2006, at web sites www.eia.doe.gov/oiaf/assumption/ and /supplement/. Model documentation reports for the National Energy Modeling System (NEMS) are available at web site www.eia.doe.gov/bookshelf/docs.html and will be updated for *AEO2006* during the first few months of 2006.

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Preface

The *Annual Energy Outlook 2006* (*AEO2006*), prepared by the Energy Information Administration (EIA), presents long-term forecasts of energy supply, demand, and prices through 2030. The projections are based on results from EIA's National Energy Modeling System (NEMS).

The report begins with an "Overview" summarizing the *AEO2006* reference case and comparing it with the *AEO2005* reference case. The next section, "Legislation and Regulations," discusses evolving legislation and regulatory issues, including recently enacted legislation and regulation, such as the Energy Policy Act of 2005, and some that are proposed. "Issues in Focus" includes a discussion of the basis of EIA's substantial revision of the world oil price trend used in the projections. It also examines the following topics: implications of higher oil price expectations for economic growth; differences among types of crude oil available on world markets; energy technologies on the cusp of being introduced; nonconventional liquids technologies beginning to play a larger role in energy markets; advanced vehicle technologies included in *AEO2006*; mercury emissions control technologies; and U.S. greenhouse gas intensity. "Issues in Focus" is followed by "Energy Market Trends," which provides a summary of the *AEO2006* projections for energy markets.

The analysis in *AEO2006* focuses primarily on a reference case, lower and higher economic growth cases, and lower and higher energy price cases. In addition, more than 30 alternative cases are included in *AEO2006*. Readers are encouraged to review the full range of cases, which address many of the uncertainties inherent in long-term forecasts. Complete tables for the five primary cases are provided in Appendixes A through C. Major results from many of the alternative cases are provided in Appendix D. Appendix E briefly describes NEMS and the alternative cases.

The *AEO2006* projections are based on Federal, State, and local laws and regulations in effect on or before October 31, 2005. 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, the *AEO2006* reference case does not include implementation of the proposed, but not yet final, increase in corporate average fuel economy (CAFE) standards based on vehicle footprint for light trucks—including pickups, sport utility vehicles, and minivans. In general, historical data used in the *AEO2006* projections are based on EIA's *Annual Energy Review 2004*, published in August 2005; however, data are taken from multiple sources. In some cases, only partial or preliminary 2004 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 2005 and 2006 incorporate the short-term projections from EIA's September 2005 *Short-Term Energy Outlook* where the data are comparable.

Federal, State and local governments, trade associations, and other planners and decisionmakers in the public and private sectors use the *AEO2006* 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 the *Annual Energy Outlook 2006* 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 estimates, 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 certainty. Many key uncertainties in the *AEO2006* 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, a complete and focused analysis of public policy initiatives.

Contents

Contents

Figures (Continued) **Page**

Contents

Figures (Continued) **Page**

Figures (Continued) **Page**

Overview

Overview

Energy Trends to 2030

The Energy Information Administration (EIA), in preparing projections for the *Annual Energy Outlook 2006* (*AEO2006*), evaluated a wide range of trends and issues that could have major implications for U.S. energy markets between today and 2030. *AEO2006* is the first edition of the *Annual Energy Outlook* (*AEO*) to provide projections through 2030. This overview focuses on one case, the reference case, which is presented and compared with the *Annual Energy Outlook 2005* (*AEO2005*) reference case.

Trends in energy supply and demand are affected by a large number of factors that are difficult to predict, such as energy prices, U.S. economic growth, advances in technologies, changes in weather patterns, and future public policy decisions. In preparing *AEO2006*, EIA reevaluated its prior expectations about world oil prices in light of the current circumstances in oil markets. Since 2000, world oil prices have risen sharply as supply has tightened, first as a result of strong demand growth in developing economies such as China and later as a result of supply constraints resulting from disruptions and inadequate investment to meet demand growth. As a result of this review, the *AEO2006* reference case includes much higher world oil prices than were projected in *AEO2005*. In the *AEO2006* reference case, world crude oil prices, which are now expressed in terms of the average price of imported low-sulfur crude oil to U.S. refiners, are projected to increase from $40.49 per barrel (2004 dollars) in 2004 to $54.08 per barrel in 2025 (about $21 per barrel higher than the projected 2025 price in *AEO2005*) and to $56.97 per barrel in 2030.

The higher world oil prices in the *AEO2006* reference case have important implications for energy markets. The most significant impact is on the outlook for U.S. petroleum imports. Net imports of petroleum are projected to meet a growing share of total petroleum demand in both *AEO2006* and *AEO2005*; however, the higher world oil prices in the *AEO2006* reference case lead to more domestic crude oil production, lower demand for petroleum products, and consequently lower levels of petroleum imports. Net petroleum imports are expected to account for 60 percent of demand (on the basis of barrels per day) in 2025 in the *AEO2006* reference case, up from 58 percent in 2004. In the *AEO2005* reference case, net petroleum imports were projected to account for 68 percent of U.S. petroleum demand in 2025.

Higher world oil prices are also projected to affect fuel choice and vehicle efficiency decisions in the transportation sector. Higher oil prices increase the demand for unconventional sources of transportation fuel, such as ethanol and biodiesel, and are projected to stimulate coal-to-liquids (CTL) production in the reference case. In some of the alternative *AEO2006* cases, with even higher oil prices, domestic production of liquid fuels from natural gas—“gas-to-liquids” (GTL)—is also stimulated. The production of alternative liquid fuels is highly sensitive to oil price levels.

The projected fuel economy of new light-duty vehicles in the *AEO2006* reference case in 2025 is higher than was projected in the *AEO2005* reference case, primarily because of higher petroleum prices. The *AEO2006* reference case does not include implementation of the proposed, but not yet final, increase in fuel economy standards based on vehicle footprint for light trucks—including pickups, sport utility vehicles, and minivans—for model years 2008 through 2011.

Much of the increase in new light-duty vehicle fuel economy in the *AEO2006* reference case reflects greater penetration by hybrid and diesel vehicles. Sales of “full hybrid” vehicles in 2025 are 31 percent (340,000 vehicles) higher in the *AEO2006* reference case, and diesel vehicle sales are 29 percent (290,000 vehicles) higher, than projected in the *AEO2005* reference case. In spite of the higher projected sales of hybrid (1.5 million) and diesel (1.3 million) vehicles in 2025, each is expected to account for only 7 percent of new vehicle sales in the *AEO2006* reference case, even though the projected hybrid sales are higher than current industry expectations. The projected

World Oil Price Concept Used in *AEO2006*

In previous *AEO*s, the world crude oil price was defined on the basis of the average imported refiner acquisition cost of crude oil to the United States (IRAC), which represented the weighted average of all imported crude oil. Historically, the IRAC price has tended to be a few dollars less than the widely cited prices of premium crudes, such as West Texas Intermediate (WTI) and Brent, which refiners generally prefer for their low viscosity and sulfur content. In the past 2 years, the price difference between premium crudes and IRAC has widened—in particular, the price spread between premium crudes and heavier, high-sulfur crudes. In an effort to provide a crude oil price that is more consistent with those generally reported in the media, *AEO2006* uses the average price of imported low-sulfur crude oil to U.S. refiners.

sales figures for hybrids do not include sales of "mild hybrids," which like full hybrids incorporate an integrated starter generator, that allows for improved efficiency by shutting the engine off when the vehicle is idling, but do not incorporate an electric motor that provides tractive power to the vehicle when it is moving.

The *AEO2006* reference case includes minimal market penetration by hydrogen fuel cell vehicles, as a result of State mandates. Although significant research and development (R&D) is being conducted through the FreedomCAR Program, a co-funded partnership between the Federal Government and private industry, those efforts are not expected to have a significant impact on the market for fuel cell vehicles before 2030.

The *AEO2006* reference case projection for U.S. imports of liquefied natural gas (LNG) is lower than was projected in the *AEO2005* reference case. LNG imports are projected to grow from 0.6 trillion cubic feet in 2004 to 4.1 trillion cubic feet in 2025, as compared with 6.4 trillion cubic feet in the *AEO2005* reference case. More rapid growth in worldwide demand for natural gas in the *AEO2006* reference case reduces the availability of LNG supplies to the United States and raises worldwide natural gas prices, making LNG less economical in U.S. markets.

AEO2006 includes consideration of the impacts of the Energy Policy Act of 2005 (EPACT2005), signed into law on August 8, 2005. Consistent with the general approach adopted in the *AEO*, the reference case does not consider those sections of EPACT2005 that require funding appropriations for implementation or sections with highly uncertain impacts on energy markets. For example, EIA does not try to anticipate the policy response to the many studies required by EPACT2005 or the impacts of the R&D funding authorizations included in the bill. The *AEO2006* reference case includes only those sections of EPACT-2005 that establish specific tax credits, incentives, or standards—about 30 of the roughly 500 sections in the legislation.

Of the EPACT2005 provisions analyzed, incentives intended to stimulate the development of advanced nuclear and renewable plants have particularly noteworthy impacts. A total of 6 gigawatts of newly constructed nuclear capacity is projected to be added by 2030 in the *AEO2006* reference case as a result of the incentives in EPACT2005.

EPACT2005 also has important implications for energy consumption in the residential and commercial sectors. In the residential sector, EPACT2005 sets efficiency standards for torchiere lamps, dehumidifiers, and ceiling fans and creates tax credits for energy-efficient furnaces, water heaters, and air conditioners. It also allows home builders to claim tax credits for energy-efficient new construction. In the commercial sector, the legislation creates efficiency standards that affect energy use in a number of commercial applications. It also includes investment tax credits for solar technologies, fuel cells, and microturbines. These policies are expected to help reduce energy use for space conditioning and lighting in both sectors.

Economic Growth

The projections for key interest rates—the Federal funds rate, the nominal yield on the 10-year Treasury note, and the AA utility bond rate—in the *AEO2006* reference case are slightly lower than those in the *AEO2005* reference case. Also, the projected value of industrial shipments has been revised downward, in part in response to the higher projected energy prices in the *AEO2006* reference case.

Despite the higher forecast for energy prices, gross domestic product (GDP) is projected to grow at an average annual rate of 3.0 percent from 2004 to 2030 in *AEO2006*, identical to the projected growth rate from 2004 through 2025 in *AEO2005*. The ratio of final energy expenditures to GDP has generally fallen over time and was only about 0.07 in 2004, down from a high of 0.14 during the 1970s. It is projected to fall to about 0.05 in 2030 as a result of continued declines in energy use per unit of output and growth in other areas of the economy. The main factors influencing long-term economic growth are growth in the labor force and sustained growth in labor productivity, not energy prices.

Energy Prices

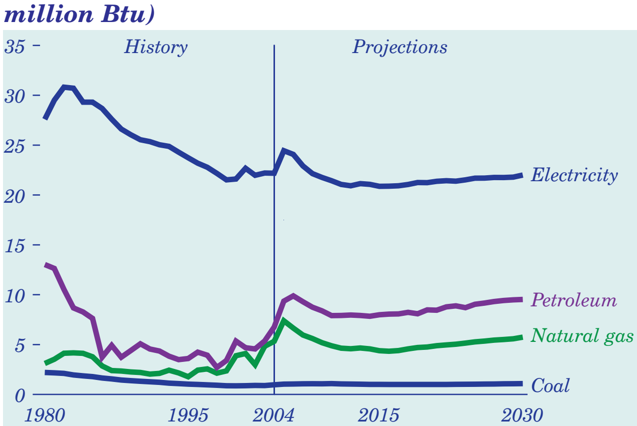
In the reference case—one of several cases included in *AEO2006*—the average world crude oil price continues to rise through 2006 and then declines to $46.90 per barrel in 2014 (2004 dollars) as new supplies enter the market. It then rises slowly to $54.08 per barrel in 2025 (Figure 1), about $21 per barrel higher than the price in *AEO2005* ($32.95 per barrel). Alternative *AEO2006* cases address higher and lower world oil prices.

The prices in the *AEO2006* reference case reflect a shift in EIA's thinking about long-term trends in oil markets. World oil markets have been extremely volatile for the past several years, and EIA now believes that the price path in *AEO2005* did not fully reflect the causes of that volatility and the implications for long-term average oil prices. In the *AEO2006* reference case, the combined production capacity of members of the Organization of the Petroleum Exporting Countries (OPEC) does not increase as much as previously projected, and consequently world oil supplies are assumed to remain tight. The United States and emerging Asia—notably, China— are expected to lead the increase in demand for world oil supplies, keeping pressure on prices though 2030.

In the *AEO2006* reference case, world petroleum demand is projected to increase from about 82 million barrels per day in 2004 to 111 million barrels per day in 2025. The additional demand is expected to be met by increased oil production from both OPEC and non-OPEC nations. In *AEO2005*, world petroleum demand was projected to reach a higher level of 121 million barrels per day in 2025. The *AEO2006* reference case projects OPEC oil production of 44 million barrels per day in 2025, 44 percent higher than the 31 million barrels per day produced in 2004. In the *AEO2005* reference case, OPEC production was projected to reach 55 million barrels per day in 2025, more than 11 million barrels per day higher than in the *AEO2006* reference case. In the *AEO2006* reference case, non-OPEC oil production increases from 52 million barrels per day in 2004 to 67 million in 2025, as compared with the *AEO2005* reference case projection of 65 million barrels per day.

The average U.S. wellhead price for natural gas in the *AEO2006* reference case declines gradually from the current level as increased drilling brings on new supplies and new import sources become available. The average price falls to $4.46 per thousand cubic feet in 2016 (2004 dollars), then rises gradually to more than $5.40 per thousand cubic feet in 2025 (equivalent to about $10 per thousand cubic feet in nominal dollars) and more than $5.90 per thousand cubic feet in 2030.

Figure 1. Energy prices, 1980-2030 (2004 dollars per million Btu)



LNG imports, Alaskan natural gas production, and lower 48 production from unconventional sources are not expected to increase sufficiently to offset the impacts of resource depletion and increased demand. The projected wellhead natural gas prices in the *AEO2006* reference case from 2016 to 2025 are consistently higher than the comparable prices in the *AEO2005* reference case, by about 30 to 60 cents per thousand cubic feet, primarily as a result of higher exploration and development costs.

In the *AEO2006* reference case, the combination of slow but continued improvements in expected mine productivity and a continuing shift to low-cost coal from the Powder River Basin in Wyoming leads to a gradual decline in the projected average minemouth coal price, to approximately $20.00 per ton ($1.00 per million British thermal units [Btu]) in 2021 (2004 dollars). Prices then increase slowly as rising natural gas prices and the need for baseload generating capacity lead to the construction of many new coal-fired generating plants. In 2025, the average minemouth price in the *AEO2006* reference case is projected to be $20.63 per ton ($1.03 per million Btu), an increase over the *AEO2005* reference case projection of $18.64 per ton ($0.93 per million Btu). Trends in coal prices measured in terms of tonnage differ slightly from the trends in prices measured in terms of energy content, because the average energy content per ton of coal consumed falls over time as Western subbituminous coal, which has a relatively low Btu content, claims a larger share of the market.

Average delivered electricity prices are projected to decline from 7.6 cents per kilowatthour (2004 dollars) in 2004 to a low of 7.1 cents per kilowatthour in 2015 as a result of declines in natural gas prices and, to a lesser extent, coal prices. After 2015, average real electricity prices are projected to increase, to 7.4 cents per kilowatthour in 2025 and 7.5 cents per kilowatthour in 2030. In the *AEO2005* reference case, electricity prices were lower in the early years of the projection but reached about the same level in 2025. The higher near-term electricity prices projected in the *AEO2006* reference case result primarily from higher expected fuel costs for natural-gas- and coal-fired electric power plants.

Energy Consumption

Total primary energy consumption in the *AEO2006* reference case is projected to increase at an average rate of 1.2 percent per year, from 99.7 quadrillion Btu in 2004 to 127.0 quadrillion Btu in 2025—6.2 quadrillion Btu less than in *AEO2005*. In 2025, coal, nuclear, and renewable energy consumption are higher—

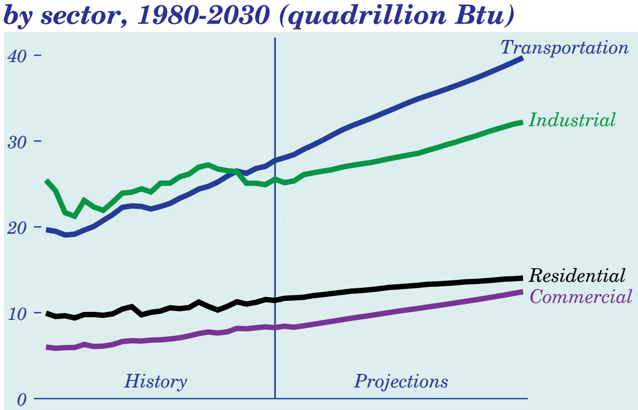
while petroleum and natural gas consumption are lower—in the *AEO2006* reference case than in *AEO-2005*. Among the most important factors accounting for the differences are higher energy prices, particularly for petroleum and natural gas; lower projected growth rates in the manufacturing portion of the industrial sector, which traditionally includes the most energy-intensive industries; greater penetration by hybrid and diesel vehicles in the transportation sector as consumers focus more on fuel efficiency; and the impacts of the recently passed EPACT2005, which are projected to reduce energy consumption in the residential and commercial sectors and slow the growth of electricity demand.

As a result of demographic trends and housing preferences, delivered residential energy consumption in the *AEO2006* reference case is projected to grow from 11.4 quadrillion Btu in 2004 to 13.6 quadrillion Btu in 2025 (Figure 2), 0.6 quadrillion Btu lower than in *AEO2005*. Higher projected energy prices in *AEO-2006* and the impacts of EPACT2005 are expected to help reduce energy consumption for space conditioning and lighting.

Consistent with projected growth in commercial floorspace in the *AEO2006* reference case, delivered commercial energy consumption is projected to reach 11.5 quadrillion Btu in 2025. In comparison, the *AEO2005* reference case projected 12.5 quadrillion Btu of commercial delivered energy consumption in 2025. Three changes contribute to the lower projection in *AEO2006*: significantly higher fossil fuel energy prices, adoption of a revised projection of commercial floorspace based on updated historical data, and the impacts of the EPACT2005 provisions included in the reference case.

After falling to relatively low levels in the early 1980s, industrial energy consumption recovered and peaked

Figure 2. Delivered energy consumption by sector, 1980-2030 (quadrillion Btu)



in 1997. In the 2000 to 2003 period, industrial sector activity was reduced by an economic recession. The industrial sector is projected to experience more typical output growth rates over the *AEO2006* projection period, and industrial energy consumption is expected to reflect this trend. The industrial value of shipments in the *AEO2006* reference case is projected to grow by 2.0 percent per year from 2004 to 2025, more slowly than in *AEO2005* (2.2 percent per year) due to a slight slowdown in projected investment spending, higher energy prices, and increased competition from imports. Delivered industrial energy consumption in the *AEO2006* reference case is projected to reach 30.6 quadrillion Btu in 2025, slightly lower than the *AEO2005* projection of 30.8 quadrillion Btu. The *AEO2006* projection includes 1.2 quadrillion Btu of coal consumption in CTL plants, which was not included in *AEO2005*.

Delivered energy consumption in the transportation sector in the *AEO2006* reference case is projected to total 37.3 quadrillion Btu in 2025, 2.7 quadrillion Btu lower than the *AEO2005* projection. The lower level of consumption reflects both slower growth in miles traveled and higher vehicle efficiency. Over the past 20 years, light-duty vehicle travel has grown by about 3 percent annually. In the *AEO2006* reference case it is projected to grow at a rate of 1.8 percent per year through 2025 (as compared with 2.1 percent per year in *AEO2005*), reflecting demographic factors (for example, the leveling off of increases in the labor force participation rate for women) and higher energy prices. The projected average fuel economy of new light-duty vehicles in 2025 is also higher in the *AEO-2006* reference case than was projected in *AEO2005*, primarily because the higher projected fuel prices in the *AEO2006* forecast are expected to lead consumers to demand better fuel economy, slowing the growth in sales of new pickup trucks and sport utility vehicles.

Total electricity consumption, including both purchases from electric power producers and on-site generation, is projected to grow from 3,729 billion kilowatthours in 2004 to 5,208 billion kilowatthours in 2025, increasing at an average annual rate of 1.6 percent in the *AEO2006* reference case. In comparison, total electricity consumption of 5,467 billion kilowatthours in 2025 was projected in *AEO2005*. Growth in electricity use for computers, office equipment, and a variety of electrical appliances in the end-use sectors is partially offset in the *AEO2006* reference case by improved efficiency in these and other, more traditional, electrical applications.

Total consumption of natural gas in the *AEO2006* reference case is projected to increase from 22.4 trillion cubic feet in 2004 to 27.0 trillion cubic feet in 2025 (Figure 3), 3.7 trillion cubic feet lower than projected in the *AEO2005* reference case, mostly as a result of higher natural gas prices. After peaking at 27.0 trillion cubic feet in 2024, natural gas consumption is projected to fall slightly by 2030, as higher natural gas prices result in a larger market share for coal in the electric power sector in the later years of the projection. The projected growth in natural gas demand in *AEO2006* results primarily from increased use of natural gas for electricity generation and industrial applications, which together account for 62 percent of the projected demand growth from 2004 to 2025. In addition, demand for natural gas in the residential and commercial sectors is projected to grow by 1.5 trillion cubic feet in total from 2004 to 2025.

In the *AEO2006* reference case, total coal consumption is projected to increase from 1,104 million short tons in 2004 to 1,592 million short tons in 2025 (Figure 3), 84 million short tons more than the 1,508 million tons projected to be consumed in 2025 in the *AEO2005* reference case. Coal consumption is projected to grow at a faster rate in *AEO2006* toward the end of the projection, particularly after 2020, as coal captures market share from natural gas, and as coal use for CTL production grows. Coal was not projected to be used for CTL production in the *AEO2005* reference case. In the *AEO2006* reference case, coal consumption in the electric power sector is projected to increase from 1,235 million short tons in 2020 to 1,502 million short tons in 2030, at an average rate of 2.0 percent per year; and coal use at CTL plants is projected to increase from 62 million short tons in 2020 to 190 million short tons in 2030.

Total petroleum consumption is projected to grow from 20.8 million barrels per day in 2004 to 26.1 million barrels per day in 2025 (Figure 3) in the *AEO-2006* reference case (1.9 million barrels per day lower than the *AEO2005* projection). Petroleum demand growth in the *AEO2006* reference case is lower in all sectors than was projected in *AEO2005*, due largely to the impact of the much higher oil prices in *AEO2006*. Most of the difference—almost two-thirds—is in the transportation sector.

Total consumption of marketed renewable fuels in the *AEO2006* reference case (including ethanol for gasoline blending, of which 1.0 quadrillion Btu in 2025 is included with “petroleum products” consumption) is projected to grow from 6.0 quadrillion Btu in 2004 to 9.6 quadrillion Btu in 2025 (Figure 3), as a result of State programs—renewable portfolio standards (RPS), mandates, and goals—for renewable electricity generation, technological advances, higher petroleum and natural gas prices, and the effects of Federal tax credits, including those in EPACT2005. In *AEO2005*, total marketed renewable fuel consumption was projected to grow to 8.5 quadrillion Btu in 2025. In *AEO2006*, more than 60 percent of the projected demand for renewables in the reference case is for grid-related electricity generation, including combined heat and power (CHP), and the rest is for dispersed heating and cooling, industrial uses, and fuel blending.

Energy Intensity

Energy intensity, measured as energy use per dollar of GDP (2000 dollars), is projected to decline at an average annual rate of 1.8 percent from 2004 to 2030 in the *AEO2006* reference case (Figure 4), with efficiency gains and structural shifts in the economy dampening growth in demand for energy services. The rate of decline in energy intensity is faster than the 1.6-percent annual rate of decline projected in *AEO2005* between 2004 and 2025, largely because of higher energy prices in *AEO2006*, resulting in generally lower projected levels of energy consumption.

Figure 3. Energy consumption by fuel, 1980-2030 (quadrillion Btu)

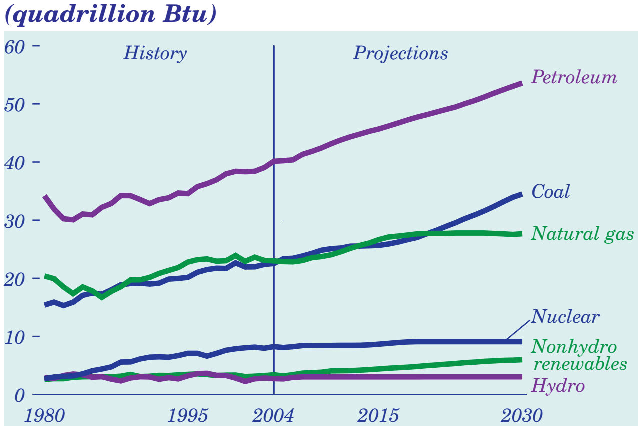
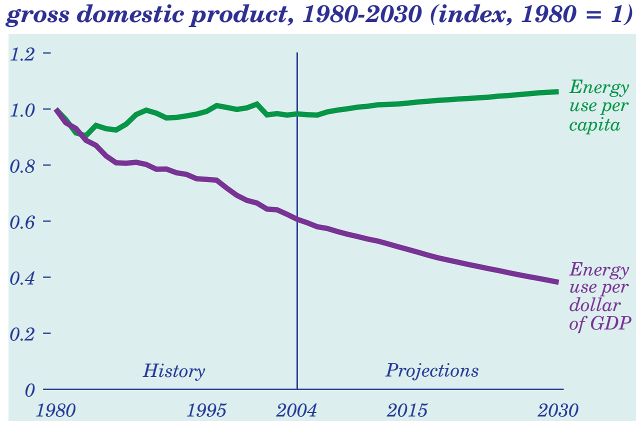


Figure 4. Energy use per capita and per dollar of gross domestic product, 1980-2030 (index, 1980 = 1)



Since 1992, the energy intensity of the U.S. economy has declined on average by 1.9 percent per year, and the share of total industrial production accounted for by the energy-intensive industries has fallen sharply, by 1.3 percent per year on average from 1992 to 2004. In the *AEO2006* reference case, the energy-intensive industries' share of total industrial output is projected to continue to decline, but at a slower rate of 0.8 percent per year, leading to a slower rate of reduction in energy intensity.

Historically, energy use per person has varied over time with the level of economic growth, weather conditions, and energy prices, among many other factors. During the late 1970s and early 1980s, energy consumption per capita fell in response to high energy prices and weak economic growth. Starting in the late 1980s and lasting through 2000, energy consumption per capita generally increased with declining energy prices and strong economic growth. Per capita energy use is projected to increase in the *AEO2006* reference case, with growth in demand for energy services only partially offset by efficiency gains. Per capita energy use increases by an average of 0.3 percent per year between 2004 and 2030 in the *AEO2006* reference case, less than was projected in the *AEO2005* reference case, 0.5 percent per year between 2004 and 2025, primarily because of the higher projected energy prices in *AEO2006*.

Recently, as energy prices have risen, the potential for more energy conservation has received increased attention. Although some additional energy conservation is induced by higher energy prices in the *AEO2006* reference case, no policy-induced conservation measures are assumed beyond those in existing legislation and regulation, nor does the reference case assume behavioral changes beyond those observed in the past.

Electricity Generation

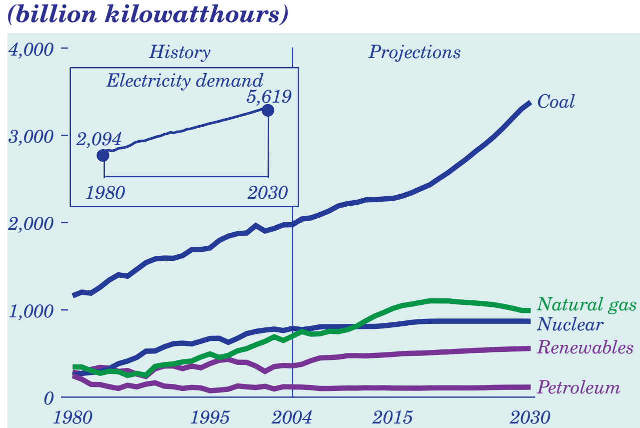
In the *AEO2006* reference case, the projected average prices of natural gas and coal delivered to electricity generators in 2025 are, respectively, 31 cents and 11 cents per million Btu higher than the comparable prices in *AEO2005*. Although the projected levels of coal consumption for electricity generation in 2025 are similar in the two forecasts, higher natural gas prices and slower growth in electricity demand in *AEO2006* lead to significantly lower levels of natural gas consumption for electricity generation. As a result, projected cumulative capacity additions and generation from natural-gas-fired power plants are lower in the *AEO2006* reference case, and capacity additions and generation from coal-fired power plants through 2025 are similar to those in *AEO2005*. In the later years of the *AEO2006* projection, natural-gas-fired generation is expected to decline, displaced by generation from new coal-fired plants (Figure 5). The *AEO2006* projection of 1,070 billion kilowatthours of electricity generation from natural gas in 2025 is 24 percent lower than the *AEO2005* projection of 1,406 billion kilowatthours.

In the *AEO2006* reference case, the natural gas share of electricity generation (including generation in the end-use sectors) is projected to increase from 18 percent in 2004 to 22 percent around 2020, before falling to 17 percent in 2030. The coal share is projected to decline slightly, from 50 percent in 2004 to 49 percent in 2020, before increasing to 57 percent in 2030. Additions to coal-fired generating capacity in the *AEO2006* reference case are projected to total 102 gigawatts between 2004 and 2025, as compared with 86 gigawatts in *AEO2005*. Over the entire period from 2004 to 2030, 174 gigawatts of new coal-fired generating capacity is projected to be added in the *AEO2006* reference case, including 19 gigawatts at CTL plants.

Nuclear generating capacity in the *AEO2006* reference case is projected to increase from about 100 gigawatts in 2004 to about 109 gigawatts in 2019 and to remain at that level (about 10 percent of total U.S. generating capacity) through 2030. The total projected increase in nuclear capacity between 2004 and 2030 includes 3 gigawatts expected to come from uprates of existing plants that continue operating and 6 gigawatts of capacity at newly constructed power plants, stimulated by the provisions in EPACT2005, that are expected to begin operation between 2014 and 2020.

Additional nuclear capacity is projected in some of the alternative *AEO2006* cases. Total electricity generation from nuclear power plants is projected to grow

Figure 5. Electricity generation by fuel, 1980-2030 (billion kilowatthours)



from 789 billion kilowatthours in 2004 to 871 billion kilowatthours in 2030 in the *AEO2006* reference case, accounting for about 15 percent of total generation in 2030.

The use of renewable technologies for electricity generation is projected to grow, stimulated by improved technology, higher fossil fuel prices, and extended tax credits in EPACT2005 and in State renewable energy programs (RPS, mandates, and goals). The expected impacts of State RPS programs, which specify a minimum share of generation or sales from renewable sources, are included in the projection. The *AEO2006* reference case also includes the extension and expansion of the Federal tax credit for renewable generation through December 31, 2007, as enacted in EPACT2005. Total renewable generation in the *AEO2006* reference case, including CHP, is projected to grow by 1.7 percent per year, from 358 billion kilowatthours in 2004 to 559 billion kilowatthours in 2030.

The Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR), issued by the U.S. Environmental Protection Agency (EPA) in March 2005, are expected to result in large reductions of pollutant emissions from power plants. In the *AEO2006* reference case, projected emissions of sulfur dioxide (SO_2) from electric power plants in 2025 are 58 percent lower, emissions of nitrogen oxide 50 percent lower, and emissions of mercury 70 percent lower than projected in the *AEO2005* reference case.

Energy Production and Imports

Net imports of energy on a Btu basis are projected to meet a growing share of total U.S. energy demand (Figure 6). In the *AEO2006* reference case, net imports are expected to constitute 32 percent and 33 percent of total U.S. energy consumption in 2025 and 2030, respectively, up from 29 percent in 2004. In comparison, the *AEO2005* reference case projected a 38-percent share for net imports in 2025. Higher projections for crude oil and natural gas prices in *AEO-2006* are expected to lead to increases in domestic energy production (Figure 7) and reductions in demand, reducing the projected growth in imports as compared with the *AEO2005* projections.

The projections for U.S. crude oil production, domestic petroleum supply, and net petroleum imports in the *AEO2006* reference case are also significantly different from those in *AEO2005*. U.S. crude oil production in the *AEO2006* reference case is projected to increase from 5.4 million barrels per day in 2004 to a peak of 5.9 million barrels per day in 2014 as a result of increased production offshore, predominantly from the deep waters of the Gulf of Mexico. Production is then projected to fall to 4.6 million barrels per day in 2030. In the *AEO2005* reference case, U.S. crude oil production was projected to peak in 2009 at 6.2 million barrels per day and then fall to 4.7 million barrels per day in 2025.

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 *AEO2006* reference case, increasing from 8.6 million barrels per day in 2004 to a peak of 10.5 million barrels per day in 2021, then declining to 10.4 million barrels per day in 2025 and remaining at about that level through 2030. The *AEO2005* projection for total domestic petroleum supply in 2025 was lower, at 8.8 million barrels per day.

In 2025, net petroleum imports, including both crude oil and refined products, are expected to account for 60 percent of demand (on the basis of barrels per day) in the *AEO2006* reference case, up from 58 percent in 2004. In *AEO2005*, net petroleum imports accounted for 68 percent of demand in 2025. The market share

Figure 6. Total energy production and consumption, 1980-2030 (quadrillion Btu)

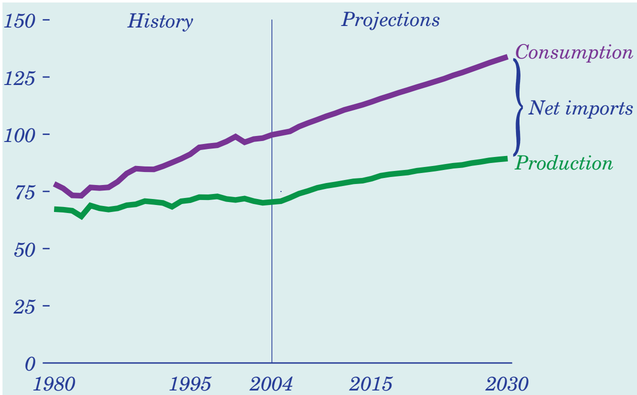
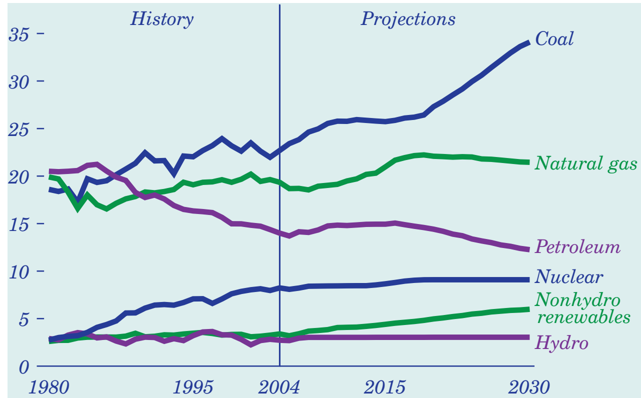


Figure 7. Energy production by fuel, 1980-2030 (quadrillion Btu)



of net petroleum imports grows to 62 percent of demand in 2030 in the *AEO2006* reference case. Despite an expected increase in distillation capacity at domestic refineries in *AEO2006*, net imports of refined petroleum products account for a growing portion of total net imports, increasing from 17 percent in 2004 to 22 percent in 2030.

Total domestic natural gas production, excluding supplemental natural gas supplies, increases from 18.5 trillion cubic feet in 2004 to 21.6 trillion cubic feet in 2019, before declining to 20.8 trillion cubic feet in 2030 in the *AEO2006* reference case. In 2025, domestic natural gas production is projected to be 21.2 trillion cubic feet, compared with 21.8 trillion cubic feet in the *AEO2005* reference case. The lower level of domestic natural gas production in the *AEO2006* reference case is entirely attributable to lower levels of offshore production. Offshore natural gas production in 2025 is lower in the *AEO2006* reference case than it was in *AEO2005*, due at least in part to the impacts of Hurricanes Katrina and Rita, which are expected to delay offshore drilling projects because of a lack of rigs and to have a long-term effect on production levels as a result of the slow recovery of production from existing fields.

The incorporation of EIA data showing a lower level of new reserve discoveries in 2004 than had been anticipated also affects the long-term forecast for offshore natural gas production. Lower 48 offshore production is projected to fall slightly from the 2004 level of 4.3 trillion cubic feet and then grow steadily through 2015, peaking at 5.1 trillion cubic feet as new resources come on line in the Gulf of Mexico. After 2015, lower 48 offshore production declines to 4.3 trillion cubic feet in 2025 and 4.0 trillion cubic feet in 2030. In the *AEO2005* reference case, offshore natural gas production was projected to increase more quickly and reach higher levels, peaking at 5.3 trillion cubic feet in 2014 before falling to 4.9 trillion cubic feet in 2025. The projection for onshore production of natural gas is also generally lower for most of the projection period in the *AEO2006* reference case than was projected in *AEO2005*. In the later years of the *AEO2006* reference case, however, with higher natural gas prices, onshore production grows strongly, to 14.7 trillion cubic feet in 2025—equal to the *AEO2005* projection. Projected onshore production in *AEO2006* remains at the 2025 level through 2030.

Lower 48 production of unconventional natural gas is expected to be a major contributor to growth in U.S. natural gas supplies. Unconventional natural gas production is projected to account for 45 percent of domestic U.S. natural gas production in 2030, as compared with the *AEO2005* reference case projection of 39 percent in 2025. In *AEO2006*, however, unconventional natural gas production is lower in the mid-term (between 2006 and 2020) than was projected in *AEO2005*. The lower levels of production in *AEO2006* before 2021 reflect a decline in overall natural gas consumption in response to higher prices. Starting in 2021, the projected levels of unconventional natural gas production in the *AEO2006* reference case are higher than those in *AEO2005,* reaching 9.5 trillion cubic feet in 2030.

Construction planning for the Alaska natural gas pipeline is expected to start soon, and the new pipeline is expected to be completed by 2015. When the pipeline goes into operation, Alaska's total natural gas production is projected to increase to 2.2 trillion cubic feet in 2025 (from 0.4 trillion cubic feet in 2004), the same level as projected in the *AEO2005* reference case.

The projection for net U.S. pipeline imports of natural gas from Canada and Mexico (predominantly Canada) in the *AEO2006* reference case in 2025 is 1.3 trillion cubic feet lower than was projected in *AEO2005*. *AEO2006* projects a continued decline in net pipeline imports, to 1.2 trillion cubic feet in 2030, as a result of depletion effects and growing domestic demand in Canada. The *AEO2006* reference case reflects an expectation that growth in Canada's unconventional natural gas production (primarily from coal seams) will not be adequate to offset a decline in conventional production in Alberta, based in part on data and projections from Canada's National Energy Board and other sources.

Growth in LNG imports is projected to meet much of the increased demand for natural gas in the *AEO2006* reference case, but the increase is less than was projected in the *AEO2005* reference case. The growth in LNG imports is moderated by three factors: higher natural gas prices reduce domestic consumption; higher world oil prices increase worldwide demand for natural gas and LNG imports, which raises the price of LNG; and, to a lesser extent, higher world oil prices lead to higher foreign demand for GTL production, which uses more natural gas as a feedstock, further increasing the price pressure on natural gas and LNG. Except for expansions of three of the four existing onshore U.S. LNG terminals (Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana), the completion of U.S. terminals currently under construction, and the addition of new facilities to serve the Gulf Coast, Southern California, Florida, and New England, no other new facilities are projected to be built to serve U.S. markets in the *AEO2006* reference case.

Total net imports of LNG to the United States in the *AEO2006* reference case are projected to increase from 0.6 trillion cubic feet in 2004 to 4.1 trillion cubic feet in 2025 (about two-thirds of the import volumes projected in the *AEO2005* reference case) and to 4.4 trillion cubic feet in 2030. In some of the *AEO2006* alternative cases, however, particularly those with relatively higher natural gas prices, additional LNG imports and new terminals are projected.

As domestic coal demand grows in the *AEO2006* reference case, U.S. coal production increases at an average rate of 1.5 percent per year, from 1,125 million tons in 2004 to 1,530 million tons in 2025 (higher than the 2025 projection of 1,488 million tons in *AEO2005*) and to 1,703 million tons in 2030. Production from mines west of the Mississippi River is expected to provide the largest share of the incremental coal production. In 2030, almost 63 percent of coal production is projected to originate from the western States if coal transportation costs remain stable.

Typically, U.S. coal production is driven by demand for electricity generation; however, projected electricity demand in 2025 is lower in *AEO2006* than in *AEO2005*, and the projected demand for coal in the electric power sector in 2025 is also lower (1,354 million tons in the *AEO2006* reference case, compared with 1,425 million tons in the *AEO2005* reference case), despite greater reliance on coal for electric power generation in the *AEO2006* forecast. The projected increase in coal production in *AEO2006* is the result of higher levels of coal use in CTL production, projected to grow to 62 million short tons in 2020 and 190 million short tons in 2030. No coal use for CTL production was projected in the *AEO2005* reference case.

Carbon Dioxide Emissions

Carbon dioxide (CO_2) emissions from energy use are projected to increase from 5,900 million metric tons in 2004 to 7,587 million metric tons in 2025 and 8,114 million metric tons in 2030 in the *AEO2006* reference case (Figure 8), an average annual increase of 1.2 percent per year. The CO_2 emissions intensity of the U.S. economy is projected to fall from 549 metric tons per million dollars of GDP in 2004 to 377 metric tons per million dollars of GDP in 2025, an average decline of 1.8 percent per year, and to 351 metric tons per million dollars of GDP in 2030. In comparison, the *AEO2005* reference case projected a 1.5-percent average annual decline in emissions intensity between 2004 and 2025 and 8,062 million metric tons of CO_2 emissions in 2025.

Projected CO_2 emissions in 2025 are lower in all sectors in the *AEO2006* reference case than they were in *AEO2005*, as higher energy prices slow energy consumption growth in all sectors. Total primary energy consumption in 2025 is more than 6 quadrillion Btu lower in *AEO2006* than was projected in *AEO2005*. Some of the effect of the lower projected consumption on CO_2 emissions in the *AEO2006* reference case after 2020 is offset by a proportionately higher share of coal use for electricity generation and the increased use of coal at CTL plants.

Figure 8. Projected U.S. carbon dioxide emissions by sector and fuel, 1990-2030 (million metric tons)

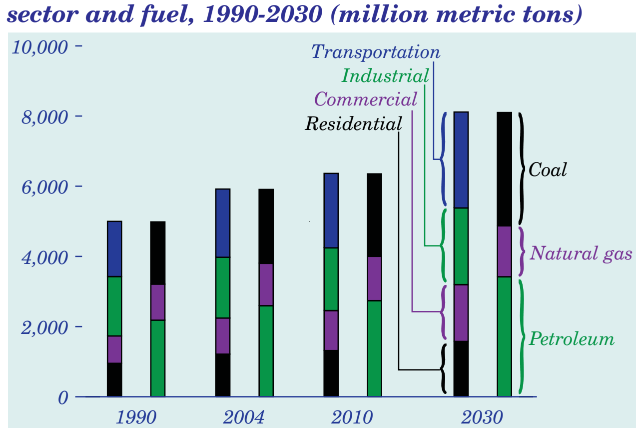


Table 1. Total energy supply and disposition in the *AEO2006* reference case: summary, 2003-2030

Energy and economic factors	2003	2004	2010	2015	2020	2025	2030	Average annual change, 2004-2030
Primary energy production (quadrillion Btu)								
Petroleum	14.40	13.93	14.83	14.94	14.41	13.17	12.25	-0.5%
Dry natural gas	19.63	19.02	19.13	20.97	22.09	21.80	21.45	0.5%
Coal	22.12	22.86	25.78	25.73	27.30	30.61	34.10	1.6%
Nuclear power	7.96	8.23	8.44	8.66	9.09	9.09	9.09	0.4%
Renewable energy	5.69	5.74	7.08	7.43	8.00	8.61	9.02	1.8%
Other	0.72	0.64	2.16	2.85	3.16	3.32	3.44	6.7%
Total	**70.52**	**70.42**	**77.42**	**80.58**	**84.05**	**86.59**	**89.36**	**0.9%**
Net imports (quadrillion Btu)								
Petroleum	24.19	25.88	26.22	28.02	30.39	33.11	36.49	1.3%
Natural gas	3.39	3.49	4.45	5.23	5.15	5.50	5.72	1.9%
Coal/other (- indicates export)	-0.45	-0.42	-0.58	0.20	0.90	1.54	2.02	NA
Total	**27.13**	**28.95**	**30.09**	**33.44**	**36.44**	**40.15**	**44.23**	**1.6%**
Consumption (quadrillion Btu)								
Petroleum products	38.96	40.08	43.14	45.69	48.14	50.57	53.58	1.1%
Natural gas	23.04	23.07	24.04	26.67	27.70	27.78	27.66	0.7%
Coal	22.38	22.53	25.09	25.66	27.65	30.89	34.49	1.7%
Nuclear power	7.96	8.23	8.44	8.66	9.09	9.09	9.09	0.4%
Renewable energy	5.70	5.74	7.08	7.43	8.00	8.61	9.02	1.8%
Other	0.02	0.04	0.07	0.08	0.05	0.05	0.05	0.9%
Total	**98.05**	**99.68**	**107.87**	**114.18**	**120.63**	**126.99**	**133.88**	**1.1%**
Petroleum (million barrels per day)								
Domestic crude production	5.69	5.42	5.88	5.84	5.55	4.99	4.57	-0.7%
Other domestic production	3.10	3.21	3.99	4.50	4.90	5.45	5.84	2.3%
Net imports	11.25	12.11	12.33	13.23	14.42	15.68	17.24	1.4%
Consumption	20.05	20.76	22.17	23.53	24.81	26.05	27.57	1.1%
Natural gas (trillion cubic feet)								
Production	19.11	18.52	18.65	20.44	21.52	21.24	20.90	0.5%
Net imports	3.29	3.40	4.35	5.10	5.02	5.37	5.57	1.9%
Consumption	22.34	22.41	23.35	25.91	26.92	26.99	26.86	0.7%
Coal (million short tons)								
Production	1,083	1,125	1,261	1,272	1,355	1,530	1,703	1.6%
Net imports	-18	-21	-26	5	36	63	83	NA
Consumption	1,095	1,104	1,233	1,276	1,390	1,592	1,784	1.9%
Prices (2004 dollars)								
Imported low-sulfur light crude oil (dollars per barrel)	31.72	40.49	47.29	47.79	50.70	54.08	56.97	1.3%
Imported crude oil (dollars per barrel)	28.46	35.99	43.99	43.00	44.99	47.99	49.99	1.3%
Domestic natural gas at wellhead (dollars per thousand cubic feet)	5.08	5.49	5.03	4.52	4.90	5.43	5.92	0.3%
Domestic coal at minemouth (dollars per short ton)	18.40	20.07	22.23	20.39	20.20	20.63	21.73	0.3%
Average electricity price (cents per kilowatthour)	7.6	7.6	7.3	7.1	7.2	7.4	7.5	0.0%
Economic indicators								
Real gross domestic product (billion 2000 dollars)	10,321	10,756	13,043	15,082	17,541	20,123	23,112	3.0%
GDP chain-type price index (index, 2000=1.000)	1.063	1.091	1.235	1.398	1.597	1.818	2.048	2.5%
Real disposable personal income (billion 2000 dollars)	7,742	8,004	9,622	11,058	13,057	15,182	17,562	3.1%
Value of manufacturing shipments (billion 2000 dollars)	5,378	5,643	6,355	7,036	7,778	8,589	9,578	2.1%
Energy intensity (thousand Btu per 2000 dollar of GDP)	**9.51**	**9.27**	**8.28**	**7.58**	**6.88**	**6.32**	**5.80**	**-1.8%**
Carbon dioxide emissions (million metric tons)	**5,785**	**5,900**	**6,365**	**6,718**	**7,119**	**7,587**	**8,114**	**1.2%**

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.

Source: AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Legislation and Regulations

Legislation and Regulations

Introduction

Because analyses by EIA are required to be policy-neutral, the projections in *AEO2006* generally are based on Federal and State laws and regulations in effect on or before October 31, 2005. **The potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require implementing regulations or appropriation of funds that are not provided or specified in the legislation itself—are not reflected in the projections.**

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

- EPACT2005, which, among other actions, includes mandatory energy conservation standards; creates numerous tax credits for businesses and individuals, covering energy-efficient appliances, hybrid vehicles, small biodiesel producers, and new nuclear power capacity; creates a renewable fuels standard (RFS); eliminates the oxygen content requirement for Federal reformulated gasoline (RFG); extends royalty relief for offshore oil and natural gas producers; and extends and expands the production tax credit (PTC) for electricity generated from renewable fuels
- The Military Construction Appropriations Act of 2005, which contains provisions to support construction of the Alaska natural gas pipeline, including Federal loan guarantees during construction
- The Working Families Tax Relief Act of 2004, which includes an extension of the 1.8-cent PTC for electricity generated from wind and closed-loop biomass to December 31, 2005; tax deductions for qualified clean-fuel and electric vehicles; and changes in the rules governing oil and natural gas well depletion
- The American Jobs Creation Act of 2004, which includes incentives and tax credits for biodiesel fuels, a modified depreciation schedule for the Alaska natural gas pipeline, and an expansion of the 1.8-cent renewable energy PTC to include geothermal and solar generation technologies
- The Maritime Security Act of 2002, which amended the Deepwater Port Act of 1974 to include offshore natural gas facilities
- State renewable portfolio standard (RPS) programs, including the California RPS passed on September 12, 2002
- The 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
- 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 Omnibus Budget Reconciliation Act of 1993, which added 4.3 cents per gallon to the Federal tax on highway fuels
- The Energy Policy Act of 1992 (EPACT1992)
- The Clean Air Act Amendments of 1990 (CAAA90), which included new standards for motor gasoline and diesel fuel and for heavy-duty vehicle emissions
- The National Appliance Energy Conservation Act of 1987
- State programs for restructuring of the electricity industry.

AEO2006 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 2003 levels (the last time the Federal taxes were changed) in nominal terms. *AEO2006* also assumes that the ethanol tax credit as modified under the American Jobs Creation Act of 2004 will be extended when it expires in 2010 and will remain in force indefinitely. Although these tax and tax incentive provisions include "sunset" clauses that limit their duration, they have been extended historically, and *AEO2006* assumes their continuation throughout the forecast. *AEO2006* also includes the biodiesel tax credits created under EPACT2005, but they are not assumed to be extended, because they have no history of legislative extension.

Selected examples of Federal and State regulations incorporated in *AEO2006* include the following:

- CAIR and CAMR—promulgated by the EPA in March 2005 and published in the *Federal Register* as final rules in May 2005—which will limit emissions from power plants in the United States
- New boiler limits established by the EPA on February 26, 2004, which limit emissions of hazardous air pollutants from industrial, commercial,

and institutional boilers and process heaters by requiring that they comply with a Maximum Achievable Control Technology (MACT) floor

- Corporate average fuel economy (CAFE) standards for light trucks promulgated by the National Highway Traffic Safety Administration (NHTSA) in 2003 (but not the new proposed increase in fuel economy standards for light trucks based on vehicle footprint in model years 2008 through 2011, which have not been promulgated)
- The December 2002 Hackberry Decision, which terminated open access requirements for new onshore receiving terminals for LNG

AEO2006 includes the CAAA90 requirement of a phased-in reduction in vehicle emissions of regulated pollutants. It also reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements finalized by the EPA in February 2000 under CAAA90. The Tier 2 standards for RFG were required by 2004, but because they included allowances for small refineries, they will not be fully realized for conventional gasoline until 2008. *AEO2006* also incorporates the ultra-low-sulfur diesel fuel (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 100 percent ULSD thereafter. It also includes the rules for nonroad diesel issued by the EPA on May 11, 2004, regulating nonroad diesel engine emissions and sulfur content in fuel.

The *AEO2006* 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 25 States. It is assumed that MTBE will be phased out completely by the end of 2008 as a result of EPACT2005, which repealed the oxygenate requirement for RFG.

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

EPACT2005 Summary

The U.S. House of Representatives passed H.R. 6 EH, the Energy Policy Act of 2005, on April 21, 2005, and the Senate passed H.R. 6 EAS on June 28, 2005. A conference committee was convened to resolve differences between the two bills, and a report was approved and issued on July 27, 2005. The House approved the conference report on July 28, 2005, and the Senate followed on July 29, 2005. EPACT2005 was signed into law by President Bush on August 8, 2005, and became Public Law 109-058 [*1*].

Consistent with the general approach adopted in the *AEO*, provisions in EPACT2005 that require funding appropriations to implement, whose impact is highly uncertain, or that require further specification by Federal agencies or Congress are not included in *AEO2006*. For example, EIA does not try to anticipate policy responses to the many studies required by EPACT2005, nor to predict the impact of R&D funding authorizations included in the bill. Moreover, *AEO2006* does not include any provision that addresses a level of detail beyond that modeled in EIA's National Energy Modeling System (NEMS), which was used to develop the *AEO2006* projections. *AEO2006* includes only about 30 sections of EPACT2005, which establish specific tax credits, incentives, or standards in the following areas:

- Mandatory energy conservation standards for torchiere lamps, dehumidifiers, and ceiling fan light kits in the residential sector and for lighting equipment, packaged air conditioning and heating equipment, refrigerator and freezer equipment, automatic icemakers, pre-rinse spray valves, exit signs, distribution transformers, and traffic signals in the commercial sector
- Tax credits for businesses and builders investing in energy efficiency and renewable energy properties; for purchasers of energy-efficient equipment, including water heaters, air conditioners, heat pumps, furnaces, boilers, windows, and other energy-efficient building shell products; for producers of energy-efficient clothes washers, dishwashers, and refrigerators; for purchasers of solar water heaters, solar photovoltaic (PV) equipment, and fuel cells; for businesses investing in fuel cells and microturbines; and for businesses investing in solar energy properties
- Tax credits for the purchase of vehicles with lean burn engines or with hybrid or fuel cell propulsion systems
- An RFS that requires the production and use of defined amounts of renewable fuel by specific dates
- Elimination of the oxygen content requirement for RFG
- Extension of tax credits for biodiesel producers and small ethanol producers
- A tax credit for small agri-biodiesel producers

- Royalty relief for oil and natural gas production in water depths greater than 400 meters in the Gulf of Mexico
- Restrictions on new oil and natural gas drilling in or under the Great Lakes
- Reduction of the existing capital recovery period for new electric transmission and distribution assets from 20 years to 15 years
- Expansion of the amortization period for pollution control equipment on coal-fired power plants from 5 years to 7 years
- A PTC of 1.8 cents per kilowatthour for up to 6,000 megawatts of new nuclear capacity brought online before 2021
- An investment tax credit for the construction and development of new or repowered coal-fired generating projects
- Extension, modification, and expansion of the PTC for renewable electricity generation.

The following discussion provides a summary of the provisions in EPACT2005 that are included in *AEO2006* and some of the provisions that could be included if more complete information were available about their funding and implementation. This discussion is not a complete summary of all the sections of EPACT2005. More extensive summaries are available from other sources [*2*].

End-Use Demand

This section summarizes the provisions of EPACT-2005 that affect the end-use demand sectors.

Buildings

EPACT2005 includes provisions with the potential to affect energy demand in the residential and commercial buildings sector. Many are included in Title I, "Energy Efficiency." Others can be found in the renewable energy, R&D, and tax titles.

Sections 101 through 105 and Section 109 address Federal energy use, allowing for energy conservation measures in congressional buildings (Section 101); updating Executive Order mandates regarding Federal purchasing requirements and energy intensity reductions (Sections 102 through 104); extending the use of Energy Savings Performance Contracts to finance projects through 2016 (Section 105); and updating performance standards for Federal buildings (Section 109). The Federal purchasing requirements and performance standards are represented in NEMS as a result of earlier Executive Orders. Other aspects of these provisions address a level of detail that is not modeled in NEMS.

Sections 135 and 136 establish or tighten mandatory energy conservation standards for a number of residential products and appliances and commercial equipment, affecting projected residential and commercial energy use. Standards for torchiere lamps are explicitly modeled in NEMS, allowing for a direct accounting of energy savings from a maximum watt allowance. Savings resulting from standards for residential dehumidifiers and ceiling fan light kits, based on shipment estimates, are phased in over the *AEO2006* forecast period to account for capital stock turnover. Standards for explicitly modeled commercial equipment, including lighting equipment, packaged air conditioning and heating equipment, refrigerator and freezer equipment, and automatic icemakers, are directly represented in the *AEO2006* projections. Savings resulting from standards for exit signs, traffic signals, distribution transformers, and pre-rinse spray valves are estimated and phased in over the *AEO2006* forecast period to account for capital stock turnover.

Provisions under Title XIII provide tax credits to businesses and individuals for investment in energy efficiency and renewable energy properties. Section 1332 provides a tax credit of $1,000 or $2,000 to builders of homes that are 30 or 50 percent more efficient than current code in 2006 and 2007. Section 1333 allows tax credits for purchasers of energy-efficient equipment, including water heaters, air conditioners, heat pumps, furnaces, boilers, windows, and other energy-efficient building shell products. The credit is available in 2006 and 2007, and the amount varies with the technology purchased. Section 1334 provides a tax credit for producers of energy-efficient clothes washers, dishwashers, and refrigerators. Section 1335 provides tax credits for purchasers of solar water heaters, solar PV equipment, and fuel cells for the years 2006 and 2007. All these tax credits are represented in *AEO2006*. For modeling purposes, it is assumed that the credits will be passed on to consumers in the form of lower first costs for purchases of the products specified.

Section 1336 provides a business investment tax credit of 30 percent for fuel cells and 10 percent for microturbines, and Section 1337 increases the business investment tax credit for solar property from the current level of 10 percent to 30 percent. These provisions, which apply to property installed in 2006 or 2007, are included in *AEO2006*.

Industrial

EPACT2005 includes few provisions that specifically affect industrial sector energy demand. Provisions in the R&D titles that may affect industrial energy consumption over the long term are not included in *AEO2006*.

Section 108 requires that federally funded projects involving cement or concrete increase the amount of recovered mineral component (e.g., fly ash or blast furnace slag) used in the cement. Such use of mineral components is a standard industry practice, and increasing the amount could reduce both the quantity of energy used for cement clinker production and the level of process-related CO_2 emissions. Because the proportion of mineral component is not specified in the legislation, this provision is not included in *AEO2006*. When regulations are promulgated, their estimated impact could be modeled in NEMS.

Section 1321 extends the Section 29 PTC for nonconventional fuel to facilities producing coke or coke gas. The credit is available for plants placed in service before 1993 and between 1998 and 2010. Each plant can claim the credit for 4 years; however, the total credit is limited to an annual average of 4,000 barrels of oil equivalent (BOE) per day. The value of the credit is currently $3.00 per BOE, and it will be adjusted for inflation in the future indexed to 2004. Previously, the $3.00 credit had been indexed to 1979, and its value in 2004 was estimated at $6.56 per BOE [*3*]. Because the bulk of the credits will go to plants already operating or under construction, there is likely to be little impact on coke plant capacity.

Transportation

EPACT2005 includes many provisions with potential effects on energy demand, alternative fuel use, and vehicle emissions in the transportation sector. These provisions provide for research, development, and demonstration (RD&D) of technologies and alternative fuels. These provisions are not reflected in *AEO2006* because of the uncertainty associated with the impacts of RD&D programs. The act also calls for policy studies and tax incentives to promote improved energy efficiency and increase alternative fuel use. Provisions specific to the supply of alternative transportation fuels are discussed below, in the sections on petroleum and renewable energy.

EPACT2005 provides a tax credit for the purchase of vehicles that have lean burn engines or employ hybrid or fuel cell propulsion systems. The amount of the credit is based the vehicle's inertia weight, improvement in city-tested fuel economy relative to an equivalent 2002 base year value, emissions classification, and type of propulsion system. The tax credit is also sales-limited, by manufacturer, for vehicles with lean burn engines or hybrid propulsion systems. A phaseout period begins with the first calendar quarter after December 31, 2005, in which a manufacturer's sales of lean burn or hybrid vehicles reach 60,000 units. Reduction of the credits begins in the following quarter. For that quarter and the next, the applicable tax credit will be reduced by 50 percent. For the next two quarters, the tax credit will be reduced to 25 percent of the original value. These tax credits are included in *AEO2006*.

Petroleum, Ethanol, and Biofuel Provisions

This section summarizes the numerous provisions of EPACT2005 affecting the supply, composition, and refining of petroleum and related products that are included in *AEO2006*.

Renewable Fuels Standard

Section 1501 includes an RFS that requires the production and use of 4.0 billion gallons of renewable fuels in 2006, increasing to 7.5 billion gallons in 2012. For calendar year 2013 and each year thereafter, the minimum required volume of renewable fuels would be an amount equal to the percentage of total gasoline sold in the Nation in that year that was represented by 7.5 billion gallons in 2012. In addition, starting in 2013, the required amount of renewable fuels must include a minimum of 250 million gallons derived from cellulosic biomass. Small refineries with a capacity not exceeding 75,000 barrels per calendar day are exempted from the RFS until 2011. Noncontiguous States or territories (Alaska, Hawaii, Puerto Rico, Guam, etc.) are not covered but could petition to join the renewable fuels program. Both ethanol and biodiesel are considered to be renewable fuels, and a 2.5-gallon credit toward the RFS is provided for every gallon of cellulosic biomass ethanol produced. A program of renewable fuels credits would allow refiners, blenders, and importers flexibility to comply with the RFS across geographical regions and over successive years.

The RFS is modeled in *AEO2006*, both for the minimum required volumes and for ethanol derived from cellulosic biomass. Actual renewable fuel supplies may or may not exceed those minimum requirements, depending on the relative costs of renewable fuels and competing petroleum products. In the *AEO2006* reference case, ethanol consumption is projected to exceed the RFS, because it is projected to be available at relatively low cost. *AEO2006* implicitly reflects the ethanol production and consumption behavior that resembles the effect of a national RFS credit trading system, resulting in ethanol blending in gasoline that varies by region.

Elimination of Oxygen Requirement for Reformulated Gasoline

Section 1504 eliminates the oxygen content requirement for RFG. This provision takes effect immediately in California and 270 days after enactment of EPACT2005 in the rest of the RFG regions. Without the oxygen content requirement, refiners are likely to phase out MTBE in gasoline as soon as practical to minimize exposure to environmental liabilities in the future. Several refiners have announced plans to stop making MTBE when the oxygen content requirement expires. Also in Section 1504, volatile organic compound (VOC) Control Regions 1 (southern) and 2 (northern) for RFG would be consolidated by eliminating the less stringent requirements applicable to gasoline designated for VOC Control Region 2.

Elimination of the oxygen requirement for RFG is included in *AEO2006*. MTBE is assumed to be phased out in all regions by the end of 2008. Ethanol is likely to be favored in RFG blending in most regions, based on economics and its other attractive blending characteristics, such as high octane value.

Biofuel Tax Credits

Currently, 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 cent is deposited in the Leaking Underground Storage Tank Trust Fund, which is extended through 2011 under Section 1362 of EPACT2005. The volumetric excise tax credit program, established in the American Jobs Creation Act of 2004, covers both ethanol and biodiesel. It allows producers to claim the tax credit directly on biofuels: 51 cents per gallon of ethanol, $1 per gallon of biodiesel made from agricultural commodities such as soybean oil, and 50 cents per gallon of biodiesel made from recycled oil such as yellow grease. The biodiesel tax credit is extended through 2008 under Section 1344 of EPACT2005, and the ethanol tax credit was previously extended through 2010 under the American Jobs Creation Act of 2004. Historically, the ethanol tax credit has been extended when it expired; *AEO2006* assumes that it will remain in force indefinitely. The biodiesel tax credits are included in *AEO2006*, but it is not assumed that they will be extended indefinitely, because they are relatively new and have only a short history of legislative extension.

Section 1345 provides for an additional credit up to 10 cents per gallon for small agri-biodiesel producers with annual production of 15 million gallons or less. Small ethanol producers currently cannot have production capacity above 30 million gallons per year to qualify for the special credit. Section 1347 raises the capacity limit to 60 million gallons per year. *AEO2006* includes both the credit for small agri-biodiesel producers and the change in the application of the credit for small ethanol producers.

Tax Incentives Related to Petroleum Refining

Section 1323 provides temporary expensing for refinery investments, which would allow taxpayers to depreciate immediately 50 percent of the cost of all investment that increases the capacity of an existing refinery by at least 5 percent or increases the throughput of qualified fuels by at least 25 percent. Qualified fuels include oil from shale and tar sands. As a condition of eligibility, refiners of liquid fuels must report the details of refinery operations to the Internal Revenue Service. Section 392 also authorizes the EPA, in a cooperative agreement with a State, to streamline the review of a refinery permit application. Because NEMS does not model individual refinery investment decisions, this provision is not included in *AEO2006*.

Natural Gas Provisions

EPACT2005 contains several provisions intended to encourage or facilitate the development of domestic oil and natural gas resources and the domestic infrastructure for importing LNG. Most are in Title III, “Oil and Gas.” Others, covering R&D and tax measures, are included in Titles IX and XIII.

Section 311 clarifies the role of the Federal Energy Regulatory Commission (FERC) as the final decisionmaking body on the construction, expansion, or operation of any facility that exports, imports, or processes LNG. Although it grants final authority to FERC, it directs the commission to consult with the States on safety issues. Section 317 requires the U.S. Department of Energy (DOE), in cooperation with the U.S. Departments of Transportation and Homeland Security, to conduct at least three forums on LNG, which are to be held in areas where LNG terminals are being considered for construction and to be designed to promote public education and encourage cooperation between State and Federal officials. Because the *AEO2006* reference case already assumes that siting issues for LNG terminals are not insurmountable, no changes were made in NEMS to address the LNG-related provisions in EPACT2005.

In addition, it is unclear to what degree this provision will affect the siting of regasification terminals.

Under Section 312, FERC is given the authority to permit a natural gas company to provide facilities for natural gas storage at market-based rates if it believes the company will not exert market power. NEMS already assumes some market impact as a result of incentive-based rates.

Sections 321, 322, and 323 clarify provisions of the Outer Continental Shelf Lands Act, the Safe Drinking Water Act, and the Federal Water Pollution Control Act. Sections 341 and 342 provide clarifications of existing programs. Sections 343 through 347 address royalty relief. Specifically, Sections 343 and 344 address incentives for natural gas production from marginal wells and from deep wells in the shallow waters of the Gulf of Mexico; Section 346 suspends royalties on offshore production in Alaska; and Section 347 provides royalty relief for production from the National Petroleum Reserve, at the discretion of the Secretary of Energy. Sections 353 and 354 deal with royalty relief for natural gas extracted from methane hydrates and for enhanced oil and natural gas production through CO_2 injection. None of these provisions is modeled in NEMS, and they are not included in *AEO2006*.

Section 345, which provides royalty relief for oil and natural gas production in water depths greater than 400 meters in the Gulf of Mexico from any oil or natural gas lease sale occurring within 5 years after enactment, is modeled in NEMS. The minimum production volumes for which royalty payments would be suspended are as follows:

- 5,000,000 BOE for each lease in water depths of 400 to 800 meters
- 9,000,000 BOE for each lease in water depths of 800 to 1,600 meters
- 12,000,000 BOE for each lease in water depths of 1,600 to 2,000 meters
- 16,000,000 BOE for each lease in water depths greater than 2,000 meters.

For *AEO2006*, the water depth categories specified in Section 345 were adjusted to be consistent with the depth categories in the Offshore Oil and Gas Supply Submodule of NEMS. The suspension volumes are 5,000,000 BOE for leases in water depths 200 to 800 meters; 9,000,000 BOE for leases in water depths of 800 to 1,600 meters; 12,000,000 BOE for leases in water depth of 1,600 to 2,400 meters; and 16,000,000 BOE for leases in water depths greater than 2,400 meters. Examination of the resources available at 200 to 400 and 2,000 to 2,400 meters showed that the differences between the depths used in the model and those specified in the act would not materially affect the model results.

Section 386, which prohibits new oil and natural gas drilling in or under the Great Lakes, is included in *AEO2006*. Specifically, it states that no Federal or State permit or lease shall be issued for new oil or natural gas slant, directional, or offshore drilling in or under one or more of the Great Lakes. To reflect this provision, oil and natural gas resources underlying the Great Lakes were removed from the resource base of the Oil and Gas Supply Module in NEMS.

In Title XIII, Sections 1325 through 1327 provide tax incentives for the oil and natural gas industries that include treatment of natural gas distribution lines as 15-year property, treatment of natural gas gathering lines as 7-year property, and exclusion of prepayments on natural gas supply contracts with government utilities from arbitrage rules. NEMS does not include sufficient detail for modeling these provisions.

Electricity Provisions

EPACT2005 includes provisions to improve the reliability and operation of the electricity transmission grid, reduce regulatory uncertainty, and increase consumer protection. These electricity provisions are included under Title XII, "Electricity Modernization Act of 2005." Most of them cannot be addressed at the level of detail included in NEMS or can be included only with additional specification not provided in EPACT2005. Title XIII, "Energy Tax Incentive Act of 2005," also includes tax incentives targeted toward electricity generation or transmission properties.

Section 1211 calls for the creation of mandatory reliability standards for the electricity grid to replace the voluntary standards in place today. The new standards would be administered by "electric reliability organizations" (EROs), which would be certified by FERC and would be responsible for developing and enforcing reliability standards for their regions. It is implicitly assumed in *AEO2006* that electricity will be provided reliably.

Several sections under Title XIII would affect the electric power industry. Section 1308 shortens the existing capital recovery period for new transmission and distribution assets from 20 years to 15 years. The property must have been placed in use after April 11, 2005, to qualify for the new recovery period. Section 1309 expands amortization of pollution control equipment on coal-fired plants from 5 years to 7 years. Only plants that came online after January 1, 1976, would qualify for the new amortization period. These tax changes are represented in *AEO2006*. Tax credits for nuclear and renewable energy production and for coal production and investment are discussed below.

Nuclear Energy Provisions

Title VI of EPACT2005 includes several provisions designed to ensure that nuclear energy will remain a major component of the Nation's energy supply. Sections 601 through 610 update the Price-Anderson Act Amendment to the Atomic Energy Act of 1954, which ensures that adequate funds are available to the public to satisfy liability claims in the event of a nuclear accident, while limiting the liability of any individual reactor owner. EPACT2005 extends the coverage to all nuclear units brought on line through 2025, adjusts the maximum assessment and liability limit, and addresses incidents that might occur outside the United States. Section 608 allows small, modular reactors to be combined and treated as a single unit for liability purposes. These provisions are not explicitly modeled in NEMS, but *AEO2006* implicitly assumes that Price-Anderson coverage will be extended to any new nuclear units built in the United States.

Under Title XIII, Section 1306 provides a PTC for new nuclear reactors brought online through 2020. The PTC is worth 1.8 cents per kilowatthour for the first 8 years of operation, subject to an annual limit of $125 million per gigawatt of capacity. It is restricted to a total of 6 gigawatts of new nuclear capacity. This provision is included in *AEO2006*. Section 1310 modifies the rules for qualified decommissioning funds and requires that a new ruling on the amounts funded be made whenever a plant receives a license renewal.

Coal Provisions

EPACT2005 includes numerous provisions that authorize funding for coal-related activities. Because they depend on future appropriations, they are not included in *AEO2006*.

Sections 431 through 438, referred to as the Coal Leasing Act, ease or remove certain requirements for coal leases on Federal lands. These provisions are not included in *AEO2006*, because specific lease requirements cannot be modeled directly in NEMS.

Title XIII includes several provisions that alter the tax treatment of certain coal-related activities. For example, Section 1301 sets qualifications for receipt of a PTC of $1.50 per ton between 2006 and 2009 and $2.00 per ton through 2013 for coal produced on Indian lands. This provision is not included in *AEO2006*, because only limited data are available on coal resources and production on Indian lands. (In 2000, coal was mined from Indian lands in Arizona, New Mexico, and Montana.) One possible outcome of this provision would be to accelerate production of coal from Indian lands while the credit is available; however, given the relatively short time horizon of the provision (qualifying mines must be in service before 2009) and the small share of total coal production made up by coal from Indian lands (3.6 percent in 2004), the impact on national average minemouth prices for coal is likely to be small.

Section 1307, Subsection 48A, establishes a $1.3 billion investment tax credit for the construction of new or repowered coal-fired generation projects, including $800 million for coal gasification projects and $500 million for other projects that achieve certain targets, such as 99 percent SO_2 removal and 90 percent mercury removal from plant emissions. For integrated gasification combined-cycle (IGCC) technologies a 20-percent investment tax credit may be applied to qualifying investments, and for other qualifying advanced technologies a 15-percent investment tax credit is applicable. Repowering projects must improve the thermal design efficiency of coal-fired plants by 4 to 7 percent. This provision is modeled in NEMS by allowing up to 3 gigawatts of IGCC and another 3 gigawatts of advanced coal-fired capacity to take advantage of the tax credit.

Renewable Energy Provisions

EPACT2005 contains several provisions intended to encourage or facilitate the use of renewable energy resources for electricity production. Most are included in Title II, "Renewable Energy." Others are in the R&D, electricity, and tax titles. In addition, the act contains provisions to encourage the use of renewable energy for transportation and in end-use applications, as described above.

Section 203 requires the Federal Government, to the extent that it is "economically feasible and technically practical," to purchase a minimum amount of electricity generated from renewable resources. The Federal purchase requirement starts at 3 percent of the total amount of electricity consumed by the Federal Government in 2007 and increases stepwise to 7.5 percent of the total in 2013 and thereafter. Renewable energy used at a Federal facility that is produced on-site at the facility, on Federal lands, or on Indian land will count double toward the requirement. Although the Federal Government is a major purchaser of electricity, the required purchases are not expected to affect the projections of renewable electricity demand in *AEO2006*.

Several sections specifically address the production of hydroelectricity at proposed or existing facilities. Section 241 revises the appeals process for the licensing of hydropower projects by FERC. Appeals on license conditions and fishway rulings will now be heard in a trial-type hearing. Applicants may also propose alternatives to the conditions specified by FERC to achieve the purposes of the original license conditions. The impacts of these provisions on the cost of developing or relicensing hydroelectric projects are not clear, and they are not included in *AEO2006*.

Under Title XII, a number of electricity market provisions directly address the use of renewable resources within the Nation's electricity grid. Section 1251 requires utilities to offer net metering upon customer request. Net metering means that eligible customer-sited generation resources may be used to offset gross customer electricity purchases during the billing cycle; that is, customer generation in excess of instantaneous demand will be fed back to the utility distribution system, causing the customer's meter to effectively "run backward." Eligible resources and applicable billing cycles are not defined in the provision, but credit will be given to States that have adopted or voted on comparable standards. Current State net metering standards typically allow renewable generation (solar and sometimes wind or other renewable fuels) and sometimes allow other favored technologies, such as fuel cells, to qualify. Generation is typically netted on a monthly basis, but netting may be allowed over longer periods. *AEO2006* assumes that excess generation from customer-sited sources will offset purchased electricity at retail rates.

Section 1253 eliminates the requirement for eligible utilities to purchase electricity from qualified facilities under the Public Utility Regulatory Policies Act (PURPA), which previously required utilities to purchase generation from small cogenerators and renewable plants at a rate equal to their avoided cost of generation. Eligible utilities must have open electricity markets, including nondiscriminatory access to wholesale generation markets and to transmission and interconnection services. *AEO2006* assumes that all generation resources will compete in a nondiscriminatory market for generation, capacity, and transmission services.

Several changes to the tax code, all involving the PTC for renewable generation, are expected to have significant impacts on the growth of renewable electricity markets. Section 1301 extends the eligibility date for new renewable generation facilities to qualify for the inflation-adjusted tax credit for the first 10 years of plant operation. Eligibility was set to expire after December 31, 2005, but will now expire after December 31, 2007. Although some eligible resources will continue to get the full, inflation-adjusted credit of 1.5 cents per kilowatthour and others one-half of that amount, all new eligible facilities—including efficiency improvements or additions of capacity at existing facilities—will receive the full credit for the first 10 years of their operation. *AEO2006* specifically accounts for the extension of the eligibility period for renewable resources and the expansion of the credit to hydroelectric facilities.

In addition to the PTC modifications discussed above, Section 1302 will allow agricultural cooperatives to allocate renewable energy production tax credits to their members, based on the "amount of business" done by each member with the cooperative. Eligible cooperatives include those that are more than 50 percent owned by agricultural producers or entities owned by agricultural producers, thus allowing otherwise tax-exempt electricity cooperatives to take advantage of the PTC by transferring the benefit directly to their membership. Although this provision is not specifically modeled, *AEO2006* assumes that all eligible renewable capacity is built by tax-paying entities and thus is entitled to take the PTC.

Incentives for Innovative Technologies

EPACT2005 Title XVII, "Incentives for Innovative Technologies," authorizes the Secretary of Energy, after consultation with the Secretary of the Treasury and subject to budget appropriations, to provide Federal loan guarantees for a wide variety of projects related to energy consumption and production technologies. Although EPACT2005 includes several other technology incentives, the Title XVII program has particular potential to influence the development of future energy technologies. The guarantees can cover up to 80 percent of the cost of a project over a period of up to 30 years (or 90 percent of a project's useful life, whichever is less). To be eligible, projects must avoid, reduce, or sequester air pollutants or anthropogenic greenhouse gas (GHG) emissions and must employ new or significantly improved technologies, as compared with those that are commercially available when the guarantee is issued. The eligible project categories include:

- Renewable energy systems
- Advanced fossil energy technologies, including coal gasification meeting certain requirements
- Hydrogen fuel cell technologies for residential, industrial, or transportation applications
- Advanced nuclear energy facilities
- Carbon capture and sequestration practices and technologies
- Technologies for efficient generation, transmission, and distribution of electric power
- Efficient end-use energy technologies
- Production facilities for fuel-efficient vehicles, including hybrids and advanced diesel vehicles
- Pollution control equipment
- Refineries.

Loan guarantees will also be available for gasification facilities that meet certain criteria. Eligible gasification projects include IGCC plants where 65 percent of the fuel used is a combination of coal, biomass, and petroleum coke and 65 percent of the energy output is used to produce electricity. IGCC plants with a capacity of at least 100 megawatts using western coal are also eligible. To receive loan guarantees, the IGCC projects must emit no more than 0.05 pound of SO_2, 0.08 pound of nitrogen oxides (NO_x), and 0.01 pound of particulates per million Btu of fuel input and must remove 90 percent of the mercury in any coal that is used.

Because funding levels and specific rules for this program are not yet known, its potential impacts are not represented in *AEO2006*. The program could provide a flexible tool for stimulating investment in a wide array of promising technologies [*4*]. The leverage achieved by the program will depend on the risks associated with the projects supported and the expected loss that would occur if a loan default occurred. For loans of the same size, riskier projects require more Federal funding.

California Greenhouse Gas Emissions Standards for Light-Duty Vehicles

The State of California was given authority under CAAA90 to set emissions standards for light-duty vehicles that exceed Federal standards. In addition, other States that do not comply with the National Ambient Air Quality Standards (NAAQS) set by the EPA under CAAA90 were given the option to adopt California's light-duty vehicle emissions standards in order to achieve air quality compliance. CAAA90 specifically identifies hydrocarbon, carbon monoxide, and NO_x as vehicle-related air pollutants that can be regulated. California has led the Nation in developing stricter vehicle emissions standards, and other States have adopted the California standards [*5*].

California Assembly Bill 1493 (A.B. 1493), signed into law in July 2002, required the California Air Resources Board (CARB) to develop and adopt GHG emissions standards for light-duty vehicles that would provide the maximum feasible reduction in emissions. In determining the maximum feasible standard, CARB was required to consider cost-effectiveness, technological capability, economic impacts, and flexibility for manufacturers in meeting the standard. CARB was not allowed to consider the following compliance options: mandatory trip reductions; land use restrictions; additional fees and/or taxes on any motor vehicle, fuel, or vehicle miles traveled; a ban on any vehicle category; reduction in vehicle weight; or a limitation or reduction of speed limits on any street or highway in the State. Tailpipe emissions of CO_2, which are directly proportional to vehicle fuel consumption, account for the vast majority of total GHG emissions from vehicles. In August 2004, CARB released a report detailing its proposed GHG emissions standards for light-duty vehicles, which were approved by California's Office of Administrative Law on September 15, 2005.

The standards approved in September 2005 cover GHG emissions associated with vehicle operation, air conditioning operation and maintenance, and production of vehicle fuel. The standards apply to noncommercial light-duty passenger vehicles manufactured for model years 2009 and beyond. The standards, specified in terms of CO_2 equivalent emissions, apply to vehicles in two size classes: passenger cars and small light-duty trucks with a loaded vehicle weight rating of 3,750 pounds or less; and heavy light-duty trucks with a loaded vehicle weight rating greater than 3,750 pounds and a gross vehicle weight rating less than 8,500 pounds. The CO_2 equivalent emission standard for heavy light trucks includes noncommercial passenger trucks between 8,500 pounds and 10,000 pounds. The regulations approved in September 2005 set near-term standards, to be phased in between 2009 and 2012, and mid-term standards, to be phased in between 2013 and 2016. After 2016, the emissions standards are assumed to remain constant. Table 2 summarizes the CO_2 equivalent standards.

In October 2003, California, 11 other States, 3 cities, and several environmental groups filed a petition in

Table 2. CARB emissions standards for light-duty vehicles, model years 2009-2016

Tier	Model Year	CO_2 equivalent emissions standard (grams per mile): Passenger cars and small light trucks (under 3,751 pounds)	CO_2 equivalent emissions standard (grams per mile): Heavy light trucks (3,751 to 8,500 pounds)
Near term	2009	323	439
	2010	301	420
	2011	267	390
	2012	233	361
Mid-term	2013	227	355
	2014	222	350
	2015	213	341
	2016	205	332

the U.S. Court of Appeals, arguing that the EPA should regulate GHG emissions from vehicles. In July 2005, the court ruled that the EPA was not required to regulate GHG emissions under the Clean Air Act.

Given the constraints on using other measures, improvements in fuel economy are the only practical way to meet the standards. The automotive industry, which opposes A.B. 1493, has filed suit against CARB, arguing that California GHG emissions standards are in essence fuel economy standards and therefore are preempted by a Federal statute that gives the U.S. Department of Transportation the only authority to regulate fuel economy [*6*]. CARB has not yet obtained a Clean Air Act waiver from the EPA, which would be required before it can implement its GHG emissions standards. For this reason and due to the uncertainty surrounding the pending lawsuit, A.B. 1493 is not represented in the *AEO2006* reference case. Potential impacts of the regulations were examined, however, in *AEO2005*, using the *AEO2005* reference case as a starting point to estimate their likely effects on vehicle prices, GHG emissions, regional energy demand, and regional fuel prices [*7*].

Proposed Revisions to Light Truck Fuel Economy Standards

In August 2005, NHTSA published proposed reforms to the structure of CAFE standards for light trucks and increases in light truck CAFE standards for model years 2008 through 2011 [*8*]. Under the proposed new structure, NHTSA would establish minimum fuel economy levels for six size categories defined by the vehicle footprint (wheelbase multiplied by track width), as summarized in Table 3. For model years 2008 through 2010, the new CAFE standards would provide manufacturers the option of complying with either the standards defined for each individual footprint category or a proposed average light truck

Table 3. Proposed light truck CAFE standards by model year and footprint category (miles per gallon)

Model year	Vehicle category and footprint range (square feet): 1 (≤43.0)	2 (>43.0-47.0)	3 (>47.0-52.0)	4 (>52.0-56.5)	5 (>56.5-65.0)	6 (>65.0)
2008	26.8	25.6	22.3	22.2	20.7	20.4
2009	27.4	26.4	23.5	22.7	21.0	21.0
2010	27.8	26.4	24.0	22.9	21.6	20.8*
2011	28.4	27.1	24.5	23.3	21.9	21.3

**Decrease due to changes in production plans provided to NHTSA and used to establish an average that increases over time.*

fleet standard of 22.5 miles per gallon in 2008, 23.1 miles per gallon in 2009, and 23.5 miles per gallon in 2010. All light truck manufacturers would be required to meet an overall standard based on sales within each individual footprint category after model year 2010.

In determining the proposed light truck fuel economy standards, NHTSA addressed concerns related to energy conservation, technology feasibility and economic practicability, other regulations on fuel economy, and safety. In the evaluation of technology and economic practicability, NHTSA used gasoline price projections from the *AEO2005* reference case, which projected that gasoline prices would range from $1.54 to $1.61 per gallon (2004 dollars) over the 2004-2025 forecast period. For the same period, the *AEO2006* reference case projects a range of $1.95 to $2.26 per gallon (2004 dollars). NHTSA, which will likely receive and address comments related to many issues, specifically asked for comments on the appropriate gasoline price projection to use in defining the final rule. Use of the *AEO2006* reference case gasoline prices in the final rule could impact the final CAFE standards. For example, using higher gasoline prices in technology evaluations could lead to a finding that additional technologies are economically practical, with corresponding changes in fuel economy standards for some footprint categories.

Because the new light truck fuel economy standards have not been finalized, they are not included in the *AEO2006* reference case. An alternative case was developed to examine the potential energy impacts of the proposed standards. Because NEMS does not currently represent the footprint-based standards included in NHTSA's recent proposal, the alternative case assumes that manufacturers will adhere to the proposed increases in light truck fleet standards. For model year 2011, the alternative case applies a fleet-wide standard of 24 miles per gallon, based loosely on the change between 2010 and 2011 in the proposed footprint-based standards. Because no further changes in fuel economy standards beyond 2011 are assumed, the projected trends in light truck fuel economy after 2011 reflect projected technology adoption and market forces.

New light truck fuel economy in the alternative case (Table 4) is projected to be 6 percent higher than the reference case projection in 2011 (24.9 miles per gallon, compared with 23.4 miles per gallon in the reference case). Consistent with the reference case projections, light truck fuel economy continues to improve after 2011 in the alternative case, to 27.4 miles per gallon in 2030, 4 percent higher than the reference case projection of 26.4 miles per gallon. The higher CAFE standards lead to higher prices for light trucks, resulting from increased use of lightweight materials, more complex valve trains, and advanced transmissions. In the alternative case, the average price of a new light truck is projected to be 1.2 percent ($350) higher than in the reference case in 2011 and 0.5 percent ($170) higher in 2030. That increase is at least partially offset, however, by the expected reduction in fuel costs that would result from the increase in average fuel efficiency.

Table 4. Key projections for light truck fuel economy in the alternative CAFE standards case, 2011-2030

Projection	2011	2015	2020	2030
Fuel economy of new light trucks (miles per gallon)	24.9	25.2	26.0	27.4
Increase from reference case projection for purchase price of new light trucks (2004 dollars)	350	250	210	170
Annual reduction from reference case projection for energy use by all light-duty vehicles (quadrillion Btu)	0.13	0.26	0.35	0.44
Cumulative reduction from reference case projection for energy use by all light-duty vehicles, 2004-2030 (quadrillion Btu)	0.31	1.19	2.76	6.85

Total projected energy use by light-duty vehicles, including both cars and light trucks, in the alternative case is projected to be 0.7 percent (0.13 quadrillion Btu) lower than the reference case projection in 2011 and 1.8 percent (0.44 quadrillion Btu) lower in 2030. Cumulative energy use by light-duty vehicles from 2004 to 2030 is almost 7 quadrillion Btu lower in the alternative case than projected in the reference case.

State Renewable Energy Requirements and Goals: Update Through 2005

AEO2005 provided a summary of 17 State renewable energy programs in existence as of December 31, 2003, in 15 States [*9*]. They included RPS programs in 9 States, renewable energy mandates in 4 States, and renewable energy goals in 4 States. Since 2003, 7 more States and the District of Columbia have established renewable energy programs (Table 5), including 6 RPS programs and two renewable energy goals. No new mandates have been enacted since 2003, although a renewable goal instituted in Vermont will become mandatory if it has not been met by 2012. In addition, major changes and refinements have been made in a number of the State programs that were in existence before 2004 (Table 6). No Federal renewables requirement currently exists, although a nationwide RPS was again considered in 2005.

Although generally resembling earlier versions, some of the new programs and changes to existing programs include unique or unusual features:

- Colorado's new RPS is the first enacted through a voter initiative. The new RPS allows a covered Colorado utility (40,000 or more customers) to opt out of the RPS, or an exempt utility to opt in, with a majority vote involving a minimum of 25 percent of the utility's customers.
- Connecticut's RPS now includes energy conservation.
- Delaware's RPS includes municipal utilities and some rural electric cooperatives, although they may opt out.
- Qualifying renewables under Hawaii's RPS now include electricity conservation measures, such as district cooling systems using seawater air conditioning, solar and heat pump water heating, and ice storage, as well as reject heat in some instances.

- Under 2005 legislation, compliance with Minnesota's objective (goal) now becomes linked to the application for a certificate of need for new transmission or generation facilities.
- New York's goals set in 2004 and the 2005 changes in the Illinois program both resulted from public utility commission orders rather than from legislation.
- In New York, the development of new generating capacity using renewable fuels is supported through centralized procurement by the New York State Energy Research and Development Authority, with funds collected through a charge on investor-owned utilities.
- The Illinois program allows imports of electricity only from directly adjacent jurisdictions designated as serious or severe NAAQS nonattainment areas.
- Vermont's goal is to meet 100 percent of additional electricity demand through 2012 with allowed renewable resources (up to 10 percent of total demand), and it broadly defines renewable

Table 5. Basic features of State renewable energy requirements and goals enacted since 2003

State	Year enacted	Requirements	Accepts existing capacity	Out-of-State supply	Credit trading
Renewable Portfolio Standards					
Colorado	*2004*	*3-10% of generation, 2007-2015; 4% of requirement must be solar*	*Yes*	*Yes*	*Yes*
Delaware	*2005*	*1-10% of retail sales, 2007-2019*	*Yes*	*Yes*	*Yes*
District of Columbia	*2005*	*11% of sales by 2022; 3.5% of requirement must be solar*	*Yes*	*Yes*	*Yes*
Maryland	*2004*	*3.5-7.5% of sales, 2006-2019*	*Yes*	*Yes*	*Yes*
Montana	*2005*	*5-15% of sales, 2008-2015*	*Yes*	*Yes*	*Yes*
Rhode Island	*2004*	*3-16% of sales, 2007-2019*	*Yes*	*Yes*	*Yes*
Goals					
New York	*2004*	*25% of generation by 2013*	*Yes*	*Yes*	*No*
Vermont	*2005*	*All growth, up to 10% of total sales, 2005-2012; goal becomes mandatory if not met by 2012*	*Yes*	*—*	*—*

Table 6. Major changes in existing State renewable energy requirements and goals since 2003

State	Date of change	New requirements
Connecticut	*July 2005*	*Effective January 1, 2006, Public Law 05-01 adds Class III renewables to the State RPS, to include new customer-side combined heat and power systems and electricity savings from energy conservation and load management at commercial and industrial facilities, equal to 1% of generation in 2007, 2% in 2008, 3% in 2009, and 4% in 2010.*
Hawaii	*June 2004*	*Senate Bill 2474 changes the goal of the State RPS, from 9% of sales by 2010 to 20% of sales by 2020, and includes ocean technologies, electricity conservation, and some cogeneration.*
Illinois	*July 2005*	*An Illinois Commerce Commission resolution adopts a sustainable energy plan that replaces the State renewable energy goal of 15% of sales by 2020 with an RPS requiring the State's largest electric utilities to begin supplying 2% renewable energy to Illinois customers by January 1, 2007, increasing by 1% annually to 8% by 2013; at least 75% of the requirement must be from wind power.*
Minnesota	*May 2005*	*Statute 216B.243 links compliance with the State's renewable energy goal of 10.0% of electricity sales (by power producers other than Xcel Energy, see Statute 216B.1691) to obtaining a certificate of need for new transmission or generation capacity.*
Nevada	*June 2005*	*Assembly Bill 03 increases overall renewables requirement from 5-15% of sales 2003-2013, to 6-20%, but (a) delays compliance by 2 years to 2005-2015, and (b) permits up to one-quarter of the requirement to be met by efficiency measures reducing electricity use.*
Pennsylvania	*November 2004*	*Senate Bill 1030 changes individual utility goals to RPS requiring 5.7% of sales in 2007, increasing to 18% in 2020 (with solar increasing to at least 0.5% of sales); RPS includes waste coal, coal gasification, and demand-side management and includes both credit trading and some capacity from out-of-State suppliers in interconnected areas.*
Texas	*August 2005*	*Senate Bill 20 increases overall renewable energy requirement from 2,000 megawatts of new renewable capacity by 2009 to 5,880 megawatts by 2015, including a non-mandatory target of at least 500 megawatts from sources other than wind.*

energy as that which "relies on a resource that is being consumed at a harvest rate at or below its natural regeneration rate" [*10*]. The Vermont legislation is designed to encourage contracts for new renewables capacity by allowing the new capacity to meet multiple States' RPS requirements. New renewable capacity in Vermont can be counted toward Vermont's program, while its renewable energy credits may be marketed separately to renewables credit markets in neighboring States.

- Pennsylvania's new Alternative Energy Portfolio Standard includes waste coal and coal gasification, which can contribute as much as 10 percent of the renewable generation requirement (set at 18 percent of total generation in 2020).

The 23 State renewable energy programs in effect in 2005 generally are concentrated in three broad geographic areas, with 11 jurisdictions along the Northeastern and Mid-Atlantic seaboard (Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont), 6 in the Southwest (Arizona, California, Colorado, Nevada, New Mexico, and Texas), 4 in the upper Midwest (Illinois, Iowa, Minnesota, and Wisconsin), and Hawaii and Montana each standing alone. No Southern, Southeastern, or Northwestern State (except Montana) currently has a renewable energy program.

Although efforts to coordinate renewable energy programs among adjacent States have begun, no formal or informal coordination systems have been finalized. An example of efforts to establish such a system include the newly formed Mid-Atlantic Organization of PJM States, Inc. In order to prevent double counting, however, States in most interconnected regions now coordinate identification and tracking of the origins and contracted destinations of renewable energy transactions via power pools or other organizations. The New England States use the Generation Information System of the New England Power Pool (NEPOOL), and the Mid-Atlantic States employ PJM's Generation Attribute Tracking System (GATS). Although the Midwestern Power Pool does not currently track the region's renewable generation, a multi-State Midwestern effort is underway to establish the Midwest Renewable Energy Tracking System (MRETS). Similarly, the California Energy Commission and the Western Governors' Association are collaborating to establish a Western Renewable Energy Generation Information Tracking System (WREGIS).

New Renewable Energy Capacity, 2004-2005

Table 7 summarizes EIA's understanding of new renewable energy capacity entering service in 2004 and 2005. However, it is difficult to quantify the specific impacts of State renewable programs. First, neither the individual States nor other sources identify all the new renewable energy capacity that is built, and some new capacity may not be reported. Although large wind projects typically are recognized, smaller projects, such as landfill gas (LFG) or end-user sited PV installations, may go unreported. Further, new capacity is not necessarily added in response to State renewable energy programs. Projects may be constructed for other reasons, and they may or may not qualify for the State programs. Projects located in one State may serve the requirements of another State or different States over time.

Table 7. New U.S. renewable energy capacity, 2004-2005 (installed megawatts, nameplate capacity)

Year	Biomass	Geothermal	Conventional hydroelectric	Landfill gas	Solar photovoltaics	Wind	Total
2004							
Without standards	0.0	0.0	65.8	32.5	0.0	199.8	**298.1**
With standards	19.9	0.0	4.5	30.0	3.0	281.6	**339.1**
2005							
Without standards	0.0	0.0	133.2	14.7	0.0	1,077.1	**1,225.0**
With standards	34.1	37.0	26.1	24.6	3.6	1,716.7	**1,842.1**
2004 and 2005							
Without standards	0.0	0.0	199.0	47.2	0.0	1,276.9	**1,523.1**
With standards	54.0	37.0	30.6	54.8	6.6	1,998.2	**2,181.2**
Total	54.0	37.0	229.6	102.0	6.6	3,275.1	**3,704.3**
Percentages							
Without standards	0.0	0.0	86.6	46.3	0.0	39.0	**41.1**
With standards	100.0	100.0	13.3	53.7	100.0	61.0	**58.9**

Projects located in States without renewable programs may be explicitly or implicitly targeted to serve programs in other States and, therefore, may be at least partially "caused" by another State's renewable program despite not being enumerated as such.

New renewable energy capacity built today that appears unsupported by a State renewable program may result from an earlier favorable experience with a State program. For example, Table 7 does not include 362 megawatts of wind capacity from new projects in Iowa in the "With Standards" category, because Iowa's mandate was fully met by 2000; nor does it include 62 megawatts of new wind capacity built in North Dakota, which has no requirement, although the new capacity serves Minnesota's RPS. Nevertheless, Table 7 provides some indication of the extent to which renewable programs are resulting in the construction of new renewable energy capacity and also suggests the extent to which other key factors (for example, the Federal PTC) may promote growth in renewable capacity.

Differences among renewable energy capacity additions in different States can result from a range of factors separate from State renewable programs, including differences in natural endowments, electricity consumption levels and rates of demand growth, the availability of alternatives, the presence or absence of renewable energy proponents and champions, and variations in consumer preferences. On the other hand, while States with renewable energy requirements accounted for only 45 percent of total U.S. electricity supply, they accounted for almost 60 percent of all new renewable energy capacity added in 2004 and 2005.

EIA's analysis indicates that State-level requirements probably have led to somewhat more biomass, geothermal, LFG, and solar capacity than would otherwise have been built, although the additional amounts are small. Hydroelectric capacity does not appear to have been advanced by State-level renewables requirements. Expansion of wind power capacity appears to be strongly affected by the combination of State requirements and the Federal PTC, as evidenced by the substantial construction of new wind capacity in 2005, particularly in States with RPS programs.

Among States with requirements and goals, the amount of renewable capacity added in 2004 and 2005 varies significantly. Of the 23 States with renewable requirements in 2004 and 2005, 4 have reported no new renewable energy capacity (although requirements in Delaware, the District of Columbia, and Maryland are new, and Connecticut is estimated to have met its program requirements already). In another 7 States (Arizona, Hawaii, Massachusetts, New Jersey, Rhode Island, Vermont, and Wisconsin) 15 megawatts or less has been added over the 2-year period. In 3 States (Maine, Nevada, and Pennsylvania), between 25 and 35 megawatts has been added; in 2 (Colorado and Illinois) between 65 and 75 megawatts has been added; and in 4 (Minnesota, Montana, New Mexico, and New York) between 100 and 200 megawatts has been added in each State over the past 2 years. California, with nearly 500 megawatts, and Texas, with more than 700 megawatts, together account for 55 percent of all new U.S. renewable capacity attributed to State-level renewable energy requirements and goals in 2004 and 2005.

In contrast, Oklahoma and Washington, which have no renewable energy requirements, each installed between 250 and 300 megawatts of new renewable capacity in 2004 and 2005, and other States without programs added smaller amounts. Most of the new capacity in those States is wind power, suggesting that good resources and the Federal PTC may be the primary factors leading to new wind power installations there.

Despite the expansion of State renewable energy programs, new renewables capacity accounted for a fairly small fraction of new U.S. electricity supply added in 2004 and 2005. Including conventional hydroelectricity, all renewables currently account for 9.3 percent of total U.S. electricity generation, with nonhydroelectric renewables accounting for 2.2 percent. The 3,700 megawatts of new renewables capacity added during 2004 and 2005 accounted for 12 percent of the 32,000 megawatts of new generating capacity that entered service during the period.

State Air Emission Regulations That Affect Electric Power Producers

Several States have recently enacted air emission regulations that will affect the electricity generation sector. The regulations govern emissions of NO_x, SO_2, CO_2, and mercury from power plants. Where firm compliance plans have been announced, State regulations are represented in *AEO2006*. For example, installations of SO_2 scrubbers and selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR) NO_x removal technologies associated with the largest State program, North Carolina's Clean Smokestacks Initiative, are included. Figure 9 shows historical trends in SO_2 emissions for selected States.

Federal Air Emissions Regulations

In 2005, the EPA finalized two regulations, CAIR and CAMR, that would reduce emissions from coal-fired power plants in the United States. Both CAIR and CAMR are included in the *AEO2006* reference case. The EPA has received 11 petitions for reconsideration of CAIR and has provided an opportunity for public comment on reconsidering certain aspects of CAIR. Public comments were accepted until January 13, 2006. The EPA has also received 14 petitions for reconsideration of CAMR and is willing to reconsider certain aspects of the rule. Public comments were accepted for 45 days after publication of the reconsideration notice in the *Federal Register*. Several States and organizations have filed lawsuits against CAMR. The ultimate decision of the courts will have a significant impact on the implementation of CAMR.

Clean Air Interstate Rule

The final CAIR was promulgated by the EPA in March 2005 and published in the *Federal Register* as a final rule in May 2005 [*11*]. The rule is intended to reduce the atmospheric interstate transport of fine particulate matter ($PM_{2.5}$) and ozone [*12*]. Both SO_2 and NO_x are precursors of $PM_{2.5}$. NO_x is also a precursor to the formation of ground-level ozone. CAIR would require 28 States and the District of Columbia to reduce SO_2 and/or NO_x emissions in a two-phase program. The Phase I cap for NO_x becomes effective in 2009, and the Phase I cap for SO_2 starts in 2010 [*13*]. The Phase II limits for both NO_x and SO_2 start in 2015. The rule would apply to all fossil-fuel-fired boilers and turbines serving electrical generators with capacity greater than 25 megawatts that provide electricity for sale. It would also apply to CHP units larger than 25 megawatts that sell at least one-third of their potential electrical output and supply more than 219,000 megawatthours of electricity to the grid. Table 8 shows EPA estimates of CAIR's impacts on SO_2 and NO_x emissions. The *AEO2006* reference case projections for SO_2 and NO_x emissions are very close to the EPA numbers.

Under CAIR, the States would be responsible for allocating NO_x emissions allowances and taking the lead in pursuing enforcement actions, and they would have flexibility in choosing the sources to be controlled. They could meet the emissions reduction requirements either by joining the EPA-managed cap and trade program for power plants or by achieving reductions through emissions control measures on sources in other sectors (industrial, transportation, residential, or commercial) or on a combination of electricity generating units and sources in other sectors. The 28 CAIR States are required to submit State Implementation Plans (SIPs) to the EPA by September 2006, showing how they intend to meet their respective caps.

In order to participate in the cap and trade program, States would be required to regulate power plant emissions within their boundaries. The EPA would be responsible for assigning State emissions budgets, reviewing and approving State plans, and administering the emissions and allowance tracking systems. Sources currently subject to the CAAA90 Title IV rules and to the NO_x SIP Call trading program can use allowances banked from those programs before 2010 for compliance with CAIR. CAIR would require additional reductions in NO_x emissions for States affected by the NO_x SIP Call. State NO_x emissions caps are based on each State's share of region-wide heat input.

The EPA plans to meet the SO_2 emission reduction requirements by implementing a progressively more stringent retirement ratio on SO_2 allowances for electricity generating units of different vintages under the CAAA90 Title IV Acid Rain Program. New SO_2 allowances would not be issued under CAIR; power

Figure 9. Sulfur dioxide emissions in selected States, 1980-2003 (thousand short tons)

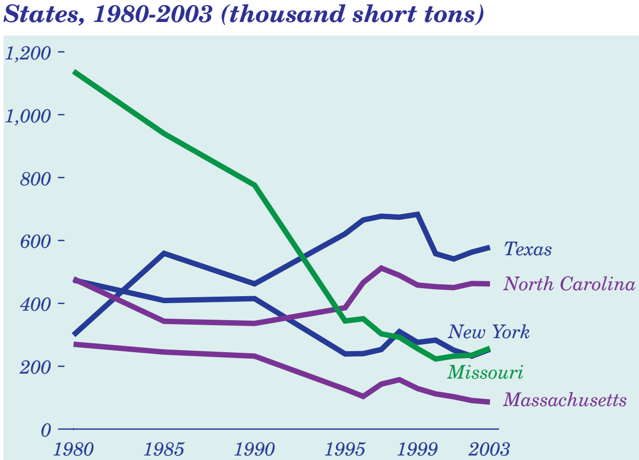


Table 8. Estimates of national trends in annual emissions of sulfur dioxide and nitrogen oxides, 2003-2020 (million short tons)

Emissions	*2003*	*Projections 2010*	*2015*	*2020*
EPA				
Sulfur dioxide	*10.6*	*6.1*	*4.9*	*4.2*
Nitrogen oxides	*4.2*	*2.4*	*2.1*	*2.1*
AEO2006				
Sulfur dioxide	*10.6*	*5.9*	*4.6*	*4.0*
Nitrogen oxides	*4.2*	*2.3*	*2.1*	*2.1*

plants would instead use the current pool of SO_2 allowances issued under Title IV. Allowances issued for vintage years 2004 through 2009 could be retired on a 1-to-1 basis, but allowances issued for vintage years 2010 through 2014 would have to be retired on a 2-to-1 basis, requiring two Title IV allowances to be retired for each ton of SO_2 emissions. Allowances issued for vintage years 2015 and later would be retired on a basis of approximately 2.9 to 1. This retirement procedure is designed to integrate the CAIR rules with the existing Title IV SO_2 emissions reduction program.

Clean Air Mercury Rule

CAMR (proposed as the Utility Mercury Reduction Rule) for controlling mercury emissions from new and existing coal-fired power plants was promulgated by the EPA in March 2005 and published as a final rule in the *Federal Register* in May 2005 [*14*]. Power plants with capacity greater than 25 megawatts and CHP units larger than 25 megawatts that sell at least one-third of their electricity would be subject to CAMR.

Under CAMR, Section 112 of the CAAA90 would be modified to allow regulation of mercury emissions under a cap and trade program. The EPA estimates that CAMR, using the cap and trade approach, would reduce mercury emissions by nearly 70 percent when fully implemented. The program would be implemented in two phases with a banking provision. The Phase I cap, to be met in 2010, would be 38 short tons; the Phase II cap, to be met in 2018, would be 15 short tons. In addition to these national caps, new power plants would be subject to output-based limits on mercury emissions.

Under the cap and trade approach, States would submit plans to the EPA to demonstrate that they would meet their assigned State-wide mercury emissions budgets. With EPA approval, the States could then participate in the cap and trade program. Allowances would be allocated by the States to power companies, which could either sell or bank any excess allowances. The final rule does not include a safety valve mechanism for allowance prices.

Update on Transition to Ultra-Low-Sulfur Diesel Fuel

On November 8, 2005, the EPA Administrator signed a direct final rule that will shift the retail compliance date for offering ULSD for highway use from September 1, 2006, to October 15, 2006. The change will allow more time for retail outlets and terminals to comply with the new 15 parts per million (ppm) sulfur standard, providing time for entities in the diesel fuel distribution system to flush higher sulfur fuel out of the system during the transition. Terminals will have until September 1, 2006, to complete their transitions to ULSD. The previous deadline was July 15, 2006.

There is no change in the June 1, 2006, start date for refiners to be producing ULSD. Also, during the extended transition period, diesel fuel meeting a 22-ppm level can be temporarily marketed as ULSD at the retail pump. Finally, the EPA extended the beginning date for the restriction on how much ULSD can be downgraded to higher sulfur fuel by 15 days, to October 15, 2006, to be consistent with the end of the new transition dates.

The 45-day transition delay will help to ensure nationwide availability of 15-ppm ULSD before the introduction of new model year 2007 diesel trucks and buses designed to operate on the improved fuel. These minor timing adjustments do not affect the *AEO2006* projections.

State Restrictions on Methyl Tertiary Butyl Ether

By the end of 2005, 25 States had barred, or passed laws banning, any more than trace levels of MTBE in their gasoline supplies, and legislation to ban MTBE was pending in 4 others. Some State laws address only MTBE; others also address ethers such as ethyl tertiary butyl ether (ETBE) and tertiary amyl methyl ether (TAME). *AEO2006* assumes that all State MTBE bans prohibit the use of all ethers for gasoline blending.

Even with the removal of the oxygen content requirement for RFG in EPACT2005, RFG is still expected to be blended with ethanol, because it is not clear where else refiners could obtain the clean, high-octane blending components needed to replace MTBE, which supplies 11 percent of the volume and a significant portion of the rated octane of RFG. Aromatic compounds and olefins are high-octane blending components, but they are limited by the RFG requirements and by the Federal Mobile Source Air Toxics program. Isooctane and alkylate are clean, high-octane blending components, but refinery capacity to produce them is limited, and it is often less expensive to use ethanol at up to 10 percent by volume to offset part of the volume loss resulting from the removal of MTBE.

As noted above, EPACT2005 also mandates the use of 7.5 billion gallons of renewable motor fuels, such as ethanol and biodiesel, by 2012 and requires renewable motor fuel use to grow at the rate of overall motor fuel use thereafter. In addition, some States have their own renewable fuels programs. Minnesota currently requires all its gasoline supply to be blended with 10 percent ethanol, increasing to 20 percent ethanol if at least 50 percent of the new cars sold in the State can be guaranteed by their manufacturers to be compatible with the higher blend. Most current automobiles can use a maximum of only 10 percent ethanol in gasoline, and automakers worry that widespread use of gasoline with 20 percent ethanol content will result in misfueling of vehicles not designed to use more than 10 percent ethanol.

Several other State programs are contingent upon local ethanol supplies. Montana's MTBE ban takes effect only when 40 million gallons of ethanol production capacity is available in the State; and Hawaii has a pending requirement for 85 percent of its gasoline to be blended with 10 percent ethanol if enough ethanol can be produced in the State.

Volumetric Excise Tax Credit for Alternative Fuels

On August 10, 2005, President Bush signed into law the Safe, Accountable, Flexible, and Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU) [*15*]. The act includes authorization for a multitude of transportation infrastructure projects, establishes highway safety provisions, provides for R&D, and includes a large number of miscellaneous provisions related to transportation, most of which are not included in *AEO2006* because their energy impacts are vague or undefined. Section 11113, which provides a volumetric excise tax credit of 50 cents per gallon for alternative fuels, such as liquid fuels derived from the Fischer-Tropsch process, is included in *AEO2006*. This tax credit is expected to have a small impact on transportation energy consumption, because it is scheduled to expire on September 30, 2009, and only a small quantity of alternative fuels will be produced in the pilot or demonstration projects that are expected to qualify for the credit.

Issues in Focus

Introduction

This section of the *AEO* provides in-depth discussions on topics of special interest that may affect the projections, including significant changes in assumptions and recent developments in technologies for energy production, energy consumption, and emissions controls. With world oil prices escalating in recent years, this year's discussions place special emphasis on world oil prices, including a discussion of EIA's world oil price outlook, the impact of higher world oil prices on economic growth, and changing trends in the U.S. refinery industry.

AEO2006 extends the *AEO* projections to 2030 for the first time. An important uncertainty with a longer projection time horizon concerns the development and implementation of various technologies. Accordingly, this section includes a discussion of those technologies that, if successful, could affect the energy supply and demand projections in later years, focusing on energy technologies that could have their greatest impacts toward the end of the projection period, those expected to have the greatest impact in the automotive sector, and nonconventional liquids technologies that will play a growing role in meeting U.S. energy needs.

World Oil Prices in *AEO2006*

World oil prices in the *AEO2006* reference case are substantially higher than those in the *AEO2005* reference case. In the *AEO2006* reference case, world crude oil prices, in terms of the average price of imported low-sulfur, light crude oil to U.S. refiners, decline from current levels to about $47 per barrel (2004 dollars) in 2014, then rise to $54 per barrel in 2025 and $57 per barrel in 2030. The price in 2025 is approximately $21 per barrel higher than the corresponding price projection in the *AEO2005* reference case (Figure 10).

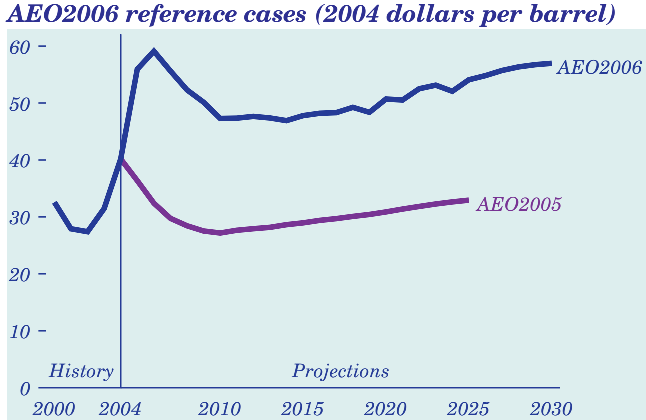
The oil price path in the *AEO2006* reference case reflects a reassessment of the willingness of oil-rich countries to expand production capacity as aggressively as envisioned last year. It does not represent a change in the assessment of the ultimate size of the world's petroleum resources but rather a lower level of investment in oil development in key resource-rich regions than was projected in *AEO2005*. Several factors contribute to the expectation of lower investment and oil production in key oil-rich producing regions, including continued strong worldwide economic growth despite high oil prices, and various restrictions on access and contracting that affect oil exploration and production companies.

Although oil prices have stayed above $40 for the past 2 years, world economies have continued to grow strongly: in 2004, global GDP registered the largest percentage increase in 25 years. As a result, major oil-exporting countries are likely to be less concerned that oil prices will cause an economic downturn that could significantly reduce demand for their oil. When economies continue to grow despite higher oil prices, key suppliers have much less incentive to expand production aggressively, because doing so could result in substantially lower prices. Given the perceived low responsiveness of oil demand to price changes, such an action could lower the revenues of oil exporters both in the short term and over the long run.

International oil companies, which normally are expected to increase production in an environment of high oil prices, lack access to resources in some key oil-rich countries. There has been increased recognition that the situation is not likely to change over the projection period. Furthermore, even in areas where foreign investment by international oil companies is permitted, the legal environment is often unreliable and complex and lacks clear and consistent rules of operation. For example, Venezuela is now attempting to change existing contracts in ways that may make oil company investments less attractive. In 2005, Russia announced a ban on majority foreign participation in many new natural resource projects and imposed high taxes on foreign oil companies. These changes, and others like them, make investment in oil exploration and development less attractive for foreign oil companies.

The structure of many production-sharing agreements also increases the risk faced by major oil companies in volatile oil price environments. Many contracts guarantee a return to the host government at a fixed price, plus some percentage if the actual

Figure 10. World oil prices in the AEO2005 and AEO2006 reference cases (2004 dollars per barrel)



world oil price increases. The foreign company bears the full risk if the actual oil price falls below the guaranteed price but does not reap significant rewards if the actual price is higher than the guaranteed price. This asymmetrical risk sharing discourages investment when oil prices are likely to remain volatile. It may also hurt the oil-rich countries, if limited foreign investment prevents them from realizing the benefits of the major technological advances that have been made in the oil sector over the past two decades.

Because OPEC has less incentive to invest in expansions of oil production capacity than was assumed in *AEO2005*, and because contracting provisions affecting international exploration and production companies have shifted more risk to those companies, the *AEO2006* reference case projects slower output growth from key oil-rich countries after 2014 than was projected in the *AEO2005* reference case.

Energy market projections are subject to considerable uncertainty, and oil price projections are particularly uncertain. Small shifts in either oil supply or demand, both of which are relatively insensitive to price changes in the short to mid-term, can necessitate large movements in oil prices to restore the balance between supply and demand. To address uncertainty about the oil price projections in the *AEO2006* reference case, two alternative cases posit world oil prices that are consistently higher or lower than those in the reference case. These high and low price cases should not be construed as representing the potential range of future oil prices but only as plausible cases given changes in certain key assumptions.

The high and low price cases in *AEO2006* are based on different assumptions about world oil supply. The *AEO2006* reference uses the mean oil and gas resource estimate published by the U.S. Geological Survey (USGS) [*16*]. The high price case assumes that the worldwide crude oil resource is 15 percent smaller and is more costly to produce than assumed in the reference case. The low price case assumes that the worldwide resource is 15 percent more plentiful and is cheaper to produce than assumed in the reference case. Thus, the major price differences across the three cases reflect uncertainty with regard to both the supply of resources (primarily undiscovered and inferred) and the cost of producing them.

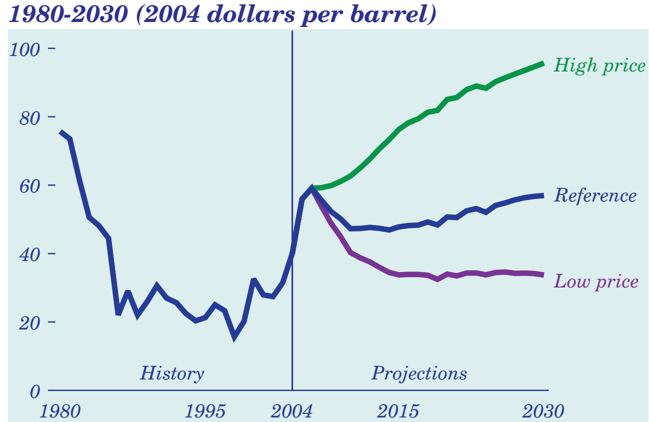
Figure 11 shows the three price projections. As compared with the reference case, the world oil price in 2030 is 68 percent higher in the high price case and 41 percent lower in the low price case. As a result, world oil consumption in 2030 is 13 percent lower in the high price case and 8 percent higher in the low price case than in the reference case. The high and low price cases illustrate that estimates of world oil resources that are lower and higher than the estimate used in the reference case can play a significant role in determining future oil prices.

The projections for world petroleum consumption in 2030 are 102, 118, and 128 million barrels per day in the high, reference, and low price cases, and the projected market share of world petroleum liquids production from OPEC in 2030 is about 31 percent in the high price case and 40 percent in the reference case and low price cases. Because assumed production costs rise from the low price case to the reference case to the high price case, the differences in net profits among the three cases are smaller than they might have been if the underlying supply curves for OPEC and non-OPEC producers had remained unchanged. Although OPEC produces less output in the high price case than in the reference case, its economic profits are also less, because resources are assumed to be tighter and exploration and production costs higher for conventional oil worldwide. In the absence of tighter resources and higher costs, an OPEC strategy that attempted to pursue the output path in the high price case would subject OPEC to the risk of losing market share to other producers, as well as to alternatives to oil. Further discussions of the three price cases and their implications for energy markets appear in other sections of *AEO2006*.

Economic Effects of High Oil Prices

The *AEO2006* projections of future energy market conditions reflect the effects of oil prices on the macroeconomic variables that affect oil demand, in particular, and energy demand in general. The variables include real GDP growth, inflation, employment, exports and imports, and interest rates.

Figure 11. World oil prices in three AEO2006 cases, 1980-2030 (2004 dollars per barrel)



Although there is wide agreement that high oil prices have negative effects on U.S. macroeconomic variables, the magnitude and duration of the effects are uncertain. For example, most of the major economic downturns in the United States, Europe, and the Asia Pacific region since the 1970s have been preceded by sudden increases in crude oil prices. Although other factors were important, high oil prices played a critical role in substantially reducing economic growth in most of these cases. Recent history, however, tells a somewhat different story. Average world crude oil prices have increased by more than $30 per barrel since the end of 2001, yet U.S. economic activity has remained robust, growing by approximately 2.8 percent per year from 2001 through 2004.

This section describes the ways in which oil prices affect the U.S. economy [*17*], presents a brief survey of the empirical literature on the economic impacts of changes in oil prices, and outlines the effects on the *AEO2006* reference case projections of alternative assumptions in the high and low price cases. The results of the alternative cases indicate how the U.S. economy is likely to be affected by different levels of oil prices.

Macroeconomic Impacts of High Oil Prices

U.S. demand for crude oil arises from demand for the products that are made from it—especially gasoline, diesel fuel, heating oil, and jet fuel; and changes in crude oil prices are passed on to consumers in the prices of the final petroleum products. Increases in crude oil prices affect the U.S. economy in five ways:

- When the prices of petroleum products increase, consumers use more of their income to pay for oil-derived products, and their spending on other goods and services declines. The extra amounts spent on those products go to foreign and domestic oil producers and, if wholesale margins increase, to refiners. Domestic producers may pay higher dividends and/or spend more on oil discovery, production, and distribution. Foreign producers may spend some or all of their extra revenues on U.S. goods and services, but the types of goods and services they buy will be different from those that domestic consumers would buy. How quickly and how much domestic and foreign oil producers spend on U.S. goods and services and financial and real assets will be critical in determining the effects of higher oil prices on the aggregate economy [*18*].
- Oil is also a vital input for the production of a wide range of goods and services, because it is used for transportation in businesses of all types. Higher oil prices thus increase the cost of inputs; and if the cost increases cannot be passed on to consumers, economic inputs such as labor and capital stock may be reallocated. Higher oil prices can cause worker layoffs and the idling of plants, reducing economic output in the short term.
- Because the United States is a net importer of oil, higher oil prices affect the purchasing power of U.S. national income through their impact on the international terms of trade. The increased price of imported oil forces U.S. businesses to devote more of their production to exports, as opposed to satisfying domestic demand for goods and services, even if there is no change in the quantity of foreign oil consumed.
- Changes in oil prices can also cause economic losses when macroeconomic frictions prevent rapid changes in nominal prices for final goods (due to the costs of changing "menu" prices) or for key inputs, such as wages. Because there is resistance on the part of workers to real declines in wages, oil price increases typically lead to upward pressure on nominal wage levels. Moreover, nominal price "stickiness" is asymmetric, in that firms, unions, and other organizations are much more reluctant to lower nominal prices and the wages they receive than they are to raise them. When a nominal increase in oil prices threatens purchasing power, the adjustment process is slowed, with multiplier effects throughout the economy [*19*].
- Finally, higher oil prices cause, to varying degrees, increases in other energy prices. Depending on the ability to substitute other energy sources for petroleum, the price increases can be large and can cause macroeconomic effects similar to the effects of oil price increases.

The nature of the oil price increases, the state of the economy, and the macroeconomic policies undertaken at the time may accentuate or dampen the severity of adverse macroeconomic effects. If price increases are large and sudden, their impacts on short-term growth may be much larger than if they are gradual, because sudden oil price shocks scare households and firms and prevent them from making optimal decisions in the near term.

On the potential output side, sudden large price increases create widespread uncertainty about appropriate production techniques, purchases of new equipment and consumer durable goods like automobiles, and wage and price negotiations. As firms and households adjust to the new conditions, some plant and equipment will remain idle, some workers will be temporarily unemployed, and the economy may no longer operate along its long-run production-possibility frontier. Although it is easy to differentiate gradual from rapid price increases on a conceptual basis, empirical differentiation is more difficult.

In terms of the state of the economy, if the economy is already suffering from high inflation and unemployment, as in the late 1970s, then the oil price increases have the potential to cause severe damage by limiting economic policy options. Many analysts assert that it was the monetary policy undertaken in the 1970s that really damaged the U.S. economy.

The economic policies that are followed in response to a combination of higher inflation, higher unemployment, lower exchange rates, and lower real output also affect the overall economic impact of higher oil prices over the longer term. Sound economic policies may not completely eliminate the adverse impacts of high oil prices described above, but they can moderate them. Conversely, inappropriate economic policies can exacerbate the adverse impacts. Overly contractionary monetary and fiscal policies to contain inflationary pressures can worsen the recessionary effects on income and unemployment; expansionary monetary and fiscal policies may simply delay the fall in real income necessitated by the increase in oil prices, stoke inflationary pressures, and worsen the impact of higher prices in the long run.

Empirical Studies of Oil Price Effects

The mechanism by which oil prices affect economic performance is generally well understood, but the precise dynamics and magnitude of the effects are uncertain. Quantitative estimates of the overall macroeconomic damage caused by oil price shocks in the past and of the economic gains realized by oil-importing countries as a result of the oil price collapse in 1986 vary substantially, in part because of differences in the models used to examine the issue [*20*]. Two different approaches have been used to estimate the magnitude of oil price effects on the U.S. economy. One uses large, disaggregated macroeconomic models of the economy, and the other uses time-series analysis of historical events to estimate directly the macroeconomic effects of oil price changes.

In the first approach, macroeconomic models are used in attempts to account for all the relationships among the major macroeconomic variables in the economy (as described by the National Income and Product, Balance of Payments, and Flow of Funds Accounts), and historical data are used to estimate statistically the parameters linking the variables. The advantages of macroeconomic models are consistent accounting of macroeconomic relationships over time and the ability to account for other events taking place.

A recent Stanford University Energy Modeling Forum (EMF) study by Hillard Huntington found that most macroeconomic models report similar economic effects of oil price increases [*21*]. Table 9 shows the results for real GDP, the GDP price deflator, and unemployment obtained from three models and their averages [*22*]. The results are shown for a 33-percent increase in the oil price, from $30 to $40. For example, the output results in Table 9 imply that a 33-percent increase in the oil price sustained for 2 years reduces real GDP relative to the baseline by 0.2 percent in the first year and 0.5 percent in the second year. In terms of an elasticity response of real GDP to oil price, the percentage change in real GDP relative to the percentage change in oil price is approximately 0.01 in the first year and 0.02 in the second year.

The second approach is simpler, focusing specifically on the relationship between changes in crude oil prices and some measure of their economic impact, such as aggregate output, inflation, or unemployment. Time-series analyses of historical data are used to estimate statistically an equation (or a system of equations called "vector autoregressions") that explains economic growth rates as a function of the past growth in the economy and past changes in crude oil prices. Many studies add the past values of additional variables to the system in order to incorporate their interactions with the oil price and GDP variables.

Table 9. Macroeconomic model estimates of economic impacts from oil price increases (percent change from baseline GDP for an increase of $10 per barrel)

Estimate	*Year 1*	*Year 2*
Global Insight, Inc.		
Real GDP	*-0.3*	*-0.6*
GDP price deflator	*0.2*	*0.5*
Unemployment	*0.1*	*0.2*
U.S. Federal Reserve Bank		
Real GDP	*-0.2*	*-0.4*
GDP price deflator	*0.5*	*0.3*
Unemployment	*0.1*	*0.2*
National Institute of Economic and Social Research		
Real GDP	*-0.2*	*-0.5*
GDP price deflator	*0.3*	*0.5*
Average		
Real GDP	*-0.2*	*-0.5*
GDP price deflator	*0.3*	*0.4*
Unemployment	*0.1*	*0.2*

Table 10 shows results for the U.S. economy from a recent study by Jimenez-Rodriguez and Sanchez [*23*], which are representative of the results obtained in the time-series literature. Due to the nature of the reduced-form framework used, the results are direct estimates of GDP elasticities with respect to oil price changes as of the given quarter after the permanent price change. The asymmetric results allow separate estimates of GDP elasticity for oil price increases, decreases, and net increases (when oil prices exceed the maximum over the previous 12 quarters). When the six-quarter GDP elasticity estimated by Jimenez-Rodriguez and Sanchez (approximately 0.05) is applied to a 33-percent price increase (to be comparable with the average macroeconomic simulation response in Table 10), real GDP declines by 1.7 percent—more than 3 times the effect on real GDP in macroeconomic simulations.

Generally, as indicated by the results in Table 10, time-series studies show larger impacts on output and other variables than do macroeconomic simulations. Huntington offers four major reasons as to why the empirical estimates are so different:

- The larger impacts calculated from direct statistical estimations often are attributed to a range of macroeconomic frictions that could make the economy's response to an oil price shock fundamentally different from its response to a smaller increase in oil prices. Large macroeconomic models do not differentiate between oil price increases and decreases, or between surprise events and more gradual price adjustments.
- The larger estimates from time-series models may also reflect baseline economic conditions before an oil price disruption that are fundamentally different from today's economic environment. For example, the oil price shocks of the 1970s hit the U.S. economy when it already was experiencing inflationary pressures.
- Historical oil price shocks reduced not only aggregate output but also the country's purchasing power. Real national income fell as the costs of buying international goods (including oil) increased more than income from exports. The higher prices made the country poorer by requiring more exports to balance each barrel of imported oil, leaving less aggregate output for domestic consumption.
- The oil price shocks of the 1970s completely surprised firms and households in many different countries at the same time. Firms and households made decisions about production and prices that had important consequences for the strategies of other firms in the economy [*24*]. And yet, there was little opportunity to coordinate strategies in such an uncertain world. Now, after several different oil price episodes, there has been significant learning about how to cope with the uncertainties created by oil price shocks. It is unlikely that firms and households will be surprised in the same way or to the same degree as they were by earlier shocks.

If crude oil prices rise early in a particular year, what will be the impact on the economy at the end of the following year? Huntington offers the following tentative answers, and Table 11 summarizes the impacts on GDP, as well as the impacts on the GDP price deflator for all goods and services and the unemployment rate. If the economy is operating at its potential output level and inflation is constant, a reasonable estimate is that a 10-percent increase in the price of oil that does not surprise households and firms (higher oil price in Table 11) will reduce potential output (GDP) by 0.2 percent. If the economy is operating well below its potential output level, the impact on GDP may be somewhat larger but is unlikely to exceed 0.2 percent after the first year. If the oil price increase comes as a complete surprise and the economy is already in a rising inflationary environment (oil price shock in Table 11), then it has the potential to cause larger economic losses, which would be closer to those predicted by time-series models.

Table 10. Time-series estimates of economic impacts from oil price increases (percent change from baseline GDP for an increase of $10 per barrel)

	Asymmetric		
Quarter	Price increase	Price decrease	Net price increase
4	-0.048	-0.014	-0.046
6	-0.051	0.002	-0.058
8	-0.046	0.011	-0.054
10	-0.044	0.010	-0.048
12	-0.042	0.010	-0.043

Table 11. Summary of U.S. oil price-GDP elasticities

Price effect	Year 1	Year 2
Higher oil price		
Real GDP	-0.011	-0.021
GDP price deflator	0.007	0.017
Unemployment rate	0.004	0.007
Oil price shock		
Real GDP	-0.024	-0.050
GDP price deflator	0.019	0.034
Unemployment rate	0.009	0.020

AEO2006 Price Cases

The key feature of the *AEO2006* high and low world oil price paths is that they are not characterized by disruption, but rather represent a gradual and sustained movement relative to the reference case path. Keeping this distinction in mind, the Macroeconomic Activity Module in NEMS, which contains the Global Insight Inc. (GII) Macroeconomic Model, is used to assess the economic impacts of the alternative price paths.

Most of the results projected for the U.S. economy in the high and low price cases relative to the reference case are similar to the results for macroeconomic models discussed above. The *AEO2006* high and low price cases are unique, however, in that they trace out, in a consistent manner, both the short-term impacts of oil price increases and the longer term adjustments of the economy in response to sustained high and low prices by employing a disaggregated macroeconomic model integrated with a very detailed energy market model—NEMS.

Figure 12 shows the percentage change from the reference case projections for real GDP and oil prices in the *AEO2006* high and low price cases. In the high price case, oil prices rise rapidly to 70 percent above reference case prices within 10 years (2016), then climb more gradually to 80 percent above reference case prices in 2030. In the low price case, oil prices do not change by as much relative to the reference case, declining to 34 percent below reference case prices in 2016 and 44 percent below in 2030. Consequently, the macroeconomic effects in the two cases are not expected to be symmetric.

In each of the three cases, the U.S. economy grows at an average annual rate of 3.0 percent from 2004 through 2030 (although the average growth rates in the three cases do differ when calculated to two or more decimal places). With such significant differences in oil price paths in the three cases, why is the impact on the long-term real GDP growth rate so small? The major reasons have to do with the nature of the oil price increases and decreases relative to the reference case and their short-term versus long-term impacts on the economy.

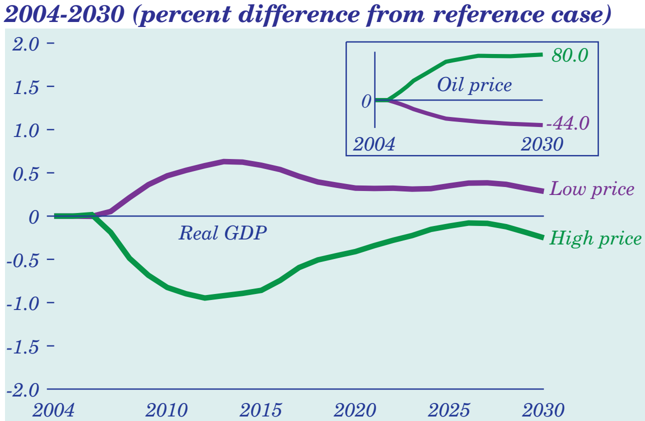
The oil price projections for 2005 and 2006 are the same in the three cases. From 2007 to 2010, the real oil price increases by more than 2 percent annually in the high price case, declines by 5 percent annually in the reference case, and declines by 9.4 percent annually in the low price case. From 2010 to 2015, the annual changes in oil prices in the three cases average 4 percent, -0.5 percent, and -5 percent, respectively. After 2015 the differences narrow considerably, and by 2030 the annual increases in oil prices average 1.1 percent in the high price case, 0.8 percent in the reference case, and zero in the low price case. With the maximum differences in growth rates among the three cases occurring in 2010, the peak impacts on real GDP and other economic variables occur approximately 2 years later, in 2012.

Over the 2006-2030 period, real GDP in the high price and low price cases deviates from that in the reference case for a considerable period. As the economy adjusts to the oil price changes, however, the differences become smaller, and by 2030 real GDP is approximately the same in the three cases, at $23,112 billion in the reference case, $23,054 billion in the high price case, and $23,178 billion in the low price case.

The discounted sum of changes in real GDP over the entire projection period provides a better indicator of net effects on the economy. In the low price case, the sum of the changes in real GDP, discounted at a 7-percent annual rate, over the 2006-2030 period is $665 billion, and in the high price case the sum is -$869 billion. These sums represent approximately 0.4 percent and -0.5 percent, respectively, of the total discounted real GDP in the reference case over the same period.

The elasticity of real GDP with respect to oil price changes over the 2006-2030 period is -0.007 in both the high price and low price cases. The year-by-year (marginal) and up-to-the-year (average) elasticities of real GDP with respect to oil price changes in the high price case (Figure 13) shows that the short-term effects of oil price increases are larger than their long-term effects.

Figure 12. Changes in world oil price and U.S. real GDP in the AEO2006 high and low price cases, 2004-2030 (percent difference from reference case)



To portray the short-term dynamics of the economy as it reacts to oil price changes, Table 12 shows 5-year average annual growth rates for U.S. oil prices (the imported refiners acquisition cost of crude oil), real GDP, potential GDP, and the consumer price index (CPI), as well as 5-year averages for the Federal funds rate and unemployment rate, over the 2005-2030 period. Higher oil prices in the short term feed through the economy and reduce aggregate expenditures on goods and services. As aggregate demand is less than aggregate supply, unemployment increases.

With higher prices there would also be a tendency for interest rates to rise. In the high price case, real GDP growth averages 3 percent per year over the 2005-2010 period, CPI inflation averages 2.3 percent per year, and the average unemployment rate for the 5-year period is 5 percent. In the reference case, the comparable rates are 3.2 percent (average annual real GDP growth), 2 percent (average annual CPI inflation), and 4.8 percent (unemployment). Potential GDP growth and the Federal funds rate are not significantly different in the two cases over the 2005-2010 period. The impacts of high prices on real GDP shown in Table 12 are in agreement with the average results shown in Table 9.

In the high price case, as unemployment increases, the Federal Reserve lowers the Federal funds rate from its projected level in the reference case. At the same time, total employment costs are lower, which tends to slow price growth in the economy. Over the 2010-2015 period, even though oil prices continue to grow by 4.1 percent annually in the high price case (as opposed to declining by 0.5 percent annually in the reference case), real GDP growth is about the same in the two cases, although it is increasing from a lower

Figure 13. GDP elasticities with respect to oil price changes in the high price case, 2006-2030

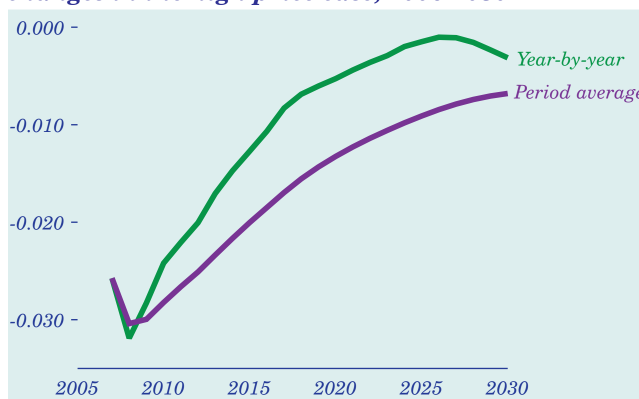


Table 12. Economic indicators in the reference, high price, and low price cases, 2005-2030 (percent)

Indicator	2005-2010	2010-2015	2015-2020	2020-2025	2025-2030	2005-2030
Reference case						
Average annual growth rates						
Oil price	-2.3	-0.5	0.9	1.3	0.8	0.0
Real GDP	3.2	2.9	3.1	2.8	2.8	3.0
Potential GDP	3.3	2.4	2.6	2.8	2.8	2.8
Consumer price index	2.0	2.7	3.0	3.0	2.8	2.7
5-year averages						
Federal funds rate	4.6	5.4	5.4	5.1	5.0	5.1
Unemployment rate	4.8	4.7	4.4	4.6	4.9	4.7
High price case						
Average annual growth rates						
Oil price	3.6	4.1	2.1	1.2	1.2	2.4
Real GDP	3.0	2.9	3.2	2.8	2.8	2.9
Potential GDP	3.2	2.4	2.7	2.8	2.8	2.8
Consumer price index	2.3	2.9	2.8	2.7	2.7	2.7
5-year averages						
Federal funds rate	4.6	5.2	4.9	4.7	4.7	4.8
Unemployment rate	5.0	5.2	4.7	4.7	4.9	4.9
Low price case						
Average annual growth rates						
Oil price	-5.6	-4.8	-0.7	0.0	0.0	-2.3
Real GDP	3.3	3.0	3.0	2.8	2.8	3.0
Potential GDP	3.3	2.4	2.6	2.9	2.9	2.8
Consumer price index	1.9	2.6	3.1	3.0	2.9	2.7
5-year averages						
Federal funds rate	4.5	5.5	5.6	5.3	5.3	5.2
Unemployment rate	4.8	4.5	4.2	4.5	4.8	4.6

base in the high price case. The Federal funds rate is lower in the high price case than in the reference case, and the unemployment and CPI inflation rates are higher.

After 2015, as the differential in the oil price growth rates between the high price and reference cases shrinks, rebound effects from the lower employment costs and lower Federal funds rate in the high price case are stronger than the contractionary impacts of higher oil prices, leading to higher real GDP growth and lower CPI inflation than in the reference case. As a result, in 2030, the real GDP growth rate and unemployment rate in the high price case are nearly the same as in the reference case, but the Federal funds rate is lower.

The assumptions behind the oil price cases are that: the price changes do not come as a shock and come to be expected over time; the Federal Reserve is able to carry out an activist monetary policy effectively, because core inflation remains low; exchange rates do not change from those in the reference case; and other countries experience impacts similar to those in the United States. Changes in any of these assumptions could increase the projected impacts on the U.S. economy.

The economic impact of oil price changes is an issue that continues to attract considerable attention, especially at this time, when oil prices have continued to rise over the past 3 years. Over the past 30 years, much has been learned about the nature of the economic impacts and the extent of damage possible. Empirical estimates based on history provide two sets of results. In the 1970s and 1980s the damages were substantial, and it is believed that recession followed—and may have been caused by—the oil price increases. Current literature suggests that, in today's U.S. economy, sustained higher oil prices can slow short-term growth but are not likely to cause a recession unless other factors are present that shock economic decisionmakers or lead to inappropriate economic policies. The *AEO2006* high and low price cases provide estimates of the economic impacts on such an economy, and the projections in the price cases are within the range that other macroeconomic models predict.

Changing Trends in the Refining Industry

There have been some major changes in the U.S. refining industry recently, prompted in part by a significant decline in the quality of imported crude oil and by increasing restrictions on the quality of finished products. As a result, high-quality crudes, such as the WTI crude that serves as a benchmark for oil futures on the New York Mercantile Exchange (NYMEX), have been trading at record premiums to the OPEC Basket price.

WTI is a "light, sweet" crude: light because of its low density and sweet because it has less than 0.5 percent sulfur content by weight. This combination of characteristics makes it an ideal crude oil to be refined in the United States, yielding a greater portion of its volume as "light products," including both gasoline and diesel fuel. Premium crudes like WTI yield almost 70 percent of their volume as light, high-value products, whereas heavier crudes like Mars (from the deepwater Gulf of Mexico) yield only about 50 percent of their volume as light products. The *AEO2006* projections use the average price of imported light, sweet crudes as the benchmark world oil price [*25*].

The average sulfur content of U.S. crude oil imports increased from 0.9 percent in 1985 to 1.4 percent in 2005 [*26*], and the slate of imports is expected to continue "souring" in coming years. Crude oils are also becoming heavier and more corrosive than they were in the past, largely because fields with higher quality varieties were the first to be developed, and refiners' preference for quality crudes has led to the depletion of those reserves over the past 100 years and reduced the market share of the light, sweet crude that remains.

The industry standard measure for oil density is API gravity; a lower gravity indicates higher density (heavy viscous oil), and a higher gravity indicates lower density (lighter, thinner oil). Over the past 20 years, the API gravity of imported crude oil has steadily declined, from 32.5 degrees to 30.2 degrees [*27*]. The standard measure for corrosiveness is the total acid number (TAN), indicating the number of milligrams of potassium hydroxide needed to neutralize the acid in 1 gram of oil. The most corrosive crudes, with TANs greater than 1, require significant accommodation to be processed. Usually, their corrosiveness is mitigated by the addition of basic compounds to neutralize the acid; however, some refiners have chosen instead to upgrade all their piping and unit materials to stainless steel. Whereas there were virtually no high-TAN crudes processed in 1990, they now make up about 2 percent of the crude oil slate, and a Purvin & Gertz forecast indicates that they will increase to 5 percent or more in 2020 [*28*] (Figure 14).

As refining inputs have declined in quality, demand for high-quality refined products has increased. The

EPA has developed new environmental rules that will require refineries to reduce the amount of sulfur in most gasoline to 30 ppm by 2006, from over 400 ppm in the early 1990s, and the sulfur content of highway diesel fuel to 15 ppm by October 2006, from over 2,000 ppm before 1993. By 2014, virtually all diesel fuel must be below 15 ppm [*29*] (Figure 15). To meet these specifications at the pump, refiners must produce diesel containing one-half that amount of sulfur before it enters the distribution system, because the low-sulfur product is expected to pick up trace amounts of sulfur as it moves through pipelines and other distribution channels.

To meet higher quality standards with poorer quality feedstocks will require significant investment by U.S. refiners. The principal method for reducing sulfur content in fuels is hydrotreating, a chemical process in which hydrogen reacts with the sulfur in crude oil to create hydrogen sulfide gas that can easily be removed from the oil. Hydrotreaters are specialized for the refinery streams they process. In aggregate, the dramatically lower sulfur specifications for petroleum fuels will necessitate a doubling of U.S. hydrotreating capacity by 2030, to 27 million barrels a day, from 14 million barrels a day in 2004. Most of the new capacity (23.4 million barrels a day) is expected to be installed by 2015 (Figure 16).

Low maximum sulfur specifications may also have implications for products not directly affected by the pending EPA rules. Suppliers of such high-sulfur products as jet fuel, home heating oil, and residual fuel may have to find alternative distribution channels if pipeline operators concerned about contamination stop accepting high-sulfur fuels.

As for adapting to heavier crude slates, there are two basic approaches. The first is to "upgrade" the oil to a lighter oil in the producing region, before it is sent to the refinery. Extra heavy oils, like those from the Orinoco region in Venezuela or the Alberta tar sands in Canada, are typically upgraded in a process that is both capital- and energy-intensive but can yield a highly desirable product. Canada's Syncrude Sweet Blend produced from tar sands is a high-quality synthetic crude (syncrude) that trades at near parity with WTI; however, the cost of the upgrades is almost $15 a barrel, in addition to the cost of tar sands recovery.

The second approach is to "convert" heavy oil at the refinery directly to light products, in a process more typical of the refining process for conventional oils. Chief among methods of conversion is thermal coking, in which heavy oil from a vacuum distillation unit is fed to a heating unit (coker) that splits off lighter hydrocarbon chains and routes them to the traditional refinery units. The almost pure carbon remaining is a coal-like substance known as petroleum coke. The accumulated coke can be removed from the coking vessels during an off cycle and either sold, primarily as a fuel for electricity generation, or used

Figure 14. Purvin & Gertz forecast for world oil production by crude oil quality, 1990-2020 (million barrels per day)

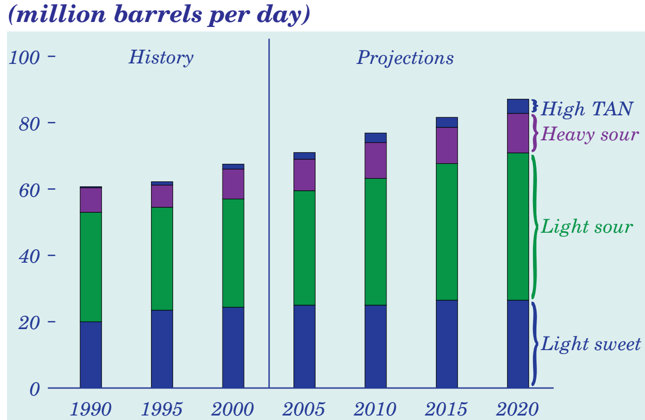


Figure 15. Sulfur content specifications for U.S. petroleum products, 1990-2014 (parts per million)

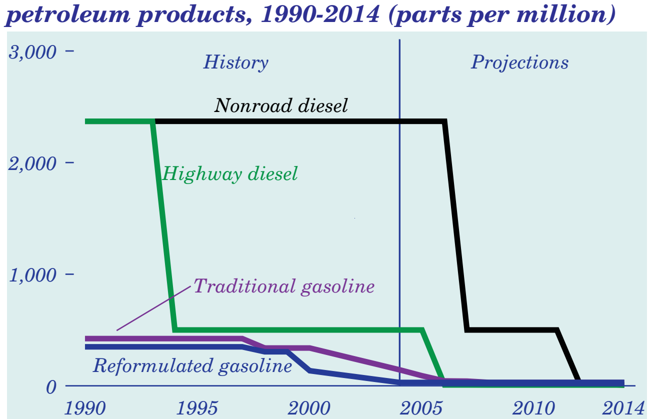
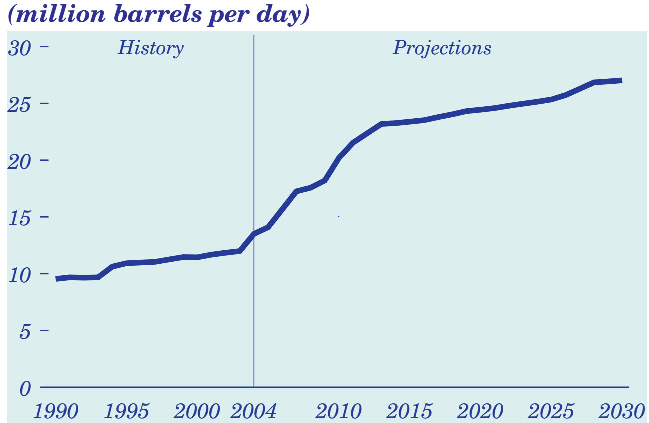


Figure 16. U.S. hydrotreating capacity, 1990-2030 (million barrels per day)



in gasification units to provide power, steam, and/or hydrogen for the refinery.

U.S. refineries are among the most advanced in the world, and their technological lead will undoubtedly leave U.S. refiners uniquely prepared to adapt and take advantage of discounts available for processing inferior crudes. Adaptation will require extensive future investments, however, and may take some time to achieve.

Energy Technologies on the Horizon

A key issue in mid-term forecasting is the representation of changing and developing technologies. How existing technologies will evolve, and what new technologies might emerge, cannot be known with certainty. The issue is of particular importance in *AEO2006*, the first *AEO* with projections out to 2030.

For each of the energy supply and demand sectors represented in NEMS, there are key technologies that, while they may not be important in the market today, could play a role in the U.S. energy economy by 2030 if their cost and/or performance characteristics improve with successful R&D. Moreover, it is possible, if not likely, that technologies not yet conceived could be important 20 to 30 years from now. Although the direction and pace of change are unpredictable, technological progress is certain to continue.

Buildings Sector

A variety of new technologies could influence future energy use in residential and commercial buildings beyond the levels projected in *AEO2006*. Two such technologies are solid-state lighting and "zero energy" homes.

Solid-state lighting. Solid-state lighting (SSL) is an emerging technology for general lighting applications in buildings. Two types of SSL currently under development are semiconductor-based light-emitting diode (LED) and organic light-emitting diode (OLED) technologies. Both are commercially available for specialized lighting applications. Consumers are likely to be familiar with the use of LEDs in traffic signals, exit signs and similar displays, vehicle tail lights, and flashlights. They are less likely to be familiar with OLEDs, used in high-resolution display panels for computers and other electronic devices.

Lighting accounted for 16 percent of total primary energy consumption in buildings in 2004, second only to space heating at 20 percent. Thus, changes in the assumptions made about development and enhancement of SSL technologies could have a significant impact on projected total energy consumption in residential and commercial buildings through 2030.

Beginning with *AEO2005*, SSL based on LED technology has been included as an option in the NEMS Commercial Module, based on currently available products. Those products are more than four times as expensive as comparable incandescent lighting, with only slightly greater efficiency (called "efficacy" and measured in lumens per watt), and so have virtually no impact in the *AEO2006* projections. In order for LEDs and OLEDs to compete successfully in general lighting applications, several R&D hurdles must be overcome: costs must be reduced, efficacy must be increased, and improved techniques must be developed for generating light with a high color rendering index (CRI) that more closely approximates the spectrum of natural light and is needed for many building applications.

DOE's R&D goals call for SSL costs to fall dramatically by 2030. The real promise for LED lighting is that efficacies could approach 150 to 200 lumens per watt—more than twice the efficacy of current fluorescent technologies and roughly 10 times the efficacy of incandescent lighting [*30*]. An additional goal is to increase LED operating lifetimes from 30,000 hours to 100,000 hours or more, which would far exceed the useful lifetimes of conventional technologies (generally, between 1,000 and 20,000 hours). Longer useful operating lives are particularly valuable in commercial applications where lamp replacement represents a major element of lighting costs.

For general illumination applications, OLED technology lags behind LED technology. If research goals are realized, the advantages of OLED technology will be lower production costs than LEDs, similar theoretical efficacies (200 lumens per watt for white light), and the flexibility to serve as a source of distributed lighting, as is currently provided by fluorescent lamps.

Zero energy homes. DOE's Zero Energy Homes (ZEH) program encompasses several existing technologies rather than a single emerging technology. The ZEH program takes a "whole house" approach to reducing nonrenewable energy consumption in residential buildings by integrating energy-efficient technologies for building shells and appliances with solar water heating and PV technologies to reduce annual net consumption of energy from nonrenewable sources to zero [*31*]. This is an emerging integrated technology; the ZEH concept is novel for conventional housing units [*32*]. ZEH prototypes have been shown to generate more electric energy than they consume during periods of peak demand for air conditioning, while approaching the goal of zero net annual energy purchases. The technological hurdle is to make ZEH homes without subsidies both cost-competitive and attractive as alternatives to conventional homes.

ZEH homes currently are not characterized or identified as an integrated technology in the NEMS Residential Module; however, most of the constituent ZEH technologies are characterized as separate options. Several whole-house options are modeled, characterized according to their efficiencies relative to current residential energy codes, with the following options:

- Current residential code
- 30 percent more efficient than current code (modeled to meet ENERGY STAR requirements)
- 40 percent more efficient than current code
- 50 percent more efficient than current code (modeled along the lines of PATH concepts [*33*])
- Solar PV and solar water heating technologies.

In addition to ZEH, a long list of emerging buildings technologies has been compiled by the American Council for an Energy-Efficient Economy. They included six identified as high-priority technologies on the basis of such criteria as the cost of conserved energy, savings potential, and likelihood of success:

- For residential and small commercial buildings: 1-watt standby power for consumer appliances, aerosol-based duct sealing, and leak-proof ducts
- For commercial buildings: integrated building design, computerized building diagnostics, and "retro-commissioning" [*34*].

Because they are still in the early stages of development, the information needed to characterize these six high-priority technologies or programs is not yet available, and they are not included in *AEO2006*; however, they do hold promise if they can be successfully commercialized.

Industrial Sector

The industrial sector is diverse, and there are many potential technological innovations that could affect industrial energy use over the next 25 years. Two technologies, fuel gasification and nanotechnologies, could have impacts across a broad array of industries. Gasification could be especially important to the paper business; successful nanotechnologies could have very broad impacts.

Black liquor gasification. Black liquor is a waste product from papermaking. It contains inorganic chemicals that are recovered for reuse in the papermaking processes and lignin from the initial pulpwood inputs that is also recovered and used as a fuel for boilers and for cogeneration. Current practice uses Tomlinson boilers to recover the inorganic chemicals and combust the organics to produce steam [*35*]. Black liquor gasification coupled with a combined-cycle power plant (BLGCC) has been proposed as a way to make better use of the lignin and recover a larger portion of the inorganic chemicals from the liquor.

R&D on BLGCC technology has been underway for several years. The American Forest and Paper Association's *Agenda 2020: Technology Vision and Research Agenda for America's Forest, Wood and Paper Industry*, first published in 1994, has been revised several times over the years. A recent progress report indicates that successful industry-wide implementation of BLGCC could provide an additional 30 gigawatts of on-site electricity generation capacity beyond the 8 gigawatts operating in 2004 [*36*].

DOE-sponsored R&D activities in support of BLGCC were evaluated by the National Academy of Sciences (NAS) in a 2001 report [*37*], in which it was indicated that DOE's expectation that Tomlinson boilers would be replaced in a 10- to 20-year time frame probably was optimistic. The report also noted that "moving from the existing black liquor gasification units to systems suitable for use with combined cycle requires bench-scale research as well as demonstration." The technology is not explicitly represented in *AEO2006* and is not expected to have an impact on the industrial sector in the reference case. In the high technology case, the potential impact of BLGCC is represented as an increasing amount of biomass-based CHP capacity, up to 3 gigawatts (43 percent) more than in the reference case in 2030.

Nanotechnology. Nanotechnology refers to a wide range of scientific or technological projects that focus on phenomena at the nanometer (nm) scale (around 0.1 to 100 nm) [*38*]. While not as far along as BLGCC, nanotechnologies have much larger potential impacts if they are successfully developed. Indeed, it has been suggested that nanotechnology applications in the industrial sector could yield a new industrial revolution [*39*]. Possible applications include, for example, very thin solar silicon panels that could be embedded in paint [*40*]; very thin video screens with about the same thickness and flexibility as newspapers, which could be updated continuously with current news [*41*]; and very strong, very light materials that could revolutionize transportation systems and dramatically reduce per capita energy consumption [*42*].

While the potential applications of nanotechnologies are diverse, many issues, including potential impacts on human health, remain to be studied. *AEO2006* does not include potential energy applications of nanotechnology, because they still are speculative.

Transportation Sector

The transportation module in NEMS addresses technologies specific to light-duty vehicles, heavy trucks, and aircraft. The majority of the advanced technologies represented reflect improvements to conventional power train components, including such technologies as variable valve timing and lift, camless valve actuation, advanced light-weight materials, six-speed and continuously variable transmissions, cylinder deactivation, and electronically driven parasitic devices (power steering pumps, water pumps, etc.). Vehicles powered by batteries or fuel cells are also explicitly represented in *AEO2006*, but their penetration results largely from legislatively mandated sales.

Transportation technologies not currently included in NEMS that could potentially become viable market options include homogeneous charge compression ignition (HCCI), grid-connected hybrid vehicles, and hydraulic hybrid vehicles. HCCI—which combines features of both spark-ignited (gasoline) and compression-ignited (diesel) engines—can operate on a variety of fuels. In the HCCI engine, an extremely lean mixture of fuel and air is autoignited in the cylinder via compression. Autoignition can damage the pistons in spark-ignited engines, but the extremely high air-to-fuel ratio in HCCI engines prevents flame propagation and results in a much cooler burn. As a result, HCCI engines are very efficient, with low levels of emissions that do not require expensive after-treatment devices. The fuel properties and cylinder conditions needed for HCCI combustion are well understood; however, it is extremely difficult to control ignition in multiple-cylinder engines across a wide range of load conditions, as needed for vehicle applications.

Grid-connected hybrid vehicles are similar to the hybrid vehicles sold today, except that the batteries provide an all-electric range of about 50 miles, and an external source to charge the batteries is required. Unlike current hybrid vehicles that use high-power batteries to supplement the power of gasoline engines, grid-connected hybrid vehicles are also designed to operate as all-electric vehicles and, as such, require a much larger battery pack for energy storage, a larger electric motor, and related components that enable them to function over a much wider range of driving conditions. Although all-electric driving greatly reduces the vehicles' gasoline consumption, the costs of the battery pack and other components are significant. Marketing studies have indicated that there is a lack of consumer interest in "plug-in" vehicles but that a limited market would exist if their incremental costs relative to conventional vehicles could be reduced to at most $5,000.

Hydraulic hybrid vehicles use hydraulic and mechanical components to store and deliver energy. In a hydraulic hybrid, the gear-driven transmission is replaced by a hydraulic pump/motor that is also used to store and recoup energy through the transfer of fluid between hydraulic accumulators. Recent hydraulic hybrid prototypes are designed to provide launch assist in heavy vehicle applications, allowing acceleration with less engine power. The hydraulic hybrid system has been shown to provide a 50-percent improvement in fuel economy at a cost of about $600. Current hydraulic systems are large and heavy, however, and the EPA is funding R&D to reduce their size and weight while improving their efficiency.

Oil and Natural Gas Supply

In the oil and natural gas supply area, new technologies for the economical development of unconventional resources could grow in importance. One of the most plentiful unconventional resources is natural gas hydrates—ice-like solids composed of light hydrocarbon molecules, primarily methane, trapped in a cage-like crystalline lattice of water and ice.

The 1995 National Oil and Gas Resource Assessment, conducted by the USGS and the Minerals Management Service, produced the first systematic appraisal of in-place natural gas hydrate resources in U.S. onshore and offshore regions [*43*]. Its mean (expected value) estimate of in-place natural gas hydrates offshore in U.S. deepwater areas was 320,000 trillion cubic feet, and its mean estimate of in-place natural gas hydrate resources onshore in Alaska's North Slope was 590 trillion cubic feet. In comparison, total U.S. natural gas production in 2003 was 19 trillion cubic feet, and year-end 2003 reserves were 193 trillion cubic feet. According to these estimates, if natural gas hydrate resources could be developed economically, they could supply U.S. natural gas needs for many years.

Commercial production of natural gas hydrates has not yet been attempted. Short-term production tests have been conducted in Canada's MacKenzie Delta region, however, and natural gas hydrates may have been produced unintentionally at the Messoyakha Field in Russia's West Siberian Basin.

Commercial production of natural gas hydrates is expected to use one or more of three techniques: pressure reduction, heat injection, and solvent phase change. The techniques used will depend on the characteristics of the natural gas hydrate formation being developed. Each has advantages and disadvantages. The pressure reduction technique has the lowest cost, but it requires a free-gas (non-hydrate) zone below the hydrate deposit, and the production rate would be limited by heat transfer rates within the formation. The heat injection technique, using steam or hot water, does not require a free-gas zone, and it would achieve higher production rates than are possible with pressure reduction. On the other hand, it is more complex and more costly, requiring large amounts of water and energy to heat it. The solvent phase change technology is the most expensive, and it could lead to water contamination problems, but it does not require energy for water heating and is not subject to the formation of ice dams, which can be a problem for the heat injection technique.

In the United States, the existence of large conventional natural gas deposits in the Prudhoe Bay and Point Thomson Fields on Alaska's North Slope is expected to preclude any significant production from hydrates on the North Slope for many years to come. For example, if the Alaska natural gas pipeline became operational in 2015, it would take about 21 years (until 2036) to deplete the 35 trillion cubic feet of proven North Slope conventional natural gas resources at a pipeline capacity of 4.5 billion cubic feet per day, or 17 years (until 2032) at a pipeline capacity of 5.6 billion cubic feet per day. Moreover, the North Slope has a large undiscovered base of conventional natural gas resources beyond the volumes estimated to be recoverable in currently known fields. Therefore, any significant commercial production of North Slope natural gas hydrates could be 30 years or more into the future.

Production of oceanic natural gas hydrates is at least as problematic, because the deposits are not as well mapped and characterized, and because no production of oceanic hydrates has yet occurred. Moreover, akin to the situation on the Alaska North Slope, there are considerable conventional natural gas deposits yet to be found and developed in the deepwater Gulf of Mexico. Considerable R&D will also be required before any exploitation of oceanic natural gas hydrates can be considered. Research on oceanic hydrates is almost certain to continue, given the vast size of the potential resource.

Biorefineries

Rising world oil prices in recent years have heightened interest in alternative sources of liquid fuels, including biofuels. Currently, two biologically derived fuels, biodiesel and ethanol, are used in the United States to augment and improve supplies of gasoline and diesel fuel. As petroleum becomes more scarce and expensive, these and potentially other biofuels could become important alternatives.

Biodiesel. The term biodiesel applies specifically to methyl or ethyl esters of vegetable oil or animal fat. In principle, biodiesel can be blended into petroleum diesel fuel or heating oil in any fraction, so long as the fuel system that uses it is constructed of materials that are compatible with the blend. The actual maximum allowable fraction of biodiesel in diesel fuel varies by engine manufacturer and by specific model line. Fuel system materials are a concern, because methyl and ethyl esters are strong solvents that can damage certain plastics or rubbers.

The solvent properties of biodiesel also make it unlikely that biodiesel blends could be shipped through petroleum product pipelines. There would be a risk of contamination when the biodiesel dissolved any material deposited on the walls of pipes, manifolds, or storage tanks. On the positive side, the addition of biodiesel to petroleum diesel reduces engine emissions of carbon monoxide, unburned hydrocarbons, and particulates. On the negative, it tends to increase nitrogen oxide emissions, and that may limit the use of biodiesel in places with excess levels of ozone at ground level.

The production of methyl esters is an established technology in the United States, but the product typically has been too expensive to be used as fuel. Instead, methyl esters have been used in products such as soaps and detergents. Proctor and Gamble, Peter Cremer, Dow Haltermann, and other large firms currently supply methyl esters to the industrial market. Most dedicated biodiesel producers are much smaller, and delivery of a consistent product is proving to be a challenge.

Several other processes for making diesel fuel from biomass are under consideration. The most mature of these technologies is biomass-to-liquids (BTL). The biomass is first reacted with steam in the presence of a catalyst to form carbon monoxide and hydrogen, or synthesis gas. Any other elements contained in the biomass are removed during the gasification step. The carbon monoxide and hydrogen are then reacted to form liquid hydrocarbons and water.

Although BTL products are high in quality, BTL plants face several challenges. They have high capital and operating costs, and their feedstock handling costs are especially high. BTL gasifiers are significantly more expensive than the gasifiers used in CTL or GTL facilities. Furthermore, the cost of a BTL plant per barrel of output is several times the cost of expanding an existing petroleum refinery or building a new one. As a result, while new BTL plants are being built in Germany, there is no commercial production of BTL in the United States. BTL production and its market implications are discussed under "Nonconventional Liquid Fuels," below.

In another process, vegetable oils and animal fats can be reacted with hydrogen to yield hydrocarbons that blend readily into diesel fuel. The oil or fat is pressurized and combined in a reactor with hydrogen in the presence of a catalyst similar to those used in hydrotreaters at petroleum refineries. The products of the process are bioparaffins. Bioparaffin diesel fuel is similar in quality to BTL diesel, with the added benefit of being free of byproducts. The improvement in quality over methyl esters (biodiesel) is not free, however. A bioparaffin plant is less expensive than a BTL plant but more expensive than a biodiesel plant, because the bioparaffin reaction takes place under pressure, and a hydrogen plant is needed. Bioparaffins also share with biodiesel the problem of feedstock costs. Vegetable oils are expensive, especially if they are food grade. The catalyst needed also adds significant expense. The world's first bioparaffin plant is being built at a petroleum refinery in Finland, but there are no plans for U.S. bioparaffin capacity at this time.

Ethanol. Ethanol can be blended into gasoline readily at up to 10 percent by volume. All cars and light trucks built for the U.S. market since the late 1970s can run on gasoline containing 10 percent ethanol. Automakers also produce a limited number of vehicles for the U.S. market that can run on blends of up to 85 percent ethanol. Ethanol adds oxygen to the gasoline, which reduces carbon monoxide emissions from vehicles with less sophisticated emissions controls. It also dilutes sulfur and aromatic contents and improves octane. Because newer vehicles with more sophisticated emissions controls show little or no change in emissions with the addition of oxygen to gasoline, ethanol blending in the future will depend largely on octane requirements, limits on gasoline sulfur and aromatics levels, and mandates for the use of renewable motor fuels.

Ethanol production from starches and sugars, such as corn, is a well-known technology that continues to evolve. In the United States, most fuel ethanol currently is distilled from corn, yielding byproducts that are used as supplements in animal feed. Three factors may limit ethanol production from starchy and sugary crops: all such crops are also used for food, and only a limited fraction of the available supply could be diverted for fuel use without driving up crop prices to the point where ethanol production would no longer be economical; there is a limit to the amount of suitable land available for growing the feedstock crops; and only a portion of the plant material from the feedstock can be used to produce ethanol. For example, corn grain can be used in ethanol plants, but the stalks, husks, and leaves are waste material, only some of which needs to be left on cornfields to prevent erosion and replenish soil nutrients.

The underutilization of crop residue has driven decades of research into ethanol production from cellulose; however, several obstacles continue to prevent commercialization of the process, including how to accelerate the hydrolysis reaction that breaks down cellulose fibers and what to do with the lignin byproduct. Research on acid hydrolysis and enzymatic hydrolysis is ongoing. The favored proposal for dealing with the lignin is to use it as a fuel for CHP plants, which could provide both thermal energy and electricity for cellulose ethanol plants, as well as electricity for the grid; however, CHP plants are expensive.

Currently, Canada's Iogen Corporation is trying to commercialize an enzymatic hydrolysis technology for ethanol production. The company estimates that a plant with ethanol capacity of 50 million gallons per year and lignin-fired CHP will cost about $300 million to build. By comparison, a corn ethanol plant with a capacity of 50 million gallons per year could be built for about $65 million, and the owners would not bear the risk associated with a new technology. Co-location of cellulose ethanol plants with existing coal-fired electric power plants could reduce the capital cost of the ethanol plants but would also limit siting possibilities.

Electricity Production

Some of the electricity generating technologies and fuels represented in NEMS are currently uneconomical, and there are still other fossil, renewable, and nuclear options under development that are not explicitly represented. Those technologies are not expected to be important throughout most of the projections, but with successful development they could have impacts in the market in the later years.

Fossil Fuels

Advanced Coal Power. FutureGen is a demonstration project announced by DOE in February 2003 that will have 275 megawatts of electricity generation capacity and will also produce hydrogen for other uses. Of the project's $1 billion cost, 80 percent will come from DOE, and 20 percent is expected to be provided through a consortium of firms from the coal and electric power industries. The demonstration plant, fueled by coal, will include carbon capture and sequestration equipment to limit GHG emissions. It will operate in an IGCC configuration and sequester approximately 1 million metric tons of CO_2 annually. The sequestered CO_2 will be used to enhance oil recovery in depleted oil fields. SO_2 and mercury emissions from the plant will also be captured.

In 2003, it was anticipated that the FutureGen project would be operational within 10 years. Site selection and environmental impact studies are expected to be completed in 2007. The site must include geological formations that can be used to store at least 90 percent of the plant's CO_2 emissions, with an annual leakage rate below 0.01 percent.

If the project proves to be technically and economically successful, it could offer a partial solution for the continued use of fossil fuels without contributing further to rising atmospheric concentrations of GHGs, by injecting CO_2 into depleted oil and gas wells while adequate space is available. Coal gasification plants with carbon capture and sequestration equipment have yet to be demonstrated, however, and many challenges remain. The capital costs for IGCC plants with carbon capture and sequestration equipment are much higher than those for conventional coal-fired plants, and their conversion efficiencies are lower. Moreover, the current conventional solvent-based absorption process for carbon capture remains energy intensive.

Advanced Fuel Cells. Fuel cells operate similarly to batteries but do not lose their charge. Instead, they rely on a supply of hydrogen, which is broken into free protons and electrons within the cell. There are several types of fuel cells, using different materials and operating at different temperatures. Stationary power fuel cells can be connected to the electricity grid, and smaller cells are envisioned for the transportation sector. Although the costs of fuel cells have been reduced since their inception, they currently remain too high for widespread market penetration.

Phosphoric acid fuel cells, which operate at relatively low temperatures, are currently being used in several applications with efficiency rates of 37 to 42 percent. An advantage of this cell type is that relatively impure hydrogen is tolerated, broadening the source of potential fuels. The major disadvantage is the high cost of the platinum catalyst.

Molten carbonate fuel cells, which use nickel in place of more costly metals, can achieve a 50-percent efficiency rate and are operating experimentally as power plants. Solid oxide fuel cells, also currently being developed, use ceramic materials, operate at relatively high temperatures, and can achieve similar efficiencies of around 50 percent. They have applications in the electric power sector, providing exhaust to turn gas turbines, and could also have future uses in the transportation sector.

The costs of fuel cells must be reduced significantly before they can become competitive in U.S. markets, and an inexpensive, plentiful source of hydrogen fuel must also be found. If those hurdles can be met, fuel cells offer several advantages over current generation technologies: they are small, quiet, and clean, and because no combustion is involved, their only byproduct is water.

Carbon Capture with Sequestration

Capturing CO_2 from the combustion of fossil fuels may allow for their continued use without significant additional contributions to GHG emissions and global warming. Currently, however, sequestration technologies are too costly for implementation on a significant scale. One of the greatest challenges is separation of CO_2 from other emissions, given typical CO_2 concentrations of 3 to 12 percent in the smokestack gases of coal-fired power plants.

One potential solution for capturing CO_2 is the use of amine scrubbers. Amines react with CO_2, and the resulting product can be heated and separated in a desorber. Another option is the IGCC process to be used in FutureGen, which will produce highly concentrated CO_2 ready for storage.

Carbon storage will most likely be underground. For example, enhanced oil recovery technologies pump CO_2 into depleted oil and natural gas fields to extend their yields and lifetimes. Other options include placing the CO_2 in coalbeds and saline formations. Ocean storage is a possibility, although the potential environmental impacts are unknown. Preliminary geological studies have shown that underground storage, if successful, has the potential to store all the CO_2 from industrial and power sector emissions for several decades. Major issues include the proximity of the geologic storage formations to potential CO_2 production sites, the long-term permanence of the storage sites, and the development of the monitoring systems needed to ensure that leakage is limited and controlled.

In 2005, DOE announced the second phase of seven partnerships involving small, field-level demonstrations to determine the feasibility of carbon sequestration technologies. In one project, ConocoPhillips, Shell, and Scottish and Southern Energy will begin designing the world's first industrial-scale facility to generate "carbon-free electricity" from hydrogen. The planned project will convert natural gas to hydrogen and CO_2, then use the hydrogen gas as fuel for a 350-megawatt power station, reducing the amount of CO_2 emitted to the atmosphere by 90 percent. The CO_2 will be exported to a North Sea oil reservoir for increased oil recovery and eventual storage. Smaller demonstration projects are already operating in Algeria and Norway.

Renewables

In the face of international concern over GHG emissions, the eventual peaking of world oil production, and recent volatility in fossil fuel prices, many have seen promise in exploiting an ever-increasing range of renewable energy resources. Renewable energy resources used to generate electricity generally reduce net GHG emissions compared to fossil generation, are accepted as being nondepletable on a time scale of interest to society, and tend to have low and stable operating costs.

To date, however, market adoption of most renewable technologies has been limited by the significant capital expense of capturing and concentrating the often diffuse energy fluxes of wind, solar, ocean, and other renewable resources. With the most successful renewable generation technology, hydropower, nature has largely concentrated the diffuse energy of falling water through the geography of watersheds. The challenge for emerging technologies, as well as those on the horizon, will be to minimize both the monetary and environmental costs of collecting and converting renewable energy fuels to more portable and useful forms.

Wind. Through a combination of significant cost reductions over the past 20 years and policy support in the United States, Europe, and elsewhere, electricity generation from wind energy has increased substantially over the past 5 to 10 years. In fact, in some areas of Western Europe, viable new sites for wind are seen as severely limited, because the best sites already are being exploited, leaving sites with poor resources, too close to populated areas, and/or in otherwise undesirable locations. In response, a number of European countries have begun to build wind plants offshore, where they are more remote from population centers and can take advantage of better resources. Although firm data on costs has been scarce, it is believed that offshore wind plants cost substantially more to construct, to transmit power, and to maintain than comparable onshore wind plants.

There have been a number of proposals for offshore wind plants in the United States, including at least two under serious consideration for near-term development, off Cape Cod, Massachusetts, and Long Island, New York. The United States has substantially larger and better wind resources than most countries of Europe, and thus is unlikely to see its onshore resources exhausted in the mid-term outlook. Still, localized factors such as State renewable energy requirements and constraints on electricity transmission from conventional power plants into coastal areas may make some offshore resources economically attractive, despite the abundance of lower cost wind resources further inland. Because NEMS models 13 relatively large electricity markets, it cannot fully account for localized effects at the State or metropolitan level, and thus is likely to miss the few economical opportunities for offshore development of wind-powered generators.

Hydropower. In addition to ocean-based wind power technologies, there are a number of technologies that could harness energy directly from ocean waters. They include wave energy technologies (which indirectly harness wind energy, in that ocean waves usually are driven by surface winds), tidal energy technologies, "in-stream" hydropower, and ocean thermal energy technologies.

Although a number of wave energy technologies are under development, including some that may be near pre-commercial demonstration, the publicly available data on resource quantity, quality, and distribution and on technology cost and performance are inadequate to describe the specifics of the technologies. A handful of tidal power stations around the world do operate on a commercial basis, but prime tidal resources are limited, and the technology seems unlikely to achieve substantial market penetration unless more marginal resources can be harnessed economically.

In-stream hydropower technologies generally use freestanding or tethered hydraulic turbines to capture the kinetic energy of river, ocean, or tidal currents without dams or diversions. As with wave energy technologies, while some of these technologies appear to be in fairly advanced pre-commercial development, there is insufficient available information to support reasonable market assessment within the NEMS framework.

Ocean thermal technologies harness energy from temperature differentials between surface waters and waters at depth. These technologies have received funding from the Federal Government in the past, and U.S. development continues today under fully private funding. To date, however, there have been no new pre-commercial demonstrations beyond those previously funded by the Federal Government. Resources suitable for ocean thermal energy development are geographically limited to tropical or near-tropical waters near land, with a relatively steep continental shelf. (Although a fully offshore deepwater technology is plausible, it would be significantly more expensive than a shore-based implementation.) These requirements eliminate virtually the entire continental United States as a potential resource base, and the technology is not included in *AEO2006*.

Geothermal. Although U.S. geothermal resources have been exploited for decades to produce electricity, commercial development to date has been limited to hydrothermal deposits at relatively shallow depths. In hydrothermal deposits, hot rock close to the surface heats naturally occurring groundwater, which is extracted at relatively low cost to drive a conventional generator. Steam may be used directly from the ground, or superheated water may be used to heat a secondary working fluid that drives the turbine. Suitable hydrothermal deposits, however, are limited in quantity and location, and in most cases they would be too expensive for development in the mid-term. Enhanced geothermal technologies to exploit deeper, drier resources are not likely to be cost-effective for widespread commercial deployment until well after 2030.

Solar. Sunlight is a renewable resource that is almost universally available. NEMS models several different technologies for harnessing solar energy, including PV cells deployed at end-user locations, PV deployed at central, utility-owned locations, and thermal conversion of sunlight to electricity. Each is based on commercially available technologies, with substantial allowances made for future improvements in cost and performance. In view of the significant contribution of government-funded R&D to the progress of solar energy technologies, much of the future improvements occur independently from actual market growth (although significant market growth is projected).

Research is continuing on a number of solar technologies—both direct conversion and thermal conversion—that could substantially improve the efficiency or reduce the cost of producing electricity from sunlight. Examples include organic PV, highly concentrated PV, "solar chimneys," and a range of improvements to PV efficiency and manufacturing. Given the wide variety of potential technologies and uncertainty as to the success of any particular one, solar technology is modeled from the known cost and performance parameters of commercial technologies, along with both production-based and production-independent improvements in cost and performance.

Hydrogen

Widespread use of hydrogen as an energy carrier has been presented by some as a long-term solution to the limitations of our largely fossil-energy based economy. Significant quantities of molecular hydrogen (H_2) are not found in nature but must be released from water, hydrocarbons, or other "chemical reservoirs" of hydrogen. Thus, hydrogen is an energy carrier, in much the same way that electricity is an energy carrier, rather than a primary source of energy. Hydrogen has a wide variety of potential end uses, including the production of electricity; but hydrogen production based on fossil fuels (primarily through methane steam reforming or other thermochemical processes), currently the least costly means of production, would at best provide only limited relief from the use of fossil fuels (by increasing the efficiency of energy end uses) and potentially could lead to more use of fossil fuels (by reducing overall "wells-to-wheels" system efficiency).

Hydrogen could also be produced from non-fossil fuels, including nuclear and renewable resources, either through electrolysis of water or by direct thermochemical conversion. Significant use of hydrogen would likely evolve as a system, with development and deployment of technologies for production, distribution, and end use closely linked. Many technologies for producing hydrogen are commercially available today, but they are expensive. Without significant technological progress, it seems unlikely that substantial incremental amounts of hydrogen will be produced before 2030.

Nuclear

The nuclear cost assumptions for *AEO2006* are based on the realized costs of advanced nuclear power plants whose designs have been certified by the U.S. Nuclear Regulatory Commission (NRC) and/or have been built somewhere in the world—specifically, the generation 3 light-water reactors (LWRs). To account for technological improvements, it is assumed that costs will fall, with cost reductions reflecting incremental improvements in the designs of reactors as they evolve from the generation 3 to generation 3+. Recently, some vendors have reported cost estimates for generation 3+ reactors that are much lower than those assumed in NEMS, even after allowing for cost reductions; however, their estimates were based on incomplete designs, and history has shown that cost estimates based on incomplete designs tend to be unreliable [*44*]. For *AEO2006*, the vendor estimates are used in a sensitivity analysis.

Although the nuclear capital cost assumptions used in both the reference case and the sensitivity analysis are representative of the costs of building LWRs whose designs reflect incremental improvements over those that have been built in the Far East or are being built in Europe, a number of small-scale and large-scale LWR designs that differ significantly from generation 3 plants could be commercially available by 2030 [*45*]. Because of technical and economic uncertainties, however, they are not included in *AEO2006*.

A number of non-LWR designs for nuclear power plants have also been suggested, including variants on the traditional fast breeder technology, such as lead-cooled and sodium-cooled reactors. These designs are often referred to as "generation 4" nuclear power plants. The technologies have all the advantages and disadvantages of the traditional breeder reactors that have been built in Europe and the Far East, and because of their large size they would be more economically advantageous in regulated electricity markets, where financial risks are not borne entirely by investors.

Examples of the small, modular power plant designs include the Pebble Bed Modular Reactor (PBMR), the Gas-Turbine Modular Helium (GT-MH) reactor and the International Reactor Innovative and Secure (IRIS) reactor. In theory at least, these plants might be built in competitive markets where it is economically advantageous to add small amounts of capacity in response to volatile and uncertain electricity prices [*46*].

The PBMR and the GT-MH reactor are also designed to operate at much higher temperatures than the LWRs currently in operation. Thus, both of these designs could potentially be used to produce both electricity and hydrogen. In fact, EPACT2005 authorizes $1.25 billion to build a prototype of such a reactor that could be used to cogenerate electricity and hydrogen. The law specifies that a prototype reactor should be completed by 2021. The economic potential of such a reactor is considerable, in that the hydrogen could be used in fuel cells or in other industrial processes; however, the technological uncertainties involved are substantial.

Advanced Technologies for Light-Duty Vehicles

A fundamental concern in projecting the future attributes of light-duty vehicles—passenger cars, sport utility vehicles, pickup trucks, and minivans—is how to represent technological change and the market forces that drive it. There is always considerable uncertainty about the evolution of existing technologies, what new technologies might emerge, and how consumer preferences might influence the direction of change. Most of the new and emerging technologies expected to affect the performance and fuel use of light-duty vehicles over the next 25 years are represented in NEMS; however, the potential emergence of new, unforeseen technologies makes it impossible to address all the technology options that could come into play. The previous section of "Issues in Focus" discussed several potential technologies that currently are not represented in NEMS. This section discusses some of the key technologies represented in NEMS that are expected to be implemented in light-duty vehicles over the next 25 years.

The NEMS Transportation Module represents technologies for light-duty vehicles that allow them to comply with current standards for safety, emissions, and fuel economy or may improve their efficiency and/or performance, based on expected consumer demand for those attributes. Technologies that can improve vehicle efficiency take two forms: those that represent incremental improvements to or advancements in the various components of conventional power trains, and those that represent significant changes in power train design. Advanced technologies used in vehicles with new power train designs include, primarily, electric power propulsion systems in hybrid, fuel cell, and battery-powered vehicles.

Historically, the development of new technologies for light-duty vehicles has been driven by the challenge of meeting increased demand for larger, quieter, more powerful vehicles while complying with emissions, safety, and fuel economy standards. The auto industry has met those challenges and, through technological innovation, delivered larger, more powerful vehicles with improved fuel economy.

In 1980, the average new car weighed 3,101 pounds, had 100 horsepower, and averaged 24.3 miles per gallon. In 2004, the average new car weighed 3,454 pounds (an 11-percent increase), had 181 horsepower (an 81-percent increase), and averaged 29.3 miles per gallon (a 21-percent increase). Improvements in new light trucks (including sport utility vehicles) from 1980 to 2004 have been even more profound: their average weight has increased by 20 percent to 4,649 pounds, their horsepower has increased by 91 percent to 231, and their average fuel economy has increased by 16 percent to 21.5 miles per gallon [*47*].

The majority of improvements in horsepower and fuel economy for new light-duty vehicles have resulted from changes in conventional vehicle components, including fuel delivery systems, valve train design, aerodynamics, and transmissions. In 1980, almost all new light-duty vehicles employed carburetors for fuel delivery; in 2004, all new light-duty vehicles used port fuel injection systems, which improve engine efficiency through very precise electronic control of fuel delivery. Advances have also been made in valve train design, improving efficiency by reducing engine pumping losses. In 1980, all engine designs used two valves per cylinder; in 2004, engines with four valves per cylinder were installed in 74 percent of new cars and 43 percent of new light trucks.

Increases in light-duty vehicle horsepower and fuel economy are projected to continue in the *AEO2006* cases at rates similar to their historical rates, while vehicle weight remains relatively constant. For example, between 2005 and 2030 new car horsepower increases by 19 percent, to 215, in the reference case, while fuel economy increases by 15 percent to 33.8 miles per gallon; and the horsepower of new light trucks increases by 14 percent, to 264, and fuel economy increases by 23 percent to 26.4 miles per gallon, while their weight increases by 4 percent to 4,828 pounds. Most of the improvements result from innovations in conventional vehicle components.

To project potential improvement in new light-duty vehicle fuel economy, 63 conventional technologies are represented in the Transportation Module. The technologies are grouped into six vehicle system categories: engine, transmission, accessory load, body, drive train, and independent (related to safety and emissions). Table 13 summarizes the technologies expected to have significant impacts over the projection period, the expected range of efficiency improvements, and initial costs.

Engineering relationships among the technologies are also modeled in the Transportation Module. The engineering relationships account for: (1) co-relationships, where the existence of one technology is required for the existence of another; (2) synergistic effects, reflecting the combined efficiency impact of two or more technologies; (3) superseding relationships, which remove replaced technologies; and (4) mandatory technologies, needed to meet safety and emissions regulations. In addition to the engineering relationships, reductions in technology cost are captured as unit production increases or cumulative production reaches a design cycle threshold.

Technologies expected to show the greatest increase in market penetration, and thus the greatest impact on new car and light truck efficiency, include lightweight materials, improved aerodynamics, engine friction reduction, improved pumps, and low rolling resistance tires (Figures 17 and 18). These technologies represent the most cost-effective options for improving fuel economy while meeting consumer expectations for vehicle performance and comfort. The weight of new cars remains relatively constant as a result of increased market penetration of high-strength low-alloy steel (63 percent by 2030), aluminum castings (24 percent by 2030), and aluminum bodies and closures (12 percent by 2030). Variable valve timing and lift and camless valve actuation are also expected to have a significant impact on new car efficiency, with installations increasing to approximately 30 percent and 4 percent, respectively, in 2030. The use of unit body construction in new light trucks increases from 23 percent in 2004 to 36 percent in 2030 as more sport utility vehicles and pickup trucks are developed from car-based platforms.

The efficiency of new light-duty vehicles also improves with increased market penetration of hybrid and diesel vehicles. Depending on the make and model, the incremental cost of a power-assisted hybrid vehicle (a “full hybrid”), currently estimated at $3,000 to $10,000, decreases to between $1,500 and $5,400 in 2030 [*48*]. As a result, the penetration of hybrid vehicles increases from 0.5 percent of new light-duty vehicle sales in 2004 to 9.0 percent in 2030.

Market penetration of diesel vehicles increases from about 2 percent in 2004 to more than 8 percent in 2030. Battery and fuel cell powered vehicles also penetrate the light-duty vehicle market as a result of legislative mandates, but with very high vehicle costs, limited driving range, and the lack of a refueling infrastructure, they account for only 0.1 percent of new vehicle sales in 2030.

Nonconventional Liquid Fuels

Higher prices for crude oil and refined petroleum products are opening the door for nonconventional liquids to displace petroleum in the traditional fuel supply mix. Growing world demand for diesel fuel is helping to jump-start the trend toward increasing production of nonconventional liquids, and technological advances are making the nonconventional

Table 13. Technologies expected to have significant impacts on new light-duty vehicles

Vehicle component and technology	Technology description	Expected efficiency improvement (percent)	Initial incremental cost (2000 dollars)
Engine			
Advanced valve train	Four valves per cylinder; variable valve timing and lift; camless valve actuation	2.5-8.0	45-750
Friction reduction	Low-mass pistons and valves; reduced piston ring and valve spring tension; improved surface coatings and tolerances	2.0-6.5	25-177
Cylinder deactivation	Reduced cylinder operation at light load, lowering displacement and reducing pumping losses	4.5	250
Lean burn	Direct injection fuel system, enabling very lean air-fuel ratios	5.0	250
Transmission			
Control system	Electronic controls, improving efficiency through shift logic and torque converter lockup	0.5-2.0	8-60
Transmission	5-speed and 6-speed automatics; continuously variable transmissions	6.5-10.0	435-615
Accessory load			
Improved pumps	Reduced engine load from oil, water, and power steering pumps	0.3-0.5	10-15
Electric pumps	Electrically powered pumps, replacing mechanical pumps	1.0-2.0	50-150
Body			
Improved materials	High-strength alloy steel; aluminum castings; lightweight interiors; aluminum body and closures	3.3-13.2	0.4-1.2 dollars per pound of vehicle weight reduction
Unit body construction	Elimination of body-on-chassis structure	4.0	100
Improved aerodynamics	Reduction in drag coefficient, with improvements specific to body type	2.3-8.0	40-225
Drive train			
Advanced tires	Reduced rolling resistance	2.0-6.0	30-135
Improved 4-wheel drive	Reduced weight; improved electronic controls	2.0	100
Independent			
Safety and emissions	Improved safety and emission systems	-3.0	200

Figure 17. Market penetration of advanced technologies in new cars, 2004 and 2030 (percent of total new cars sold)

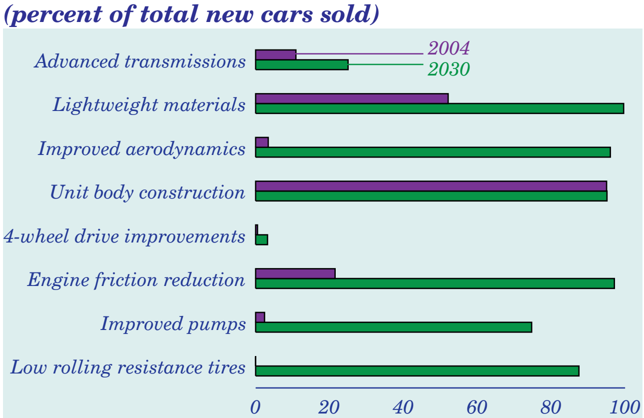
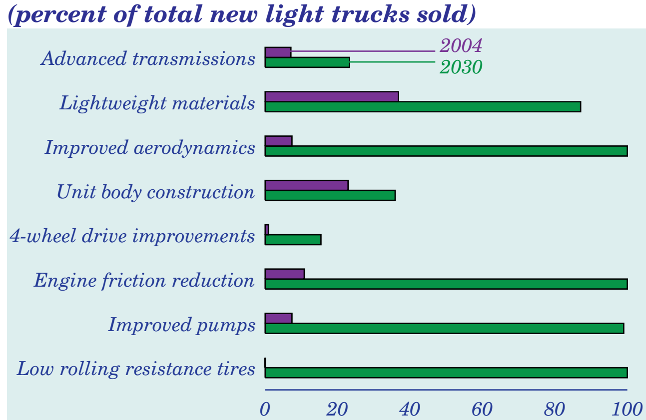


Figure 18. Market penetration of advanced technologies in new light trucks, 2004 and 2030 (percent of total new light trucks sold)



alternatives more viable commercially. Those trends are reflected in the *AEO2006* projections.

In the reference case, based on projections for the United States and project announcements covering other world regions through 2030, the supply of syncrude, synthetic fuels, and liquids produced from renewable fuels approaches 10 million barrels per day worldwide in 2030. In the high price case, nonconventional liquids represent 16 percent of total world oil supply in 2030, at more than 16.4 million barrels per day. The U.S. share of world nonconventional liquids production in 2030 is 15 percent in the reference case and nearly 20 percent in the high price case (Table 14).

The term "nonconventional liquids" applies to three different product types: syncrude derived from the bitumen in oil sands, from extra-heavy oil, or from oil shales; synthetic fuels created from coal, natural gas, or biomass feedstocks; and renewable fuels—primarily, ethanol and biodiesel—produced from a variety of renewable feedstocks. Generally, these resources are economically competitive only when oil prices reach relatively high levels.

Synthetic Crude Oils

At present, two nonconventional oil resources—bitumens (oil sands) and extra-heavy crude oils—are actively being developed and produced. With technology innovations ongoing and production costs declining steadily, their production increases in the *AEO2006* projections, provided that the world oil price remains above $30 per barrel. Development of a third nonconventional resource, shale oil, is more speculative. The greatest risks facing syncrude production are higher production costs and lower crude oil prices. In *AEO2006*, production of syncrude worldwide increases to 5.3 million barrels per day in the reference case and 8.5 million barrels per day in the high price case in 2030.

Oil sands. Bitumen, the "oil" in oil sands, is composed of carbon-rich, hydrogen-poor long-chain molecules. Its API gravity is less than 10, and its viscosity is so high that it does not flow in a reservoir. It can contain undesirable quantities of nitrogen, sulfur, and heavy metals.

The percentage of bitumen in oil sands deposits ranges from 1 to 20 percent [*49*]. After the bitumen is extracted from the sand matrix, various processes, including coking, distillation, catalytic conversion, and hydrotreating, must be applied to create syncrude. On average, about 1.16 barrels of bitumen is required to produce 1 barrel of syncrude. Canada's resource of 2.5 trillion barrels of in-place bitumen is estimated to be 81 percent of the world total [*50*]. Economically recoverable deposits in Canada amount to about 315 billion barrels of bitumen under current economic and technological conditions [*51*], and in 2004 Canada shipped more than 87 million barrels of light, sweet syncrude [*52*]. If fully developed, the bitumen resources in Canada could supply more than 40 years of U.S. oil consumption at current demand levels.

Currently, there are two methods for extracting bitumen from oil sands: open-pit mining and *in situ* recovery. For deposits near the surface, open-pit mining is used to extract the bitumen by physically separating it from the sand and clay matrix, at recovery rates approaching 95 percent. For deposits deeper than 225 feet, the *in situ* process is used. Two wells are drilled, one of which is used to inject steam into the deposit to heat the sand and lower the viscosity of the bitumen and the other to collect the flowing bitumen and bring it to the surface. Addition of gas condensate, light crude, or natural gas can also reduce viscosity and allow the bitumen to flow. Much of today's production comes from open-pit mining operations; however, 80 percent of the Canadian oil sands reserves are too deep for open-pit mining.

Table 14. Nonconventional liquid fuels production in the AEO2006 reference and high price cases, 2030 (million barrels per day)

	Synthetic crude oils			Synthetic fuels			Renewable fuels		
Total production	Oil sands	Extra-heavy oil	Shale oil	CTL	GTL	BTL	Biodiesel	Ethanol	Total
Reference case									
United States	—	—	—	0.8	—	—	0.02	0.7	**1.5**
World	2.9	2.3	0.05	1.8	1.1	—	—	1.7[a]	**9.9**
High price case									
United States	—	—	0.4	1.7	0.2	—	0.03	0.9	**3.2**
World	4.9	3.1	0.5	2.3	2.6	—	—	3.0[a]	**16.4**

[a]Includes biodiesel.

According to most analysts, oil sands syncrude production is economically viable, covering fixed and variable costs, only when syncrude prices exceed $30 per barrel. The variable costs of producing syncrude have declined to around $5 per barrel today, from estimates of $10 per barrel in the late 1990s and $22 per barrel in the 1980s.

Syncrude tends to yield poor quality distillate and gas-oil products owing to its low hydrogen content. Refineries processing oil sands syncrude need more sophisticated conversion capacity including catalytic cracking, hydrocracking, and coking to create higher quality fuels suitable for transportation markets.

Extra-heavy oil. Extra-heavy oil is crude oil with API gravity less than 10 and viscosity greater than 10,000 centipoise. Unlike bitumen, extra-heavy oil will flow in reservoirs, albeit much more slowly than ordinary crude oils. Extra-heavy oil deposits are located in at least 30 countries. One singularly large deposit, representing the majority of the known extra-heavy oil resource is located in the Orinoco oil belt of eastern Venezuela. Petroleos de Venezuela SA (PDVSA) estimates that 1.36 trillion barrels of extra-heavy oil are in place in the Orinoco belt, with an estimated 270 billion barrels of currently recoverable reserves.

There are three main recovery methods: cyclic steam injection/steam flood; diluents and gas lift; and steam-assisted gravity drainage (SAGD) using stacked horizontal wells. Other methods substitute CO_2 for natural gas injection or solvents for steam injection. The Orinoco projects currently use a two-step upgrading process, partially upgrading the bitumen in the field, followed by deep conversion refining in the importing country.

Extra-heavy oil recovery rates currently range from 5 to 10 percent of oil in place, although R&D efforts are steadily and significantly improving the performance. Lifting and processing costs range from $8 to $11 per barrel (2004 dollars) [*53*]. According to the latest PDVSA filings with the U.S. Securities and Exchange Commission, production of extra-heavy crude oil from the Orinoco area totaled 430,000 barrels per day in 2003 [*54*].

It is not clear that PDVSA can continue to provide the massive capital investment necessary to sustain the growth of its extra-heavy oil production in the future. Relationships with possible foreign investors have been strained due to actions by the Venezuelan government to renegotiate existing contracts and to structure new ones so as to sharply reduce potential returns to investors. In addition, the recent deterioration of political relations between Venezuela and the United States could limit the market for Orinoco-produced extra-heavy crude oils.

Shale oil. The term "oil shale" is something of a misnomer. First, the rock involved is not a shale; it is a calcareous mudstone known as marlstone. Second, the marlstone does not contain crude oil but instead contains an organic material, kerogen, that is a primitive precursor of crude oil. When oil shale is heated at moderate to high temperatures for a sufficient period of time, kerogen can be cracked to smaller organic molecules like those typically found in crude oils and then converted to a vapor phase that can be separated by boiling point and processed into a variety of liquid fuels in a distillation process. The synthetic liquid distilled from oil shale is commonly known as shale oil. Oil shale has also been burned directly as a solid fuel, like coal, for electricity generation.

The global resource of oil shale base is huge—estimated at a minimum of 2.9 trillion barrels of recoverable oil [*55*], including 750 billion barrels in the United States, mostly in Utah, Wyoming, and Colorado [*56*]. Deposits that yield greater than 25 gallons per ton are the most likely to be economically viable [*57*]. Based on an estimated yield of 25 gallons of syncrude from 1 ton of oil shale, the U.S. resource, if fully developed, could supply more than 100 years of U.S. oil consumption at current demand levels.

There are two principal methods for oil shale extraction: underground mining and *in situ* recovery. Underground mining, followed by surface retorting, is the primary approach used by petroleum companies in demonstration plants built in the mid to late 1970s. In this approach, oil shale is mined from the ground and then transferred to a processing facility, where the kerogen is heated in a retort (a large, cylindrical furnace) to around 900 degrees Fahrenheit and enriched with hydrogen to release hydrocarbon vapors that are then condensed to a liquid. There is some risk that, despite its apparent promise, the underground mining/surface retorting technology ultimately will not be viable, because of its potentially adverse environmental impacts associated with waste rock disposal and the large volumes of water required for remediation of waste disposal piles.

A comprehensive *in situ* process is currently under experimental development by Shell Oil [*58*]. Shale rock is heated to 650-750 degrees Fahrenheit, causing water in the shale to turn into steam that "micro-fractures" the formation. The *in situ* process generates a greater yield from a smaller land surface area at a lower cost than open-pit mining. The technology also avoids several adverse issues connected to mining and waste rock remediation, minimizes water usage, and has the potential to recover at least 10 times more oil per acre than the conventional surface mining and retorting process; however, it could take as long as 15 years to demonstrate the commercial viability of the Shell *in situ* process.

For a conventional mining and retorting process, $55 to $70 per barrel (2004 dollars) is the estimated breakeven price. That estimate is based in part on technical literature from the late 1970s and early 1980s, however, and thus may no longer be relevant today. The older estimates are likely to understate the cost of waste rock remediation. Advances in equipment technology over the years could increase operating efficiencies and reduce costs. A 1 million barrel per day shale oil industry based on underground mining/surface retorting would require mining and remediation of more than 500 million tons of oil shale rock per year—about one-half of the annual tonnage of domestic coal production. The process would also consume approximately 3 million barrels of water per day [*59*].

A 2005 industry study prepared for the National Energy Technology Laboratory estimates that crude oil prices (WTI basis) would need to be in the range of $70 to $95 per barrel for a first-of-kind shale oil operation to be profitable [*60*] but could drop to between $35 and $48 per barrel within a dozen years as a result of experience-based learning ("learning-by-doing"). In the *AEO2006* high price case, assuming the use of underground mining with surface retorting, U.S. oil shale production begins in 2019 and grows to 410,000 barrels per day in 2030.

Synthetic Fuels

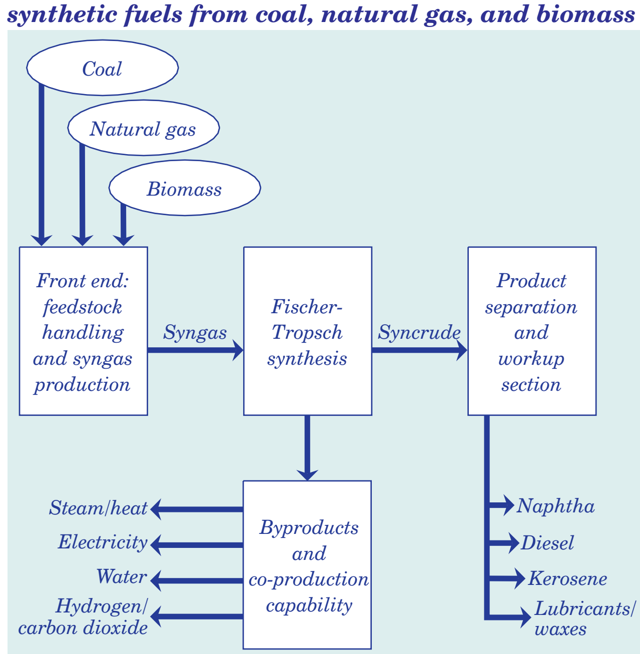
Synfuels can be produced from coal, natural gas, or biomass feedstocks through chemical conversion into syncrude and/or synthetic liquid products. Huge industrial facilities gasify the feedstocks to produce synthesis gas (carbon monoxide and hydrogen) as an initial step. Synfuel plants commonly employ the Fischer-Tropsch process, with front-end processing facilities that vary, depending on the feedstock. The manufacturing process for the synthetic fuels typically bypasses the traditional oil refining system, creating fuels that can go directly to final markets. A simplified flow diagram of the synthetic fuels process is shown in Figure 19.

In the basic Fischer-Tropsch reaction, syngas is fed to a reactor where it is converted to a paraffin wax, which in turn is hydrocracked to produce hydrocarbons of various chain lengths. End products are determined by catalyst selectivity and reaction conditions, and product yields are adjustable within ranges, depending on reaction severity and catalyst selection. Potential products include naphtha, kerosene, diesel, methanol, dimethyl ether, alcohols, wax, and lube oil stock. A product workup section separates the liquids and completes the transformation into final products. The diesel fuel produced ("Fischer-Tropsch diesel") is limited by a lack of natural lubricity, which can be remedied by additives [*61*]. Water and CO_2 are typically produced as byproducts of the process.

Coal-to-Liquids. A CTL plant transforms coal into liquid fuels. CTL is economically competitive at an oil price in the low to mid-$40 per barrel range and a coal cost in the range of $1 to $2 per million Btu, depending on coal quality and location.

A CTL plant requires several decades of coal reserves to justify construction. Given the economies of scale required, 30,000 barrels per day is regarded as a minimum plant size. Coal reserves of approximately 2 to 4 billion tons are required to support a commercial CTL plant with a capacity of 70,000 to 80,000 barrels per day over its useful life [*62*]. Capital expenses are estimated to be in the range of $50,000 to $70,000 (2004 dollars) per barrel of daily capacity. The front-end (coal handling) portion of a CTL plant accounts for about one-half of the capital cost [*63*].

Figure 19. System elements for production of synthetic fuels from coal, natural gas, and biomass



There are two leading technologies for converting coal into transportation fuels and liquids. The original process, indirect coal liquefaction (ICL), gasifies coal to produce a syngas and rebuilds small molecules in the Fischer-Tropsch process to produce the desired fuels. Direct coal liquefaction (DCL) breaks the coal down to maximize the proportion of compounds with the correct molecular size for liquid products. The process reacts coal molecules with hydrogen under high temperatures and pressures to produce a syncrude that can be refined into products. The conversion efficiency of DCL is greater than that of ICL and requires higher quality coal; however, DCL currently exists only in the laboratory and at pilot plant scale. China's first two CTL plants, which will use the DCL process, are slated to be operational after 2008 [*64*].

When combined with related processes such as CHP or IGCC, CTL can be considered a byproduct, with Fischer-Tropsch added as a part of a poly-generation configuration (steam, electricity, chemicals, and fuels). Revenues from the sale of electricity and/or steam can significantly offset CTL production costs [*65*]. Prospects for CTL production could be constrained, however, by plant siting issues that include waste disposal, water supply, and wastewater treatment and disposal. Water-cooling limitations can be overcome through the use of air-cooling, although it adds to the cost of production. CTL requires water for the front-end steps of coal preparation, and processing of coal with excessive moisture content can also produce contaminated water that requires disposal. These issues are similar to those associated with typical coal-fired power plants.

AEO2006 projects 800,000 barrels per day of domestic CTL production in the reference case and 1.7 million barrels per day in the high price case in 2030. Most of this activity initially occurs in coal-producing regions of the Midwest. Worldwide CTL production in 2030 totals 1.8 million barrels per day in the reference case and 2.3 million barrels per day in the high price case.

Gas-to-Liquids. GTL is the chemical conversion of natural gas into a slate of petroleum fuels. The process begins with the reaction of natural gas with air (or oxygen) in a reformer to produce syngas, which is fed into the Fischer-Tropsch reactor in the presence of a catalyst, producing a paraffin wax that is hydrocracked to products. A product workup section then separates out the individual products. Distillate is the primary product, ranging from 50 percent to 70 percent of the total yield.

Given the significant capital costs of a GTL plant, natural gas reserves of 4 to 5 trillion cubic feet are required to provide a feedstock supply of 500 to 600 million cubic feet per day over 25 years to support a plant with nominal capacity of 75,000 barrels per day. GTL competes with LNG for reserves of inexpensive, stranded natural gas located in scattered world regions. Stranded natural gas lies far from markets and would otherwise require major pipeline investments to commercialize. One processing advantage for GTL plants is that they can use natural gas with high CO_2 content as a feedstock and can target smaller fields than are required for LNG production. Competition between GTL and LNG plants for the world's stranded natural gas supplies is not a limiting issue, however. All the GTL and LNG plants envisioned between now and 2030 would tap less than 15 percent of the total world supply of stranded natural gas.

Capital costs for GTL plants range from $25,000 to $45,000 (2004 dollars) per barrel of daily capacity, depending on production scale and site selection. Those costs have dropped significantly, however, from more than $100,000 per barrel of total installed capacity for the earliest plants. Opportunities to further lower the capital costs include reducing the size of air separation units, syngas reformers, and Fischer-Tropsch reactors. Another opportunity lies in reducing cobalt and precious metals content in catalysts. An industry goal is to reduce GTL capital costs below $20,000 per barrel, but recent increases in steel prices and process equipment are making the goal more elusive. By comparison, the cost of a conventional petroleum refinery is around $15,000 per barrel per day. In terms of engineering and construction metrics, a GTL facility with a capacity of 34,000 barrels per day is roughly equivalent to a grassroots refinery with a capacity of 100,000 barrels per day [*66*].

GTL is profitable when crude oil prices exceed $25 per barrel and natural gas prices are in the range of $0.50 to $1.00 per million Btu. The economics of GTL are extremely sensitive to the cost of natural gas feedstocks. As in the case of LNG, the presence of natural gas liquids (NGL) in the feedstock stream can augment total producer revenues, reducing the effective cost of the natural gas input. In addition, the GTL process is exothermic, generating excess heat that can be used to produce electricity, steam, or desalinated water and further enhance revenue streams.

The technologies used for GTL are similar to those that have been employed for decades in methanol and ammonia plants, and most are relatively mature; however, the suite of integrated GTL technologies has not been used on a commercial scale. One looming uncertainty with regard to GTL is whether a proven pilot plant can be scaled up to the size of a commercial plant while reducing capital and operating costs. A key engineering goal is to improve the thermal efficiency of the GTL process, which is more complex than either LNG liquefaction or petroleum refining.

The leading GTL processes include those developed by Shell, Sasol, Exxon, Rentech, and Syntroleum. At this time, there is no indication as to which technology will prevail. Currently, the proponents of these various processes have nearly 800,000 barrels per day of first generation capacity under development in Qatar.

AEO2006 projects domestic GTL production originating in Alaska, reflecting a longstanding proposal to monetize stranded natural gas on the North Slope. GTL liquids would be transported to the lower 48 refining system. In 2030, domestic GTL production totals 200,000 barrels per day in the high price case, even though it competes directly with the Alaska natural gas pipeline project. In *AEO2006,* both investments are feasible simultaneously. What will actually occur depends on how and where Alaska natural gas stakeholders ultimately decide to make their investments. GTL production worldwide exceeds 1.1 million barrels per day in the reference case and 2.6 million barrels per day in the high price case in 2030.

Biomass-to-Liquids. BTL encompasses the production of fuels from waste wood and other non-food plant sources, in contrast to conventional biodiesel production, which is based primarily on food-related crops. Because BTL does not ordinarily use food-related crops, it does not conflict with increasing food demands, although crops grown for BTL feedstocks would compete with food crops for land.

BTL gasification technology is based on the CTL process. The resulting syngas is similar, but the distribution of the hydrocarbon components differs. BTL uses lower temperatures and pressures than CTL. Like GTL, the BTL reaction is exothermic and requires a catalyst [*67*]. There are at least 13 known processes covering directly and indirectly heated gasifiers for this step.

BTL originates from renewable sources, including wood waste, straw, grain waste, crop waste, garbage, and sewage/sludge. According to a leading process developer, 5 tons of biomass yields 1 ton of BTL [*68*]. One hectare (2.471 acres) of land generates 4 tons of BTL. A modestly sized BTL plant under sustained operation would require the biomass of slightly more than 12,000 acres [*69*]. Unlike biodiesel or ethanol, BTL uses the entire plant and, thereby, requires less land use.

BTL fuels are several times more expensive to produce than gasoline or diesel. Without taxes and distribution expenses, a leading European developer estimates BTL production costs approaching $3.35 per gallon by 2007 and falling to $2.43 per gallon by 2020 [*70*]. This equates to a crude oil equivalent price in the high $80 per barrel range at current capital cost levels.

BTL technology is at the pilot-plant stage of development. The capital cost of a commercial-scale BTL plant could approach $140,000 (2004 dollars) per barrel of capacity, according to a study conducted for DOE by Bechtel in 1998 [*71*]. The estimated initial investment level is comparable with those for early CTL and GTL plants, which have since declined by 50 percent or more. Technological innovations over time and economies of scale could further reduce BTL costs. The first commercial-scale BTL plant, with a capacity just over 4,000 barrels per day. is planned to begin operation in Germany after 2008, followed by four additional facilities. About two-thirds of a BTL plant's capital cost is related to biomass handling and gasification. BTL front-end technology is new and evolving and has parallels with cellulose ethanol technology.

Large BTL plants require huge catchment (staging) areas and incur high transportation costs to move feedstocks to a central plant. From a process standpoint, the main challenge for BTL is the high cost of removing oxygen. It is unclear whether gasification and other processing steps can achieve the cost reductions necessary to make it more competitive. Catalyst costs are high, as they are for other Fischer-Tropsch processes. Without additional technological advances to lower costs, BTL could be limited to the production of fuel extenders rather than primary fuels.

Renewable Biofuels

Not to be confused with BTLs are the renewable biofuels, ethanol and biodiesel. These fuels can be blended with conventional fuels, which enhances their commercial attractiveness. Biofuels have high production costs and are about 2 to 3 times more expensive than conventional fuels. Renewable biofuel technology is relatively mature for corn-based ethanol production, and future innovations are not expected to bring its costs down substantially. Future cost reductions are likely to be achieved by increasing production scale and implementing incremental process optimizations. Energy is a significant component of operating costs, followed by catalysts, chemicals, and labor. Production costs are highly localized.

The greatest challenge facing biofuels production is to secure sufficient raw material feedstock for conversion into finished fuels. Production of biofuels requires significant land use dedicated to the growth of feedstock crops, and land prices could represent a significant constraint.

Ethanol. Ethanol, the most widely used renewable biofuel, can be produced from any feedstock that contains plentiful natural sugars. Popular feedstocks include sugar beets (Europe), sugar cane (Brazil), and corn (United States). Ethanol is produced by fermenting sugars with yeast enzymes that convert glucose to ethanol. Crops are processed to remove sugar (by crushing, soaking, and/or chemical treatment), the sugar is fermented to alcohol using yeasts and microbes, and the resulting mix is distilled to obtain anhydrous ethanol.

There are two ethanol production technologies: sugar fermentation and cellulose conversion. Sugar fermentation is a mature technology, whereas cellulose conversion is new and still under development. Cellulose-to-biofuel (bioethanol) can use a variety of feedstocks, such as forest waste, grasses, and solid municipal waste, to produce synthetic fuel.

Capital costs for a corn-based ethanol plant can range from $21,000 to $33,000 (2004 dollars) per barrel of capacity, depending on size [*72*]. Manufacturing costs can be as low as $0.75 per gallon, as demonstrated by the low-cost production in Brazil, where climate conditions are favorable and labor costs are low. One industry risk is drought, which can limit the availability of feedstocks. Another issue is competition with the food supply. Based on current land use, industry trade sources estimate that annual corn ethanol production in the United States is limited to

Capital costs in transition for synthetic fuel facilities

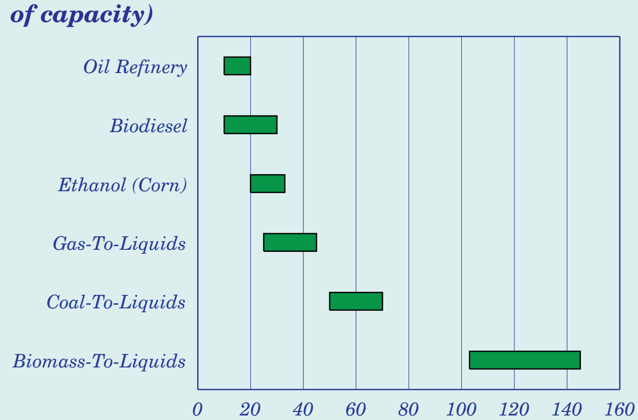
The chart below shows the range of capital investment costs for the synthetic fuel technologies. A traditional crude oil refinery is shown as a point of reference. Each of the alternative fuel technologies is more expensive than an oil refinery, with a range of capital costs for each technology resulting from individual site location factors, facility layouts, competing vendor technologies, and production scale. Over time, investment costs for synthetic fuel facilities are expected to decrease as a result of "learning-by-doing." As the installed base of synthetic fuel plants grows, cost reductions are expected to parallel those seen in the past for LNG liquefaction facilities, which have achieved cost reductions of two-thirds over the past three decades.

At present, observed capital costs generally are inversely proportional to installed capacity. There is about 300,000 barrels per day of installed corn ethanol capacity in the United States, whereas biodiesel capacity amounts to about 12,000 barrels per day of dedicated capacity plus another 7,000 barrels per day of swing capacity from the oleochemical industry.

The liquefaction industry is still in its infancy. At present there are no commercial GTL or CTL plants in the United States other than pilot plants. Worldwide, GTL capacity is nearly 60,000 barrels per day (Malaysia and South Africa) and global CTL capacity totals 150,000 barrels per day at the original development plants in South Africa. There is no commercial BTL capacity in the United States or elsewhere in the world, except for pilot plants.

Putting the current production capacity of these various fuels into perspective with traditional oil-based fuels, U.S. refining capacity for all nonconventional liquid fuels is over 17 million barrels per day, out of a worldwide total that is approaching 83 million barrels per day.

Range of capital investment costs for synthetic fuel facilities (thousand 2004 dollars per daily barrel of capacity)



approximately 12 billion gallons to avoid disrupting food markets.

AEO2006 projects 700,000 barrels per day of ethanol production in 2030 in the reference case, representing about 47 percent of world production. The high price case projects production of 900,000 barrels per day in 2030, representing 30 percent of the world total. Worldwide, ethanol production (including biodiesel) in 2030 totals nearly 1.7 million barrels per day in the reference case and 3 million barrels per day in the high price case.

Biodiesel. Biodiesel is produced from a variety of feedstocks, including soybean oil (United States), palm oil (Malaysia), and rapeseed and sunflower oil (Europe). The technology is mature and proven. In general, the feedstock for biodiesel undergoes an esterification process, which removes glycerin and allows the oil to perform like traditional diesel. Although biodiesel has been produced and used in stationary applications (heat and power generation) for nearly a century, its use as a transportation fuel is recent. Today it is used primarily as an additive to "stretch" conventional diesel supplies, rather than as a standalone primary fuel. One technical limitation of biodiesel is its blend instability and tendency to form insoluble matter. In the United States, those limitations are further aggravated by the introduction of new ULSD into the national fuel supply [*73*].

Capital costs for biodiesel production facilities are similar to those for ethanol facilities, ranging from $9,800 to $29,000 (2004 dollars) per daily barrel of capacity, depending on size [*74*, *75*]. Feedstocks for biodiesel, which can be expensive, include inedible tallow ($41 per barrel), jatropha oil ($43 per barrel), palm oil ($46 per barrel), soybean oil ($73 per barrel), and rapeseed oil ($78 per barrel) [*76*]. On a gasoline-equivalent basis, production costs in the United States range from 80 cents per gallon for biodiesel from waste grease to $1.14 per gallon for biodiesel from soybeans oil. U.S. biodiesel production totals 20,000 barrels per day in 2030 in the *AEO2006* reference case and 30,000 barrels per day in the high price case.

Mercury Emissions Control Technologies

The *AEO2006* reference case assumes that States will comply with the requirements of the EPA's new CAMR regulation. CAMR is a two-phase program, with a Phase I cap of 38 tons of mercury emitted from all U.S. power plants in 2010 and a Phase II cap of 15 tons in 2018. Mercury emissions in the electricity generation sector in 2003 are estimated at around 50 tons. Generators have a variety of options to meet the mercury limits, such as: switching to coal with a lower mercury content, relying on flue gas desulfurization or selective catalytic reduction equipment to reduce mercury emissions, or installing conventional activated carbon injection (ACI) technology.

The reference case assumes that conventional ACI technology will be available as an option for mercury control. Conventional ACI has been shown to be effective in removing mercury from bituminous coals but has not performed as well on subbituminous or lignite coals. On the other hand, brominated ACI—a relatively new technology—has shown promise in its ability to control mercury emissions from subbituminous and lignite coals. Therefore, an alternative mercury control technology case was developed to analyze the potential impacts of brominated ACI technology.

Preliminary tests sponsored by DOE indicate that brominated ACI can achieve high efficiencies in removing mercury (approximately 90 percent or higher for subbituminous coal and lignite, compared with about 60 percent for conventional ACI) at relatively low carbon injection rates [*77*]. For the sensitivity case, the mercury removal efficiency equations were revised to reflect the latest brominated ACI data available from DOE-sponsored tests [*78*]. Brominated ACI is about 33 percent more expensive than conventional ACI, and this change was also incorporated in the alternative case. Other than the change in mercury removal efficiency and the higher cost of brominated ACI, the mercury emissions case uses the reference case assumptions.

Figure 20 compares mercury emissions in the reference and mercury control technology cases. Both cases show substantial reductions in mercury emissions, with the greatest reductions occurring around 2010 to 2012, when the CAMR Phase I cap has to be met. The availability of brominated ACI results in slightly greater reductions in mercury emissions in the 2010-2012 period, as generators are able to utilize the technology to overcomply and bank allowances for later use. In the reference case, mercury emissions from U.S. power plants total 37 tons in 2012, compared with 31 tons in the mercury control technology case. In 2030, emissions are approximately the same in the two cases, at 15.3 and 15.6 tons.

Figure 21 shows mercury allowance prices in the reference and mercury control technology cases. When brominated ACI is assumed to be available, it has a substantial impact on mercury allowance prices in the early years of the projection. In 2010, mercury allowance prices are reduced from $23,400 per pound in the reference case to $8,700 per pound in the mercury control technology case, a reduction of 63 percent. The mercury control technology case incorporates improved ACI performance data for a limited number of plant configurations (those for which data were available from the DOE-sponsored tests), because not all plant configurations had been tested with brominated ACI technology at the time [*79*]. In the alternative case, the difference in allowance prices between the reference and mercury control technology cases narrows over the forecast horizon.

Mercury allowance prices have a substantial impact on the market for pollution control equipment. The mercury control technology case shows that, as expected, increased use of brominated ACI would greatly influence the ACI equipment market. Figure 22 compares the amounts of coal-fired capacity expected to be retrofitted with ACI systems in the reference and mercury control technology cases. The impact is significant in the alternative case throughout the projection period. In the reference case, about 125 gigawatts of coal-fired capacity is retrofitted with ACI by 2030. In the mercury control technology case, as a result of more effective mercury removal with brominated ACI, only about 88 gigawatts of coal-fired capacity is retrofitted with ACI by 2030.

Figure 20. Mercury emissions from the electricity generation sector, 2002-2030 (short tons per year)

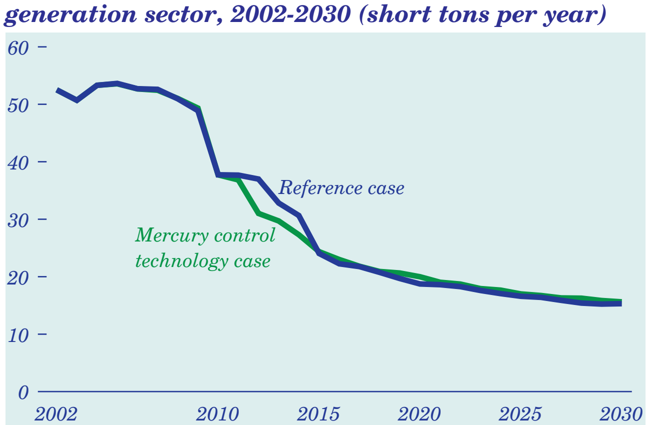
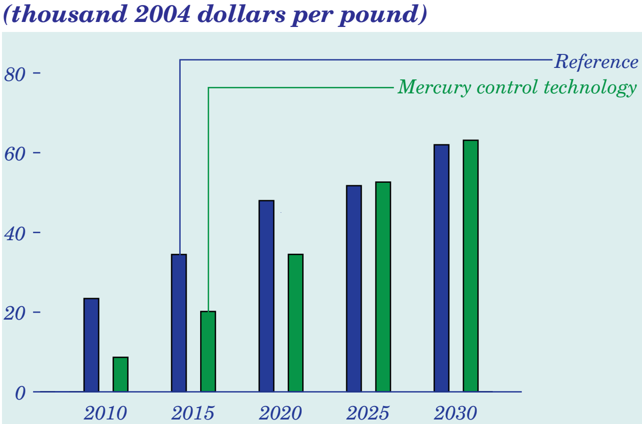


Figure 21. Mercury allowance prices, 2010-2030 (thousand 2004 dollars per pound)

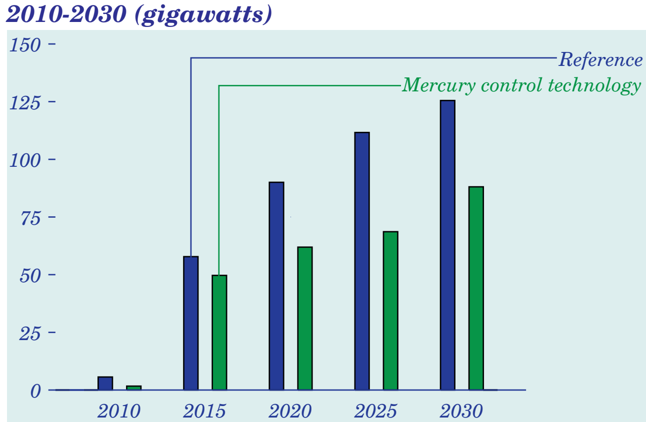


The mercury control technology case assumes that brominated ACI will be commercially available before 2010 (CAMR Phase I), and that the cost and performance levels seen in the initial DOE-sponsored tests will be replicable in the systems being offered commercially. Under these assumptions, comparison of the reference and mercury control technology cases highlights several important points. The mercury emissions levels are similar in the two cases, but allowance prices are much lower in the alternative case, through 2020. Corresponding to the difference in allowance prices, significantly less coal-fired capacity is retrofitted with ACI in the mercury control technology case than in the reference case. Overall, electricity generators are able to comply with the CAMR requirements more easily when they have access to the brominated ACI technology, while achieving the same reductions in mercury emissions as in the reference case and complying with the CAMR caps.

U.S. Greenhouse Gas Intensity and the Global Climate Change Initiative

On February 14, 2002, President Bush announced the Administration's Global Climate Change Initiative [*80*]. A key goal of the Climate Change Initiative is to reduce U.S. GHG intensity—defined as the ratio of total U.S. GHG emissions to economic output—by 18 percent over the 2002 to 2012 time frame.

Figure 22. Coal-fired generating capacity retrofitted with activated carbon injection systems, 2010-2030 (gigawatts)



AEO2006 projects energy-related CO_2 emissions, which represented approximately 83 percent of total U.S. GHG emissions in 2002. Projections for the other GHGs are derived from an EPA "no-measures" case, a recent update to the "business-as-usual" case cited in the White House Greenhouse Gas Policy Book Addendum [*81*] released with the Climate Change Initiative. The projections from the Policy Book were based on several EPA-sponsored studies conducted in preparation for the U.S. Department of State's *Climate Action Report 2002* [*82*]. The no-measures case was developed by EPA in preparation for a planned 2006 "National Communication" to the United Nations in which a "with-measures" policy case is to be published [*83*]. Table 15 combines the *AEO2006* reference case projections for energy-related CO_2 emissions with the projections for other GHGs.

According to the combined emissions projections in Table 15, the GHG intensity of the U.S. economy is expected to decline by 17 percent between 2002 and 2012, and by 28 percent between 2002 and 2020 in the reference case. The Administration's goal of reducing GHG intensity by 18 percent by 2012 would require emissions reductions of about 116 million metric tons CO_2 equivalent from the projected levels in the reference case.

Although *AEO2006* does not include cases that specifically address alternative assumptions about GHG intensity, the integrated high technology case does give some indication of the feasibility of meeting the 18-percent intensity reduction target. In the integrated high technology case, which combines the high technology cases for the residential, commercial, industrial, transportation, and electric power sectors, CO_2 emissions in 2012 are projected to be 166 million metric tons less than the reference case projection. As a result, U.S. GHG intensity would fall by 18.6 percent from 2002 to 2012, more than enough to meet the Administration's goal of 18 percent (Figure 23).

Figure 23. Projected change in U.S. greenhouse gas intensity in three cases, 2002-2020 (percent)

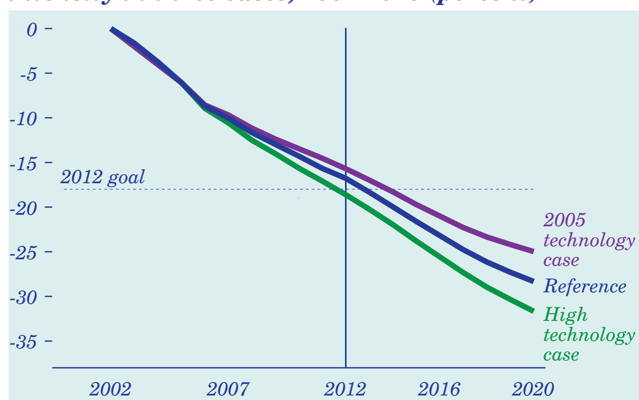


Table 15. Projected changes in U.S. greenhouse gas emissions, gross domestic product, and greenhouse gas intensity, 2002-2020

	Projection			Percent Change	
Measure	*2002*	*2012*	*2020*	*2002-2012*	*2002-2020*
Greenhouse gas emissions (million metric tons carbon dioxide equivalent)					
Energy-related carbon dioxide	5,746	6,536	7,119	13.7	23.9
Methane	626	686	739	9.5	18.0
Nitrous oxide	335	351	366	4.9	9.3
Gases with high global warming potential	143	245	339	71.2	136.6
Other carbon dioxide and adjustments for military and international bunker fuel	62	79	86	26.7	37.2
Total greenhouse gases	**6,913**	**7,897**	**8,649**	**14.2**	**25.1**
Gross domestic product (billion 2000 dollars)	10,049	13,793	17,541	37.3	74.6
Greenhouse gas intensity (thousand metric tons carbon dioxide equivalent per billion 2000 dollars of gross domestic product)	688	573	493	-16.8	-28.3

Market Trends

The projections in *AEO2006* 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 estimates, 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.

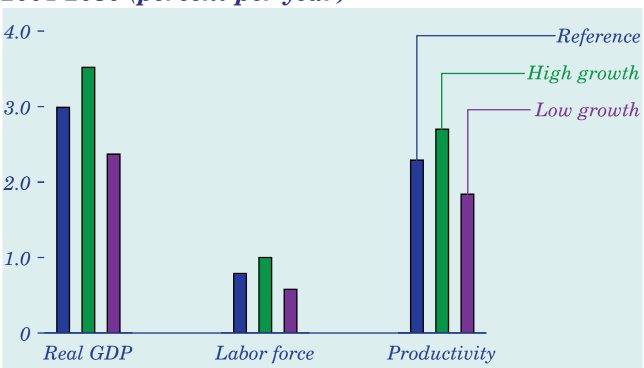
Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics 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 certainty. Many key uncertainties in the *AEO2006* 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, a complete and focused analysis of public policy initiatives.

Strong Economic Growth Is Expected To Continue Through 2030

Figure 24. Average annual growth rates of real GDP, labor force, and productivity in three cases, 2004-2030 (percent per year)

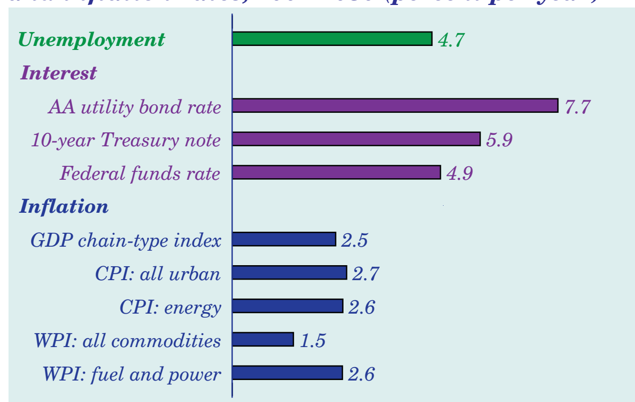


AEO2006 presents three views of economic growth for the forecast period from 2004 through 2030. Although probabilities are not assigned, the reference case reflects the most likely view of how the economy will unfold over the period. In the reference case, the Nation's economic growth, measured in terms of real GDP based on 2000 chain-weighted dollars, is projected to average 3.0 percent per year (Figure 24). The labor force is projected to grow by 0.8 percent per year on average; labor productivity growth in the nonfarm business sector is projected to average 2.3 percent per year; and investment growth is projected to average 4.0 percent per year. Disposable income grows by 3.1 percent per year in the reference case and disposable income per capita by 2.2 percent per year. Nonfarm employment grows by 1.1 percent per year, while employment in manufacturing shrinks by 0.5 percent per year.

The high and low economic growth cases show the effects of alternative growth assumptions on the energy market projections. The high growth case assumes higher growth rates for population (1.2 percent per year), nonfarm employment (1.4 percent), and productivity (2.7 percent). With higher productivity gains and employment growth, projected inflation and interest rates are lower than in the reference case. The low growth case assumes lower growth rates for population (0.5 percent per year), nonfarm employment (0.7 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.

Unemployment, Interest, and Inflation Rates Near Historical Norms

Figure 25. Average annual unemployment, interest, and inflation rates, 2004-2030 (percent per year)

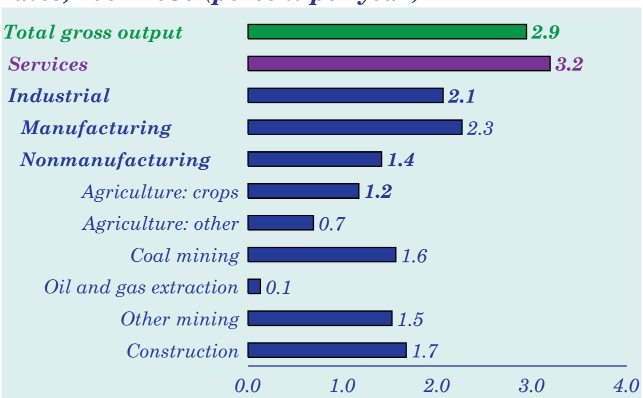


In the reference case, U.S. economic indicators generally are projected to follow historical trends, on average, from 2004 through 2030. Economic factors that are widely viewed as barometers for conditions in the markets for labor, credit, and goods and services include: the average annual unemployment rate; yields on Federal funds, 10-year U.S. Treasury notes, and AA utility corporate bonds; and average annual inflation rates as measured by various wholesale and retail price indexes (Figure 25). For *AEO2006*, unemployment and interest rates are calculated as annual averages over the 2004-2030 period, and inflation rates are calculated as average annual percent changes in the price indexes.

From 2004 through 2010, the economy (in terms of real GDP) is projected to grow more rapidly than its projected long-term average growth rate in the reference case. Over the same period, the unemployment rate is projected to decline from 5.5 percent in 2004 to 4.7 percent in 2010. After an initial rise through 2015, the Federal funds rate is projected to decline to its historical norm of 5 percent. Longer term rates are expected to be higher than the Federal funds rate, with the 10-year Treasury note yielding 6 percent and AA utility corporate bonds yielding approximately 8 percent per year, on average, for the entire forecast period. The reference case projects an average annual inflation rate of 2.7 percent, as measured by all urban CPI—slightly higher than the CPI for energy commodities and services or the wholesale price index (WPI) for fuel and power.

Output Growth for Energy-Intensive Industries Is Expected To Slow

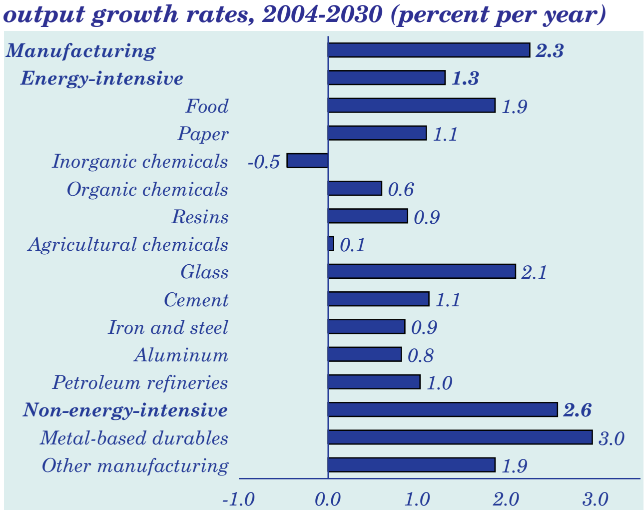
Figure 26. Sectoral composition of output growth rates, 2004-2030 (percent per year)



The industrial sector (all non-service industries) has shown slower output growth than the economy as a whole in recent decades, with imports meeting a growing share of demand for industrial goods. That trend is expected to continue in the reference case projections.

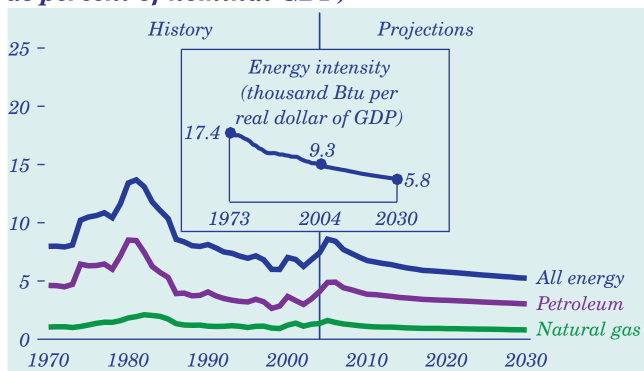
Within the industrial sector, the output of manufacturing industries is projected to grow more rapidly than that of nonmanufacturing industries, which include agriculture, mining, and construction (Figure 26). With higher energy prices and more foreign competition expected, however, the energy-intensive manufacturing sectors [*84*] are projected to grow by only 1.3 percent per year from 2004 through 2030, compared with a projected 2.6-percent average annual rate of growth for non-energy-intensive manufacturing output (Figure 27).

Figure 27. Sectoral composition of manufacturing output growth rates, 2004-2030 (percent per year)



Energy Expenditures Relative to GDP Are Projected To Decline

Figure 28. Energy expenditures as share of gross domestic product, 1970-2030 (nominal expenditures as percent of nominal GDP)

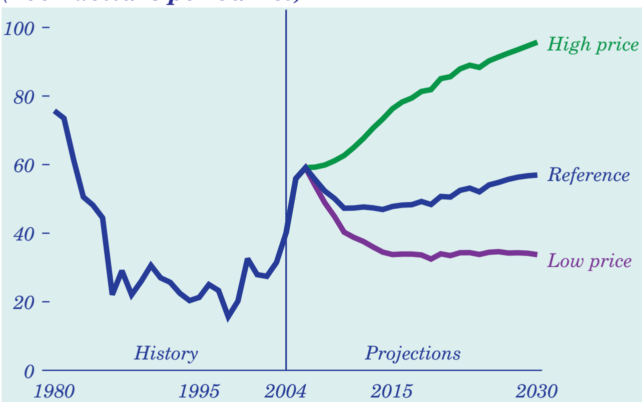


The ratio of total expenditures for energy relative to total GDP (both in nominal dollars) provides an indication of the importance of energy expenditures in the aggregate economy. Before the oil embargo of 1973-74, total energy expenditures were equal to 8 percent of U.S. GDP, petroleum expenditures just under 5 percent, and natural gas expenditures 1 percent. Following the price shocks of the 1970s and early 1980s, those shares rose dramatically—to 14 percent, 8 percent, and 2 percent, respectively, in 1981. Since then they have fallen consistently, to 2004 levels of about 7 percent for total energy expenditures, 4 percent for petroleum expenditures, and just over 1 percent for natural gas expenditures. Although recent developments in the world oil market have pushed the shares upward, they are projected to decline from current levels in the reference case. In 2030, total nominal energy expenditures are projected to equal 5 percent of nominal GDP, petroleum expenditures 3 percent, and natural gas expenditures less than 1 percent (Figure 28).

The overall decline in energy expenditures relative to GDP has resulted in large part from a decline in world oil prices (in real dollar terms) from their peak in 1981. And although oil prices have risen recently, their long-term trajectory in the *AEO2006* reference case is relatively flat in real terms. Another reason for the declining share of energy expenditures has been a steady decline in the energy intensity of the U.S. economy, measured as energy consumption (thousand Btu) per dollar of real GDP. Structural shifts in the economy and improvements in energy efficiency have allowed for the decline in energy intensity, which is projected to continue through 2030.

Oil Price Cases Show Uncertainty in Prospects for World Oil Markets

Figure 29. World oil prices in three cases, 1980-2030 (2004 dollars per barrel)



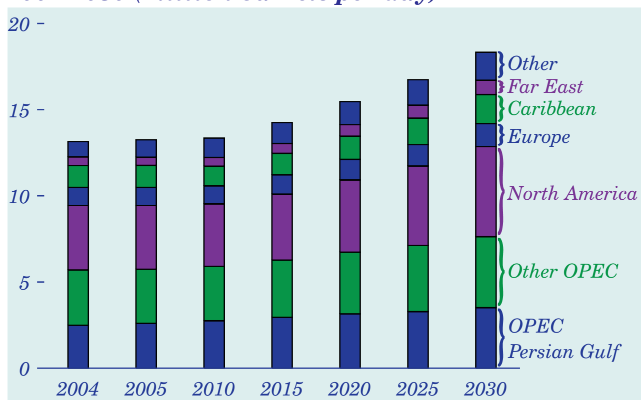
World oil price projections in the *AEO2006* reference case, in terms of the average price of imported low-sulfur crude oil to U.S. refiners, are considerably higher than those presented in the *AEO2005* reference case. The higher price path in the reference case does not result from different assumptions about the ultimate size of world oil resources but rather anticipates a lower level of future investment in production capacity in key resource-rich regions and a reassessment of the willingness of OPEC to produce at higher rates than projected in last year's outlook.

The historical record shows substantial variability in world oil prices, and there is arguably even more uncertainty about future prices in the long term. *AEO2006* considers three price cases, allowing an assessment of alternative views on the course of future oil prices (Figure 29). In the reference case, world oil prices moderate from current levels to \$47 per barrel in 2014, before rising to \$57 per barrel in 2030 (2004 dollars). The low and high price cases define a wide range of potential world oil price paths, which in 2030 range from \$34 to \$96 per barrel. This variability is meant to show the uncertainty about prospects for future world oil resources and economics.

In all three price cases, non-OPEC suppliers produce to capacity. Thus, the variation in price paths has the greatest impact on the need for OPEC supply in the long term. In 2030, the call on OPEC is 46.8 million barrels per day in the reference case and 51.3 million barrels per day in the low price case, but only 31.7 million barrels per day in the high price case—not much more than current OPEC production levels.

Oil Imports Reach More Than 18 Million Barrels per Day by 2030

Figure 30. U.S. gross petroleum imports by source, 2004-2030 (million barrels per day)



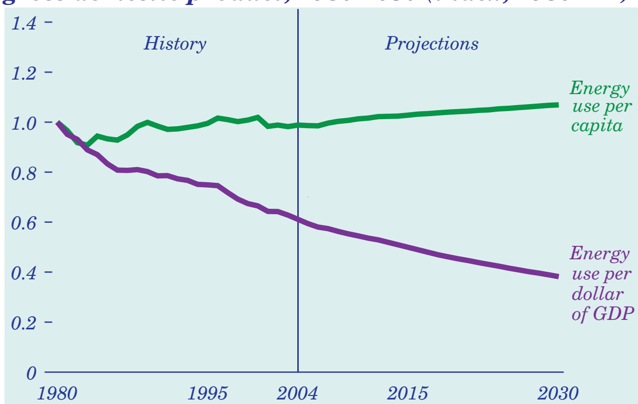
Total U.S. gross petroleum imports increase in the reference case, from 13.1 million barrels per day in 2004 to 18.3 million in 2030 (Figure 30), deepening U.S. reliance on imported oil in the long term. In 2030, gross petroleum imports account for 64 percent of total U.S. petroleum supply.

More than one-half of the increase in U.S. gross imports comes from OPEC suppliers. Crude oil imports from the North Sea decline as production ebbs, and West Coast refiners import small volumes of crude oil from the Far East to replace a decline in supplies of Alaskan crude oil. Canada and Mexico continue to be important sources of U.S. petroleum supply. Much of the future Canadian contribution comes from the development of its enormous oil sands resource base; however, the availability of such nonconventional oil supplies is linked to world oil prices. In the high price case, nonconventional supplies are more competitive with conventional sources, rising to about 21.1 million barrels per day worldwide in 2030. In the low price case, nonconventional production totals only 7.1 million barrels per day in 2030.

U.S. imports of refined petroleum products also increase. Most of the increase comes 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.

Average Energy Use per Person Increases Through 2030

Figure 31. Energy use per capita and per dollar of gross domestic product, 1980-2030 (index, 1980 = 1)



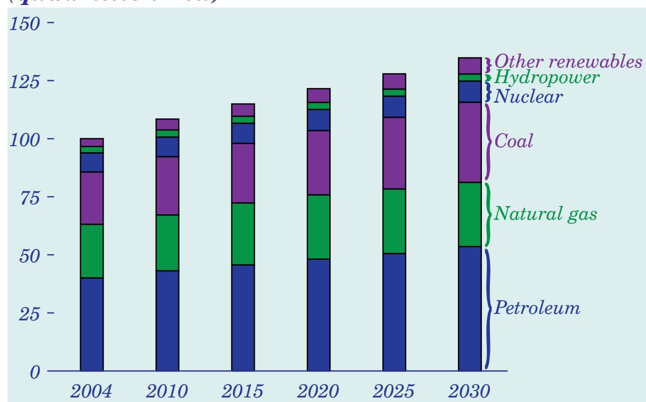
Population growth is a key determinant of total energy consumption, closely linked to rising demand for housing, services, and travel. Energy consumption per capita, controlling for population growth, shows the combined effect of other factors, such as economic growth and technology improvement. In the *AEO-2006* reference case, energy consumption per capita grows faster than it has in recent history (Figure 31), as a result of continued growth in disposable income.

In dollar terms, the economy as a whole is becoming less dependent on energy, the Nation's growing reliance on imported fuel notwithstanding. Projected energy intensity, as measured by energy use per 2000 dollar of GDP, declines at an average annual rate of 1.8 percent in the reference case. Efficiency gains and faster growth in less energy-intensive industries account for much of the decline, more than offsetting the expected growth in demand for energy services in buildings, transportation, and electricity generation. Energy intensity declines more rapidly in the near term, as consumers and businesses react to high energy prices. As energy prices moderate over the longer term, energy intensity declines at a slower rate. A similar pattern occurred from 1986 to 1992, when energy prices were generally falling.

AEO2006 does not assume policy-induced conservation measures beyond those in existing legislation and regulation, nor does it assume behavioral changes that could result in greater energy conservation, beyond those experienced in the past.

Coal and Petroleum Lead Increases in Primary Energy Use

Figure 32. Primary energy use by fuel, 2004-2030 (quadrillion Btu)



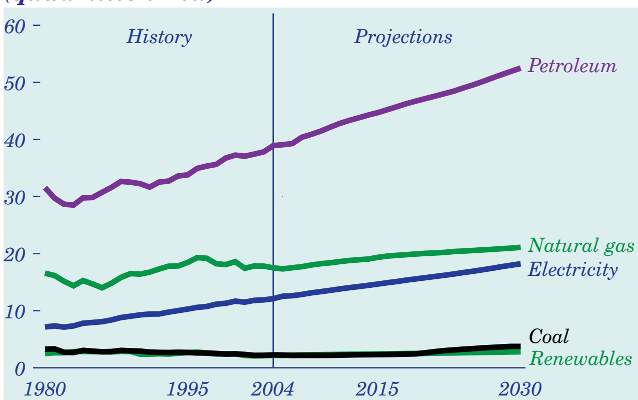
Total primary energy consumption, including energy for electricity generation, grows by 1.1 percent per year from 2004 to 2030 (Figure 32). Fossil fuels account for 88 percent of the growth, with coal use increasing by 53 percent, petroleum by 34 percent, and natural gas by 20 percent over that period. The increase in coal consumption occurs primarily in the electric power sector, with strong growth in electricity demand and favorable economics prompting increases in coal-fired baseload capacity. More than one-half of the increase in coal consumption is expected after 2020, when higher natural gas prices make coal the fuel choice for most new power plants. Growth in natural gas consumption for power generation is restrained by its high price relative to coal. Industry and buildings account for 71 percent of the increase in natural gas consumption from 2004 to 2030.

Transportation accounts for 87 percent of the increase in petroleum consumption, dominated by growth in fuel use for light-duty vehicles. Fuel use by freight trucks, second in energy use among travel modes, grows by 1.9 percent per year on average, the fastest annual rate among the major forms of transport. Petroleum use in the buildings sectors, mostly for space heating, declines slightly in the projection.

AEO2006 projects rapid growth in energy production from nonhydroelectric renewable sources, partly as a result of State mandates for renewable electricity generation and renewable energy production tax credits. An increase in power generation from nuclear energy is also projected, as tax credits spur construction of new nuclear plants between 2014 and 2018.

Petroleum and Electricity Lead Growth in Energy Consumption

Figure 33. Delivered energy use by fuel, 1980-2030 (quadrillion Btu)



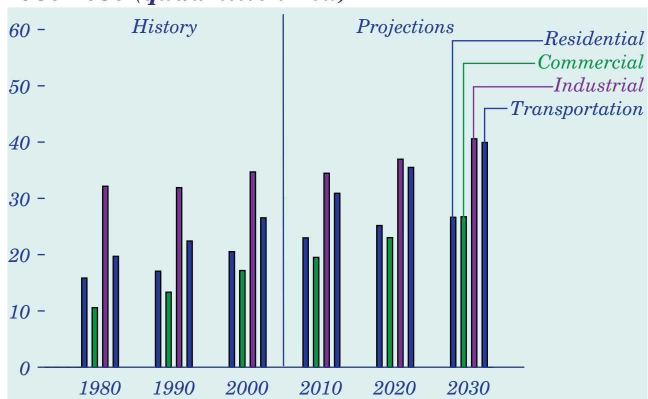
Delivered energy use (excluding losses in electricity generation) grows by 1.1 percent per year on average from 2004 through 2030. Petroleum use, which makes up more than one-half of total delivered energy use, grows at about the same rate (Figure 33). The fastest growth in petroleum use is projected for transportation energy use. Although high fuel prices tend to restrain travel by passenger and commercial vehicles, economic growth and more travel per capita increase demand for gasoline and diesel fuel, assuming no changes in consumer behavior.

Past trends in electricity consumption are expected to continue, with future increases resulting from strong growth in commercial floorspace, continued penetration of electric appliances in the residential sector, and increases in industrial output. Natural gas use grows more slowly than overall delivered energy demand, in contrast to its more rapid growth during the 1990s. As a result, natural gas meets 21 percent of total end-use energy requirements in 2030, compared with 24 percent in 2004.

End-use demand for energy from marketed renewables, such as wood, grows by 1.0 percent per year. Biomass used in the industrial sector, mostly as a byproduct fuel in the pulp and paper industry, is the largest source of renewable fuel for end use. Demand for purchased wood for home heating remains steady in the projections, with potential growth constrained by its limited availability and inconvenience. Energy from nonmarketed renewables, such as solar and geothermal heat pumps, more than doubles over the projection period but is less than 1 percent of delivered residential energy use throughout the period.

U.S. Primary Energy Use Climbs to 134 Quadrillion Btu in 2030

Figure 34. Primary energy consumption by sector, 1980-2030 (quadrillion Btu)



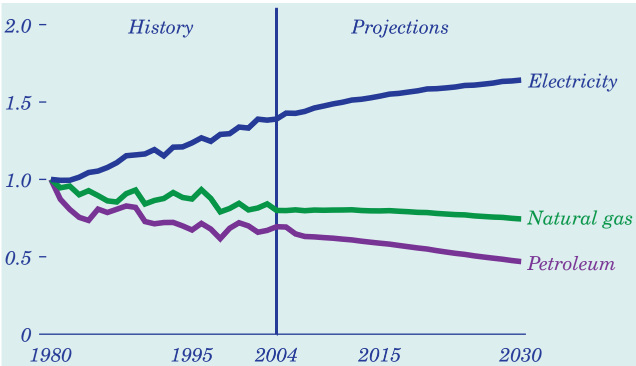
Primary energy use (including electricity generation losses) increases by one-third over the next 26 years (Figure 34). The projected growth rate of energy consumption in the *AEO2006* reference case approximately matches the average from 1981 to 2004. Demand for energy in the early 1980s fell in the face of recession, high energy prices, and changing regulations; but beginning in the mid-1980s, declining real energy prices and economic expansion contributed to a marked increase in energy consumption. The long-term upward trend in energy consumption is projected to continue in the reference case, with growth slowed somewhat by rising energy prices.

The most rapid growth in sectoral energy use is in the commercial sector, where services continue to expand more rapidly than the economy as a whole. The growth rate for residential energy use is about half that for the commercial sector, with demographic trends being a dominant factor. Transportation energy use grows at a slightly slower rate than it has since 1980, despite high fuel prices. Increases in travel by personal and commercial vehicles are only partially offset by vehicle efficiency gains. Primary energy use in the industrial sector grows more slowly than in the other sectors, with efficiency gains, higher real energy prices, and shifts to less energy-intensive industries moderating the expected growth.

Alternative cases have been developed to explore the key uncertainties in the forecast, including two economic growth cases and two world oil price cases. Detailed projections and comparisons with the reference case are provided in Appendixes B, C, and D.

Demographic Shifts Lead to Changes in Residential Energy Use per Capita

Figure 35. Delivered residential energy consumption per capita by fuel, 1980-2030 (index, 1980 = 1)



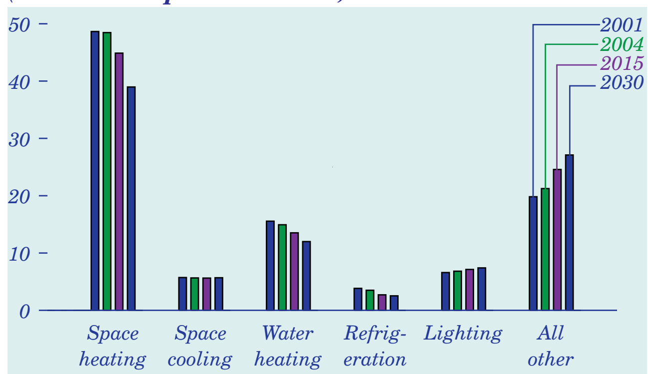
Residential electricity use per person has increased significantly since 1980 (Figure 35). With the U.S. population migrating south and west, electricity use for air conditioning has become more important than natural gas and petroleum for space heating. The South and West Census regions, which accounted for 52 percent of the U.S. population in 1980, increased to 59 percent in 2004 and continue increasing to nearly 65 percent in 2030.

The type and size of houses, household energy uses, and the fuels chosen vary by region. In the Northeast, 37 percent of households (compared with 27 percent nationally) live in multifamily units, which generally are smaller and use less energy per household than other types of housing. Fuel use for space heating is relatively more important in this region than in other regions. The Northeast, which accounted for 21 percent of the U.S. population in 1980, decreased to 19 percent in 2004 and falls to 16 percent in 2030. This is one of the factors that contributes to a decline in heating oil use per capita in the U.S. residential sector.

Natural gas use per capita has remained relatively constant in the residential sector since 1990. In 2004, 56 percent of all households and 63 percent of new single-family households used natural gas for home heating. Natural gas consumption per household declines as a growing share of the population lives in warmer climates; but per capita consumption of natural gas does not change significantly, because the average size of new houses increases.

Energy Use per Household for Space and Water Heating Is Expected To Fall

Figure 36. Delivered residential energy consumption by end use, 2001, 2004, 2015, and 2030 (million Btu per household)



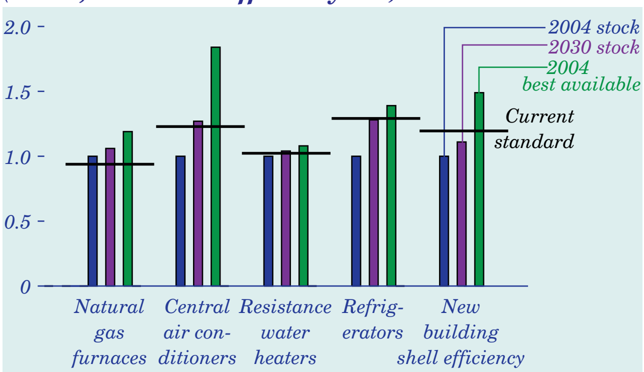
The size, type, and location of housing affect not only the type and amount of energy consumed per household but also which services are used more intensively. Larger houses require more energy to heat, cool, and illuminate, and as housing size continues to grow, energy use per household for these services can be expected to grow, all else being equal. Energy consumption for space heating, water heating, and refrigeration per household decreases over time, while energy use for lighting and all other applications grows, despite continuing increases in their energy efficiency (Figure 36).

In 2004, houses required 101 million Btu of delivered energy on average to provide all services. Energy use for space heating, the largest single energy-consuming service, declines by about 9 million Btu per household (20 percent) from 2004 to 2030 as a result of increasing energy efficiency and a 5-percent decrease in the average number of heating degree-days per year. Energy use for space cooling per household increases slightly, based on an 8-percent increase in cooling degree-days and the expectation that central air conditioning will be installed in more existing homes over time.

The “all other” category shows the fastest growth on a per household basis, as higher incomes and new uses lead to additional purchases of electronics and other miscellaneous devices. In 2004, 21 percent of the energy used in the average home was for small appliances. Their share of energy use per household grows to 29 percent in 2030, as more large-screen television sets, computers, and related equipment are purchased.

Increases in Energy Efficiency Are Projected To Continue

Figure 37. Efficiency indicators for selected residential appliances, 2004 and 2030 (index, 2004 stock efficiency = 1)



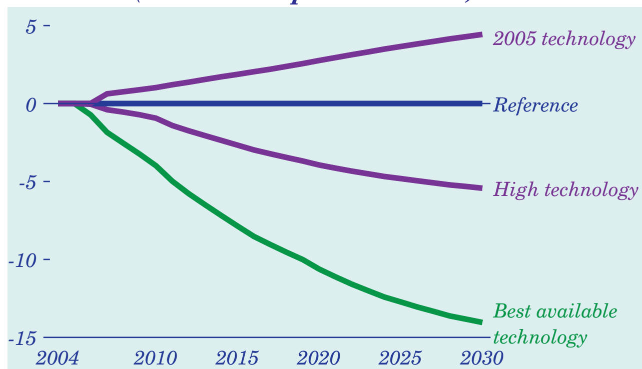
The energy efficiency of new household appliances plays a large role in determining the type and amount of energy used in the residential sector. As a result of stock turnover and purchases of more efficient equipment, the amount of energy used by residential consumers on a per household basis has fallen over time, and many technologies exist today that can further reduce residential energy consumption if they are purchased and used by more consumers (Figure 37).

The most efficient technologies can provide significant long-run savings in energy bills, but their higher purchase costs (and in some cases unsuitability for retrofit applications) may 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 units that just meet the current standard. In contrast, there is little room for efficiency improvements in electric resistance water heaters, because the technology is approaching its thermal limit.

In 2004, 8 percent of all new single-family homes were certified as ENERGY STAR compliant, implying at least a 30-percent energy savings for heating and cooling relative to comparable homes built to current code. Four States—Texas, California, Arizona, and Nevada—account for two-thirds of all ENERGY STAR home completions, concentrating energy savings in areas with relatively moderate climates. ENERGY STAR completions, as a percent of total completions, are expected to increase over time as builders become more familiar with the required building practices and the cost of the more efficient components used decreases.

Advanced Technologies Could Reduce Residential Energy Use

Figure 38. Variation from reference case delivered residential energy use in three alternative cases, 2004-2030 (million Btu per household)

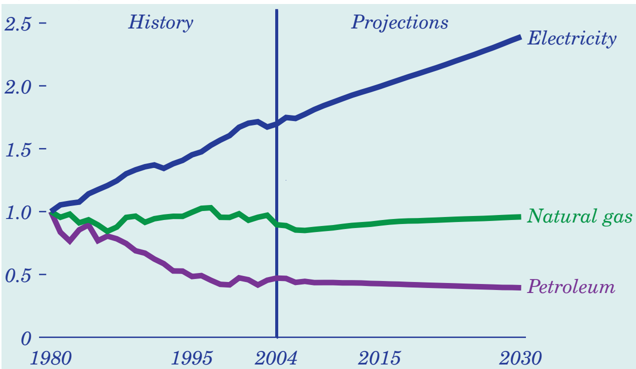


The reference case includes the effects of several policies aimed at increasing residential end-use efficiency, including minimum efficiency standards and voluntary energy savings programs designed to promote energy efficiency through innovations in manufacturing, building, and mortgage financing. In the 2005 technology case, which assumes no increase in the efficiency of equipment or building shells beyond that available in 2005, energy use per household in 2030 would be 5 percent higher than projected in the reference case (Figure 38). In the best available technology case, which assumes that the most energy-efficient technology is always chosen regardless of cost, energy use per household in 2030 would be 15 percent lower than in the reference case and 19 percent lower than in the 2005 technology case. In the high technology case, which assumes earlier availability of the most energy-efficient technologies, with lower costs and higher efficiencies, but does not constrain consumer choices, energy use per household would be 6 percent lower than projected in the reference case but higher than in the best available case.

In the high technology case, the consumer discount rates used to determine the purchased efficiency of all residential appliances do not vary from those used in the reference case; that is, consumers value efficiency equally across the two cases. Energy-efficient equipment, such as central air conditioners with efficiency ratings 50 percent higher than the current standard, can significantly reduce electricity use for space cooling. Likewise, home builders can construct homes that use 50 percent less energy for heating and cooling relative to current code in most regions of the country.

Economic, Population Growth Shape Trends in Commercial Energy Use

Figure 39. Delivered commercial energy consumption per capita by fuel, 1980-2030 (index, 1980 = 1)



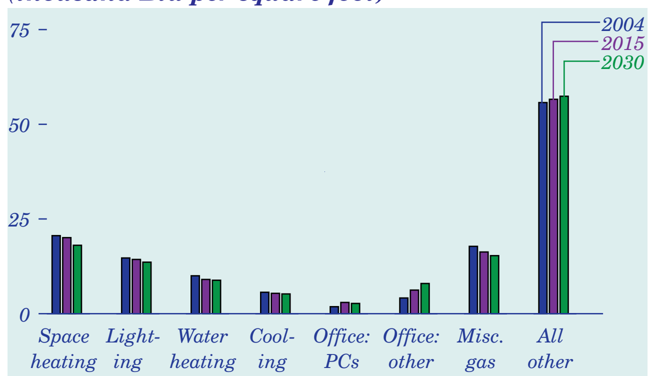
Recent trends in commercial fuel use are expected to continue, with growth in overall consumption similar to its pace in recent history (Figure 39). Commercial delivered energy use (excluding primary energy losses in electricity generation) grows at about the same rate as commercial floorspace, by 1.6 percent per year from 2004 through 2030.

Commercial floorspace growth and, in turn, commercial energy use are driven by trends in economic and population growth. Growth in disposable income leads to increased demand for services ranging from hotels and restaurants to stores, theaters, galleries, and arenas. These establishments continue to grow more electricity-based, as well as depending on electricity-based support services such as electronic processing centers and Internet providers to complete business transactions.

Increases in cooling demand contribute to the growth in commercial electricity use per capita, as the commercial sector expands to serve expected population growth in the South and West. Slower population growth in the Northeast, where heating oil is used more extensively, contributes to a decline in per capita petroleum use. Population effects on projected commercial energy use are not limited to regional trends. The share of the population over age 65 increases from 12 to 20 percent between 2004 and 2030, increasing the need for healthcare and assisted living facilities and for electricity to power medical and monitoring equipment in those facilities.

Efficiency Gains Moderate Increases in Commercial Energy Intensity

Figure 40. Delivered commercial energy intensity by end use, 2004, 2015, and 2030 (thousand Btu per square foot)



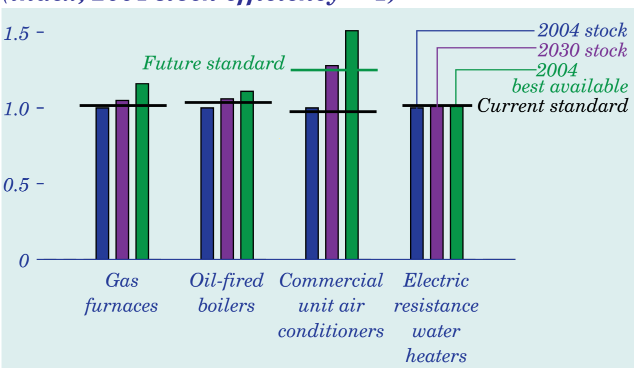
The determinants of commercial energy demand include both structural and demographic components. The Nation's continued move to a service economy implies growth in commercial services that use energy intensively, such as health care; however, new construction must meet building codes and efficiency standards, offsetting potential increases in energy intensity (consumption per square foot of commercial floorspace).

Energy intensity for the major commercial end uses declines as more energy-efficient equipment is adopted (Figure 40). Minimum efficiency standards, including those in EPACT2005, contribute to projected efficiency improvements in commercial space heating, space cooling, water heating, and lighting, moderating the growth in commercial energy demand. An increase in building shell efficiency also contributes to the trend. In addition, the prospect of high fossil fuel prices factors into expected efficiency increases for space and water heating equipment.

Increases in energy intensity are expected only for end uses that have not yet saturated the commercial market, including electricity use for office equipment, as well as new telecommunications technologies and medical imaging equipment in the "all other" end-use category. The "all other" category also includes ventilation, refrigeration, minor fuel consumption, municipal water services, service station equipment, elevators, vending machines, and a myriad of other uses.

Current Technologies Provide Potential Energy Savings

Figure 41. Efficiency indicators for selected commercial equipment, 2004 and 2030 (index, 2004 stock efficiency = 1)

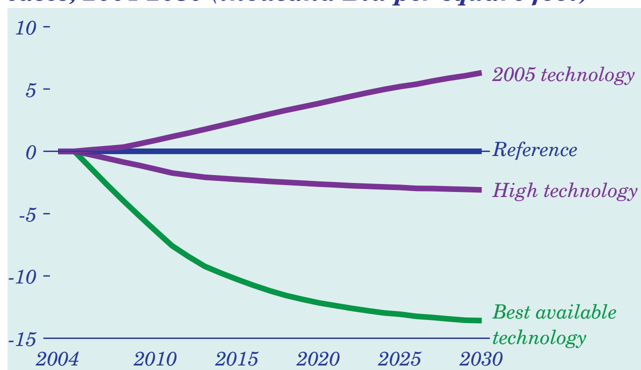


The stock efficiency of energy-using equipment in the commercial sector increases in the *AEO2006* reference case (Figure 41). As equipment is replaced and new buildings are built, technology advances are expected to reduce commercial energy intensity in most end-use services, although the long equipment service lives for many technologies moderate the pace of efficiency improvement in the forecast. For much of the equipment covered by the EPACT1992, the existing Federal efficiency standards are higher than the average efficiency of the 2004 stock, ensuring some increase in the stock average efficiency as new equipment is added. EPACT2005 includes efficiency standards for a variety of commercial technologies, such as air-cooled air conditioners, guaranteeing further increases in stock efficiency. Future updates to the Federal standards could have significant effects on commercial energy consumption, but they are not included in the reference case.

Currently available technologies have the potential to reduce commercial energy consumption significantly. Improved heat exchangers for oil-fired boilers can raise efficiency by 8 percent over the current standard; and the use of multiple compressors and enhanced heat exchanger surfaces can increase the efficiency of unit air conditioners by more than 50 percent over the current standard and more than 20 percent over the new standard. When a business is considering an equipment purchase, however, the additional capital investment required for the most efficient technologies often carries more weight than do future energy savings, limiting the adoption of more efficient technologies.

Advanced Technologies Could Reduce Commercial Energy Use

Figure 42. Variation from reference case delivered commercial energy intensity in three alternative cases, 2004-2030 (thousand Btu per square foot)



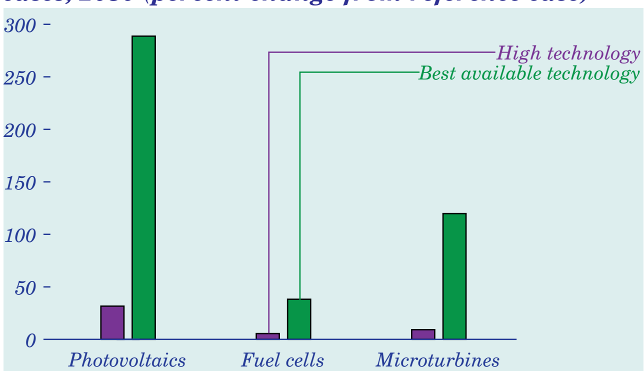
The *AEO2006* reference case incorporates efficiency improvements for commercial equipment and building shells, resulting in little change in projected commercial energy intensity (delivered energy use per square foot of floorspace) over the projection period, despite increased demand for services. The 2005 technology case assumes that future equipment and building shells will be no more efficient than those available in 2005. 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 2005 technology case, energy use per square foot in 2030 is 6 percent higher than in the reference case (Figure 42), as a result of an 0.3-percent average annual increase in commercial delivered energy intensity. The high technology case projects a 3-percent energy savings per square foot in 2030 relative to the reference case. In the best available technology case, commercial delivered energy intensity in 2030 is 12 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 2030, commercial solar PV systems generate more than three times as much electricity in the best technology case as in the reference case.

Advanced Technologies Could Slow Electricity Sales Growth for Buildings

Figure 43. Buildings sector electricity generation from advanced technologies in two alternative cases, 2030 (percent change from reference case)

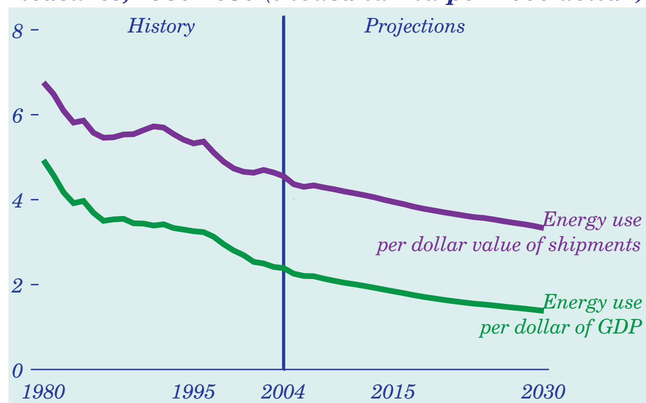


Alternative technology cases for the residential and commercial sectors include varied assumptions for the availability and market penetration of advanced distributed generation technologies (solar PV systems, fuel cells, and microturbines). In the high technology case, buildings generate 1.2 billion kilowatthours (10 percent) more electricity in 2030 than in the reference case (Figure 43), most of which offsets residential and commercial electricity purchases. In the best available technology case, electricity generation in buildings in 2030 is 10.9 billion kilowatthours (90 percent) higher than in the reference case, with solar systems responsible for 96 percent of the increase relative to the reference case. The optimistic assumptions of the best technology case affect solar PV systems more than fuel cells and microturbines, because there are no fuel expenses for solar systems. In the 2005 technology case, assuming no further technological progress or cost reductions after 2005, electricity generation in buildings in 2030 is 2.8 billion kilowatthours (23 percent) lower than in the reference case.

Some of the heat produced by fossil-fuel-fired generating systems may be used to satisfy heating requirements, increasing system efficiency and enhancing the attractiveness of the advanced technologies. On the other hand, the additional natural gas use for fuel cells and microturbines in the high technology and best technology cases offsets some of the reductions in energy costs that result from improvements in building shells and end-use equipment. In addition, the prospect of high natural gas prices may slow or limit their adoption.

Economic Growth, Structural Change Shape Industrial Energy Intensity

Figure 44. Industrial energy intensity by two measures, 1980-2030 (thousand Btu per 2000 dollar)

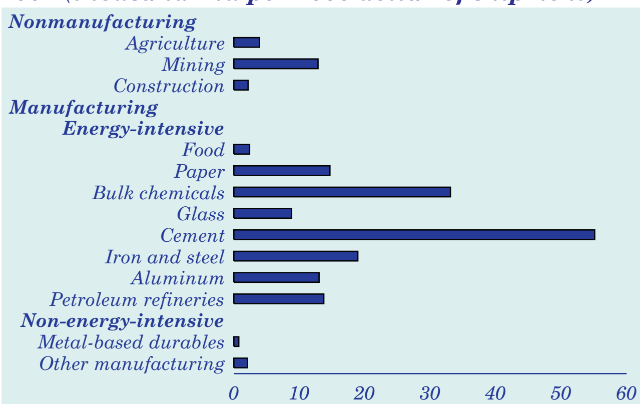


For the U.S. industrial sector, delivered energy consumption in 2004 was approximately the same as in 1980, although GDP more than doubled and the value of shipments in the industrial sector was 50 percent higher. Thus, aggregate industrial energy intensity, measured as industrial delivered energy per dollar of GDP, declined by 3.0 percent per year, and industrial delivered energy per dollar of industrial value of shipments declined by 1.6 percent per year from 1980 to 2004 (Figure 44). Factors contributing to the decline in industrial energy intensity included a greater focus on energy efficiency after the energy price shocks of the 1970s and 1980s and a reduction in the share of manufacturing activity accounted for by the most energy-intensive industries. As the economy evolved, a larger portion of the nation's output was provided by the services sector and a smaller portion by the industrial sector.

In the *AEO2006* reference case, these trends continue at a slower pace through 2030. Industrial energy use per dollar of GDP declines by 2.1 percent per year on average from 2004 through 2030, and energy use per dollar of industrial value of shipments declines by 1.2 percent per year. The rates of decline in industrial energy intensity are less rapid than those from 1980 to 2004, in part because the nonmanufacturing portion of industrial value of shipments (agriculture, mining, and construction) grows more slowly than the manufacturing portion, which includes the more energy-intensive manufacturing sectors.

Most Energy-Intensive Industries Are in the Manufacturing Sector

Figure 45. Energy intensity in the industrial sector, 2004 (thousand Btu per 2000 dollar of shipment)

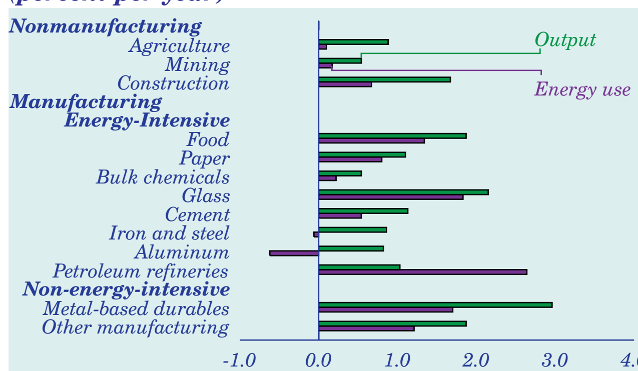


In the industrial sector, the manufacturing subsector is more energy-intensive than the nonmanufacturing subsector (Figure 45), using about 50 percent more energy per dollar of output in 2004 [*85*]. From 1985 to 2004, energy intensity declined more rapidly for nonmanufacturing industries than for manufacturing, primarily because most of the historical reduction in energy intensity for the manufacturing subsector had already occurred by 1985 in response to the high energy prices of the late 1970s and early 1980s. In the nonmanufacturing subsector, much of the decline in energy intensity from 1985 to 2004 resulted from a compositional shift: the relatively low-intensity construction industry grew more rapidly, particularly in the late 1990s and early 2000s, than the relatively high-intensity mining sector.

From 2004 levels, energy intensity in the manufacturing subsector, based on value of shipments, declines in the reference case at an average annual rate of 1.2 percent through 2030, compared with an average decline of 1.0 percent per year in the nonmanufacturing subsector. The improvement in aggregate energy intensity for the manufacturing subsector is accelerated by a compositional shift. In 2004, the energy-intensive group of manufacturing industries accounted for 21 percent of industrial value of shipments and the non-energy-intensive group 54 percent. With more rapid output growth in the non-energy-intensive group from 2004 to 2030, the 2030 shares are 17 percent and 61 percent, respectively.

Energy-Intensive Industries Grow Less Rapidly Than Industrial Average

Figure 46. Average growth in industrial output and delivered energy consumption by sector, 2004-2030 (percent per year)



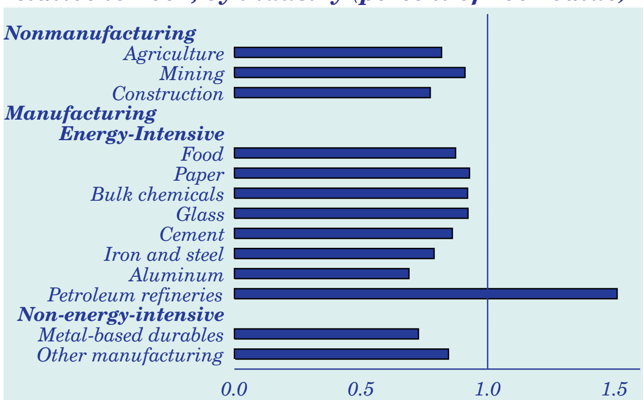
The shift in value of shipments from the industrial sector to the service sectors seen in recent decades continues in the *AEO2006* reference case. Total industrial sector value of shipments grows by 2.1 percent per year on average from 2004 through 2030, while GDP grows by 3.0 percent per year. Among the industrial subsectors, average annual growth rates range from 3.0 percent for metal-based durables to 0.5 percent for bulk chemicals (Figure 46).

The energy-intensive manufacturing subsector accounted for nearly two-thirds of industrial delivered energy consumption in 2004. From 2004 through 2030, the value of shipments for the energy-intensive subsector grows by an average of 1.3 percent per year, while the non-energy-intensive subsector grows at about twice that rate. The energy-intensive industries maintain their 2004 share of industrial energy consumption in 2030. With the growth of coal-to-liquids production in the refining sector, the bulk chemicals industry accounts for a smaller share of total industrial energy use in 2030 than it did in 2004; however, it remains the largest industrial energy consumer, accounting for nearly 25 percent of total industrial energy consumption in 2030. Together, the paper, bulk chemicals, and petroleum refining subsectors account for more than 50 percent of all the energy consumed in the industrial sector.

Nonfuel use of energy in the industrial sector is concentrated in the bulk chemicals and construction industries. More than 60 percent of the energy consumed in the bulk chemicals industry is in the form of feedstock, and asphalt accounts for more than 50 percent of the energy consumed in construction.

Energy Intensity Declines in Most Industrial Subsectors

Figure 47. Projected energy intensity in 2030 relative to 2004, by industry (percent of 2004 value)

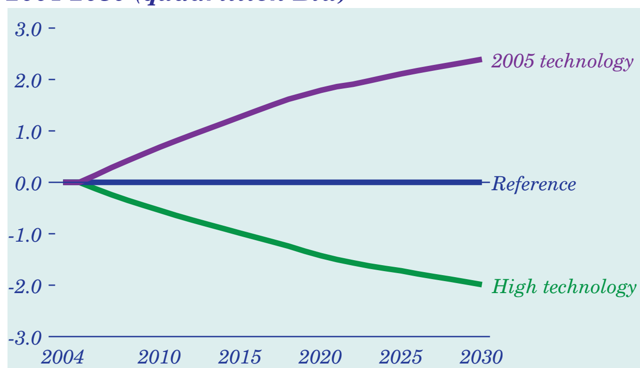


Within the industrial sector, the energy intensity of different industries (Figure 47) can change for a variety of reasons. For example, there may be a change in the types of activities or the methods used in a given subsector, or more energy-efficient new capacity may be installed to accommodate growth or replace worn-out machinery.

For each industry with a relatively rapid projected change in energy intensity from 2004 to 2030, there is a unique explanation. In the steel industry, most new capacity is expected to use electric arc furnace technology, which has a lower energy intensity than the older blast furnace/basic oxygen furnace technology. Thus, the average energy intensity for the iron and steel industry declines by 21 percent overall from 2004 to 2030. In the U.S. aluminum industry, no new primary smelting capacity is expected to be constructed, and secondary smelting, a less energy-intensive process of melting scrap, is expected to become the dominant technology. As a result, the energy intensity of the aluminum industry in 2030 is nearly one-third less than in 2004. In the metal-based durables industry, a robust growth projection, with output 114 percent greater in 2030 than in 2004, requires substantial amounts of new, more energy-efficient capital stock to meet demand for the industry's output. In the petroleum refining industry, coal consumption increases by 1.6 quadrillion Btu from 2004 to 2030, as CTL production grows. Consequently, its energy intensity increases over time.

Alternative Technology Cases Show Range of Industrial Efficiency Gains

Figure 48. Variation from reference case delivered industrial energy use in two alternative cases, 2004-2030 (quadrillion Btu)



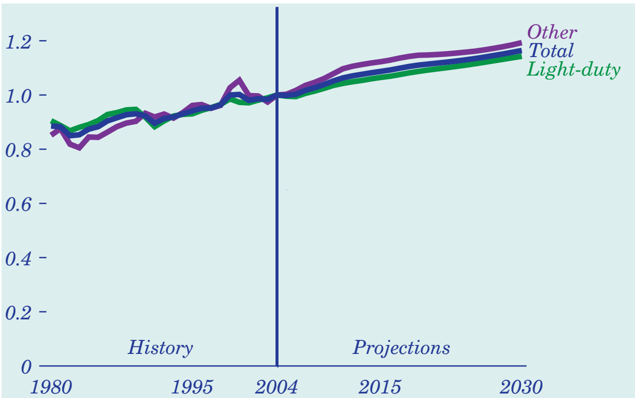
The technology cases for the industrial sector represent alternative views of the evolution and adoption of energy-reducing technologies. In some sectors, energy-reducing technologies make significant contributions to lower energy intensity. For example, energy intensity in mining would increase if there were more widespread adoption of technologies to produce fuels from oil shale. In other subsectors, such as glass, technologies or techniques that tend to improve output quality have the ancillary effect of reducing energy consumption. Generally, the manufacturing sector has more potential than the nonmanufacturing sector for the adoption of energy-reducing technologies.

In the high technology case, increased biomass recovery and additions of CHP capacity offset process-related reductions in on-site energy consumption. Industrial cogeneration capacity increases more rapidly in the high technology case (3.4 percent per year) than in the reference case (3.1 percent per year) [*86*]. Still, total industrial delivered energy consumption in 2030 is 2 quadrillion Btu less than in the reference case for the same level of output, and industrial energy intensity improves by 1.4 percent per year on average, compared with 1.2 percent in the reference case (Figure 48).

In the 2005 technology case, industrial delivered energy use in 2030 is 2.4 quadrillion Btu higher than in the reference case. Although the energy efficiency of new equipment remains at its 2005 level in this case, average efficiency improves as old equipment is retired, and aggregate industrial energy intensity improves by 0.9 percent per year.

Transportation Energy Use Per Capita in 2030 Is 15 Percent Over 2004 Level

Figure 49. Transportation energy use per capita, 1980-2030 (index, 2004 = 1)



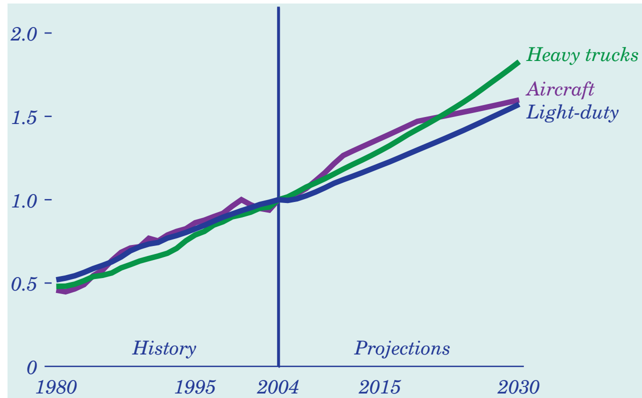
Total delivered energy consumption for transportation in the *AEO2006* reference case grows from 27.8 quadrillion Btu in 2004 to 39.7 quadrillion Btu in 2030, an increase of 43 percent. On a per-capita basis, however, the corresponding increase is only 15 percent (Figure 49). By mode, the most rapid increases are in demand for freight movement and air travel. Energy use for freight trucks increases by 61 percent from 2004 to 2030, followed by increases of 47 percent for aircraft and 42 percent for light-duty vehicles.

The increase in diesel fuel consumption by heavy freight trucks averages 1.9 percent annually from 2004 through 2030, primarily as a result of growth in industrial output that averages 2.1 percent per year. Economic growth is the primary reason for the increase in demand for air travel, which results in a 1.5-percent average annual increase in jet fuel use.

Demand for light-duty vehicle fuels increases from 16.2 quadrillion Btu in 2004 to 23.0 quadrillion Btu in 2030. Although the vast majority of light-duty fuel use continues to be gasoline, diesel fuel consumption grows from 1.6 percent of total light-duty vehicle fuel consumption in 2004 to 5.2 percent in 2030. Transportation demand for alternative fuels, mostly ethanol used in gasoline blending and liquefied petroleum gas (LPG), increases from 1.9 percent of total transportation energy use in 2004 to 5.9 percent in 2030.

Travel Demand Is Projected To Grow for All Modes of Transportation

Figure 50. Transportation travel demand by mode, 1980-2030 (index, 2004 = 1)



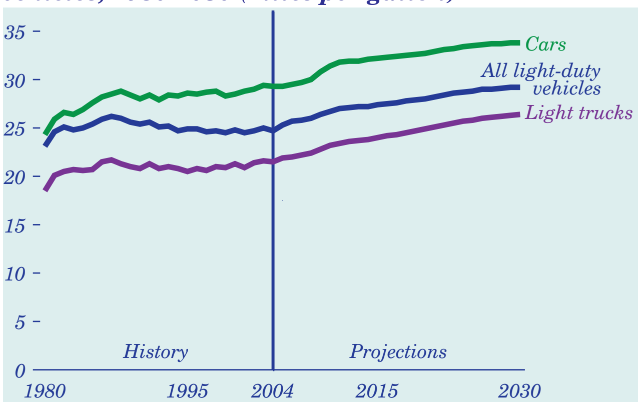
From 2004 to 2030, demand for transportation services increases for all modes of travel (Figure 50). Light-duty vehicle travel grows by 1.8 percent annually through 2030, significantly slower than the average of 2.9 percent per year over the past 3 decades. Approximately 50 percent of the growth in light-duty vehicle travel can be attributed to growth in the driving age population, which increases by 0.9 percent annually. Higher fuel prices through 2008 slow the growth in demand for light-duty vehicle travel, but as fuel prices stabilize and per capita disposable income rises, there is a more rapid increase in travel demand.

Historically, freight truck travel has grown by 3.0 percent annually. In the reference case, its growth averages 2.3 percent per year from 2004 through 2030. Although output grows in many manufacturing sectors, most of the future increase in demand for freight movement is tied to increased output from the electronics, food, plastics, furniture, and miscellaneous sectors.

Demand for air travel increases by 1.8 percent annually from 2004 through 2030, down from its historical annual growth rate of 3.3 percent. The airline industry is expected to recover from current financial conditions and experience a strong recovery period through 2011, when growth slows as congested conditions begin to affect the market. By 2019, severe constraints associated with available infrastructure make airport capacity expansion a requirement for increasing air travel.

New Technologies Promise Improved Fuel Economy for Light-Duty Vehicles

Figure 51. Average fuel economy of new light-duty vehicles, 1980-2030 (miles per gallon)

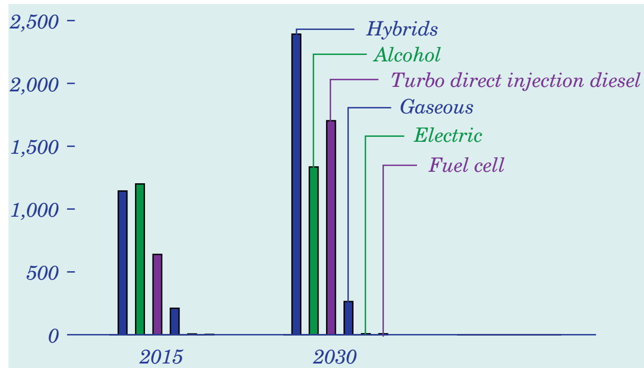


The average fuel economy of new light-duty vehicles, which peaked at 26.2 miles per gallon in 1987, declined to 24.9 miles per gallon in 2004 (Figure 51). The downward trend in light-duty vehicle fuel economy resulted from a rapid increase in sales of light trucks (sport utility vehicles, minivans, and pickups), which were required to meet a CAFE standard of 20.7 miles per gallon, compared with 27.5 miles per gallon for cars. In April 2003, NHTSA increased the CAFE standards for light trucks to 21 miles per gallon for model year 2005, 21.6 miles per gallon for model year 2006, and 22.2 miles per gallon for 2007, and more recently the agency has proposed a restructuring of light truck standards, with additional increases in fuel efficiency standards for model years 2008 through 2011. *AEO2006* assumes no changes in currently promulgated fuel efficiency standards for cars and light trucks.

Reversing the historic trend, the average fuel economy of new light-duty vehicles increases in the reference case as a result of advances in fuel-saving technologies. Fuel economy for new light-duty vehicles is 29.2 miles per gallon in 2030. Although higher personal incomes are expected to increase demand for larger, more powerful vehicles, and the average horsepower for new cars is 27 percent above the 2004 average in 2030, advanced technologies and materials permit increases in performance and size of new vehicles without sacrificing improvements in fuel economy.

Advanced Technologies Are Projected To Exceed 25 Percent of Sales by 2030

Figure 52. Sales of advanced technology light-duty vehicles by fuel type, 2015 and 2030 (thousand vehicles sold)

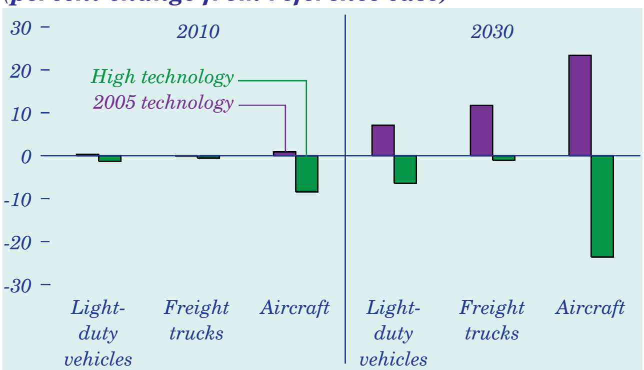


Sales of advanced technology vehicles, representing automotive technologies that use alternative fuels or require advanced engine technology, reach 5.7 million per year (Figure 52) and make up more than 25 percent of total light-duty vehicle sales in 2030. Hybrid electric vehicles (including those specifically designed to use electric motors and batteries in combination with a combustion engine to drive the vehicle and those incorporating only an integrated starter generator for fuel economy) are anticipated to sell well, with 1.1 million units sold in 2015, increasing to 2.4 million units in 2030. Sales of turbo direct injection diesel vehicles increase to 638,500 units in 2015 and 1.7 million units in 2030. Sales of alcohol flexible-fueled vehicles continue to increase, with 1.3 million sold in 2030.

About 40 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 CAFE regulations. In the *AEO2006* reference case, the majority of gasoline hybrid, electric, and fuel cell vehicle sales result from compliance with low-emission vehicle programs in California, Connecticut, Maine, Massachusetts, New Jersey, New York, Rhode Island, Washington, and Vermont. *AEO2006* does not include the impacts of California Assembly Bill 1493, which effectively sets carbon emission standards for light-duty vehicles, because of uncertainty about the State's ability to enforce the standards.

Vehicle Technology Advances Reduce Transportation Energy Demand

Figure 53. Changes in projected transportation fuel use in two alternative cases, 2010 and 2030 (percent change from reference case)

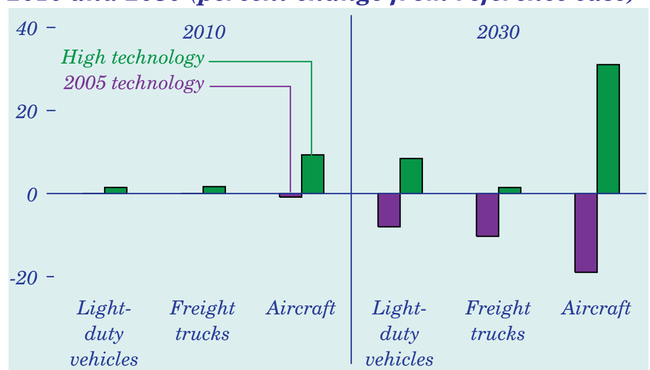


In the *AEO2006* reference case, delivered energy use in the transportation sector increases from 27.8 quadrillion Btu in 2004 to 39.7 quadrillion Btu in 2030. In the high technology case, the projection for 2030 is 2.8 quadrillion Btu (7.1 percent) lower, with about 54 percent (1.5 quadrillion Btu) of the difference attributed to efficiency improvements in light-duty vehicles (Figure 53) as a result of increased penetration of advanced technologies, including variable valve lift, electrically driven power steering pumps, and advanced electronic transmission controls. Similarly, projected fuel use by heavy freight trucks in 2030 is 0.1 quadrillion Btu (0.9 percent) lower in the high technology case than in the reference case, and advanced aircraft technologies reduce fuel use for air travel by 1.0 quadrillion Btu (23.7 percent) in 2030.

In the 2005 technology case, with new technology efficiencies fixed at 2005 levels, efficiency improvements can result only from stock turnover. As a result, total delivered energy demand for transportation in 2030 is 3.7 quadrillion Btu (9.2 percent) higher in 2030 in the 2005 technology case than in the reference case. Fuel use for air travel in 2030 is 1.0 quadrillion Btu (23.4 percent) higher in the 2005 technology case than in the reference case, and freight trucks use 0.9 quadrillion Btu (11.9 percent) more fuel in 2030 [*87*].

Technology Assumptions Include Improvements in Vehicle Efficiency

Figure 54. Changes in projected transportation fuel efficiency in two alternative cases, 2010 and 2030 (percent change from reference case)



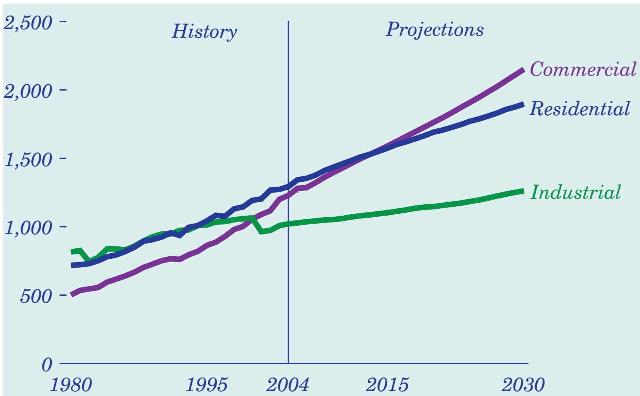
The high technology case assumes lower costs and higher efficiencies for new transportation technologies. Advances in conventional technologies increase the average fuel economy of new light-duty vehicles in 2030 from 29.2 miles per gallon in the reference case to 32.1 miles per gallon in the high technology case. The average efficiency of the light-duty vehicle stock is 20.6 miles per gallon in 2010 and 24.4 miles per gallon in 2030 in the high technology case, compared with 20.4 miles per gallon in 2010 and 22.5 miles per gallon in 2030 in the reference case (Figure 54).

For freight trucks, average stock efficiency in the high technology case is 0.6 percent higher in 2010 and 1.1 percent higher in 2030 than the reference case projection of 6.8 miles per gallon. Advanced aircraft technologies increase aircraft efficiency by 9.3 percent in 2010 and 31.0 percent in 2030 relative to the reference case projections.

In the 2005 technology case, the average fuel economy of new light-duty vehicles is 26.2 miles per gallon in 2030, and the average for the entire light-duty vehicle stock is 20.7 miles per gallon in 2030. For freight trucks, the average stock efficiency in 2030 is 6.1 miles per gallon. Aircraft efficiency in 2030 averages 61.6 seat-miles per gallon in the 2005 technology case, compared with 76.0 seat-miles per gallon in the reference case.

Continued Growth in Electricity Use Is Expected in All Sectors

Figure 55. Annual electricity sales by sector, 1980-2030 (billion kilowatthours)



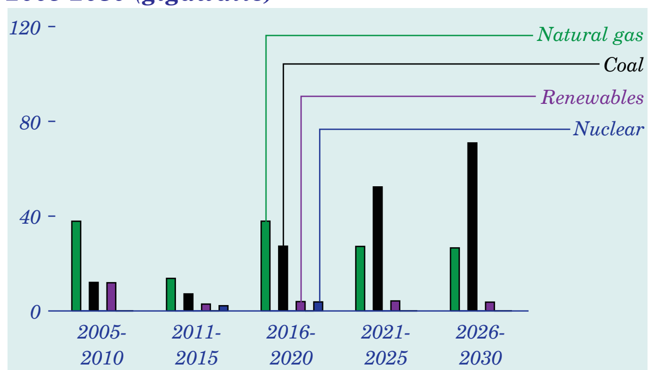
Total electricity sales increase by 50 percent in the *AEO2006* reference case, from 3,567 billion kilowatthours in 2004 to 5,341 billion kilowatthours in 2030 (Figure 55). The largest increase is in the commercial sector, as service industries continue to drive economic growth. By customer sector, electricity demand grows by 75 percent from 2004 to 2030 in the commercial sector, by 47 percent in the residential sector, and by 24 percent in the industrial sector.

Efficiency gains are expected in both the residential and commercial sectors as a result of new standards in EPACT2005 and higher energy prices that prompt more investment in energy-efficient equipment. In the residential sector, the increase in electricity demand that results from a trend toward houses with more floorspace, in addition to population shifts to warmer regions, is mitigated by an increase in the efficiency of air conditioners and refrigerators. In the commercial sector, increases in demand as a consequence of larger building sizes and more intensive use of electrical equipment is offset by increases in the efficiency of heating, cooling, lighting, refrigeration, and cooking appliances.

Personal computers become more energy-efficient on average as residents and companies replace monitors that use cathode ray tubes with new models that use more efficient flat screens. New telecommunications technologies and medical imaging equipment increase electricity demand in the "other" commercial end-use category, which accounts for one-half of the increase in commercial demand. In the industrial sector, increases in electricity sales are offset by rapid growth in on-site generation.

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

Figure 56. Electricity generation capacity additions by fuel type, including combined heat and power, 2005-2030 (gigawatts)



With growing electricity demand and the retirement of 65 gigawatts of inefficient, older generating capacity, 347 gigawatts of new capacity (including end-use CHP) will be needed by 2030. Most retirements are expected to be oil- and natural-gas-fired steam capacity, along with smaller amounts of oil- and natural-gas-fired combustion turbines and coal-fired capacity, which are not cost-competitive with newer plants.

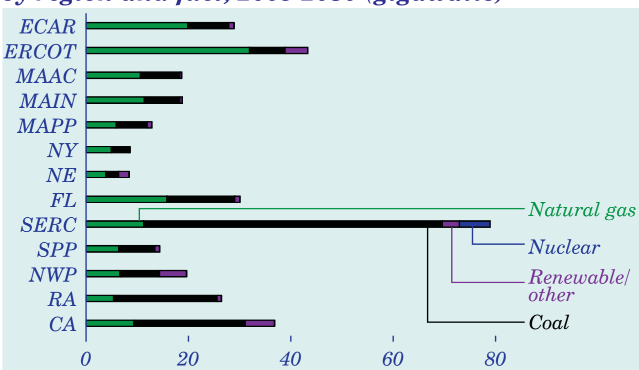
Capacity decisions depend on the costs and operating efficiencies of different options, fuel prices, and the availability of Federal tax credits for investments in some technologies. Natural gas plants are generally the least expensive capacity to build but are characterized by comparatively high fuel costs. Coal, nuclear, and renewable plants are typically expensive to build but have relatively low operating costs and, in addition, receive tax credits under EPACT2005.

Coal-fired and natural-gas-fired plants account for about 50 percent and 40 percent, respectively, of the capacity additions from 2004 to 2030 (Figure 56). Coal-fired capacity is generally more economical to operate than natural-gas-fired capacity, because coal prices are considerably lower than natural gas prices. As a result, new natural-gas-fired plants are built to ensure reliability and operate for comparatively few hours when electricity demand is high.

About 8 percent of the expected capacity expansion consists of renewable generating units. New nuclear capacity additions total 6 gigawatts, but no additional new nuclear plants are built after 2020, when the EPACT2005 production tax credit expires.

Capacity Additions Are Expected To Be Required in All Regions

Figure 57. Electricity generation capacity additions, including combined heat and power, by region and fuel, 2005-2030 (gigawatts)



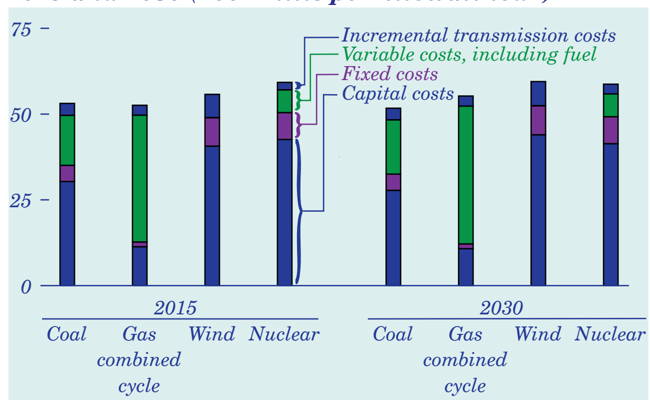
Most areas of the United States currently have excess generation capacity, but all electricity demand regions (see Appendix F for definitions) are expected to need additional, currently unplanned, capacity by 2030 (Figure 57). The largest amounts of new capacity are expected in the Southeast (FL and SERC) and the West (NWP, RA, and CA). In the Southeast, electricity demand represents a relatively large share of total U.S. electricity sales, and its need for new capacity is greater than in other regions.

With natural gas prices rising in the reference case, coal-fired plants make up most of the capacity additions through 2030. The largest concentrations of new coal-fired plants are in the Southeast and the West. In the Southeast, new coal-fired plants are built in view of the size of the electricity market and the corresponding need for additional capacity. In the West, where the capacity requirement is much smaller, the choice to build mostly coal-fired plants is based on the region's lower-than-average coal prices and higher-than-average natural gas prices.

Nationwide, some new natural-gas-fired plants are built to maintain a diverse capacity mix or to serve as reserve capacity. Most are located in the Midwest (MAPP, MAIN, and ECAR) and South (ERCOT and SPP). The Midwest has a surplus of coal-fired generating capacity and does not need to add many new coal-fired plants. In the South, natural gas prices are lower than the national average, and natural-gas-fired plants are more economical than in other regions.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 58. Levelized electricity costs for new plants, 2015 and 2030 (2004 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 58) [*88*]. 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.

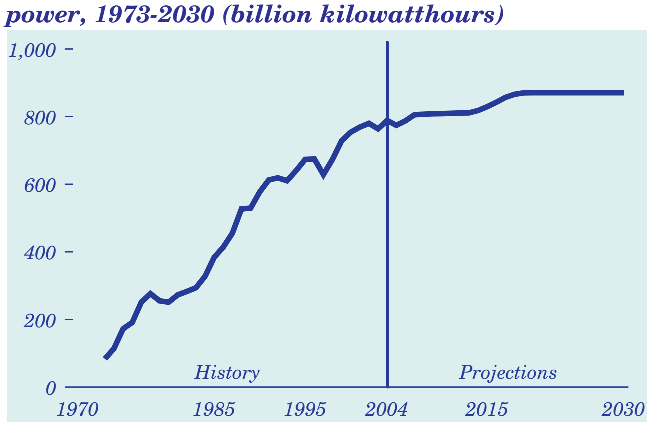
Capital costs decline over time (Table 16), at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, the costs are assumed to decline. The decline continues at a progressively slower rate as more units are built. The efficiency of new plants is also assumed to improve through 2015, with heat rates for advanced combined cycle and coal gasification units declining to 6,333 and 7,200 Btu per kilowatthour, respectively.

Table 16. Costs of producing electricity from new plants, 2015 and 2030

Costs	2015 Advanced coal	2015 Advanced combined cycle	2030 Advanced coal	2030 Advanced combined cycle
	2004 mills per kilowatthour			
Capital	30.34	11.33	27.78	10.76
Fixed	4.73	1.40	4.73	1.40
Variable	14.58	36.97	15.82	40.18
Incremental transmission	3.47	2.88	3.40	2.94
Total	**53.12**	**52.58**	**51.73**	**55.28**

EPACT2005 Tax Credits Are Expected To Stimulate New Nuclear Builds

Figure 59. Electricity generation from nuclear power, 1973-2030 (billion kilowatthours)



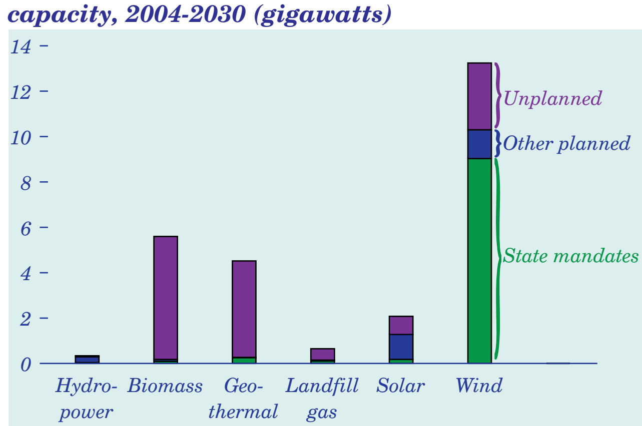
In the *AEO2006* reference case, nuclear capacity increases from 99.6 gigawatts in 2004 to 108.8 gigawatts in 2030. The increase includes 6.0 gigawatts of capacity at new plants stimulated by EPACT2005 tax incentives and 3.2 gigawatts of capacity expansion at existing plants. EPACT2005 provides an 8-year production tax credit of 1.8 cents per kilowatthour for up to 6 gigawatts of capacity built before 2021. If the capacity limit is reached before 2020, the credit program ends, and no additional units are expected. The increase in capacity at existing units assumes that all uprates approved, pending, or expected by the NRC will be carried out.

All existing nuclear plants are expected to continue operating through 2030, although most will be beyond their original license expiration dates by then. As of September 2005, the NRC had approved license renewals for 35 nuclear units, and 14 other applications were being reviewed. As many as 28 additional applicants have announced intentions to pursue license renewals over the next 7 years, indicating a strong interest in maintaining the existing stock of nuclear plants.

Because of the increase in capacity, from new capacity and uprates, and the continued strong performance of existing units, nuclear generation grows from 789 billion kilowatthours in 2004 to 871 billion kilowatthours in 2030 (Figure 59). That increase is not sufficient, however, for nuclear power to maintain its current 20-percent share of total generation. In 2030, even with a national average capacity factor of more than 90 percent, nuclear power accounts for about 15 percent of total U.S. generation.

State Programs Support Renewable Generating Capacity Additions

Figure 60. Additions of renewable generating capacity, 2004-2030 (gigawatts)



From 2004 to 2030, 26.4 gigawatts of new renewable generating capacity is added in the reference case, including 21.9 gigawatts in the electric power sector and 4.5 gigawatts in the end-use sectors. Nearly one-half of the total (11.7 gigawatts in the electric power sector and 0.75 in the end-use sectors) is at least partially stimulated by State programs, with the remainder resulting from commercial projects.

Overall, 9.0 gigawatts of central-station capacity, primarily in near-term projects, results from specific State standards: 3.7 gigawatts in Texas, 3.4 in California, 0.9 in Nevada, and 0.5 in Minnesota. Three States—Montana, New Mexico, and New York—add 100 to 200 megawatts each. Ten States—Arizona, Colorado, Hawaii, Illinois, Massachusetts, Maine, New Jersey, Pennsylvania, Vermont, and Wisconsin—add less than 100 megawatts each. Several States without specific requirements also add new renewable capacity, including nearly 400 megawatts in Washington, 300 in Oklahoma, 200 in Iowa, 150 in Kansas, and smaller amounts elsewhere.

The combination of Federal production tax credits and State programs results primarily in new wind power. More than 93 percent of the capacity additions stimulated by State programs are wind plants (Figure 60). State programs also spur small amounts of PV and solar thermal capacity, totaling 180 megawatts. On the other hand, with the Federal production tax credit assumed to expire on December 31, 2007, its potential to trigger capacity additions using technologies with longer lead times, such as biomass, geothermal, and hydropower, is limited.

Renewables Are Expected To Become More Competitive Over Time

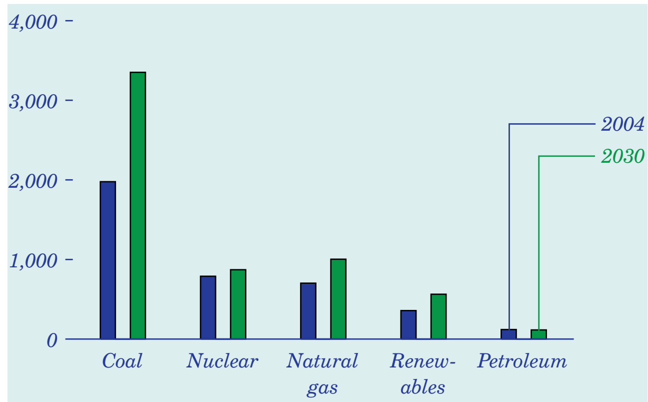
Figure 61. Levelized and avoided costs for new renewable plants in the Northwest, 2015 and 2030 (2004 mills per kilowatthour)

The competitiveness of both conventional and renewable generation resources is based on the most cost-effective mix of capacity that satisfies the demand for electricity across all hours and seasons. Baseload technologies tend to have low operating costs and set the market price for power only during the hours of least demand. Dispatchable geothermal and biomass resources compete directly with new coal and nuclear plants, which to a large extent determine the avoided cost [*89*] for baseload energy (Figure 61). In some regions and years, new geothermal or biomass plants may be competitive with new coal-fired plants, but their development is limited by the availability of geothermal resources or competitive biomass fuels.

Wind and solar are intermittent technologies that can be used only when resources are available. With relatively low operating costs and limited resource availability, their avoided costs are determined largely by the operating costs of the most expensive units in operation when their resources are available. Solar generators tend to operate during peak load periods, when natural-gas-fired combustion turbines and combined-cycle units with higher fuel costs tend to determine the avoided cost. The levelized cost of solar thermal generation is significantly higher than its avoided cost through 2030. The availability of wind resources varies among regions, but wind plants generally tend to displace intermediate load generation. Thus, the avoided costs of wind power will be determined largely by the low-to-moderate operating costs of combined-cycle and coal-fired plants, which set power prices during intermediate load hours. In some regions and years, the levelized costs for wind power are below its avoided costs.

Natural Gas and Coal Meet Most Needs for New Electricity Supply

Figure 62. Electricity generation by fuel, 2004 and 2030 (billion kilowatthours)



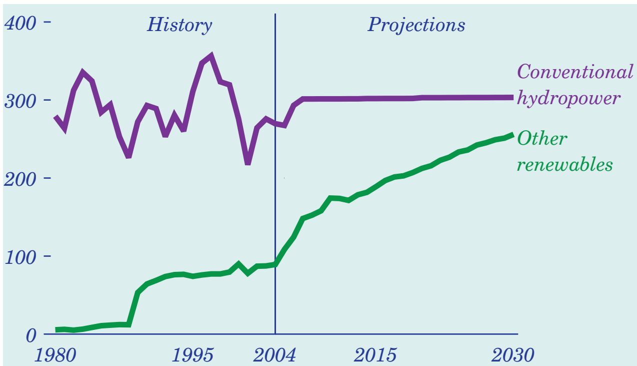
Coal-fired power plants (including utilities, independent power producers, and end-use CHP) continue to supply most of the Nation's electricity through 2030 (Figure 62). Coal-fired plants accounted for 50 percent of all electricity generation in 2004, and their share increases to 57 percent in 2030. In the near term, coal use increases gradually as a result of greater utilization of existing facilities, but its share of total generation remains relatively constant. In the longer term, the share of coal-fired generation increases as new plants begin to operate.

Because of comparatively high fuel prices, natural-gas-fired plants are not used as intensively as coal-fired plants. Natural-gas-fired plants provided 18 percent of total supply in 2004, and their share declines slightly to 17 percent in 2030. Natural-gas-fired generation increases initially as the recent wave of newer, more efficient plants come online, but it declines toward the end of the forecast period as natural gas prices continue to rise.

Both nuclear and renewable generation increase as new plants are built, stimulated by Federal tax incentives and rising fossil fuel prices. Modest increases in nuclear generation also result from improvements in plant performance and expansion of existing facilities, but the share of generation from nuclear plants declines from 20 percent in 2004 to 15 percent in 2030 as total generation grows at a faster rate than nuclear generation. The share of generation from renewable capacity increases slightly, to account for about 9 percent of total electricity supply in 2030.

Technology Advances, Tax Provisions Increase Renewable Generation

Figure 63. Grid-connected electricity generation from renewable energy sources, 1980-2030 (billion kilowatthours)

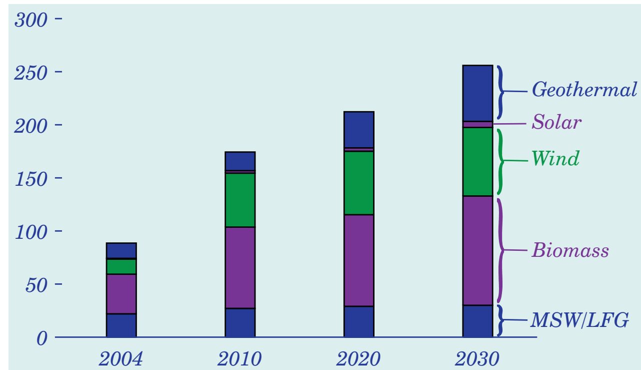


Despite technology improvements, rising fossil fuel costs, and public support, the contribution of renewable fuels to U.S. electricity supply remains relatively small in the *AEO2006* reference case at 9.4 percent of total generation in 2030, up from 9.0 percent in 2004 (Figure 63). Although conventional hydropower remains the largest source of renewable generation through 2030, a lack of untapped large-scale sites, coupled with environmental concerns, limits its growth, and its share of total generation falls from 6.8 percent in 2004 to 5.1 percent in 2030. Electricity generation from nonhydroelectric alternative fuels increases, however, bolstered by technology advances and State and Federal supports. The share of nonhydropower renewables increases by 95 percent, from 2.2 percent of total generation in 2004 to 4.3 percent in 2030.

Biomass is the largest source of renewable electricity generation among the nonhydropower renewable fuels. Co-firing with coal is relatively inexpensive when low-cost biomass resources are available; and as the cost of biomass increases over time, new dedicated biomass facilities, such as IGCC plants, are built. Electricity generation from biomass increases from 0.9 percent of total generation in 2004 to 1.7 percent in 2030, with 38 percent of the increase coming from biomass co-firing, 36 percent from dedicated power plants, and 26 percent from new on-site CHP capacity.

Biomass, Wind, and Geothermal Lead Growth in Renewables

Figure 64. Nonhydroelectric renewable electricity generation by energy source, 2004-2030 (billion kilowatthours)

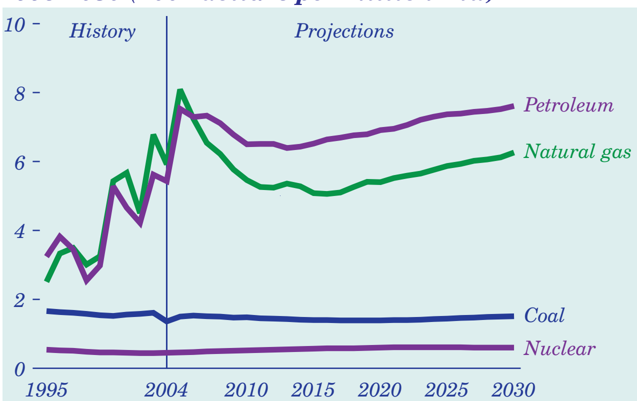


Electricity generation from wind and geothermal energy also increases in the reference case (Figure 64). There is considerable uncertainty about the growth potential of wind power, which depends on a variety of factors, including fossil fuel costs, State renewable energy programs, technology improvements, access to transmission grids, public concerns about environmental and other impacts, and the future of Federal production tax credits. In the reference case, generation from wind power increases from 0.4 percent of total generation in 2004 to 1.1 percent in 2030. Generation from geothermal facilities increases from 0.4 percent of total generation in 2004 to 0.9 percent in 2030, despite limited opportunities for the development of new sites. Most of the suitable sites, restricted mainly to Nevada and California, involve relatively high up-front costs and performance risks; and although geothermal power plants are eligible for the Federal production tax credit through 2007, the long construction lead times required make it unlikely that significant new capacity could be built in time to benefit from the current credit.

Among the other alternative fuel technologies, generation from municipal solid waste (MSW) and LFG slips from 0.5 percent of total generation in 2004 to 0.5 percent in 2030. Solar technologies in general remain too costly for grid-connected applications, but demonstration programs and State policies support some growth in central-station solar PV, and small-scale customer-sited PV applications grow rapidly [*90*]. Grid-connected solar generation remains at less than 0.1 percent of total generation through 2030.

Fuel Costs Drop From Recent Highs, Then Increase Gradually

Figure 65. Fuel prices to electricity generators, 1995-2030 (2004 dollars per million Btu)

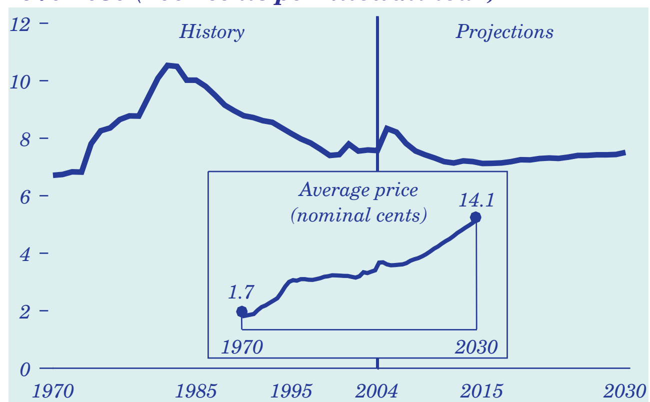


Electricity production costs are a function of the costs for fuel, operations and maintenance, and capital. In the reference case, fuel costs account for about two-thirds of the generating costs for new natural-gas-fired plants, less than one-third for new coal-fired units, and less than one-tenth for new nuclear power plants in 2030. For most fuels, delivered prices to electricity generators peak by 2006, fall in the middle years of the projections, and then increase steadily through 2030. As a yearly average, natural gas prices drop to $5.06 in 2016 and then rise to $6.26 per million Btu in 2030 (Figure 65). Similarly, petroleum prices decline to $6.39 in 2013 and then rise to $7.61 per million Btu in 2030. Coal prices remain relatively low, with highs of about $1.50 per million Btu at the beginning and end of the projection period and lows of about $1.40 in the middle years. Nuclear fuel costs, averaging $0.45 per million Btu in 2004, rise to $0.60 per million Btu in 2030.

Electricity generation from natural-gas-fired power plants, which have relatively low capital costs and emissions levels, increased in the early years of this decade. More recently, higher fuel prices have increased the cost of natural-gas-fired generation. For example, the price of natural gas to generators jumped by 37 percent from 2004 to 2005. With natural gas prices rising after 2016 in the reference case, the natural gas share of total electricity generation drops, and both coal-fired and renewable generation increase.

Electricity Prices Moderate in the Near Term, Then Rise Gradually

Figure 66. Average U.S. retail electricity prices, 1970-2030 (2004 cents per kilowatthour)



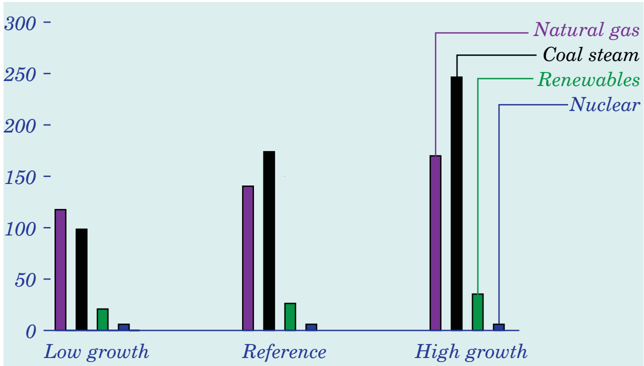
Electricity prices are determined primarily by the costs of generation, which make up about two-thirds of the total retail price. The 2004-2005 spikes in natural gas and petroleum prices, along with elevated coal prices, led to a jump in electricity prices. Average retail prices (in 2004 dollars) fall to 7.1 cents per kilowatthour in 2015, as new sources of natural gas and coal are brought on line. After 2015, natural gas and petroleum prices rise steadily, and power producers increase their reliance on lower priced coal. As a result, retail electricity prices rise gradually, to 7.5 cents per kilowatthour in 2030 (Figure 66).

Customers in States with competitive retail markets for electricity see the effects of natural gas prices in their electricity bills more rapidly than those in regulated States, because their prices are determined to a greater extent by the marginal cost of energy—the average operating cost of the last, most expensive unit run each hour—rather than the average of all plant costs. Natural gas plants, with their higher operating costs, often set the hourly marginal price.

Distribution costs, which accounted for more than one-quarter of retail electricity prices in 2004, decline by 14 percent from 2004 to 2030, as the cost of distribution infrastructure is spread over a growing customer base, and technology improvements lower the costs of billing, metering, and call-center services. Because of the additional investment needed to meet consumers' growing electricity use and to facilitate competitive wholesale energy markets, transmission costs rise by 27 percent, increasing their share of the total electricity price from 7 percent to 9 percent.

Faster Economic Growth Stimulates Capacity Additions, Particularly Coal

Figure 67. Cumulative new generating capacity by technology type in three economic growth cases, 2004-2030 (gigawatts)



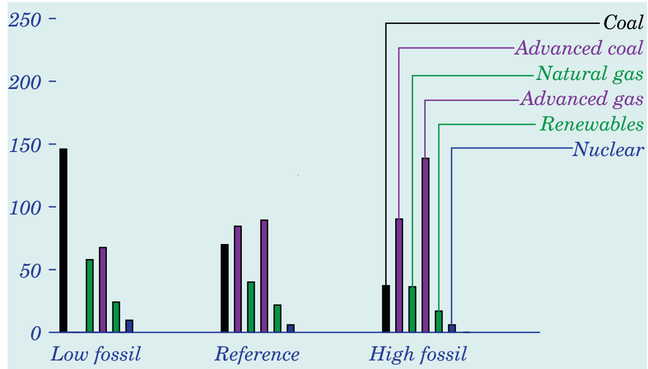
The need for new generating capacity, particularly coal-fired capacity, is influenced by economic growth. From 2004 to 2030, average annual GDP growth ranges from 2.4 percent in the low economic growth case to 3.5 percent in the high economic growth case. The difference leads to a 21-percent variation in the level of electricity demand in 2030 between the low and high economic growth cases, with a corresponding difference of 215 gigawatts in the amount of new capacity added from 2004 through 2030, including CHP in the end-use sectors.

Most (65 percent) of the capacity added in the high economic growth case, relative to the reference case, consists of new coal-fired plants. Higher demand for electricity and lower interest rates in the high economic growth case make new coal plants attractive. The stronger demand growth assumed in the high growth case also stimulates additions of renewable plants and, to a lesser degree, new natural-gas-fired capacity (Figure 67). In the low economic growth case, total capacity additions are reduced by 104 gigawatts, and 73 percent of that projected reduction is in coal-fired capacity additions.

Average electricity prices in 2030 are 4 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 2030 are 4 percent lower in the low economic growth case than in the reference case. In the high economic growth case, a 9-percent increase in consumption of fossil fuels results in a 10-percent increase in CO_2 emissions from electricity generators in 2030.

Natural-Gas-Fired Capacity Additions Vary With Cost and Performance

Figure 68. Cumulative new generating capacity by technology type in three fossil fuel technology cases, 2004-2030 (gigawatts)

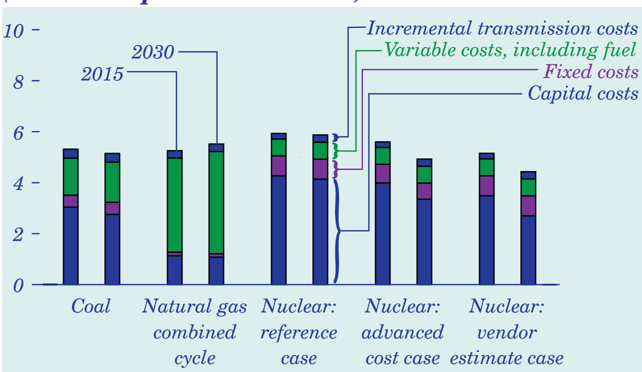


The cost and performance characteristics for various fossil fuel generating technologies in the *AEO2006* reference case are determined in consultation with industry and government specialists. To test the significance of uncertainty in the assumptions, alternative cases vary key parameters. In the high fossil fuel case, capital costs, heat rates, and operating costs for advanced fossil-fired generating technologies in 2030 are assumed to be 10 percent lower than in the reference case. The low fossil fuel case assumes no change in capital costs and heat rates for advanced technologies from their 2006 levels.

With different cost and performance assumptions, the mix of generating technologies changes (Figure 68). In the high fossil case, natural gas technologies make up the largest share of new capacity additions; in the reference and low fossil cases, coal technologies account for most of the new capacity additions. In the high fossil case, advanced technologies are used for 79 percent of all natural-gas-fired capacity additions and 71 percent of all coal-fired capacity additions by 2030; in the low fossil case, advanced technologies are used for only 54 percent of natural-gas-fired capacity additions and a negligible percentage of coal-fired capacity additions, but almost 10 gigawatts of nuclear generating capacity is added by 2030. The average efficiency of fossil-fuel-fired power plants varies only slightly among the three cases—from 36 percent in the low fossil case to almost 38 percent in the high fossil case in 2030—because plant owners are not expected to upgrade the large base of older generating units.

New Nuclear Plants Are Competitive When Lower Costs Are Assumed

Figure 69. Levelized electricity costs for new plants by fuel type in two nuclear cost cases, 2015 and 2030 (2004 cents per kilowatthour)

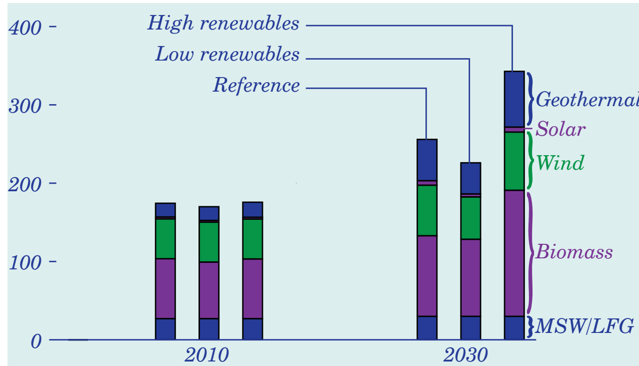


The reference case assumptions for the cost and performance characteristics of new technologies are based on cost estimates by government and industry analysts, allowing for uncertainties about new designs. Because no new nuclear plants have been ordered in this country since 1977, there is no reliable estimate of what they might cost. In recent years, various nuclear vendors have argued that their new plants will be simpler and less costly. Two alternative nuclear cost cases address this uncertainty. The advanced nuclear cost case assumes capital and operating costs 20 percent below those in the reference case in 2030, reflecting a 31-percent reduction in overnight capital costs from 2006 to 2030. The vendor estimate case assumes reductions relative to the reference case of 18 percent initially and 44 percent in 2030, consistent with estimates from British Nuclear Fuels Limited (Westinghouse) for the manufacture of its AP1000 advanced pressurized-water reactor.

Nuclear generating costs in the alternative nuclear cost cases are competitive with the generating costs for new coal- and natural-gas-fired units toward the end of the projection period (Figure 69). (The figure shows average generating costs, assuming generation at the maximum capacity factor for each technology; the costs and relative competitiveness of the technologies could vary by region.) In the reference case, Federal tax credits result in 6 gigawatts of new nuclear capacity. In the advanced nuclear case 34 gigawatts of new nuclear capacity is added between 2004 and 2030, and in the vendor estimate case 77 gigawatts of new nuclear capacity is added. The additional nuclear capacity displaces primarily new coal-fired capacity.

Lower Cost Assumptions Increase Biomass and Geothermal Capacity

Figure 70. Nonhydroelectric renewable electricity generation by energy source in three cases, 2010 and 2030 (billion kilowatthours)



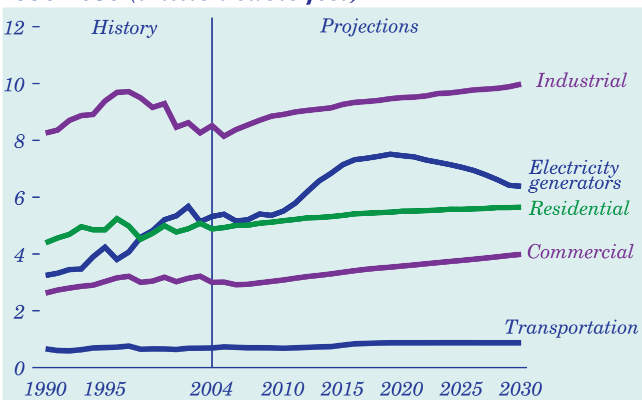
The impacts of key assumptions about the availability and cost of nonhydroelectric renewable energy resources for electricity generation are shown in two alternative technology cases. In the low renewables case, the cost and performance of generators using renewable resources are assumed to remain unchanged throughout the forecast. The high renewables case assumes cost reductions of 10 percent in 2030 on a site-specific basis for hydroelectric, geothermal, biomass, wind, and solar capacity.

In the low renewables case, construction of new renewable capacity is less than projected in the reference case (Figure 70). In the high renewables case, more additions of biomass, geothermal, and wind capacity are projected through 2030 than in the reference case, with most of the incremental capacity added between 2020 and 2030.

Biomass, available in some quantity in all U.S. regions, provides desirable baseload and intermediate-load capacity. In the high renewables case, the largest increase in generation relative to the reference case is seen for biomass, which nearly doubles in 2030. Geothermal resources are limited to the West, and despite limited opportunities for expansion, generation increases by 39 percent from 2004 to 2030. Generation from wind power, with significant expansion in the reference case over current capacity, increases by a modest 15 percent over the reference case in 2030, and there is little or no increase in generation from solar and hydropower. Even with the assumptions of reduced costs, nonhydropower renewables account for less than 6 percent of total generation in 2030 in the high renewables case.

Increases in Natural Gas Use Are Moderated by High Prices

Figure 71. Natural gas consumption by sector, 1990-2030 (trillion cubic feet)



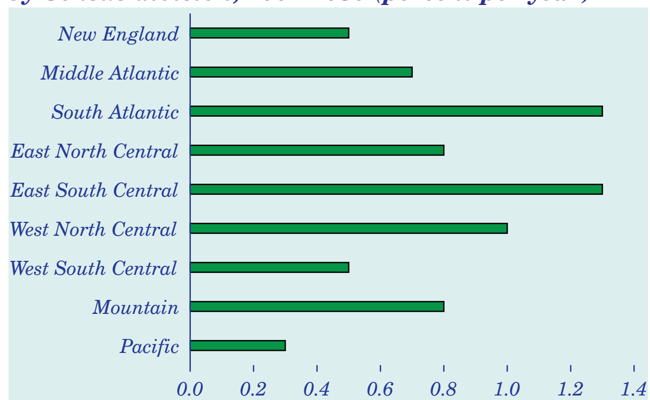
In the *AEO2006* reference case, total natural gas consumption increases from 22.4 trillion cubic feet in 2004 to 26.9 trillion cubic feet in 2030. Most of the increase is seen before 2017, when total U.S. natural gas consumption reaches just under 26.5 trillion cubic feet. After 2017, high natural gas prices limit consumption to about 27 trillion cubic feet through 2030. Consequently, the natural gas share of total energy consumption drops from 23 percent in 2004 to 21 percent in 2030.

Currently, high natural gas prices discourage the construction of new natural-gas-fired electricity generation plants. As a result, only 130 gigawatts of new natural-gas-fired capacity is added from year-end 2004 through 2030, as compared with 154 gigawatts of new coal-fired capacity. Natural gas consumption in the electric power sector peaks at 7.5 trillion cubic feet in 2019, then starts falling as new coal-fired electricity generation increasingly displaces natural-gas-fired generation. Natural gas use for electricity generation declines to 6.4 trillion cubic feet in 2030 (Figure 71).

With natural gas prices remaining relatively high throughout the projection period, consumption of natural gas in the industrial sector gas grows slowly, from 8.5 trillion cubic feet in 2004 to 10.0 trillion cubic feet in 2030. Natural gas consumption increases in all the major industrial sectors, with the exception of the refining industry. High prices also limit consumption increases in the buildings sector (residential and commercial), where natural gas use grows from 7.9 trillion cubic feet in 2004 to 9.6 trillion cubic feet in 2030.

U.S. Natural Gas Consumption Grows the Most East of the Mississippi River

Figure 72. Increases in natural gas consumption by Census division, 2004-2030 (percent per year)

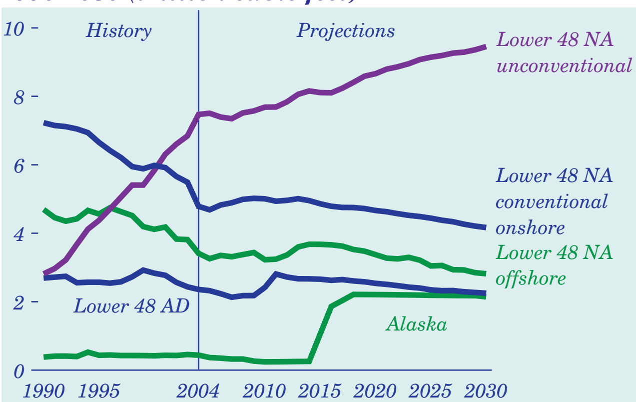


From 2004 to 2030, 60 percent of the projected growth in lower 48 end-use consumption of natural gas occurs east of the Mississippi River (Figure 72). Variation in regional growth rates for natural gas consumption results from different prospects for population growth, economic activity, and natural-gas-fired electricity generation. The most rapid increases in natural gas consumption, averaging 1.3 percent per year from 2004 through 2030, are in the South Atlantic and East South Central Census divisions. In the West North Central division, consumption grows by 1.0 percent per year, and growth rates in the other Census divisions are less than that, including annual averages of 0.5 percent in New England, 0.7 percent in the Middle Atlantic, 0.8 percent in the East North Central, 0.5 percent in the West South Central, 0.8 percent in the Mountain, and 0.3 percent in the Pacific divisions.

The Rocky Mountain and Alaska regions provide most of the increase in domestic natural gas production from 2004 to 2030. Because 60 percent of the projected growth in natural gas consumption occurs east of the Mississippi River, new natural gas pipelines are built from supply regions in the West to meet natural gas demand in the East, including a North Slope Alaska pipeline. An exception is the construction of new pipeline capacity originating in the Rocky Mountains to provide its increasing production to Pacific Coast markets. Also, some additional pipeline construction is expected to provide new LNG terminals access to the major consumption markets and to link deepwater natural gas production to major onshore transmission pipelines.

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

Figure 73. Natural gas production by source, 1990-2030 (trillion cubic feet)



A large proportion of the onshore lower 48 conventional natural gas resource base has been discovered. New reservoir discoveries are expected to be smaller and deeper, and thus more expensive and riskier to develop and produce. Much of the onshore lower 48 nonassociated (NA) conventional natural gas production in the reference case comes from existing large fields, as lower 48 NA onshore conventional natural gas production declines from 4.8 trillion cubic feet in 2004 to 4.2 trillion cubic feet in 2030 (Figure 73). Production of associated-dissolved (AD) natural gas from lower 48 crude oil reserves also declines, from 2.4 trillion cubic feet in 2004 to 2.3 trillion cubic feet in 2030.

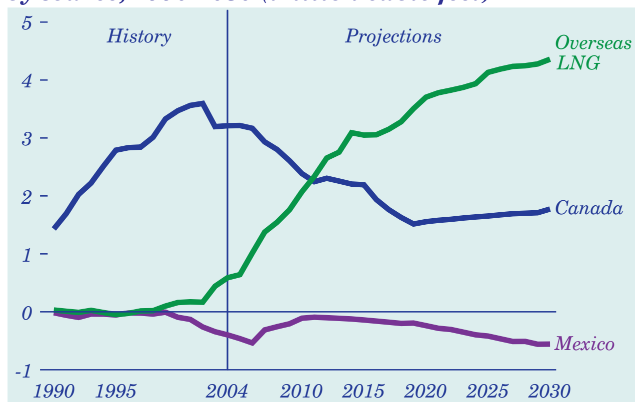
Incremental production of lower 48 onshore natural gas production comes primarily from unconventional resources, including coalbed methane, tight sandstones, and gas shales. Lower 48 unconventional production increases from 7.5 trillion cubic feet in 2004 to 9.5 trillion cubic feet in 2030.

Considerable natural gas resources remain in the offshore Gulf of Mexico, especially in the deep waters. Deepwater natural gas production in the Gulf of Mexico increases from 1.8 trillion cubic feet in 2004 to a peak of 3.2 trillion cubic feet in 2014, then declines to 2.1 trillion cubic feet in 2030. Production in the shallower waters of the Gulf of Mexico declines throughout the projection period, from 2.4 trillion cubic feet in 2004 to 1.8 trillion cubic feet in 2030.

The Alaska pipeline begins transporting natural gas to the lower 48 States in 2015. In 2030, Alaska's natural gas production totals 2.1 trillion cubic feet.

Net Imports of Natural Gas Grow in the Projections

Figure 74. Net U.S. imports of natural gas by source, 1990-2030 (trillion cubic feet)



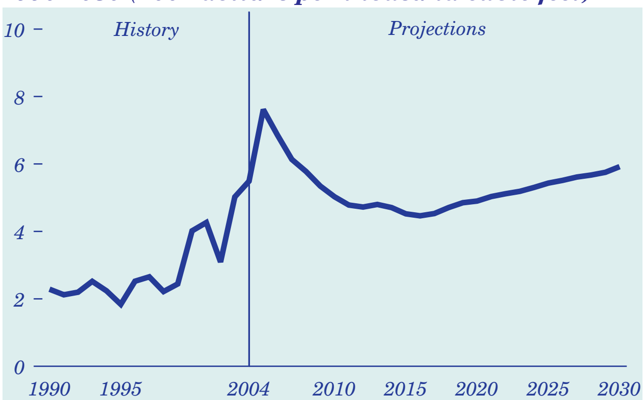
With U.S. natural gas production declining, imports of natural gas rise to meet increasing domestic consumption. A decline in Canada's non-Arctic conventional natural gas production is only partially offset by its Arctic and unconventional production. Although a MacKenzie Delta natural gas pipeline is expected to begin transporting natural gas in 2011 in the reference case, net imports from Canada fall from 3.2 trillion cubic feet in 2004 to 1.5 trillion cubic feet in 2019. After 2019, net imports from Canada begin to increase, as unconventional production eventually offsets the decline in conventional production. Net imports of natural gas from Canada total 1.8 trillion cubic feet in 2030.

Most of the projected growth in U.S. natural gas imports is in the form of LNG, some of which flows into the United States by pipeline from Mexico. The total capacity of U.S. LNG receiving terminals increases rapidly, from 1.4 trillion cubic feet in 2004 to 4.9 trillion cubic feet in 2015, when net LNG imports total 3.1 trillion cubic feet. Construction of new LNG terminals slows after 2015. With terminal capacity of 5.8 trillion cubic feet in 2030, U.S. net LNG imports total 4.4 trillion cubic feet (Figure 74).

Net exports of U.S. natural gas to Mexico decrease from 2004 through 2011, as new LNG terminals are built in Mexico. After 2011 U.S. net exports of natural gas to Mexico increase, to 560 billion cubic feet in 2030.

Projected Natural Gas Prices Remain Above Historical Levels

Figure 75. Lower 48 natural gas wellhead prices, 1990-2030 (2004 dollars per thousand cubic feet)

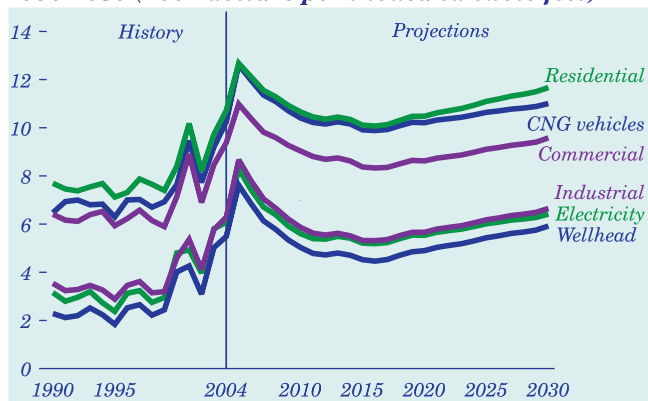


In the reference case, wellhead natural gas prices decline from current levels to an average of $4.46 (2004 dollars) per thousand cubic feet in 2016, then rise to $5.92 per thousand cubic feet in 2030 (Figure 75). Current high prices for natural gas are expected to accelerate the construction of new LNG terminal capacity, resulting in a significant increase in total U.S. LNG receiving capacity by 2015. High natural gas prices are also expected to increase support for the construction of an Alaska natural gas pipeline that begins operations in 2015, and to stimulate production of unconventional natural gas. On the demand side, high prices reduce the growth of natural gas consumption.

As a result of the development of new natural gas supplies and slower growth in consumption, wellhead natural gas prices decline through 2016. After 2016, as the cost of developing the remaining U.S. natural gas resource base increases, wellhead natural gas prices increase. World LNG prices also increase after 2016 in the reference case, slowing the growth of U.S. LNG imports.

Delivered Natural Gas Prices Follow Trends in Wellhead Prices

Figure 76. Natural gas prices by end-use sector, 1990-2030 (2004 dollars per thousand cubic feet)



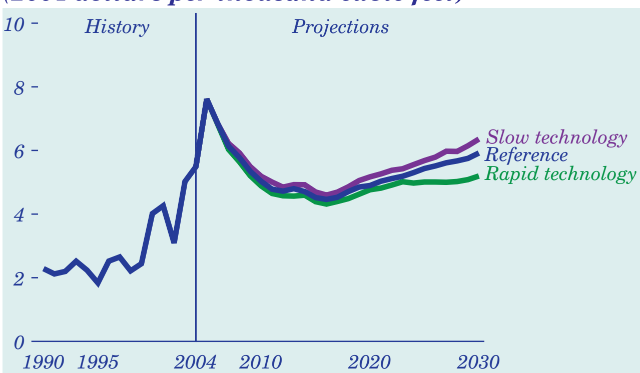
Trends in delivered natural gas prices largely reflect changes in wellhead prices. In the reference case, prices for natural gas delivered to the end-use sectors decline through 2016 as wellhead prices decline, then increase along with wellhead prices (Figure 76).

On average, end-use transmission and distribution margins remain relatively constant, because the cost of adding new facilities largely offsets the reduced depreciation expenses of existing facilities. Transmission and distribution margins in the end-use sectors reflect both the volumes of natural gas delivered and the infrastructure arrangements of the different sectors. 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. In addition, summer-peaking electricity generators reduce transmission costs by using interruptible transportation services 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 reference case assumes that sufficient transmission and distribution capacity will be built to accommodate the growth in natural gas consumption. If future public opposition were to prevent the building of new infrastructure, delivered prices could be higher than projected in the reference case.

Technology Advances Could Moderate Future Natural Gas Prices

Figure 77. Lower 48 natural gas wellhead prices in three technology cases, 1990-2030 (2004 dollars per thousand cubic feet)



Technological progress affects natural gas production by reducing production costs and expanding the economically recoverable gas resource base. An example is the relatively recent development of technologies for producing unconventional natural gas resources, which allow previously uneconomical deposits to be produced profitably, whereas 50 years ago industry technology was capable of exploiting only conventional deposits.

In the slow oil and gas technology case, advances in exploration and production technologies are assumed to be 50 percent slower than those assumed in the reference case, which are based on historical rates. As a result, domestic natural gas development costs are higher, production is lower, wellhead prices are higher at $6.36 per thousand cubic feet in 2030 (Figure 77), natural gas consumption is reduced, and LNG imports are higher than in the reference case.

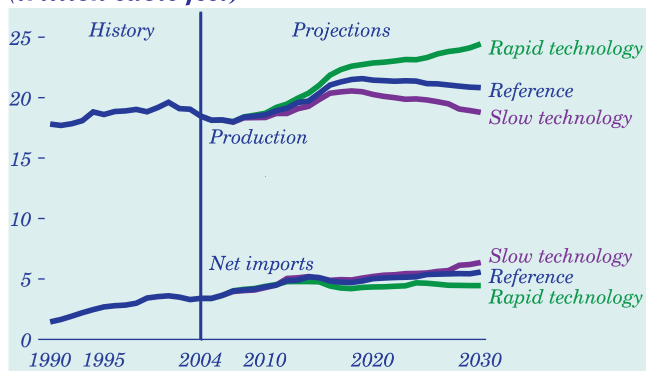
The rapid technology case assumes 50 percent faster technology progress than in the reference case, resulting in lower development costs, higher production levels, lower wellhead prices ($5.20 per thousand cubic feet in 2030), increased consumption of natural gas, and lower LNG imports than in the reference case. Technically recoverable natural gas resources (Table 17) are expected to be adequate to support the higher production levels in the rapid technology case [*91*].

Table 17. Technically recoverable U.S. natural gas resources as of January 1, 2004 (trillion cubic feet)

Proved	Unproved	Total
189.0	1,115.0	1,304.0

Natural Gas Supply Projections Reflect Technological Progress Rates

Figure 78. Natural gas production and net imports in three technology cases, 1990-2030 (trillion cubic feet)



In the rapid technology case, lower wellhead prices for natural gas lead to increased consumption and lower import levels. Natural gas production increases to meet the increased demand (Figure 78). In 2030, natural gas production is 24.4 trillion cubic feet (17 percent higher than in the reference case), net natural gas imports are 4.4 trillion cubic feet (20 percent lower), and domestic natural gas consumption is 29.4 trillion cubic feet (9 percent higher).

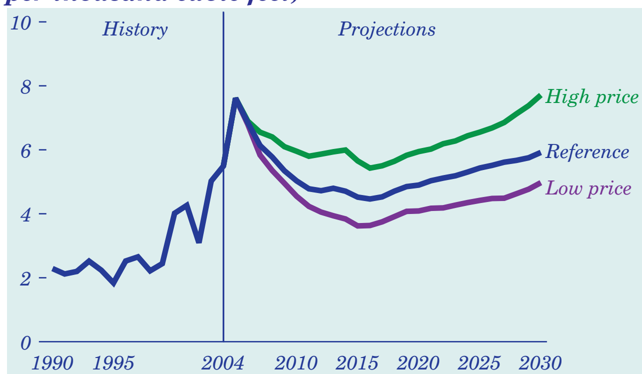
In the slow technology case, higher wellhead prices reduce domestic consumption of natural gas, increase natural gas imports, and reduce domestic production. In 2030, natural gas production is 18.8 trillion cubic feet (10 percent lower than in the reference case), net natural gas imports are 6.4 trillion cubic feet (14 percent higher), and domestic natural gas consumption is 25.6 trillion cubic feet (5 percent lower).

Canada's natural gas production also varies with changes in assumptions about technological progress rates. In the rapid technology case, U.S. imports of natural gas from Canada in 2030 increase to 2.0 trillion cubic feet, 10 percent higher than in the reference case. In the slow technology case, imports from Canada in 2030 fall to 1.5 trillion cubic feet, 16 percent lower than in the reference case.

Lower domestic prices for natural gas reduce net imports of LNG, and higher prices increase net imports. In the rapid and slow technology cases, net LNG imports in 2030 are 3.2 and 5.3 trillion cubic feet, respectively, compared with 4.4 trillion cubic feet in the reference case.

Natural Gas Prices Vary With Assumptions About Resource Levels

Figure 79. Lower 48 natural gas wellhead prices in three price cases, 1990-2030 (2004 dollars per thousand cubic feet)

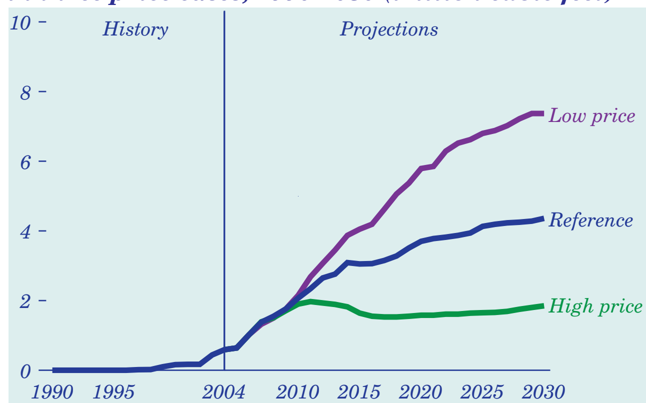


The high and low price cases assume that the unproven domestic natural gas resource base is 15 percent lower and 15 percent higher, respectively, than the estimates used in the reference case. As the estimate of the domestic natural gas resource base increases, projected natural gas prices decline, because the more abundant resource base keeps natural gas exploration and production costs lower over time. With the lower resource level in the high price case, the wellhead price for natural gas in 2030 rises to $7.71 per thousand cubic feet (2004 dollars), 30 percent higher than in the reference case ($5.92 per thousand cubic feet). In the low price case, with a higher resource level, the wellhead price in 2030 falls to $4.97 per thousand cubic feet in 2030, 16 percent lower than in the reference case (Figure 79).

The high and low price cases affect domestic consumption, production, and imports. In the high price case, domestic natural gas consumption in 2030 is 2.9 trillion cubic feet (11 percent) lower than in the reference case. In the low price case, domestic natural gas consumption in 2030 is 4.2 trillion cubic feet (16 percent) higher than in the reference case. Demand for natural gas in the electricity generation sector is more responsive to prices than demand in the other end-use sectors and shows more variation in the two natural gas price cases. In 2030, natural gas consumption in the electric power sector varies from 4.0 trillion cubic feet in the high price case to 9.9 trillion cubic feet in the low price case, as compared with 6.4 trillion cubic feet in the reference case.

LNG Imports Are the Source of Supply Most Affected in the Price Cases

Figure 80. Net imports of liquefied natural gas in three price cases, 1990-2030 (trillion cubic feet)



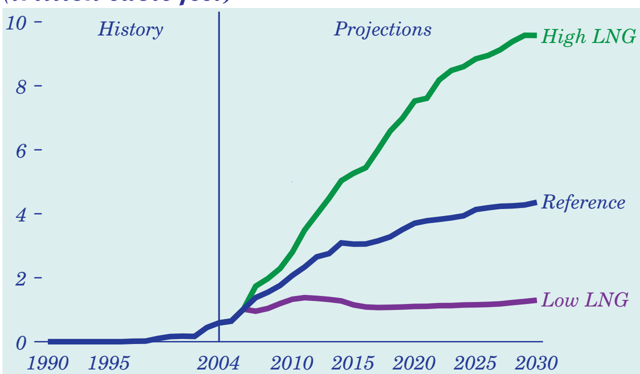
Among the major sources of natural gas supply, LNG imports are the most affected in the three price cases. Net imports of LNG in the reference case are 4.4 trillion cubic feet in 2030; in the low price case net imports in 2030 increase to 7.4 trillion cubic feet, and in the high price case they fall to 1.9 trillion cubic feet (Figure 80).

Higher world oil prices are expected to result in a shift away from petroleum consumption and toward natural gas consumption in all sectors of the international energy market. In addition, some LNG contract prices are tied directly to crude oil prices, putting further upward pressure on LNG prices. Finally, higher oil prices are expected to promote increases in GTL production, which in turn would lead to more price pressure on world natural gas supplies. In the high price case, the result is higher prices for natural gas and LNG, both in the United States and internationally, reducing U.S. LNG imports, new LNG receiving capacity, and the utilization rates for existing LNG terminals.

With higher and lower wellhead prices for natural gas in the high and low price cases, domestic consumption is reduced or increased by about the same amount as LNG imports. As a result, domestic natural gas production does not vary significantly among the three cases. From 18.5 trillion cubic feet in 2004, U.S. natural gas production increases to 20.8 trillion cubic feet in 2030 in the reference case, 21.2 trillion cubic feet in the high price case, and 21.4 trillion cubic feet in the low price case.

LNG Supply Cases Address Uncertainty in Future LNG Imports

Figure 81. Net imports of liquefied natural gas in three LNG supply cases, 1990-2030 (trillion cubic feet)

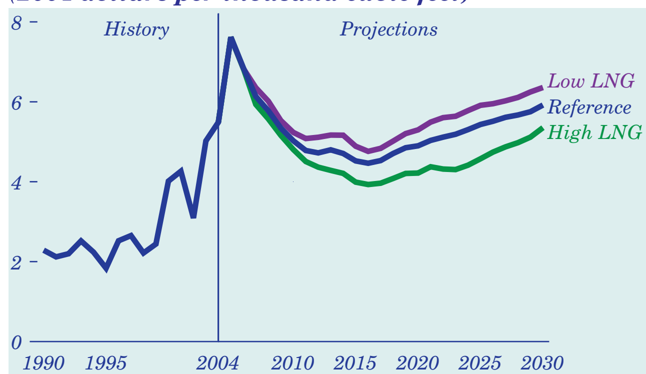


The *AEO2006* reference case assumes that two LNG terminals under construction as of August 1, 2005, will be completed: the Cheniere Energy terminals in Freeport, Texas (1.5 billion cubic feet per day), and Cameron Parish, Louisiana (2.6 billion cubic feet per day), with assumed in-service dates of 2008 and 2009, respectively. The reference case also assumes expansions at three of the four existing terminals, including a proposed expansion of 0.8 billion cubic feet per day at Cove Point, Maryland, and approved expansions of 1.1 billion cubic feet per day at Lake Charles, Louisiana, and 0.54 billion cubic feet per day at Elba Island, Georgia. In addition, the reference case assumes that new facilities will be built to serve the Gulf Coast, Southern California, Florida, and New England.

High and low LNG supply cases were developed to examine the impacts of variations in LNG supply on domestic natural gas supply, consumption, and prices. The low LNG supply case assumes a future level of LNG imports 30 percent lower than in the high price case, with imports in 2030 at 1.3 trillion cubic feet, compared with 4.4 trillion cubic feet in the reference case (Figure 81). The high LNG supply case assumes future LNG imports 30 percent higher than in the low price case, with imports in 2030 at 9.6 trillion cubic feet.

LNG Import Levels Have a Direct Effect on Domestic Natural Gas Prices

Figure 82. Lower 48 natural gas wellhead prices in three LNG supply cases, 1990-2030 (2004 dollars per thousand cubic feet)



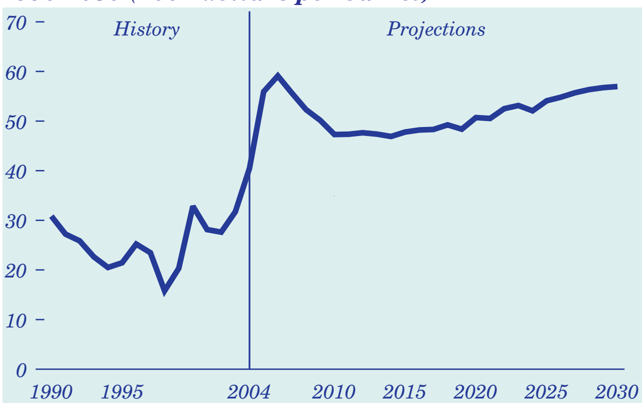
In the high LNG supply case, domestic natural gas production and wellhead prices are lower than those in the reference case, and natural gas consumption is higher. In 2030, natural gas wellhead prices in the high LNG case are 10 percent lower than in the reference case, at $5.35 per thousand cubic feet (Figure 82), and natural gas production is 8 percent lower than in the reference case, at 19.1 trillion cubic feet. Domestic natural gas consumption in 2030 in the high LNG case is 12 percent higher than in the reference case, at 30.1 trillion cubic feet.

In the low LNG supply case the total supply of natural gas to U.S. consumers is less than in the reference case, leading to higher prices, lower consumption, and more domestic natural gas production. In 2030, natural gas wellhead prices in the low LNG case are 7 percent higher than in the reference case, at $6.36 thousand cubic feet, natural gas production is 6 percent higher, at 22.0 trillion cubic feet, and domestic natural gas consumption is 6 percent lower, at 25.3 trillion cubic feet.

Lower and higher wellhead prices for natural gas in the high and low LNG supply cases have the greatest impact on natural gas consumption in the electric power sector, both because of its high projected growth rate and because of the competition between coal and natural gas. In the high LNG case, natural gas consumption for electricity generation in 2030 is 44 percent higher than in the reference case, at 9.2 trillion cubic feet, and in the low LNG case it is 21 percent lower than in the reference case, at 5.0 trillion cubic feet.

Oil Prices Decline in the Short Term, Then Rise Through 2030

Figure 83. World oil prices in the reference case, 1990-2030 (2004 dollars per barrel)



The world oil price in *AEO2006* is defined as the weighted average price of all crude oil containing less than 0.5 percent sulfur by weight that is imported by U.S. refiners. The price projection in the reference case is based on the mean conventional petroleum resource estimate (Table 18) reported by the USGS and the U.S. Minerals Management Service [*92*]. The reference case assumes that the Arctic National Wildlife Refuge (ANWR) will continue to be off limits to petroleum exploration and development.

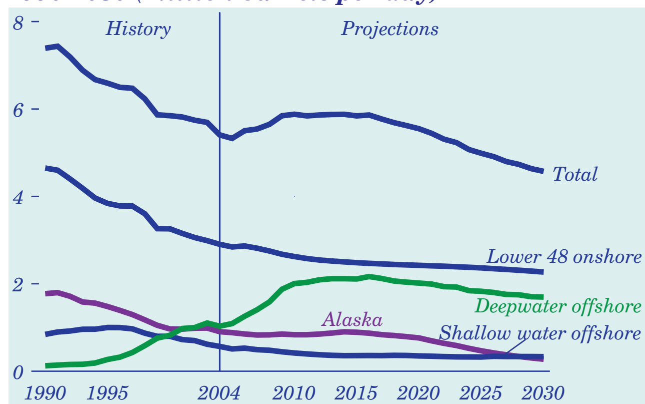
In the *AEO2006* reference case, as new oil fields are brought into production worldwide, world oil prices decline to $46.90 per barrel (2004 dollars) in 2014, then rise to $56.97 in 2030 (Figure 83). The increase after 2014 reflects rising costs for the development and production of non-OPEC oil resources. There is considerable uncertainty associated with the price projections, related to world economic growth, world oil demand, OPEC's long-term oil production policies, and international political stability.

Table 18. Technically recoverable U.S. crude oil resources as of January 1, 2004 (billion barrels)

Proved	Unproved	Total
23.1	124.1	147.2

Domestic Crude Oil Production Begins To Decline After 2016

Figure 84. Domestic crude oil production by source, 1990-2030 (million barrels per day)



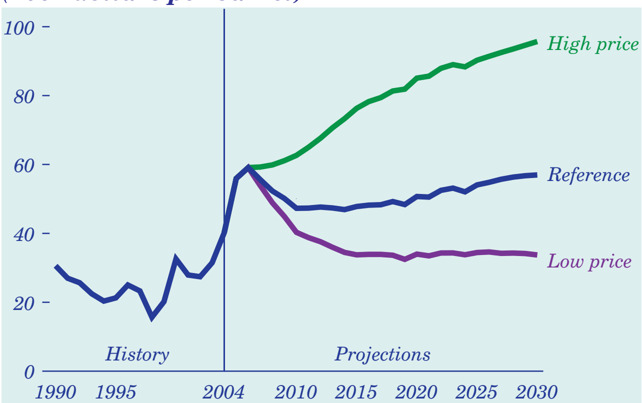
A large proportion of the total U.S. resource base of onshore conventional oil has been produced, and new oil reservoir discoveries are likely to be smaller, more remote, and increasingly costly to exploit. While higher oil prices make it economical to produce higher cost resources, lower 48 onshore oil production declines in the reference case from 2.9 million barrels per day in 2004 to 2.3 million barrels per day in 2030 (Figure 84).

The remaining onshore conventional oil resource base is not expected to provide significant new supplies of oil, with the exception of production from the National Petroleum Reserve in Alaska. Oil production in the Reserve begins in 2007, increases to a peak of 458,000 barrels per day in 2016, and declines thereafter. As a result, Alaska's total oil production—which falls from 906,000 barrels per day in 2004 to 828,000 barrels per day in 2007—rebounds to 902,000 barrels per day in 2014 before beginning a steady decline to 274,000 barrels per day in 2030.

Considerable oil resources remain in the offshore, especially in the deep waters of the Gulf of Mexico. Oil production in the shallow waters of the Gulf, starting from 0.4 million barrels per day in 2004, slips to 0.3 million barrels per day in 2030, while deepwater production increases from 1.0 million barrels per day in 2004 to a peak of 2.2 million barrels per day in 2016 and then declines to 1.7 million barrels per day in 2030. As a result, total U.S. offshore oil production increases from 1.6 million barrels per day in 2004 to 2.5 million barrels per day in 2016, then falls back to 2.0 million barrels per day in 2030.

Price Cases Assess Alternative Futures for World Oil Market

Figure 85. World oil prices in three cases, 1990-2030 (2004 dollars per barrel)

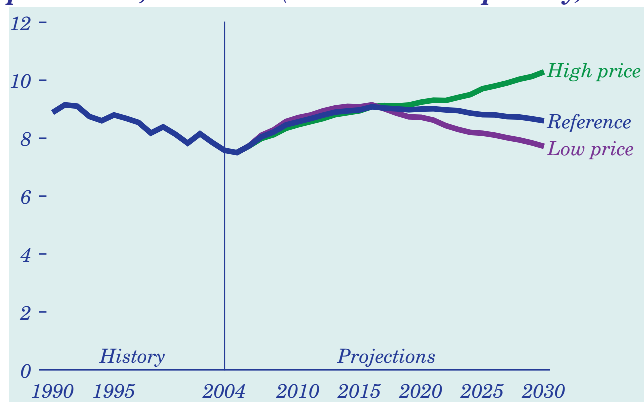


The high and low price cases reflect different assumptions about the size of the conventional world oil resource, and they project different market shares for OPEC and non-OPEC oil production. The high price case assumes that the world conventional crude oil resource base is 15 percent smaller than the USGS mean oil resource estimate. In the high price case, world oil production reaches 102 million barrels per day in 2030, with OPEC contributing 31 percent of total world oil production. World oil prices increase to $76.30 per barrel (2004 dollars) in 2015 and $95.71 per barrel in 2030 (Figure 85).

The low price case assumes that the conventional worldwide oil resource base is 15 percent larger than the USGS mean estimate. In the low price case, world oil production reaches 128 million barrels per day in 2030, with OPEC contributing 40 percent of total world oil production. World oil prices, in terms of the average price of imported low-sulfur crude oil to U.S. refiners, drop to $33.78 per barrel in 2015 and remain relatively stable thereafter.

U.S. Oil Production is Marginally Sensitive to World Oil Prices

Figure 86. Total U.S. petroleum production in three price cases, 1990-2030 (million barrels per day)



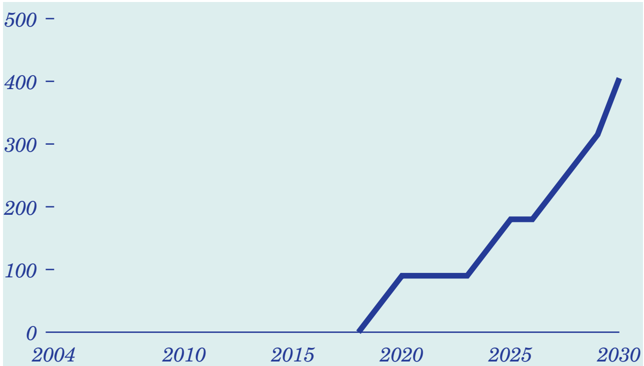
The high price case assumes that conventional domestic oil resources are 15 percent less than in the reference case, and the low price case assumes they are 15 percent greater. The difference has a direct effect on the cost and availability of newly developed domestic oil supplies. A higher (or lower) oil price also induces more (or less) exploration activity and the development of more (or less) expensive oil resources. In all cases, a significant portion of total domestic oil production comes from large, existing oil fields, such as the Prudhoe Bay Field.

Oil prices also determine whether unconventional oil production (such as oil shale, CTL, and GTL) is economical, as illustrated in the alternative price cases. CTL production is projected in both the reference and high price cases; however, GTL production and syncrude production from oil shale, both of which require higher prices before they become economical, are projected only in the high price case.

With higher oil prices, unconventional sources of oil become economical, and unconventional production increases. In the high price case, total conventional and unconventional domestic petroleum production (including NGL and refinery processing gain) in 2030 is 20 percent higher than in the reference case, at 10.3 million barrels per day. In the low price case, total production is 10 percent lower than in the reference case, at 7.7 million barrels per day in 2030 (Figure 86).

U.S. Syncrude Production From Oil Shale Requires Higher Oil Prices

Figure 87. U.S. syncrude production from oil shale in the high price case, 2004-2030 (thousand barrels per day)



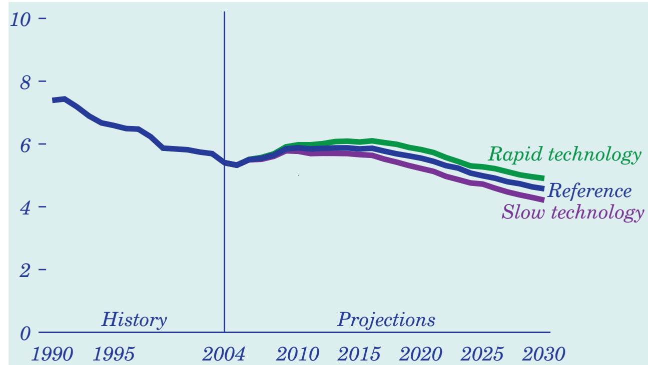
In the United States, the commercial viability of syncrude produced from oil shale largely depends on oil prices. Although the production costs for oil shale syncrude decline through 2030 in all cases, it becomes economical only in the high price case, with production starting in 2019 and increasing to 405,000 barrels per day in 2030, when it represents 4 percent of U.S. petroleum production, including NGL and refinery processing gain (Figure 87).

Production costs for oil shale syncrude are highly uncertain. Development of this domestic resource came to a halt in the mid-1980s, during a period of low oil prices. The cost assumptions used in developing the projections represent an oil shale industry based on underground mining and surface retorting; however, the development of a true *in situ* retorting technology could substantially reduce the cost of producing oil shale syncrude.

The development of U.S. oil shale resources is also uncertain from an environmental perspective. Oil shale costs will remain highly uncertain until the petroleum industry builds a demonstration project. An oil shale industry based on underground mining and surface retorting could face considerable public opposition because of its potential environmental impacts, involving scenic vistas, waste rock disposal and remediation, and water availability and contamination. Consequently, there is a high level of uncertainty in the projection for oil shale syncrude production in the high price case.

More Rapid Technology Advances Could Raise U.S. Oil Production

Figure 88. Total U.S. crude oil production in three technology cases, 1990-2030 (million barrels per day)



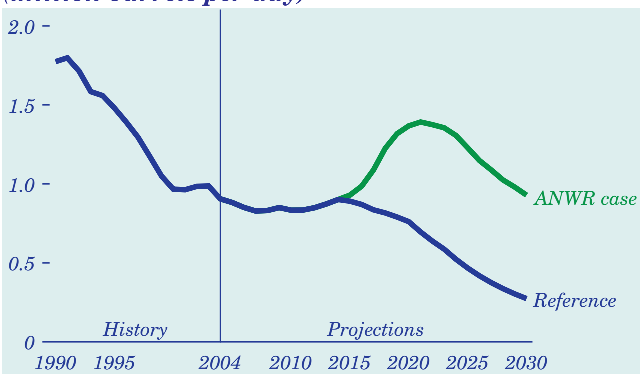
The rapid and slow oil and gas technology cases assume rates of technological progress in the petroleum industry that are 50 percent higher and 50 percent lower, respectively, than the historical rate. The rate of technological progress determines the cost of developing and producing the remaining domestic oil resource base. Higher (or lower) rates of technological progress result in lower (or higher) oil development and production costs, which in turn allow more (or less) oil production.

With domestic oil consumption determined largely by oil prices and economic growth rates, oil consumption does not change significantly in the technology cases. Domestic crude oil production in 2030, which is 4.6 million barrels per day in the reference case, increases to 4.9 million barrels per day in the rapid technology case and drops to 4.2 million barrels per day in the slow technology case (Figure 88). The projected changes in domestic oil production result in different projections for petroleum imports. In 2030, projected net crude oil and petroleum product imports range from 16.7 million barrels per day in the rapid technology case to 17.7 million barrels per day in the slow technology case, as compared with 17.2 million barrels per day in the reference case. U.S. dependence on petroleum imports in 2030 ranges from 61 percent in the rapid technology case to 64 percent in the slow technology case.

Cumulatively, from 2004 through 2030, U.S. total crude oil production is projected to be 1.9 billion barrels (3.8 percent) higher in the rapid technology case and 2.1 billion barrels (4.1 percent) lower in the slow technology case than in the reference case.

Drilling in ANWR Could Sustain Alaska's Oil Production

Figure 89. Alaskan oil production in the reference and ANWR cases, 1990-2030 (million barrels per day)



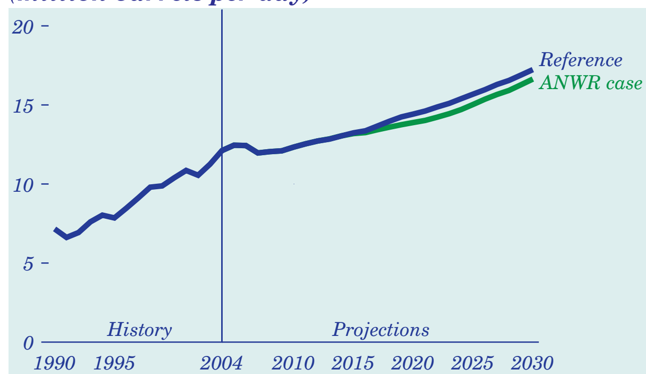
Whether Federal oil and natural gas leasing in ANWR will ever occur remains uncertain. The *AEO-2006* ANWR alternative case suggests the potential impact of opening ANWR to leasing. The ANWR case uses the same assumptions as the reference case, except that oil and natural gas development and production are allowed in ANWR, starting in 2005.

The opening of ANWR to development in 2005 results in the initiation of ANWR oil production in 2015. Oil production from ANWR grows to a peak of 780,000 barrels per day in 2024, then declines to 650,000 barrels per day in 2030. In the reference case, with no oil production from ANWR, Alaska's total oil production grows to 900,000 barrels per day in 2014 and then declines to 270,000 barrels per day in 2030. In the ANWR case, Alaskan oil production rises to 1.4 million barrels per day in 2021 and then falls to 930,000 barrels per day in 2030 (Figure 89).

World oil prices are slightly lower in the ANWR case than in the reference case. The largest difference is 79 cents per barrel in 2024 (in 2004 dollars), when ANWR oil production is at its peak. After 2024, as ANWR production declines, the difference narrows to 68 cents per barrel in 2030.

ANWR Oil Production Could Lower U.S. Net Oil Imports Through 2030

Figure 90. U.S. net imports of oil in the reference and ANWR cases, 1990-2030 (million barrels per day)



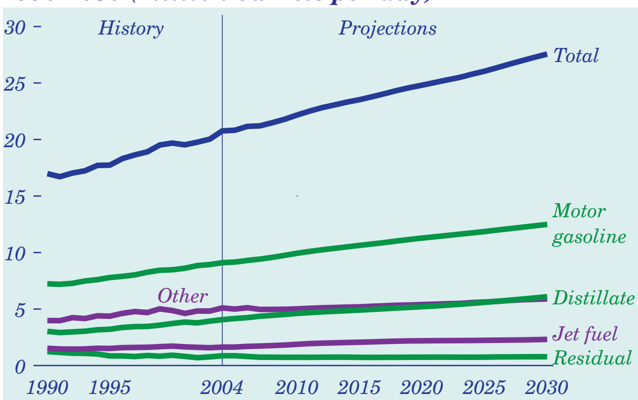
The opening of ANWR to Federal oil and natural gas leasing increases domestic oil production. In the reference case, U.S. total crude oil production peaks in 2010 at 5.9 million barrels per day, then declines to 4.6 million barrels per day in 2030. In the ANWR case, total domestic oil production peaks in 2020 at 6.2 million barrels per day and then falls to 5.2 million barrels per day in 2030.

Every additional barrel of oil produced in ANWR effectively displaces a barrel of imported crude oil. In 2024, when ANWR production peaks in the alternative case, the import share of total domestic petroleum supply is 57 percent (14.7 million barrels per day), compared with 60 percent (15.4 million barrels per day) in the reference case (Figure 90). In 2030, when ANWR production is declining, the import share of total domestic petroleum supply is 60 percent in the ANWR case and 62 percent in the reference case.

Although the opening of ANWR to Federal oil and natural gas leasing reduces projected oil prices, the impact on domestic oil consumption is negligible. In 2024, when projected ANWR oil production is highest and the reduction in oil prices is largest, domestic consumption of petroleum products is only about 60,000 barrels per day higher in the ANWR case than in the reference case. The difference in domestic oil consumption is the same in 2030.

Transportation Uses Lead Growth in Petroleum Consumption

Figure 91. Consumption of petroleum products, 1990-2030 (million barrels per day)



Between 70 and 74 percent of U.S. petroleum use is for transportation, and much of the projected growth in domestic consumption reflects growth in the use of transportation fuels (Figure 91). Gasoline, distillate fuel (ultra-low-sulfur diesel), and jet fuel are the main transportation fuels. In the *AEO2006* reference case, improvements in technology increase the efficiency of motor vehicles and aircraft, but growth in demand for each mode of transit far outpaces increases in fuel efficiency, as transportation demand grows in proportion to increases in population and GDP.

In the residential sector, the use of distillate for home heating declines as natural gas and LPG are used increasingly as substitutes. Both burn more cleanly than distillate, eliminating the annual maintenance that is needed for an oil-fired furnace or boiler. Natural gas, where available, is more convenient than distillate or LPG.

In the industrial and commercial sectors, distillate is used as a fuel for heating and for diesel engines. In the near term, high prices for distillate lead to fuel switching away from heating oil; but as prices moderate, there is some switching back to distillate for heating uses.

Residual fuel is blended from the heaviest crude oil components. Undiluted residual fuel is used to power ships and electricity plants. Residual fuel diluted with distillate is used to fire boilers and to power some locomotives. Residual fuel consumption declines in the reference case as environmental restrictions tighten, and because refiners find it more attractive to upgrade residual fuel to lighter products.

Expansion at Existing Refineries Increases U.S. Refining Capacity

Figure 92. Domestic refinery distillation capacity, 1990-2030 (million barrels per day)

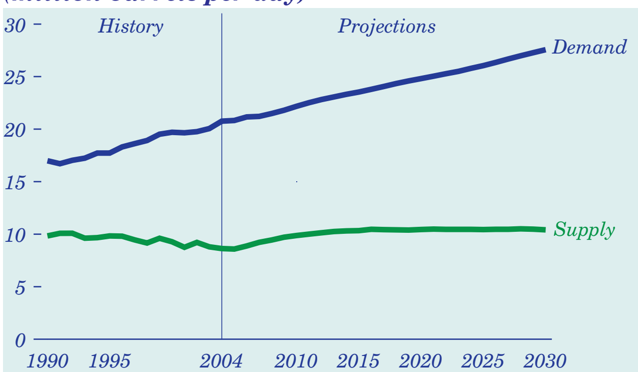
Distillation capacity at U.S. refineries expands in the reference case (Figure 92) as demand for refined petroleum products increases. More than 30 years have passed since a new U.S. refinery was built, and most of the expansion occurs at existing sites. Although it is not difficult technically for refiners and refinery process developers to expand the capacity of existing units, obtaining permits is difficult, and getting permits to build a new refinery is even harder. Nonetheless, a startup company has announced plans to open a major new refinery in Arizona in 2010.

The most basic refinery operation is atmospheric distillation of crude oil. Crude oil is heated to about 750 degrees Fahrenheit and then fed into a tower where it separates into fractions according to the boiling points of the many compounds it contains. The separated fractions are sent on to other units in the refinery for further processing and, ultimately, blending into finished products.

Other processing units in a refinery generally expand at about the same rate as distillation capacity; however, tighter product specifications, poorer crude oil quality, and dwindling demand for residual fuel increase the capacity needed for two processes, coking and hydrotreating. Coking is used to break the heaviest fractions of crude oil into elemental carbon, or coke, and lighter fractions. Material used in the coker would otherwise be usable only as residual fuel or asphalt. Hydrotreating capacity, which is used to take sulfur out of petroleum products, allows refiners to meet tighter limits on sulfur content and to run higher sulfur crude oils through their refineries.

Imports of Petroleum Products Increase With Rising U.S. Demand

Figure 93. U.S. petroleum product demand and domestic petroleum supply, 1990-2030 (million barrels per day)



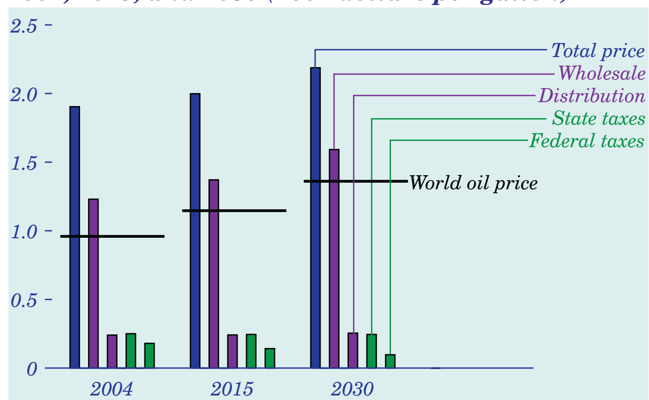
U.S. petroleum market regulations before the 1980s encouraged the U.S. refinery industry to overinvest in capacity. In the 1980s, deregulation encouraged the shutdown of inefficient refineries, and strong demand growth in response to the low oil prices of the late 1980s and the 1990s eliminated any excess capacity that remained. In the *AEO2006* reference case, refinery utilization increases from 93 percent in 2004 to 95 percent in 2030. In the 1980s, capacity utilization at U.S. refineries averaged only 69 percent.

The most advantageous locations for refineries are near crude oil production sites or where demand for petroleum products is concentrated. As both a major producer and consumer of petroleum products, the United States has a large refinery complex, but U.S. demand for petroleum exceeded domestic production long ago, and the Nation has been a net importer of crude oil for more than 50 years (Figure 93).

In the reference case, demand for refined products continues to increase more rapidly than refining capacity, and petroleum product imports increase to fill the gap. Historically, the availability of product imports has been limited by a lack of foreign refineries capable of meeting the stringent U.S. standards for petroleum products. More recently, petroleum demand has grown rapidly in Eastern Europe and Asia, and those nations are moving to adopt the same quality standards as the developed world. As a result, refineries throughout the world are becoming more sophisticated, and more of them will be able to provide products suitable for the U.S. market in the future, which they may do if it is profitable.

U.S. Motor Gasoline Prices Rise and Fall With Changes in World Oil Price

Figure 94. Components of retail gasoline prices, 2004, 2015, and 2030 (2004 dollars per gallon)

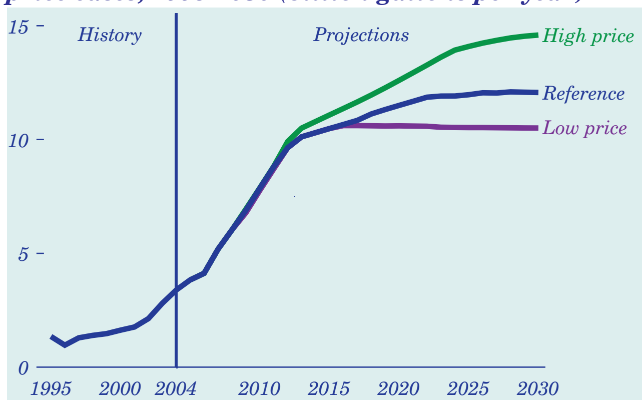


Changes in crude oil prices have a direct impact on wholesale prices for petroleum products. In the reference case, the world price (the price of imported low-sulfur light crude oil in 2004 dollars) reachs a low of $47.79 per barrel in 2015, then begins a slow increase that continues to a level of $56.97 per barrel in 2030. The U.S. average gasoline price in 2015 is $2.00 per gallon and $2.19 per gallon in 2030 (Figure 94). Accordingly, the wholesale price makes up 69 percent of the retail price for transportation gasoline in 2015 and 73 percent in 2030. In comparison, for transportation diesel fuel, the wholesale price is 71 percent of the retail price in 2015 and 74 percent in 2030.

The most recent increase in the Federal excise tax on motor fuels was enacted in 1993. Consistent with historical trends, State taxes on gasoline decline slightly in real terms in the reference case, and Federal taxes decline substantially. As a result, Federal taxes on gasoline and highway diesel in 2030 are only 52 percent of their 2004 levels. State and Federal taxes make up 19 percent of retail gasoline prices in 2015 and 16 percent in 2030. For transportation diesel, taxes make up 20 percent of the retail price in 2015 and 16 percent in 2030.

U.S. Demand for Ethanol Fuel Varies With World Oil Price Projections

Figure 95. U.S. ethanol fuel consumption in three price cases, 1995-2030 (billion gallons per year)



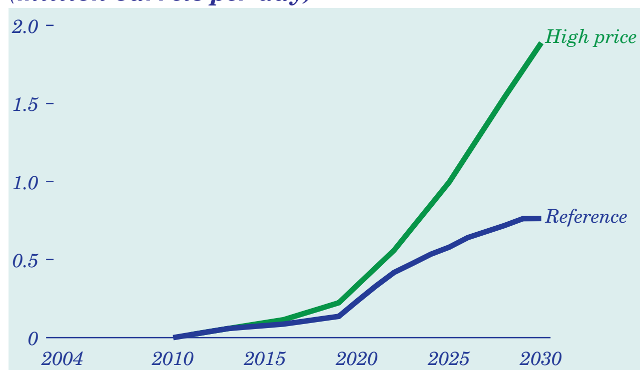
EPACT2005 repealed the oxygenate requirement for Federal RFG. The only economically feasible oxygenates are ethanol and MTBE. It is easier to meet the other requirements for RFG, such as volatility and aromatics emissions limits, with MTBE; however, MTBE readily contaminates groundwater when blended gasoline is leaked or spilled. Refiners see the repeal of the oxygenate requirement as increasing their liability for MTBE pollution of water. They are expected to stop making and blending MTBE by 2008, but ethanol blending into RFG is expected to continue, because ethanol is a clean, high-octane blending component that can be used to replace MTBE.

Ethanol is a substitute for hydrocarbons, and when crude oil prices increase, more ethanol is used to meet demand for gasoline (Figure 95). In 2030, ethanol blending into gasoline ranges from about 5 percent of the gasoline pool in the low price case to almost 9 percent in the high price case.

Virtually all the fuel ethanol produced in the United States is distilled from corn. EPACT2005 requires the use of 250 million gallons per year of ethanol distilled from cellulosic materials, starting in 2012. Declining corn prices in real terms and improvements in grain ethanol technology prevent further penetration of cellulosic ethanol use in the reference case. Corn ethanol production is near practical limits in the reference case, however, and production of ethanol from cellulose feedstocks begins in 2010. In the high price case, cellulosic ethanol production exceeds the level mandated in EPACT2005.

Synthetic Fuel Production Grows Rapidly in the High Price Case

Figure 96. Coal-to-liquids and gas-to-liquids production in two price cases, 2004-2030 (million barrels per day)



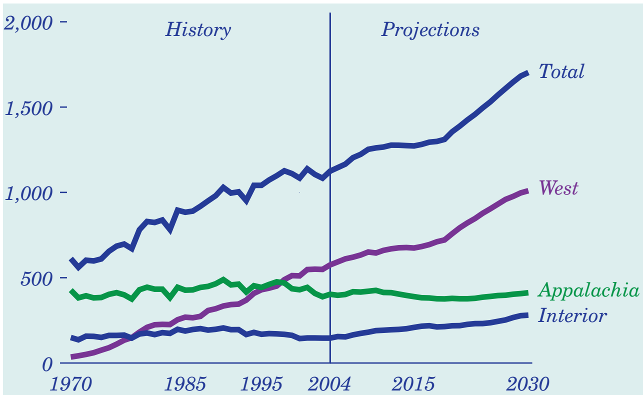
GTL and CTL processes are used to convert natural gas and coal, respectively, into high-quality blending components for diesel fuel. Naphthas, waxes, and lubrication oil components are produced as byproducts.

Per unit of capacity, CTL and GTL plants are more expensive to construct than are petroleum refineries. The natural gas needed to feed a GTL plant is also expensive. In the reference case, the cost of natural gas makes GTL unattractive, and no U.S. plants are built by 2030. Coal, however, is much cheaper than natural gas, and CTL fuels enter the market in 2011 (Figure 96). CTL production in 2030 totals 760,000 barrels per day in the reference case and makes up 13 percent of distillate fuel supply.

Higher crude oil prices encourage the substitution of natural gas and coal for oil. In the high price case, GTL enters the market in 2020, and production grows to 194,000 barrels per day in 2030. CTL production grows to 1.69 million barrels per day in 2030 in the high price case. Together, GTL and CTL provide 32 percent of the Nation’s distillate fuel supply in 2030 in the high price case. Neither GTL nor CTL fuels are economically feasible in the low price case.

Market Share of Western Coal Continues To Increase

Figure 97. Coal production by region, 1970-2030 (million short tons)



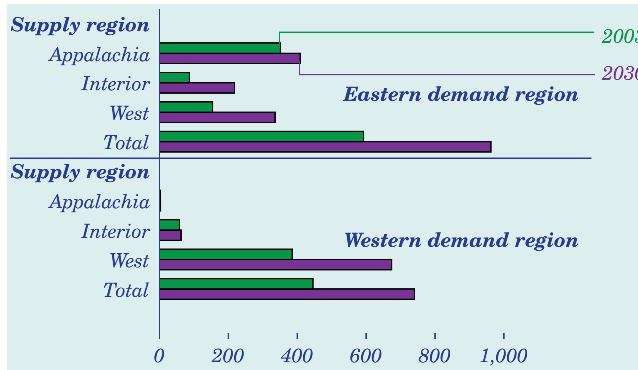
U.S. coal production has remained near 1,100 million tons annually since 1996. In the *AEO2006* reference case, increasing coal use for electricity generation at existing plants and construction of a few new coal-fired plants lead to annual production increases that average 1.1 percent per year from 2004 to 2015, when total production is 1,272 million tons. The growth in coal production is even stronger thereafter, averaging 2.0 percent per year from 2015 to 2030, as substantial amounts of new coal-fired generating capacity are added, and several CTL plants are brought on line.

Western coal production, which has grown steadily since 1970, continues to increase through 2030 (Figure 97), especially in the Powder River Basin, where vast reserves are contained in thick seams accessible to surface mining. Easing of rail transportation bottlenecks will be needed for producers in the West to exploit the market opportunities presented by slow growth in Appalachian coal production and by demand for coal at new power plants built to serve electricity markets in the Southwest and California.

Appalachian coal production remains nearly flat in the reference case. Although producers in Central Appalachia are well situated geographically to supply coal to new generating capacity in the Southeast, the Appalachian basin has been mined extensively, and production costs have been increasing more rapidly than in other regions. The Eastern Interior coal basin (Illinois, Indiana, and western Kentucky), with extensive reserves of mid- and high-sulfur bituminous coals, does benefit from the new builds of coal-fired generating capacity in the Southeast.

More Eastern Power Plants Are Expected To Use Western Coal

Figure 98. Distribution of domestic coal by demand and supply region, 2003 and 2030 (million short tons)

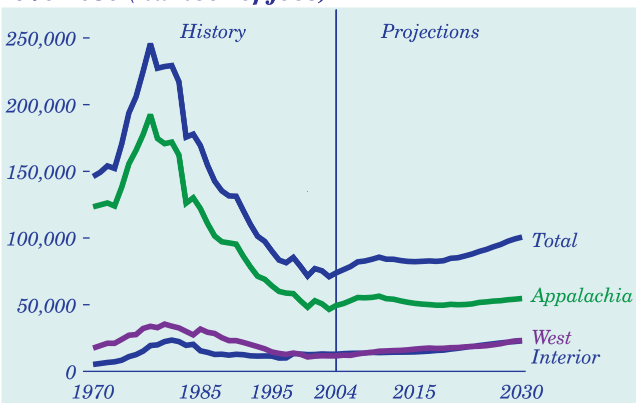


In the reference case, low-cost Western coal continues to gain market share east of the Mississippi River and remains the dominant supplier in markets west of the Mississippi River (Figure 98). Use of low-sulfur Western coal continues to increase through 2030, even though 141 gigawatts of existing coal-fired capacity is retrofitted with flue gas desulfurization equipment and another 174 gigawatts of new environmentally compliant coal-fired capacity is built. Even in the absence of sulfur compliance costs, Western coal is the lowest cost fuel option for electricity generation in many areas of the country. As a result, each year typically sees more coal-fired plants switching to Western coal, particularly from the Powder River Basin. In 2004, approximately 20 plants, many located east of the Mississippi River, used Powder River Basin coal for the first time.

Although two new pieces of environmental legislation enacted in 2005, CAIR and CAMR, will increase the cost of coal-fired generation, they have only minor impacts on overall coal use in the electric power sector or regional coal production patterns. As a result of the stricter caps on SO_2 emissions in CAIR, allowance prices increase substantially, virtually eliminating by 2030 the use of medium- and high-sulfur coals (containing more than 0.6 pounds sulfur per million Btu) at power plants not equipped with scrubbers. In 2004, medium- and high-sulfur coals accounted for about 40 percent of the 638 million tons of coal consumed at generating units without scrubbers [*93*]. In 2030, coal-fired power plants without scrubbers consume only 233 million tons.

Coal Mine Employment Increases As Production Expands

Figure 99. U.S. coal mine employment by region, 1970-2030 (number of jobs)



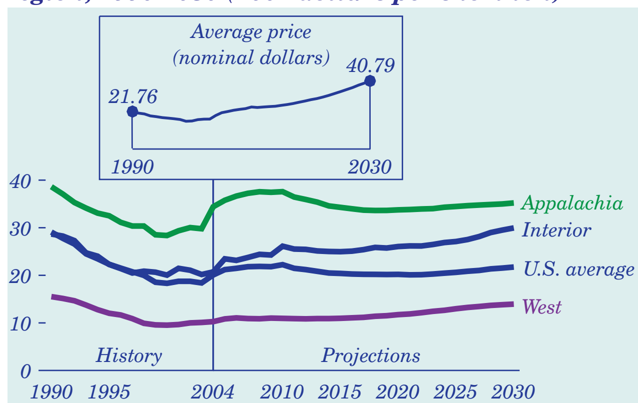
Most jobs in the U.S. coal industry remain east of the Mississippi River, mainly in the Appalachian region (67 percent in 2004). Most coal production, however, occurs west of the Mississippi River (56 percent in 2004), with the major share from the Powder River Basin. As coal demand increases, pressure to keep prices low will shift more production to mines with higher labor productivity. Large surface mines in the Powder River Basin take advantage of economies of scale, using large earth-moving equipment and combining adjacent mines to increase operating flexibility. Underground mines in the Northern Appalachia and Rocky Mountain supply regions use highly productive and increasingly automated longwall equipment to maximize production while reducing the number of miners required.

In the reference case, labor productivity remains near current levels in most coal supply regions, reflecting the trend of the past 5 years. Higher stripping ratios and the additional labor needed to maintain more extensive underground mines offset productivity gains achieved from improved equipment, automation, and technology. Productivity in some areas of the East declines as operations move to marginal reserve areas. Regulatory restrictions on surface mines and fragmentation of underground reserves limit the benefits that can be achieved by Appalachian producers from economies of scale.

Some 27,000 additional mining jobs are created between 2004 and 2030 (Figure 99). In the East, job losses in Central Appalachia are more than offset by additional jobs at more productive mines in Northern Appalachia.

Average Minemouth Coal Prices Increase Slowly

Figure 100. Average minemouth price of coal by region, 1990-2030 (2004 dollars per short ton)

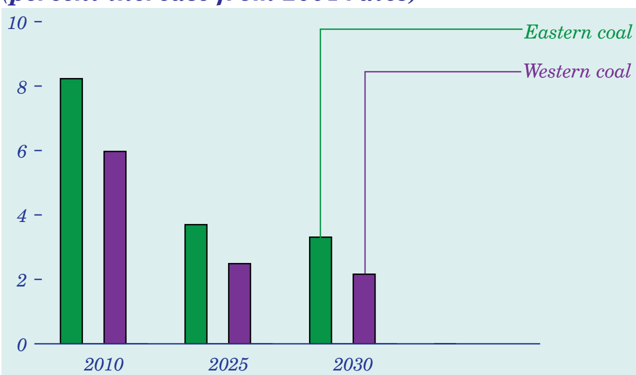


From 1990 to 1999, the average minemouth price of coal declined by 4.9 percent per year, from $29.09 per ton (2004 dollars) to $18.54 per ton (Figure 100). Increases in U.S. coal mining productivity of 6.3 percent per year during the period helped to reduce mining costs and contributed to the decline in prices. Since 1999, growth in U.S. coal mining productivity has slowed to 0.6 percent per year, and the average minemouth coal price has increased by 1.6 percent per year, to $20.07 per ton in 2004.

In the reference case, the average minemouth coal price drops slightly from 2010 to 2020, as mine capacity utilization declines and production shifts away from higher cost Central Appalachian mines. After 2020, rising natural gas prices and the need for baseload generating capacity result in the construction of 126 gigawatts of new coal-fired generating plants (72 percent of all coal builds from 2004 to 2030 in the reference case), and production in most of the major coal supply basins increases. The substantial investment in new mining capacity required to meet increasing demand during the period, combined with low productivity growth and rising utilization of mining capacity, leads to an increase in the average minemouth price, from $20.20 per ton in 2020 to $21.73 per ton in 2030. Strong growth in production in the Interior and Western supply regions, combined with limited improvement in coal mining productivity, results in minemouth price increases of 1.4 and 1.2 percent per year, respectively, in those regions from 2004 through 2030. With little increase in production, average minemouth prices in Appalachia increase by only 0.1 percent per year over the same period.

Rising Regional Coal Transportation Rates Depart from Historical Trend

Figure 101. Changes in regional coal transportation rates, 2010, 2025, and 2030 (percent increase from 2004 rates)



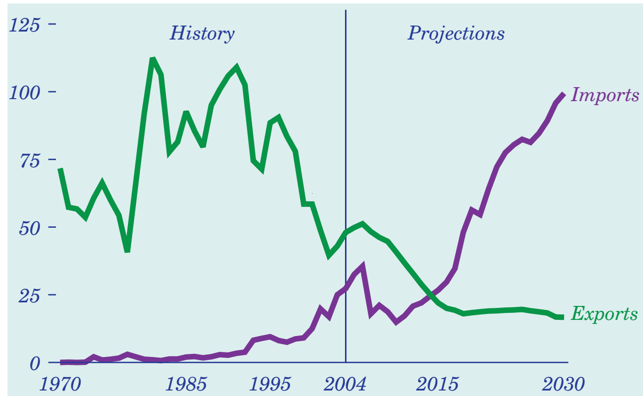
Coal transportation rates (in constant 2004 dollars), rise in the reference case, ending the decreasing trend of the past 20 years. Historically, infrastructure investments and subsequent overcapacity, as well as the efficiency gains associated with consolidation of the railroad industry, have steadily reduced coal transportation rates. Productivity improvements continue in the forecast, but they are dampened by larger demands on rail infrastructure and an expectation that investments will be made incrementally, as needed, rather than in anticipation of higher demand.

Periodic bottlenecks are likely as railroads adapt to increasing traffic flows from western mines and changing coal distribution patterns in the East. In constant dollars, coal transportation costs peak in 2010, then fall to 2.2 percent and 3.3 percent above 2004 levels in 2030 for coal originating in the West and East, respectively (Figure 101). In general, western suppliers are at a greater disadvantage than eastern suppliers when transportation rates rise, because western coal typically travels over longer distances.

Despite the increases in transportation rates, the national average continues to decline, because 76 percent of the increase in demand from 2004 to 2030 is from CTL plants and new electric power plants, many of which are expected to be built near sources of coal supply. In 2030, the average coal transportation rate for new electric power capacity is $7.14 per short ton (2004 dollars), compared with $8.63 for existing capacity.

Demand for Imported Coal Increases in the East and Southeast

Figure 102. U.S. coal exports and imports, 1970-2030 (million short tons)



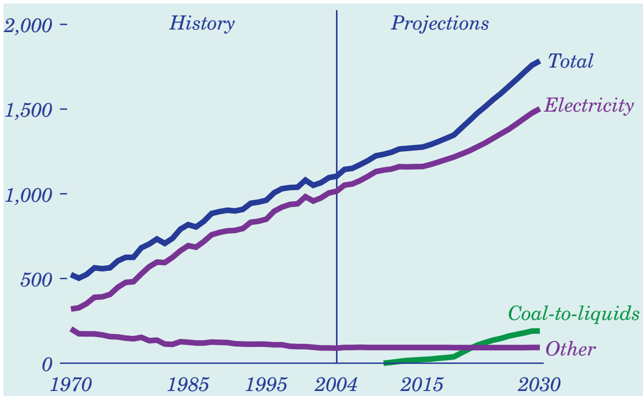
U.S. imports of low-sulfur coal rise from 27 million tons in 2004 to 99 million tons in 2030 (Figure 102). In addition to further displacement of more expensive Central and Southern Appalachian coal at existing power plants, imports fuel some of the new coal-fired generating capacity expected to be built in the U.S. East and Southeast. Much of the additional import tonnage originates from mines in Colombia, Venezuela, and Indonesia.

U.S. coal exports have been in steady decline from their 1996 level of 90 million tons, falling to 40 million tons in 2002, despite a substantial increase in world coal trade (from 503 million tons to 656 million tons). Low-cost supplies of coal from China, Colombia, Indonesia, Russia, and Australia satisfied much of the growth in international demand for steam coal during the period, and low-cost supplies of coking coal from Australia supplanted substantial amounts of U.S. coking coal in world markets. Since 2002, however, U.S. exports have rebounded, including increases in steam coal exports to Canada in 2003 and coking coal to overseas customers in 2004.

Although U.S. exports remain near their 2004 level for the next several years, their share of total world coal trade ultimately falls from 6 percent in 2004 to 1 percent in 2030, as international competition intensifies and imports of coal to Europe and the Americas (excluding the United States) grow more slowly or decline. With the planned decommissioning of Ontario's five coal-fired generating plants, U.S. coal exports to Canada decline from 19 million tons in 2004 to 7 million tons in 2030.

Coal-Fired Generators Can Comply With CAIR and CAMR

Figure 103. Electricity and other coal consumption, 1970-2030 (million short tons)

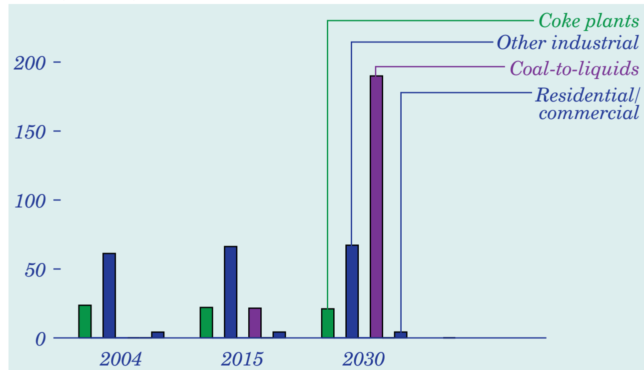


EPA's CAIR and CAMR regulations tighten restrictions on emissions of SO_2 and NO_x and, for the first time, address mercury emissions from electric power plants. Even with the new regulations, however, the average capacity utilization of coal-fired power plants rises from 72 percent in 2004 to 80 percent in 2012. Coal-fired power plants fitted with emissions control equipment remain competitive with natural-gas-fired generators because of their lower fuel costs. Coal consumption in the electric power sector rises to 1.5 billion tons in 2030 (Figure 103). To comply with CAIR and CAMR, selective catalytic reduction equipment is added to 118 gigawatts of coal-fired capacity between 2004 and 2030 in the reference case, flue gas desulfurization equipment is added to 141 gigawatts, and supplemental fabric filters are added to 126 gigawatts between 2004 and 2030. Activated carbon, a sorbent added to post-combustion flue gases to remove mercury, is also used in some plants.

In the projections, a mix of advanced IGCC and conventional coal-fired capacity is built in the electric power sector; 55 percent of the 154 gigawatts of new coal capacity is IGCC, which has low emissions of both SO_2 and mercury. A typical IGCC plant may remove 99 percent of the sulfur and 95 percent of the mercury present in bituminous coal. In addition, sustained high world oil prices combined with competitive coal prices stimulate investment in 19 gigawatts of CTL capacity, requiring 190 million tons of coal per year, by 2030. SO_2 and mercury emissions from CTL plants are comparable with those from IGCC plants.

Emerging Coal-to-Liquids Industry Increases Industrial Coal Use

Figure 104. Coal consumption in the industrial and buildings sectors and at coal-to-liquids plants, 2004, 2015, and 2030 (million short tons)



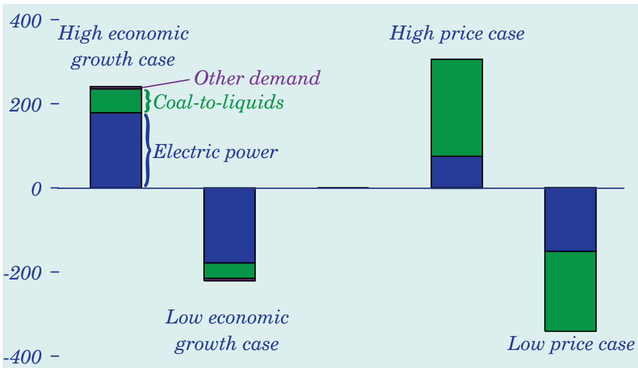
Although the electric power sector accounts for the bulk of U.S. coal consumption, 89 million tons of coal currently is consumed in the industrial and buildings (residential and commercial) sectors (Figure 104). In the industrial sector, steam coal is used to manufacture or produce cement, paper, chemicals, food, primary metals, and synthetic fuels; as a boiler fuel to produce process steam and electricity; as a direct source of heat; and as a feedstock. Coal consumption in the other industrial sector (excluding production of coal-based synthetic liquids) increases slightly in the *AEO2006* reference case.

Coal is also used to produce coke, which in turn is used as a source of energy and as a raw material input at blast furnaces to produce iron. A continuing shift from coke-based production at integrated steel mills to electric arc furnaces, combined with a relatively flat outlook for U.S. steel production, leads to a slight decline in consumption of coal at coke plants.

Outside the electric power sector, most of the increase in coal demand in the reference case is for production of coal-based synthetic liquids. High world oil prices spur investment in the CTL industry, leading to the construction of new plants in the West and Midwest that produce just under 0.8 million barrels of liquids per day in 2030. In *AEO2006*, CTL technology is represented as an IGCC coal plant equipped with a Fischer-Tropsch reactor to convert the synthesis gas to liquids. Of the total amount of coal consumed at each plant, 49 percent of the energy input is retained in the product, 20 percent is used for conversion, and 31 percent is used for grid-connected electricity generation.

High Economic Growth, High Oil and Gas Prices Increase Coal Demand

Figure 105. Projected variation from the reference case projection of U.S. total coal demand in four cases, 2030 (million short tons)



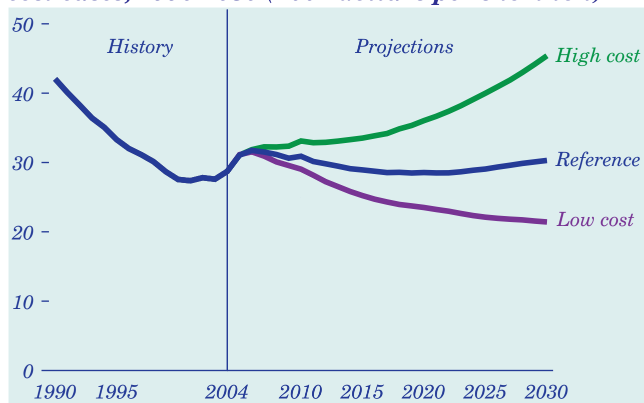
In comparison with the reference case, electricity demand is higher in the high economic growth case and lower in the low growth case. Accordingly, coal consumption also rises and falls in the high and low growth cases, respectively (Figure 105). As in the reference and high growth cases, the first CTL plant comes on line in 2011 in the low economic growth case; but total CTL capacity in 2030 in the low growth case is only 62 percent of that in the high growth case.

In the high price case, higher natural gas prices discourage natural-gas-fired generation and boost coal-fired generation. Delivered natural gas prices to the electric power sector in 2030 are $1.63 per million Btu higher in the high price case than in the reference case, whereas coal prices are only 10 cents per million Btu higher than in the reference case. In the reference case, coal fuels 57 percent of total electricity generation in 2030 in the reference case, as compared with 64 percent in the high price case and 46 percent in the low price case.

Higher world oil prices in the high price case favor increased investment in CTL, and the demand for coal at CTL facilities increases to 20 percent of total coal consumption in 2030. In the low price case, no CTL plants are operating in 2030. Because electricity generation at CTL plants displaces some generation in the electric power sector in the high price case, coal demand in the electric power sector is only 75 million tons higher than in the reference case. In the low price case there is more natural-gas-fired electricity generation, and as a result coal demand in the electric power sector is 151 million tons lower than in the reference case.

Higher Mining and Transportation Costs Reduce Demand for Coal

Figure 106. Average delivered coal prices in three cost cases, 1990-2030 (2004 dollars per short ton)



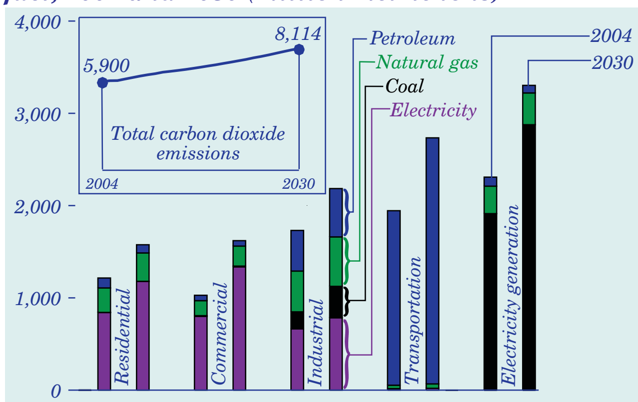
Alternative assumptions about future coal mining and transportation costs affect coal prices and, consequently, demand. The two alternative coal cost cases developed for *AEO2006* examine the impacts on U.S. coal markets of alternative assumptions about mining productivity, labor costs and mine equipment costs on the production side, and railroad productivity and rail equipment costs on the transportation side. Adjustments of about 2.5 percent from the reference case assumptions are based on variations in historical growth rates for the coal mining and rail transportation industries since 1980.

In the high cost case, the average delivered coal price in 2030, in constant 2004 dollars, is $45.39 per ton—50 percent higher than in the reference case (Figure 106). As a result, U.S. coal consumption is 284 million tons (16 percent) lower than in the reference case in 2030, reflecting both a switch from coal to natural gas, nuclear, and renewables in the electricity sector and reduced production of coal-based synthetic liquids. In the electric power sector, 111 gigawatts of new coal-fired generating capacity is built by 2030 in the high cost case—63 gigawatts less than in the reference case. CTL production in 2030 in the high cost case totals only 0.2 million barrels per day, or 77 percent less than in the reference case.

In the low cost case, the average delivered coal price in 2030 is $21.42 per ton—29 percent lower than in the reference case—and total coal consumption is 160 million tons (9 percent) higher than in the reference case.

Higher Energy Consumption Forecast Increases Carbon Dioxide Emissions

Figure 107. Carbon dioxide emissions by sector and fuel, 2004 and 2030 (million metric tons)

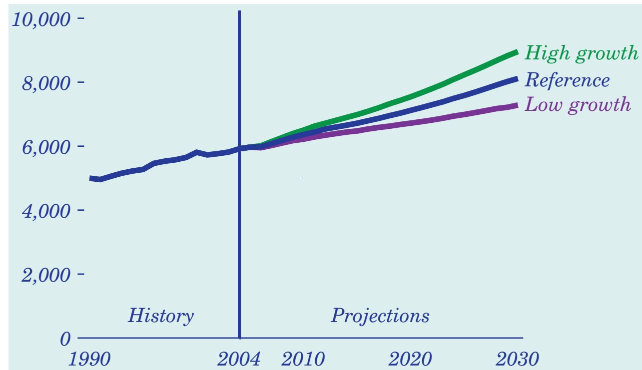


CO_2 emissions from the combustion of fossil fuels are proportional to fuel consumption. Among fossil fuel types, coal has the highest carbon content, natural gas the lowest, and petroleum in between. In the *AEO2006* reference case, the shares of these fuels change slightly from 2004 to 2030, with more coal and less petroleum and natural gas. The combined share of carbon-neutral renewable and nuclear energy is stable from 2004 to 2030 at 14 percent. As a result, CO_2 emissions increase by a moderate average of 1.2 percent per year over the period, slightly higher than the average annual increase in total energy use (Figure 107). At the same time, the economy becomes less carbon intensive: the percentage increase in CO_2 emissions is one-third the increase in GDP, and emissions per capita increase by only 11 percent over the 26-year period.

The factors that influence growth in CO_2 emissions are the same as those that drive increases in energy demand. Among the most significant are population growth; increased penetration of computers, electronics, appliances, and office equipment; increases in commercial floorspace; growth in industrial output; increases in highway, rail, and air travel; and continued reliance on coal and natural gas for electric power generation. The increases in demand for energy services are partially offset by efficiency improvements and shifts toward less energy-intensive industries. New CO_2 mitigation programs, more rapid improvements in technology, or more rapid adoption of voluntary programs could result in lower CO_2 emissions levels than projected here.

Emissions Projections Change With Economic Growth Assumptions

Figure 108. Carbon dioxide emissions in three economic growth cases, 1990-2030 (million metric tons)



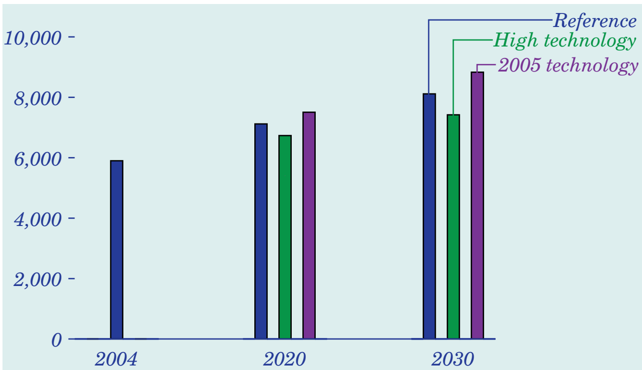
The high economic growth case assumes higher growth in population, labor force, and productivity than in the reference case, leading to higher industrial output, higher disposable income, lower inflation, and lower interest rates. The low economic growth case assumes the reverse. The spread in GDP projections increases over time, with GDP in the alternative cases varying by about 15 percent from the reference case in 2030.

Alternative projections for industrial output, commercial floorspace, housing, and transportation influence the demand for energy and result in variations in CO_2 emissions (Figure 108). Emissions in 2030 are 10 percent lower in the low growth case and 10 percent higher in the high growth case. The strength of the relationship between economic growth and emissions varies by end-use sector. It is strongest for the industrial sector and, to a lesser extent, the transportation sector, where economic activity strongly influences energy use and emissions, and where fuel choices are limited. It is weaker in the commercial and residential sectors, where population and building characteristics have large influences and vary less across the three cases.

In the electricity sector, changes in electricity sales across the cases affect the amount of new, more efficient generating capacity required, reducing the sensitivity of energy use to GDP. However, the choice of coal for most new baseload capacity increases CO_2 intensity in the high growth case while decreasing it in the low case, offsetting the effects of changes in efficiency across the cases.

Technology Advances Could Reduce Carbon Dioxide Emissions

Figure 109. Carbon dioxide emissions in three technology cases, 2004, 2020, and 2030 (million metric tons)



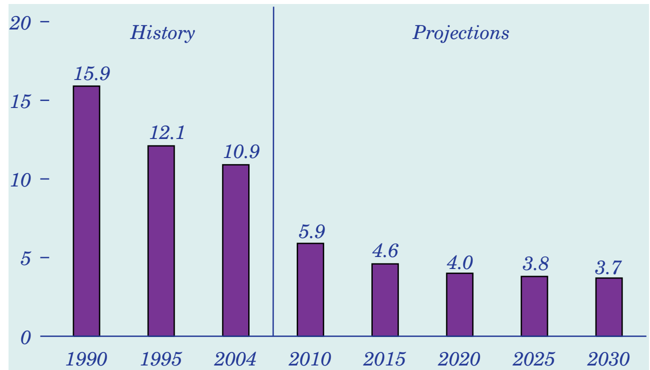
Future CO_2 emissions depend, in part, on the timing, effectiveness, and costs of new energy technologies. The reference case assumes continuing improvement in energy-consuming and producing technologies. The high technology case assumes earlier introduction, lower costs, and higher efficiencies for energy technologies in the end-use sectors, as well as improved costs and efficiencies for advanced fossil-fired and new renewable generating technologies in the electric power sector [*94*]. As in the reference case, however, technology adoption is assumed to be consistent with past patterns of market behavior.

Energy use grows more slowly in the high technology case, with prospects for greater energy savings constrained by gradual turnover of energy-using equipment and buildings. Increased use of renewables and less new coal-fired generating capacity accompany the efficiency improvements in the high technology case. As a result, CO_2 emissions in 2030 are 9 percent lower in the high technology than in the reference case, while total energy consumption is only 8 percent lower (Figure 109).

In contrast, the 2005 technology case assumes that only the equipment and vehicles available in 2005 will be available through 2030, with no further improvements in efficiency for new building shells and electric power plants. Consequently, more energy is used, and CO_2 emissions in 2030 are 9 percent higher than in the reference case, with the difference quantifying the effects of technology improvement assumptions on the reference case projections.

Sulfur Dioxide Emissions Fall Sharply in Response to Tighter Regulations

Figure 110. Sulfur dioxide emissions from electricity generation, 1990-2030 (million short tons)

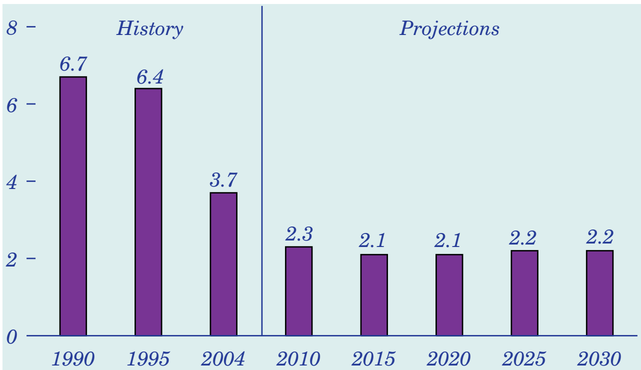


EPA's CAIR regulation, promulgated in March 2005, caps emissions of SO_2 for the District of Columbia and 28 eastern and midwestern States that were determined by the EPA to contribute to nonattainment of the NAAQS for $PM_{2.5}$ and ozone. CAIR is scheduled to supersede Title IV of the Clean Air Act through the use of a cap and trade approach. Phase I of CAIR comes into effect in 2010 for SO_2. Phase II takes effect in 2015. States can achieve the required emissions reductions by using one of two compliance options: meet the State's emissions budget by requiring power plants to participate in an EPA-administered interstate cap and trade system that caps emissions in two stages; or meet an individual State emissions budget through measures of the State's choosing.

Power companies are projected to add flue gas desulfurization equipment to 141 gigawatts of capacity in order to comply with State or Federal initiatives. As a result of those actions and the growing use of lower sulfur coal, SO_2 emissions drop from 10.9 million short tons in 2004 to 3.7 million short tons in 2030 (Figure 110). The SO_2 emissions allowance price rises to nearly $890 per ton in 2015 and remains between $880 and $980 per ton from 2015 through 2030. The reference case projections indicate that the level of SO_2 reductions called for in CAIR can be achieved without significantly raising electricity prices, which are determined by many factors, including natural gas prices, environmental compliance costs, and the status of electricity deregulation activities.

Nitrogen Oxide Emissions Fall As New Regulations Take Effect

Figure 111. Nitrogen oxide emissions from electricity generation, 1990-2030 (million short tons)



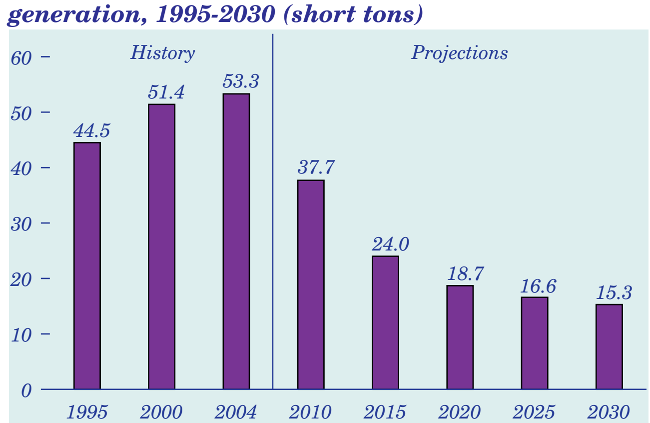
In the reference case, NO_x emissions from electricity generation in the U.S. power sector fall as new regulations take effect. The required reductions are intended to reduce the formation of ground-level ozone, for which NO_x emissions are a major precursor. Together with VOCs and hot weather, NO_x emissions contribute to unhealthy air quality in many areas during the summer months.

EPA's CAIR will apply to NO_x emissions from 28 eastern and midwestern States and the District of Columbia. Each State will be subject to two NO_x limits under CAIR: a 5-month summer season limit and an annual limit. These caps are expected to stimulate additions of emission control equipment to some existing coal-fired power plants.

National NO_x emissions fall from 3.7 million short tons in 2004 to 2.2 million short tons in 2030 in the reference case (Figure 111). The largest decrease occurs in 2009, when Phase I of CAIR is implemented, and there is a smaller reduction in 2015 with the start of Phase II caps. Between 2009 and 2030, NO_x allowance prices range from roughly \$2,000 to \$2,500 per ton, and they are expected to be highly volatile as the emission caps tighten. These projections are indicative of the general range and direction of the allowance prices. Power companies are expected to add selective catalytic reduction equipment to 118 gigawatts of coal-fired capacity in order to comply with both Federal and State initiatives; however, as with the requirements for SO_2 compliance, the CAIR NO_x caps are not expected to lead to significantly higher electricity prices for consumers.

New Environmental Regulations Reduce Mercury Emissions

Figure 112. Mercury emissions from electricity generation, 1995-2030 (short tons)



EPA's CAMR regulation, also promulgated in March 2005, establishes a cap and trade program to reduce mercury emissions from coal-fired power plants in the United States. In addition to nationwide caps, each new and existing coal-fired power plant must meet mercury emissions standards based on coal type. Emissions of mercury must be reduced in two phases: the national Phase I mercury cap is 38 short tons in 2010, and the Phase II cap is 15 short tons in 2018.

Emissions of mercury depend on a variety of site-specific factors, including the amounts of mercury and other compounds (such as chlorine) in the coal, the boiler type and configuration, and the presence of pollution control equipment, such as fabric filters, electrostatic precipitators, flue gas desulfurization, and selective catalytic reduction equipment.

The *AEO2006* reference case assumes that States will comply with CAMR regulations. As a result, mercury emissions decline from 53.3 short tons in 2004 to 15.3 short tons in 2030 (Figure 112). National emissions will be slightly higher than the Phase II cap in 2018 due to the use of banked allowances from earlier years. Electricity generators are expected to retrofit about 126 gigawatts of coal-fired capacity with ACI technology in order to comply with the CAMR caps. Mercury allowance prices increase steadily from 2010 on, to about \$62,000 per pound in 2030. As with the CAIR requirements for SO_2 and NO_x compliance, the CAMR mercury caps are not expected to lead to significantly higher electricity prices for consumers.

Forecast Comparisons

Only GII produces a comprehensive energy projection with a time horizon similar to that of *AEO2006*. Other organizations address one or more aspects of the energy markets. The most recent projection from GII, as well as others that concentrate on economic growth, international oil prices, energy consumption, electricity, natural gas, petroleum, and coal, are compared here with the *AEO2006* projections.

Economic Growth

In the *AEO2006* reference case, the projected growth in real GDP, based on 2000 chain-weighted dollars, is 3.0 percent per year from 2004 to 2030 (Table 19). For the period from 2004 to 2025, real GDP growth in the *AEO2006* reference case is similar to the average annual growth projected in *AEO2005*. The *AEO2006* projections of economic growth are based on the August short-term forecast of GII, extended by EIA through 2030 and modified to reflect EIA's view on energy prices, demand, and production.

The projected average annual GDP growth rate for the United States from 2004 through 2010 ranges from 2.8 percent to 3.3 percent. The *AEO2006* reference case projects annual growth of 3.3 percent, matching the average annual real GDP growth projected by the Office of Management and Budget (OMB), the Congressional Budget Office (CBO), and the consensus Blue Chip forecast. GII and Energy Ventures Analysis, Inc. (EVA) project real GDP growth at 3.2 percent per year. Two other organizations project somewhat lower annual growth: Interindustry Forecasting at the University of Maryland (INFORUM) at 2.9 percent and Energy and Environmental Analysis, Inc. (EEA) at 2.8 percent.

When the projection period is extended to 2015, the uncertainty in the projected rate of GDP growth is reflected in the wider range of the projections (2.5 to 3.2 percent per year). *AEO2006* remains in the upper half of the range, whereas the CBO projection shows a considerable slowing of GDP growth from 2010 through 2015. There are few public or private projections of GDP growth rates for the United States that extend to 2030. The *AEO2006* reference case projection reflects a slowing of the GDP growth rate after 2020, consistent with an expected slowing of population growth.

World Oil Prices

Comparisons with other oil price projections are shown in Table 20. The world oil prices in EIA's *AEO2006* are generally toward the high end of the oil price projections. Of the nine other publicly available long-term projections, only two—Petroleum Industry Research Associates, Inc. (PIRA) and Petroleum Economics, Ltd. (PEL)—have projections of world oil prices for specific years after 2010 that exceed the *AEO2006* reference case projections. Four of the nine—GII, Altos Partners (Altos), Strategic Energy and Economic Research, Inc. (SEER), and the International Energy Agency (IEA) Reference Scenario—have prices lower than those in the *AEO2006* low price case for at least some years. All the projections—except for the price forecast from Altos, which has not been revised since July 2003—have raised their long-term price expectations relative to last year's releases.

Table 19. Forecasts of annual average economic growth, 2004-2030

	Average annual percentage growth			
Forecast	2004-2010	2010-2015	2015-2020	2020-2030
AEO2005	3.2	3.1	3.0	NA
AEO2006				
Reference	3.3	3.0	3.1	2.8
Low growth	2.6	2.3	2.7	2.4
High growth	3.9	3.5	3.4	3.7
GII	3.2	3.0	3.0	2.8
OMB	3.3	NA	NA	NA
CBO	3.3	2.6	NA	NA
Blue Chip	3.3	3.2	NA	NA
INFORUM	2.9	2.5	2.6	NA
EEA	2.8	2.8	2.8	2.8
EVA	3.2	NA	NA	NA

NA = not available.

Table 20. Forecasts of world oil prices, 2010-2030 (2004 dollars per barrel)

Forecast	2010	2015	2020	2025	2030
AEO2005 (reference case)	27.18	28.97	30.88	32.95	NA
AEO2006					
Reference	47.29	47.79	50.70	54.08	56.97
High price	62.65	76.30	85.06	90.27	95.71
Low price	40.29	33.78	33.99	34.44	33.73
GII	37.82	34.06	31.53	33.50	34.50
Altos	27.58	31.14	34.02	37.89	40.03
IEA (reference)	35.00	36.00	37.00	38.00	39.00
IEA (deferred investment)	41.00	43.50	46.00	49.00	52.00
PEL	47.84	47.84	49.80	50.77	NA
PIRA	44.10	49.95	63.35	NA	NA
EEA	46.74	43.85	42.79	41.76	NA
DB	31.75	31.75	31.75	31.75	31.75
SEER	29.54	31.00	32.00	34.18	36.50
Delphi	NA	52.50	57.50	62.50	72.50

NA = not available.

The world oil price measure does vary by projection. In some cases, the measure is the WTI spot price, Brent equivalent, weighted average U.S. refiner acquisition cost of imported crude oil, or a basket of crude oils. For *AEO2006*, EIA redefined its world oil price path to represent the average U.S. refiners acquisition price of imported low-sulfur light crude oil (see “Issues in Focus” for discussion). Those prices are considered comparable to the WTI prices most often cited in the trade press as a proxy for world oil prices. The different price measures used in the various projections do not wholly explain the different price expectations among the projections. For instance, GII publishes a WTI spot price forecast that is considerably lower than the *AEO2006* reference case prices, and PIRA publishes a WTI spot price forecast that is considerably higher than the *AEO2006* reference case prices in most years (Table 20).

Recent variability in crude oil prices demonstrates the uncertainty inherent in projections for crude oil markets. The oil price paths projected by several organizations, including EIA, illustrate the uncertainty. For example, for 2010, the price range in the projections is from a low of about $28 per barrel by Altos to a high of almost $48 per barrel projected by PEL. The range in the projections widens in 2020, from a low of $32 per barrel (GII and DB) to a high of $63 per barrel (PIRA). In 2030, the band of prices represented by the published projections narrows to $23 per barrel, probably in part because the PIRA forecast horizon ends in 2020.

To construct the world oil price cases for *AEO2006*, EIA employed input from a Delphi group of energy analysts. In August 2005, an informal, nonrandom sample of expert oil analysts from outside DOE were invited to participate, with the stipulation that the responses were to reflect the analysts’ personal views and not necessarily the views of the organizations with which they were affiliated. In addition, the analysts were told that their responses would be anonymous. Seventeen analysts were surveyed, and eight responses were received. The median response from the Delphi group was generally higher than any of the other published projections, though still falling within the range defined by the *AEO2006* low and high price cases (Table 20). The group expected oil prices to continue rising through the 2005-2030 time period, to nearly $73 per barrel in 2030—more than $20 per barrel higher than the nearest alternative, the Deferred Investment Scenario published by IEA.

Total Energy Consumption

The *AEO2006* projects higher growth in end-use sector consumption of petroleum, natural gas, and coal than occurred from 1980 to 2004 but lower growth in electricity consumption (Table 21). Much of the projected growth in petroleum consumption is driven by increased demand in the transportation sector, with continued growth in personal travel and freight transport projected to result from demographic trends and economic expansion. Natural gas consumption is expected to increase in the residential, commercial, and industrial sectors, despite relatively high prices. Natural gas is cleaner than other fuels, does not require on-site storage, and has tended to be priced competitively with oil for heating. Coal consumption as a boiler fuel in the commercial and industrial sectors is expected to decline slightly, with potential use in new boilers limited by environmental restrictions; however, the projections for industrial coal consumption include its use in CTL plants, a technology that is expected to become competitive at the high oil prices assumed in *AEO2006*.

While strong growth in electricity use is projected to continue in the *AEO2006* projections, the pace slows from historical rates. Some rapidly growing applications, such as air conditioning and computers, slow as penetration approaches saturation levels. Electrical efficiency also continues to improve, due in large part to efficiency standards, and the impacts tend to accumulate with the gradual turnover of appliance stocks.

The *AEO2006* projections are generally consistent with the outlook from GII; however, GII projects slightly faster growth in petroleum and natural gas consumption and slightly slower growth in electricity

Table 21. Forecasts of average annual growth rates for energy consumption, 2004-2030 (percent)

Energy use	History 1980-2004	Projections	
		AEO2006	GII
Petroleum*	0.9	1.2	1.3
Natural gas*	0.2	0.7	0.9
Coal*	-1.5	2.0	-0.4
Electricity	2.2	1.6	1.5
Delivered energy	0.7	1.1	1.1
Electricity losses	1.9	1.2	0.9
Primary energy	1.0	1.2	1.1

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

consumption and losses. The differences can be attributed largely to the higher oil and natural gas prices assumed in *AEO2006*. Differences between the *AEO2006* and GII projections for coal result from an increase in coal use for CTL in *AEO2006*.

Electricity

The *AEO2006* projections for the electricity generation sector assume that new generating capacity will be built by independent power producers rather than utilities. Retail price projections are based on average costs for electricity supply regions that are still regulated; marginal costs for regions that are competitive; and a mixture of average and marginal costs, weighted by the amounts of load, in regions with a mix of regulated and competitive markets. As of 2005, only four electricity market regions had fully competitive retail markets in operation; seven had mixed competitive and regulated retail markets; and two had fully regulated markets. The *AEO2006* cases assume that no additional retail markets will be restructured, but that partial restructuring (particularly in wholesale markets) will lead to increased competition in the electric power industry, lower operating and maintenance costs, and early retirement of inefficient generating units.

Comparison of the *AEO2006* and GII projections shows some variation in electricity sales (Table 22). The projections for total electricity sales in 2030 range from 4,828 billion kilowatthours (*AEO2006* low economic growth case) to 5,854 billion kilowatthours (*AEO2006* high economic growth case). The rate of demand growth ranges from 1.2 percent (*AEO2006* low economic growth) to 1.9 percent (*AEO2006* high economic growth). All price projections reflect competition in wholesale markets and slow growth in electricity demand relative to GDP growth, exerting downward pressure on real electricity prices through 2030. Rising natural gas and coal prices balance some of the downward pressure and tend to push electricity prices up in the later years of the projections.

The *AEO2006* reference case shows a slight decline in real electricity prices over the full period of the projection (except for the industrial sector), 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 in electricity prices over the second half of the projection, as lower delivered natural gas prices to generators ($5.08 per million Btu in the GII projection, compared with $6.26 in the *AEO2006* reference case in 2030) contribute to a small decrease in average electricity prices, from 7.6 cents per kilowatthour in 2015 to 7.4 cents per kilowatthour in 2030. The higher natural gas price in the *AEO2006* reference case leads to an increase in average electricity price, from 7.1 cents per kilowatthour in 2015 to 7.5 cents per kilowatthour in 2030.

Both the *AEO2006* reference case and GII projections include some planned capacity additions in the near term, with the *AEO2006* reference case expecting about 29 gigawatts through 2006 and GII expecting about 25 gigawatts. Virtually all the projected capacity additions are natural gas fired. Both projections show electricity prices falling in the near term as a result of excess total capacity.

Except for GII, all the projections for electricity demand show the fastest growth in the commercial sector, and more additions of cycling and baseload capability than peaking units. All the projections show significant net additions to coal-fired capacity, including 167 gigawatts through 2030 in the *AEO2006* reference case and 136 gigawatts through 2030 in the GII projection. Both GII and the *AEO2006* reference case project no nuclear retirements; however, each of the three *AEO2006* cases (reference and high and low economic growth) projects 6 gigawatts of nuclear capacity additions by 2030 as a result of the incentives in EPACT2005.

The fuel mix in the EVA projection differs from that in the *AEO2006* reference case and the other projections. Except for EVA, all the projections show coal meeting about one-half and natural gas about one-quarter of the growth in electricity generation capacity over the projection period. The EVA projection assumes that legislation similar to the Clear Skies Act—including further restrictions on SO_2, NO_x, and mercury emissions—will be in effect by 2010. The EVA projection also includes a tax of $5 per ton on CO_2 emissions, beginning in 2013. *AEO2006* includes the impact of the EPA's new CAIR and CAMR regulations, which have environmental effects similar to those of the Clear Skies Act; however, *AEO2006* does not assume any tax on CO_2 emissions. In the EVA projection, the combination of further environmental restrictions, a tax on CO_2, and aggregate State-level RPS requirements leads to greater growth in nonhydroelectric generation.

Table 22. Comparison of electricity forecasts, 2015 and 2030 (billion kilowatthours, except where noted)

Projection	2004	AEO2006 Reference	AEO2006 Low economic growth	AEO2006 High economic growth	Other forecasts GII	EVA	EEA	SEER	PIRA
					2015				
Average end-use price (2003 cents per kilowatthour)	**7.6**	**7.1**	**6.9**	**7.3**	**7.6**	**NA**	**NA**	**NA**	**NA**
Residential	8.9	8.3	8.1	8.5	8.8	9.0	NA	NA	NA
Commercial	8.0	7.4	7.2	7.6	8.2	8.0	NA	NA	NA
Industrial	5.3	5.1	4.9	5.3	5.2	5.8	NA	NA	NA
Net energy for load, including CHP	**3,614**	**4,813**	**4,642**	**4,984**	**4,663**	**4,966**	**4,970**	**4,875**	**4,658**
Coal	1,977	2,277	2,245	2,360	2,217	2,267	2,281	2,211	2,293
Oil	136	120	116	126	56	37	96	126	90
Natural gas [a]	326	1,018	929	1,069	1,080	1,286	1,323	1,238	1,004
Nuclear	789	829	807	840	814	842	811	826	819
Hydroelectric/other [b]	349	482	469	495	496	521	381	457	452
Nonutility sales to grid [c]	26	62	57	70	NA	NA	41	NA	NA
Net imports	11	23	19	25	17	13	38	17	22
Electricity sales	**3,567**	**4,300**	**4,147**	**4,449**	**4,239**	**4,638**	**4,456**	**NA**	**NA**
Residential	1,293	1,576	1,539	1,613	1,593	1,697	1,575	NA	NA
Commercial/other [d]	1,253	1,620	1,583	1,650	1,493	1,718	1,602	NA	NA
Industrial	1,021	1,103	1,024	1,185	1,153	1,225	1,278	NA	NA
Capability, including CHP (gigawatts) [e]	**965**	**1,002**	**977**	**1,026**	**1,008**	**1,055**	**1,046**	**NA**	**NA**
Coal	314	326	323	336	331	338	331	NA	NA
Oil and natural gas	433	439	422	451	429	487	478	NA	NA
Nuclear	100	104	101	105	101	105	102	NA	NA
Hydroelectric/other	118	133	131	134	147	125	136	NA	NA
					2030				
Average end-use price (2002 cents per kilowatthour)	**7.6**	**7.5**	**7.2**	**7.8**	**7.4**	**NA**	**NA**	**NA**	**NA**
Residential	8.9	8.5	8.2	8.8	8.5	NA	NA	NA	NA
Commercial	8.0	7.8	7.4	8.2	8.0	NA	NA	NA	NA
Industrial	5.3	5.4	5.2	5.7	5.0	NA	NA	NA	NA
Net energy for load, including CHP	**3,614**	**6,119**	**5,496**	**6,748**	**5,828**	**NA**	**NA**	**6,237**	**NA**
Coal	1,977	3,381	2,835	3,897	3,032	NA	NA	3,221	NA
Oil	136	131	121	138	27	NA	NA	127	NA
Natural gas [a]	326	993	1,010	990	1,453	NA	NA	1,407	NA
Nuclear	789	871	856	871	774	NA	NA	926	NA
Hydroelectric/other [b]	349	550	517	609	542	NA	NA	528	NA
Nonutility sales to grid [c]	26	179	143	229	NA	NA	NA	NA	NA
Net imports	11	14	13	15	12	NA	NA	28	NA
Electricity sales	**3,567**	**5,341**	**4,828**	**5,854**	**5,289**	**NA**	**NA**	**NA**	**NA**
Residential	1,293	1,897	1,759	2,036	2,001	NA	NA	NA	NA
Commercial/other [d]	1,253	2,182	1,997	2,366	1,926	NA	NA	NA	NA
Industrial	1,021	1,262	1,073	1,453	1,362	NA	NA	NA	NA
Capability, including CHP (gigawatts) [e]	**965**	**1,248**	**1,134**	**1,362**	**1,209**	**NA**	**NA**	**NA**	**NA**
Coal	314	481	405	555	449	NA	NA	NA	NA
Oil and natural gas	433	513	483	545	501	NA	NA	NA	NA
Nuclear	100	109	107	109	101	NA	NA	NA	NA
Hydroelectric/other	118	145	139	154	158	NA	NA	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 *AEO2006*, 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.

CHP = combined heat and power. NA = not available.

Sources: ***2004 and AEO2006:*** AEO2006 National Energy Modeling System, runs AEO2006.D111905A (reference case), LM2006.D113005A (low economic growth case), and HM2006.D112505B (high economic growth case). **GII:** Global Insight, Inc., *Summer 2005 U.S. Energy Outlook* (August 2005). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2005). **EEA:** Energy and Environmental Analysis, Inc., *EEA's Compass Service Base Case* (October 2005). **SEER:** Strategic Energy and Economic Research, Inc., *2005 Energy Outlook* (October 2005). **PIRA:** PIRA Energy Group (October 2005).

Natural Gas

Published projections of natural gas prices, production, consumption, and imports (Table 23) differ considerably. The differences highlight the uncertainty of future market trends. Because the projections depend heavily on the underlying assumptions that shape them, the assumptions made in each should be considered when they are compared.

The *AEO2006* reference case in general projects lower total natural gas consumption than in the other projections, and it is the only one showing a period of decline. The exception is in the early part of the projection period: in 2015, PIRA and Deutsche Bank AG (DB) project lower natural gas consumption than the *AEO2006* reference case, but by 2025 the *AEO2006* reference case projects lower consumption than any of the others. The primary reason is that *AEO2006* expects a stronger demand response to higher natural gas prices, particularly in the electricity generation sector.

The highest projected level of total natural gas consumption is in the EVA projection, due to strong growth in natural gas consumption for electric power

Table 23. Comparison of natural gas forecasts, 2015, 2025, and 2030 (trillion cubic feet, except where noted)

Projection	2004	AEO2006 reference case	Other forecasts						
			GII[a]	EEA[b]	EVA	PIRA	DB	SEER	Altos
		2015							
Dry gas production[c]	**18.46**	**20.36**	**19.19**	**21.12**	**18.64[d]**	**17.61**	**21.38**	**19.68**	**20.74**
Net imports	**3.40**	**5.10**	**6.80**	**7.11**	**9.67**	**7.33**	**4.30**	**7.86**	**7.92**
Pipeline	2.81	2.05[e]	2.17	2.82	4.78	3.28	1.75	3.00	1.82
LNG	0.59	3.05	4.63	4.29	4.89	4.05	2.55	4.85	6.10
Consumption	**22.41**	**25.91**	**26.16**	**27.98**	**28.32**	**25.32**	**25.67**	**28.18**	**NA**
Residential	4.88	5.36	5.15	5.49	5.33	5.24	5.53	5.45	5.41
Commercial	3.00	3.36	3.09	3.35	3.41	3.53	3.53	3.28	3.54
Industrial[f]	7.41	8.08	7.57[g]	6.98[h]	7.99[i]	6.61[j]	8.17	7.83	7.53
Electricity generators[k]	5.32	7.14	8.44[l]	10.08[m]	9.42	8.01[n]	6.63	9.61	9.30
Other[o]	1.80	1.97	1.92	2.08	2.17[p]	1.95	1.81	2.01	NA
Lower 48 wellhead price (2004 dollars per thousand cubic feet)	**5.49**	**4.52**	**4.73**	**5.91**	**5.53**	**5.55[q]**	**5.03**	**4.65**	**4.15**
End-use prices (2004 dollars per thousand cubic feet)									
Residential	10.72	10.11	9.21	9.33	NA	NA	NA	9.68	NA
Commercial	9.38	8.37	8.11	8.57	NA	NA	NA	7.97	NA
Industrial[f]	6.29	5.32	6.09[r]	6.81	NA	NA	NA	5.75	NA
Electricity generators[k]	6.07	5.21	5.13	6.62	NA	NA	NA	5.32	NA
		2025							
Dry gas production[c]	**18.46**	**21.16**	**20.46**	**21.38**	**19.27[d]**	**NA**	**18.95**	**21.53**	**25.77**
Net imports	**3.40**	**5.37**	**8.64**	**8.89**	**11.80**	**NA**	**8.19**	**8.47**	**7.69**
Pipeline	2.81	1.24[e]	1.61	1.81	3.64	NA	4.75	1.90	0.70
LNG	0.59	4.13	7.03	7.07	8.16	NA	3.44	6.57	6.99
Consumption	**22.41**	**26.99**	**29.28**	**30.33**	**31.08**	**NA**	**27.74**	**30.44**	**NA**
Residential	4.88	5.57	5.61	5.88	5.44	NA	6.11	5.89	6.09
Commercial	3.00	3.77	3.34	3.56	3.76	NA	3.99	3.49	4.19
Industrial[f]	7.41	8.51	8.14[g]	7.64[h]	8.95[i]	NA	9.03	8.37	7.73
Electricity generators[k]	5.32	7.05	10.10[l]	11.14[m]	10.55	NA	6.97	10.50	11.37
Other[o]	1.80	2.08	2.09	2.12	2.38[p]	NA	1.64	2.19	NA
Lower 48 wellhead price (2003 dollars per thousand cubic feet)	**5.49**	**5.43**	**4.52**	**6.45**	**6.07**	**NA**	**5.03**	**5.13**	**5.67**
End-use prices (2003 dollars per thousand cubic feet)									
Residential	10.72	11.10	8.82	9.71	NA	NA	NA	9.92	NA
Commercial	9.38	9.11	7.73	8.99	NA	NA	NA	8.30	NA
Industrial[j]	6.29	6.18	5.81[r]	7.22	NA	NA	NA	6.07	NA
Electricity generators[o]	6.07	6.02	4.90	6.86	NA	NA	NA	5.61	NA

NA = not available. See notes and sources at end of table.

generation. Altos projects the strongest growth in residential and commercial sector natural gas consumption through both 2025 and 2030, whereas the GII and EVA projections have the lowest projected consumption levels. The *AEO2006* reference case projection for residential natural gas consumption in 2030 is lower than all but the EVA projection, but its commercial sector projection is higher than the GII, EVA, and SEER projections. Natural gas consumption in the industrial and electric power sectors is more difficult to compare, given potential definitional differences. The combined total of industrial and electric power sector natural gas consumption from 2004 to 2030 is projected to grow the fastest in the EVA and Altos projections; the DB projection shows much slower growth but still faster than is projected in the *AEO2006* reference case. The DB combined total in 2030 exceeds the *AEO2006* reference case by less than 10 percent, whereas the GII, EVA, SEER, and Altos projections all exceed the *AEO2006* by more than 25 percent.

Domestic natural gas production provides a decreasing share and net imports an increasing share of total natural gas supply in all the projections. The EVA projection shows the greatest increase in the net import share of supply, at more than 41 percent of total supply in 2030. More than 34 percent of supply is projected to come from imports in 2030 in the DB projection, and GII and SEER both show net imports

Table 23. Comparison of natural gas forecasts, 2015, 2025, and 2030 (continued)
(trillion cubic feet, except where noted)

Projection	2004	AEO2006 reference case	Other forecasts						
			GII[a]	EEA[b]	EVA	PIRA	DB	SEER	Altos
		2030							
Dry gas production[c]	**18.46**	**20.83**	**21.40**	**NA**	**18.96[d]**	**NA**	**18.95**	**21.70**	**28.13**
Net imports	**3.40**	**5.57**	**9.06**	**NA**	**13.30**	**NA**	**9.86**	**9.33**	**7.92**
Pipeline	2.81	1.22[e]	1.37	NA	2.80	NA	1.75	1.00	0.20
LNG	0.59	4.36	7.68	NA	10.50	NA	8.11	8.33	7.72
Consumption	**22.41**	**26.86**	**30.64**	**NA**	**32.39**	**NA**	**28.81**	**31.56**	**NA**
Residential	4.88	5.64	5.84	NA	5.49	NA	6.42	6.12	6.48
Commercial	3.00	3.99	3.48	NA	3.96	NA	4.20	3.63	4.56
Industrial[f]	7.41	8.81	8.48[g]	NA	9.45[i]	NA	9.49	8.73	7.85
Electricity generators[k]	5.32	6.38	10.67[l]	NA	11.01	NA	7.14	10.85	12.54
Other[o]	1.80	2.04	2.17	NA	2.48[p]	NA	1.56	2.24	NA
Lower 48 wellhead price (2004 dollars per thousand cubic feet)	**5.49**	**5.92**	**4.65**	**NA**	**6.52**	**NA**	**5.02**	**5.42**	**6.30**
End-use prices (2004 dollars per thousand cubic feet)									
Residential	10.72	11.67	8.86	NA	NA	NA	NA	10.16	NA
Commercial	9.38	9.58	7.79	NA	NA	NA	NA	8.60	NA
Industrial[f]	6.29	6.65	5.90[r]	NA	NA	NA	NA	6.37	NA
Electricity generators[k]	6.07	6.41	5.02	NA	NA	NA	NA	5.92	NA

NA = not available.

[a]February 2005 (previously DRI-WEFA). Conversion factors: 1,000 cubic feet = 1.027 million Btu for production, 1.028 million Btu for end-use consumption, 1.019 million Btu for electric power. [b]The EEA projection shows a cyclical price trend; forecast values for an isolated year may be misleading. [c]Does not include supplemental fuels. [d]Includes supplemental fuels. [e]Includes LNG imports into Florida via the Bahamas. [f]Includes consumption for industrial combined heat and power (CHP) plants and a small number of electricity-only plants; excludes consumption by nonutility generators. [g]Excludes gas used in cogeneration or other nonutility generation. [h]Includes natural gas consumed in cogeneration. [i]Includes transportation fuel consumed in natural gas vehicles. [j]Excludes gas demand for nonutility generation. [k]Includes consumption of energy by electricity-only and CHP plants whose primary business is to sell electricity, or electricity and heat, to the public; includes electric utilities, small power producers, and exempt wholesale generators. [l]Includes gas used in cogeneration or other nonutility generation. [m]Includes independent power producers; excludes cogenerators. [n]Equals the sum of natural gas demand for nonutility generation (NUG) and for utility generation. [o]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles. [p]Includes lease, plant, and pipeline fuel. [q]Henry Hub daily cash price for natural gas, in 2004 dollars per thousand cubic feet. [r]On-system sales or system gas (i.e., does not include gas delivered for the account of others).

Sources: **2004 and *AEO2006*:** AEO2006 National Energy Modeling System, run AEO2006.D111905A (reference case). **GII:** Global Insight, Inc., *Summer 2005 U.S. Energy Outlook* (August 2005). **EEA:** Energy and Environmental Analysis, Inc., *EEA's Compass Service Base Case* (October 2005). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2005). **PIRA:** PIRA Energy Group (October 2005). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski on October 31, 2005. **SEER:** Strategic Energy and Economic Research, Inc., *2005 Energy Outlook* (October 2005). **Altos:** Altos Partners North American Regional Gas Model (NARG) Long-Term Base Case (October 7, 2005).

providing about 30 percent of total natural gas supply. The *AEO2006* reference case and Altos project that net imports will meet the smallest share of total supply—21 percent and 22 percent, respectively—in 2030. Most of the projections show a notable decline in pipeline imports over the forecast period. Only DB shows an increase from 2015 to 2025. EVA's pipeline import projection, although significantly greater than the rest, also declines after 2015. Much of the variation in imports reflects different projections of net LNG imports in 2030, ranging from a low of 4.4 trillion cubic feet in the *AEO2006* reference case to 10.5 trillion cubic feet in the EVA projection.

The *AEO2006* reference case projections for wellhead natural gas prices in 2025 and 2030 fall within the range of the other projections, with the EEA, EVA, and Altos projections higher than *AEO2006* and the others lower. In the earlier years, however, all the projections with the exception of Altos show wellhead natural gas prices exceeding those in the *AEO2006* reference case. Of the three projections that project end-use prices for 2030 (*AEO2006*, GII, and SEER), the *AEO2006* reference case and SEER show the highest end-use-to-wellhead margins for the electric power sector ($0.50 and $0.51, respectively). The *AEO2006* reference case shows the lowest end-use-to-wellhead margins for the industrial sector. While GII's margins for the electric power sector are the lowest, some of the difference may be definitional. For the residential and commercial sectors, the projected margins in the *AEO2006* reference case exceed the other projections by more than 15 percent.

Petroleum

As discussed earlier in this report, crude oil prices in the *AEO2006* reference case are substantially higher than they were in earlier *AEO*s. They are also considerably higher than those in most of the other projections. The *AEO2006* reference case shows the weighted average refiners acquisition cost of imported crude oil (the price basis used in most of the other forecasts) ranging from $43 to $50 per barrel (2004 dollars) between 2015 and 2030 and the average refiners acquisition cost of imported low-sulfur light crude oil (the reference price used in *AEO2006*) ranging from $48 to $57 per barrel (2004 dollars) over the same period. DB assumes that the refiners acquisition cost of crude oil will average $31.75 per barrel from 2010 through 2030; GII assumes that the refiners acquisition cost of crude oil will be between $28 and $31 per barrel from 2015 through 2030. PIRA gives its oil price forecast in terms of WTI, a low-sulfur, light crude oil, assuming prices of $50 per barrel in 2015 and $63 per barrel in 2020.

Despite much lower crude oil price projections, GII and DB project gasoline consumption levels that are essentially the same as those in the *AEO2006* reference case (Table 24). The GII and DB projections for gasoline demand are within 1 percent of the *AEO2006* reference case from 2015 to 2030. PIRA sees slower growth in gasoline demand, 14 percent below the *AEO2006* reference case in 2015, due to more rapid improvement in vehicle efficiency.

In comparison with the *AEO2006* reference case, projected distillate consumption is about 2 percent lower in the DB and PIRA projections in 2015 and 5 percent lower in 2030 in the DB projection. GII also projects lower levels of distillate consumption than the *AEO2006* reference case, 6 percent less in 2015 and 13 percent less in 2030. Most of the variation is accounted for by the projected level of highway diesel consumption.

The projected pattern of growth in jet fuel consumption varies significantly by projection, and the basis of the variation is not always clear. Relative to the *AEO2006* reference case, PIRA projects slightly higher jet fuel consumption in 2015, whereas GII projects higher jet fuel consumption only toward the end of the projection (25 percent higher in 2030 but 4 percent lower in 2015). DB also projects lower jet fuel consumption in the middle years, 9 percent below the *AEO2006* reference case in 2015, but is nearly identical with the *AEO2006* reference case in the later years of the projection.

The projections also differ substantially on the projected future use of residual fuel oil. PIRA and GII project a steady decline in residual fuel oil consumption, but DB sees some growth in the future. In the GII projection, residual fuel oil consumption is 3 percent below that in the *AEO2006* reference case in 2015 and 18 percent below in 2030. Both GII and PIRA project deep declines in residual fuel oil consumption for electricity generation. The *AEO2006* reference case projects more modest reductions through 2015 and then slow growth for the remainder of the projection. The DB projections are 14 percent and 17 percent above the *AEO2006* reference case in 2015 and 2030, respectively.

Domestic crude oil production declines in all the projections, but at different rates. As compared with the *AEO2006* reference case, domestic crude oil production declines more rapidly in the earlier years and much more slowly in the later years of the GII projection. GII projects domestic crude oil production 14 percent lower than in the *AEO2006* reference case in 2015 but essentially the same in 2030. DB and PIRA project a much more rapid decline in domestic crude oil production: both are about 15 percent below the *AEO2006* reference case in 2015, and DB projects a further decline, to 19 percent below the *AEO2006* reference case in 2030.

The projections do not agree on domestic production of NGL. The *AEO2006* reference case projects NGL production slightly above current levels in 2015 and 2030, with peak production in 2020. DB is bearish on NGL production, projecting 19 percent lower levels than in the *AEO2006* reference case in 2015 and 42 percent lower in 2030. GII, on the other hand, is bullish on NGL production, projecting domestic production 24 percent above the levels in the *AEO2006* reference case in 2015 and 38 percent above in 2030. EVA and DB project the lowest totals of domestic crude oil and NGL production in 2015 and 2030.

Declining domestic production of crude oil and rising petroleum product demand imply greater dependence on imports in all the projections. The decreases in crude oil production are offset somewhat by projected increases in NGL production in the *AEO2006* reference case and GII. DB projects substantial declines in crude oil and NGL production and therefore projects the highest levels of net imports of crude and petroleum products. DB projects import shares 9 percentage points above the *AEO2006* reference case in 2015 and 14 percentage points above in 2030. GII projects import shares that are 8 percentage points above the *AEO2006* reference case in 2015 and 2030.

AEO2006 also includes alternative price cases. The *AEO2006* low price case assumes that the average

Table 24. Comparison of petroleum forecasts, 2015 and 2030 (million barrels per day, except where noted)

Projection	2004	AEO2006			Other forecasts			
		Reference	Low price	High price	GII	DB	EVA	PIRA
		2015						
Crude oil and NGL production	**7.23**	**7.72**	**7.34**	**6.49**	**6.56**	**NA**	**7.88**	**7.61**
Crude oil	5.42	5.84	5.02	4.98	NA	4.99	5.99	5.76
Natural gas liquids	1.81	1.88	2.32	1.51	NA	NA	1.89	1.85
Total net imports	**12.11**	**13.23**	**15.08**	**15.31**	**NA**	**14.37**	**14.06**	**11.87**
Crude oil	10.06	10.47	11.28	NA	NA	11.74	11.06	9.65
Petroleum products	2.05	2.76	3.79	NA	NA	2.63	3.00	2.22
Petroleum demand	**20.76**	**23.53**	**23.71**	**23.43**	**NA**	**23.01**	**24.48**	**22.21**
Motor gasoline	9.10	10.63	10.69	10.39	NA	9.14	11.07	9.85
Jet fuel	1.63	2.06	1.98	1.88	NA	2.11	2.09	2.03
Distillate fuel	4.06	4.91	4.60	4.81	NA	4.83	5.05	4.72
Residual fuel	0.87	0.73	0.71	0.83	NA	0.72	0.83	0.66
Other	5.10	5.20	5.74	5.51	NA	6.21	5.44	4.95
Import share of product supplied (percent)	**58**	**56**	**64**	**65**	**NA**	**62**	**57**	**53**
		2030						
Crude oil and NGL production	**7.23**	**6.44**	**7.17**	**4.78**	**4.70**	**NA**	**6.41**	**6.85**
Crude oil	5.42	4.57	4.59	3.69	NA	NA	4.49	4.96
Natural gas liquids	1.81	1.87	2.58	1.09	NA	NA	1.92	1.89
Total net imports	**12.11**	**17.24**	**19.69**	**21.13**	**NA**	**NA**	**20.21**	**13.28**
Crude oil	10.06	13.51	13.01	NA	NA	NA	15.51	11.24
Petroleum products	2.05	3.73	6.67	NA	NA	NA	4.70	2.04
Petroleum demand	**20.76**	**27.57**	**28.24**	**27.74**	**NA**	**NA**	**29.57**	**25.17**
Motor gasoline	9.10	12.49	12.59	12.25	NA	NA	13.68	10.96
Jet fuel	1.63	2.31	2.89	2.29	NA	NA	2.33	2.09
Distillate fuel	4.06	6.09	5.31	5.81	NA	NA	6.29	5.99
Residual fuel	0.87	0.78	0.64	0.91	NA	NA	1.01	0.70
Other	5.10	5.89	6.80	6.49	NA	NA	6.26	5.44
Import share of product supplied (percent)	**58**	**62**	**70**	**76**	**NA**	**NA**	**68**	**53**

NA = Not available.

Sources: ***2004 and AEO2006:*** AEO2006 National Energy Modeling System, runs AEO2006.D111905A (reference case), LP2006.D113005A (low price case), and HP2006.D120105A (high price case). **GII:** Global Insight, Inc., *Summer 2005 U.S. Energy Outlook* (August 2005). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski on October 31, 2005. **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2005). **PIRA:** PIRA Energy Group (October 2005).

refiners acquisition cost of imported crude oil will remain at about $28 per barrel from 2015 to 2030 (2004 dollars), and that the average refiners acquisition cost of imported low-sulfur light crude oil will remain at about $34 per barrel over the same period. The *AEO2006* low price case is somewhat lower than GII's crude oil price path. The *AEO2006* high price case assumes that the average refiners acquisition cost of imported crude oil will range between $72 and $90 per barrel from 2015 to 2030, and that the average refiners acquisitions cost of imported low-sulfur light crude oil will range between $76 and $96 per barrel over the same period. The crude oil prices in the *AEO2006* high price case are well above PIRA's projected levels. The *AEO2006* low price case shows the highest levels of total petroleum demand in 2015 and 2030, and the *AEO2006* high price case shows the lowest. The projected demand reduction in the *AEO-2006* high price case also results in the least reliance on imports to meet petroleum demand in 2015 and 2030. The DB projection shows the greatest reliance on petroleum imports, because it assumes the lowest levels of domestic crude oil and NGL production.

Coal

The coal projections for the *AEO2006* reference case and economic growth cases (Table 25) incorporate CAAA90, CAIR, and CAMR. EVA's forecast assumes legislation similar to the Clear Skies Act but also includes a fee of $5 per ton on CO_2 emissions, beginning in 2013. The *AEO2006*, PIRA, and GII projections do not include assumptions about reductions in CO_2 emissions for the United States. In addition to environmental assumptions, differences among the

Table 25. Comparison of coal forecasts, 2015, 2025, and 2030 (million short tons, except where noted)

Projection	2004	AEO2006			Other forecasts		
		Reference	Low economic growth	High economic growth	PIRA	EVA	GII
				2015			
Production	**1,125**	**1,272**	**1,251**	**1,318**	**1,250**	**1,234**	**1,149**
Consumption by sector							
Electric power	1,015	1,161	1,145	1,199	1,171	1,140	1,071
Coke plants	24	22	21	23	NA	29	19
Coal-to-liquids	0	22	19	27	NA	NA	NA
Industrial/other	65	71	69	72	88[a]	65	66
Total	**1,104**	**1,276**	**1,254**	**1,321**	**1,259**	**1,234**	**1,156**
Net coal exports	**20.7**	**-4.8**	**-4.8**	**-4.8**	**-8.0**	**-17.3**	**-7.7**
Exports	48.0	22.0	22.0	22.0	NA	28.0	28.6
Imports	27.3	26.7	26.7	26.8	NA	45.3	36.3
Minemouth price							
(2004 dollars per short ton)	20.07	20.39	20.04	20.67	NA	19.69[b]	17.82[d]
(2004 dollars per million Btu)	0.98	1.01	0.99	1.02	NA	0.99[c]	0.86[d]
Average delivered price to electricity generators							
(2004 dollars per short ton)	27.43	28.12	27.74	28.50	NA	29.45[b]	28.17[e]
(2004 dollars per million Btu)	1.36	1.40	1.39	1.42	NA	1.48[b]	1.36
				2025			
Production	**1,125**	**1,530**	**1,394**	**1,710**	**NA**	**1,404**	**1,296**
Consumption by sector							
Electric power	1,015	1,354	1,248	1,486	NA	1,329	1,226
Coke plants	24	21	19	23	NA	26	16
Coal-to-liquids	0	146	115	192	NA	NA	NA
Industrial/other	65	71	68	73	NA	60	67
Total	**1,104**	**1,592**	**1,450**	**1,774**	**NA**	**1,415**	**1,309**
Net coal exports	**20.7**	**-62.8**	**-57.9**	**-65.5**	**NA**	**-29.2**	**-15.1**
Exports	48.0	19.6	19.6	18.4	NA	30.1	23.4
Imports	27.3	82.4	77.4	84.0	NA	59.3	38.5
Minemouth price							
(2004 dollars per short ton)	20.07	20.63	19.40	21.73	NA	20.15[b]	16.12[d]
(2004 dollars per million Btu)	0.98	1.03	0.98	1.09	NA	1.02[c]	0.78[d]
Average delivered price to electricity generators							
(2004 dollars per short ton)	27.43	29.02	27.48	30.87	NA	30.12[b]	25.84[e]
(2004 dollars per million Btu)	1.36	1.44	1.37	1.52	NA	1.53[b]	1.25

Btu = British thermal unit. NA = Not available. See notes and sources at end of table.

AEO2006, EVA, PIRA, and GII projections reflect variation in other assumptions, including those about economic growth, the natural gas outlook, and world oil prices.

While all the projections show increases in coal consumption over their projection horizons, the *AEO2006* reference case projects the highest level of total coal consumption. Given its more restrictive environmental assumptions after 2012 and an average economic growth rate of 2.5 percent per year from 2004, EVA projects lower levels of coal consumption (11 percent lower in 2025) than the *AEO2006* reference case. The EVA and PIRA projections for total coal consumption in the 2015-2020 period most closely resemble those in the *AEO2006* low economic growth case. GII's projection, which does not include a carbon tax, has the lowest projection of total coal consumption. Although the GII projection shows 21 percent less total coal consumption than the *AEO2006* reference case in 2030, GII's outlook for coal consumption in the electric power sector in 2030 is virtually identical to that in the *AEO2006* low economic growth case.

In contrast to the *AEO2006* reference case, the other projections show natural gas with a larger share of electricity generation than coal's. GII, PIRA, and EVA expect imports of LNG to be greater than projected in the *AEO2006* reference case. Although EVA and the *AEO2006* reference case project similar levels of generation in the electric power sector, the *AEO2006* reference case also projects 19 gigawatts of generation capacity at CTL plants by 2030, representing 11 percent of total coal consumption in 2030.

For coke plants, both GII and the *AEO2006* reference case project declining consumption of coal. EVA differs from the other projections and projects an increase in coal consumption at coke plants, peaking at around 30 million tons before falling to 26 million tons in 2025—2 million tons higher than 2004

Table 25. Comparison of coal forecasts, 2015, 2025, and 2030 (continued)
(million short tons, except where noted)

Projection	2004	AEO2006			Other forecasts		
		Reference	Low economic growth	High economic growth	PIRA	EVA	GII
		2030					
Production	**1,125**	**1,703**	**1,497**	**1,936**	**NA**	**NA**	**1,395**
Consumption by sector							
Electric power	1,015	1,502	1,331	1,680	NA	NA	1,330
Coke plants	24	21	19	23	NA	NA	14
Coal-to-liquids	0	190	153	247	NA	NA	NA
Industrial/other	65	72	68	75	NA	NA	67
Total	**1,104**	**1,784**	**1,571**	**2,025**	**NA**	**NA**	**1,411**
Net coal exports	**20.7**	**-82.7**	**-69.3**	**-89.0**	**NA**	**NA**	**-18.7**
Exports	48.0	16.7	16.4	16.8	NA	NA	22.3
Imports	27.3	99.4	85.7	105.8	NA	NA	41.0
Minemouth price							
(2004 dollars per short ton)	20.07	21.73	19.91	23.05	NA	NA	15.65 [d]
(2004 dollars per million Btu)	0.98	1.09	1.00	1.15	NA	NA	0.76 [d]
Average delivered price to electricity generators							
(2004 dollars per short ton)	27.43	30.58	28.28	32.79	NA	NA	25.23 [e]
(2004 dollars per million Btu)	1.36	1.51	1.41	1.61	NA	NA	1.22

Btu = British thermal unit. NA = Not available.
[a]Includes coal consumed at coke plants.
[b]The average coal price is a weighted average of the projected spot market price for the electric power sector only and was converted from 2005 dollars to 2004 dollars to be consistent with *AEO2006*.
[c]Estimated by dividing the minemouth price in dollars per short ton by the average heat content of coal delivered to the electric power sector.
[d]The minemouth prices are average prices for the electric power sector only and are calculated as a weighted average from Census region prices.
[e]Calculated by multiplying the delivered price of coal to the electric power sector in dollars per million Btu by the average heat content of coal delivered to the electric power sector.
Sources: ***2004 and AEO2006*:** AEO2006 National Energy Modeling System, runs AEO2006.D111905A (reference case), LM2006.D113005A (low economic growth case), and HM2006.D112505B (high economic growth case). **PIRA:** PIRA Energy Group (October 2005). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2005). **GII:** Global Insight, Inc., *U.S. Energy Outlook* (Summer 2005).

consumption. In the GII projection, coke plants consume only 14 million tons of coal in 2030, compared with 21 million tons in the *AEO2006* reference case. The *AEO2006* reference case shows no change in industrial/other coal consumption, whereas EVA projects a drop in industrial/other consumption, to 60 million short tons in 2025.

In the GII projections, minemouth coal prices (electric power sector only) appear to peak by 2010 and then fall below 2004 levels by 2030 (in real dollars). The *AEO2006* reference case shows a similar downward trend after 2010 in its average national minemouth price (all sectors combined) through 2020; however, prices rise after 2020, in response to substantial growth in coal demand from the electric power sector and CTL. GII's average delivered price of coal to the electric power sector in 2030 is 19 percent lower than the *AEO2006* reference case (on a Btu basis). The average delivered price of coal to the electricity sector in the GII forecast is still 13 percent lower (on a Btu basis) than the *AEO2006* low economic growth case, despite comparable levels of coal consumption in the electricity sector.

All the forecasts reviewed meet coal demand primarily through domestic production. *AEO2006* projects the largest increase in production over the forecast horizon, 51 percent higher in 2030 than in 2004. As with consumption, the PIRA and EVA projections for coal production most closely resemble those in the *AEO2006* low economic growth case. GII projects coal consumption levels for 2015, 2025, and 2030 that are more than 100 million tons less than projected in the *AEO2006* reference case.

In all the projections, gross exports of coal represent a small and declining part of domestic coal production. EVA projects the most exports, 30 million tons in 2025, and the other projections are around 20 million tons. The *AEO2006* reference case shows coal exports falling to 17 million tons in 2030, and GII projects 22 million tons. In the *AEO2006* reference case, the export share of total U.S. coal production falls from 4 percent in 2004 to roughly 1 percent in 2030. Currently, coal is the only domestic U.S. energy resource for which exports exceed imports. All the projections expect the United States to become a net importer of coal over the projection period. GII projects the lowest level of coal imports, only 14 million tons in 2030. The *AEO2006* reference case projection for coal imports in 2025 is 23 million tons higher than the EVA projection, which is the next highest.

List of Acronyms

ACI	Activated carbon injection
AD	Associated-dissolved (natural gas)
AEO	*Annual Energy Outlook*
AEO2005	*Annual Energy Outlook 2005*
AEO2006	*Annual Energy Outlook 2006*
Altos	Altos Partners
ANWR	Arctic National Wildlife Refuge
API	American Petroleum Institute
BLGCC	Black liquor gasification coupled with a combined-cycle power plant
BOE	Barrels of oil equivalent
BTL	Biomass-to-liquids
Btu	British thermal units
CAAA90	Clean Air Act Amendments of 1990
CAFE	Corporate average fuel economy
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CARB	California Air Resources Board
CBO	Congressional Budget Office
CHP	Combined heat and power
CO_2	Carbon dioxide
CPI	Consumer price index
CRI	Color rendering index
CTL	Coal-to-liquids
DB	Deutsche Bank AG
DCL	Direct coal liquefaction
DOE	U.S. Department of Energy
E85	Fuel containing a blend of 70 to 85 percent ethanol
EEA	Energy and Environmental Analysis, Inc.
EIA	Energy Information Administration
EMF	Stanford University Energy Modeling Forum
EPA	U.S. Environmental Protection Agency
EPACT1992	Energy Policy Act of 1992
EPACT2005	Energy Policy Act of 2005
ERO	Electric Reliability Organization
ETBE	Ethyl tertiary butyl ether
EVA	Energy Ventures Analysis, Inc.
FERC	Federal Energy Regulatory Commission
GATS	Generation Attribute Tracking System
GDP	Gross domestic product
GHG	Greenhouse gas
GII	Global Insight, Inc.
GT-MH	Gas-Turbine Modular Helium reactor
GTL	Gas-to-liquids
H_2	Molecular hydrogen
HCCI	Homogeneous charge compression ignition
ICL	Indirect coal liquefaction
IEA	International Energy Agency
IGCC	Integrated gasification combined-cycle
INFORUM	Interindustry Forecasting at the University of Maryland
IRAC	Average imported refiner acquisition cost of crude oil to the United States
IRIS	International Reactor Innovative and Secure reactor
LED	Light-emitting diode
LFG	Landfill gas
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LWR	Light-water reactor
MACT	Maximum Achievable Control Technology
MRETS	Midwest Renewable Energy Tracking System
MSW	Municipal solid waste
MTBE	Methyl tertiary butyl ether
NA	Nonassociated (natural gas)
NAAQS	National Ambient Air Quality Standards
NARG	Altos Partners North American Regional Gas Model
NAS	National Academy of Sciences
NEMS	National Energy Modeling System
NEPOOL	New England Power Pool
NGL	Natural gas liquids
NHTSA	National Highway Traffic Safety Administration
nm	Nanometer (one-billionth of a meter)
NO_x	Nitrogen oxides
NRC	U.S. Nuclear Regulatory Commission
NYMEX	New York Mercantile Exchange
OLED	Organic light-emitting diode
OMB	Office of Management and Budget
OPEC	Organization of the Petroleum Exporting Countries
PATH	Partnership for Advanced Technology in Housing
PBMR	Pebble Bed Modular Reactor
PDVSA	Petroleos de Venezuela SA
PEL	Petroleum Economics, Ltd.
PIRA	Petroleum Industry Research Associates, Inc.
$PM_{2.5}$	Fine particulate matter
ppm	Parts per million
PTC	Production tax credit
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
R&D	Research and development
RD&D	Research, development, and demonstration
RFG	Reformulated gasoline
RFS	Renewable fuels standard
RPS	Renewable portfolio standard
SAFETEA-LU	Safe, Accountable, Flexible, and Efficient Transportation Equity Act: A Legacy for Users
SAGD	Steam-assisted gravity drainage
SCR	Selective catalytic reduction
SEER	Strategic Energy and Economic Research, Inc.
SIP	State Implementation Plan
SNCR	Selective noncatalytic reduction
SO_2	Sulfur dioxide
SSL	Solid-state lighting
Syncrude	Synthetic crude
TAME	Tertiary amyl methyl ether
TAN	Total acid number
ULSD	Ultra-low-sulfur diesel fuel
USGS	U.S. Geological Survey
VOC	Volatile organic compound
WPI	Wholesale price index
WREGIS	Western Renewable Energy Generation Information Tracking System
WTI	West Texas Intermediate (crude oil)
ZEH	Zero Energy Home

Notes and Sources

Text Notes

Legislation and Regulations

[*1*] For the complete text of the Energy Policy Act of 2005, see web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_public_laws&docid=f:publ058.109.pdf.

[*2*] See, for example, web site http://energy.senate.gov/public/_files/PostConferenceBillSummary.doc.

[*3*] Joint Committee on Taxation, *Description and Technical Explanation of the Conference Agreement of H.R.6, Title XIII, The "Energy Tax Incentives Act of 2005,"* JCX-60-05 (Washington, DC, July 28, 2005), pp. 6-8, web site www. house.gov/jct/x-60-05.pdf.

[*4*] Other Federal credit assistance programs, such as that created by the Transportation Infrastructure Finance and Innovation Act of 1998 (TIFIA), have used loan guarantees to leverage limited Federal resources and stimulate private capital investment. With a budget authorization of $130 million for fiscal year 2003, the TIFIA program was able to support loans valued at $2.6 billion. See web site http://tifia.fhwa.dot.gov.

[*5*] Other States that have adopted the California emission standards include Connecticut, Maine, Massachusetts, New Jersey, New York, Rhode Island, Vermont, and Washington.

[*6*] On December 7, 2004, the Alliance of Automobile Manufacturers and several California auto dealerships filed suit in the U.S. District Court in Fresno, California, against A.B. 1493.

[*7*] Energy Information Administration, *Annual Energy Outlook 2005*, DOE/EIA-0383(2005) (Washington, DC, February 2005), pp. 27-31, web site www.eia.doe.gov/oiaf/archive/aeo05/index.html.

[*8*] National Highway Traffic Safety Administration, Average Fuel Economy Standards for Light Trucks Model Years 2008-2011, Notice of Proposed Rulemaking, 49 CFR Parts 523, 533, and 537, Docket No. 2005-22223, RIN 2127-AJ61 (Washington, DC, August 2005), web site www.nhtsa.dot.gov/cars/rules/rulings/LightTrucksRuling-2008-2001/ProposedRulemaking/CAFE-LigthTrucks-PR-24Aug05.pdf.

[*9*] Energy Information Administration, "State Renewable Energy Requirements and Goals: Status Through 2003," *Annual Energy Outlook 2005*, DOE/EIA-0383(2005) (Washington, DC, February 2005), pp. 20-23, web site www.eia.doe.gov/oiaf/archive/aeo05/index.html.

[*10*] Vermont Senate Bill 52, Sec. 2 (8002)(2) (June 14, 2005).

[*11*] *Federal Register*, Vol. 70, No. 91 (May 12, 2005), 40 CFR Parts 51, 72, 73, 74, 77, 78, and 96.

[*12*] U.S. Environmental Protection Agency, "Clean Air Interstate Rule," web site www.epa.gov/cair.

[*13*] States are required to meet both seasonal and annual NO_x caps. The SO_2 caps are annual only.

[*14*] *Federal Register*, Vol. 70, No. 95 (May 18, 2005), 40 CFR Parts 60, 72, and 75.

[*15*] For the complete text of SAFETEA-LU, Public Law 109-59, see web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_public_laws&docid=f:publ059.109.pdf.

Issues in Focus

[*16*] The USGS provides three point estimates of undiscovered and inferred resources: the mean, a 5-percent confidence interval, and a 95-percent confidence interval with no price relationship. *AEO2006* assumes that proven reserves are not subject to much uncertainty.

[*17*] For readers interested in the international effects of higher oil prices, an International Energy Agency paper, "Impact of Higher Oil Prices on the World Economy" (2003) is available from web site www.iea.org/Textbase/publications/free_new_Desc.asp? PUBS_ID=886.

[*18*] The more that is spent back in the U.S. economy, the lower will be the net effect. If the receivers of the extra income, domestic oil companies and oil-exporting countries, do not spend it back in the U.S. economy, aggregate demand for goods and services will be reduced in the short term. Even if all additional oil revenues are spent back in the United States, there still will be distribution effects involving a move toward different categories of consumption. There will also be an indirect impact on demand for U.S. goods and services through third-country effects; when higher oil prices have negative effects on economic growth in other countries, their demand for imports from the United States will be reduced.

[*19*] See K.A. Mork, "Oil and the Macroeconomy When Prices Go Up and Down: An Extension of Hamilton's Results," *Journal of Political Economy*, Vol. 97 (1989), pp. 740-744.

[*20*] There have been several recent surveys of past research on the economic impacts of oil price shocks. See S.P.A. Brown, M.K. Yücel, and J. Thompson, "Business Cycles: The Role of Energy Prices," in *Encyclopedia of Energy*, C.J. Cleveland, Ed. (New York, NY: Academic Press, 2004); S.P.A. Brown and M.K. Yucel, "Energy Prices and Aggregate Economic Activity: An Interpretative Survey," *Quarterly Review of Economics and Finance*, Vol. 42 (2002), pp. 193-208; and D.W. Jones, P.N. Leiby, and I.K. Paik, "Oil Price Shocks and the Macroeconomy: What Has Been Learned Since 1996," *Energy Journal*, Vol. 25, No. 2 (2004).

[*21*] H.G. Huntington, *The Economic Consequences of Higher Crude Oil Prices*, EMF SR 9 (Stanford, CA, October 2005), web site www.stanford.edu/group/EMF/publications/doc/EMFSR9.pdf.

[*22*] Results of Global Insight's Macroeconomic Model of the U.S. Economy are from N. Gault, "Impacts on the U.S. Economy: Macroeconomic Models," Presented at the Energy Modeling Forum Workshop on Macroeconomic Impacts of Oil Shocks (Arlington, VA, February 8, 2005), web site www.stanford.edu/group/EMF/research/doc/gault.pdf. Federal Reserve Bank macroeconomic model results are from D. Reifschneider, R. Tetlow, and J. Williams, "Aggregate Disturbances, Monetary Policy, and the Macroeconomy: The FRB/US Perspective," *Federal Reserve Bulletin* (January 1999), web site www.federalreserve.gov/pubs/bulletin/1999/0199lead.pdf. Results from the NiGEM global macroeconomic model are from R. Barrell and O. Pomerantz, "Oil Prices and the World Economy," National Institute of Economic and Social Research Discussion Paper 242 (London, UK, December 2004), web site www.niesr.ac.uk/pubs/dps/dp242.pdf.

[23] R. Jimenez-Rodriguez and M. Sanchez. "Oil Price Shocks and Real GDP Growth: Empirical Evidence for Some OECD Countries," *Applied Economics*, Vol. 37, No. 2 (February 2005), pp. 201-228.

[24] H.G. Huntington, "Energy Disruptions, Interfirm Price Effects and the Aggregate Economy," *Energy Economics*, Vol. 25, No. 2 (March 2003), pp. 119-136.

[25] Quality and prices vary among imported light, sweet crudes. For example, Nigerian Bonny Light usually is worth 15 cents a barrel more than WTI, and Norwegian Oseberg is discounted by about 55 cents a barrel. See NYMEX Light Sweet Crude Oil Futures Contract Specifications, web site www.nymex.com/CL_spec.aspx.

[26] Energy Information Administration, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report" (1985-2005).

[27] Energy Information Administration, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report" (1985-2005).

[28] See Purvin & Gertz, Inc., "Global Petroleum Market Outlook—An Online Global Service," Petroleum Balances (2004), web site www.purvingertz.com/studies.html.

[29] U.S. Environmental Protection Agency, "Tier 2/Gasoline Sulfur Final Rule" (Washington, DC, February 2000), web site www.epa.gov/tier2/finalrule.htm; "Control of Air Pollution From New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements Final Rule" (Washington, DC, January 2001), web site www.epa.gov/fedrgstr/EPA-AIR/2001/January/Day-18/a01a.htm; and "Control of Emissions of Air Pollution From Nonroad Diesel Engines and Fuel Final Rule" (Washington, DC, June 2004), web site www.epa.gov/fedrgstr/EPA-AIR/2004/June/Day-29/a11293a.htm.

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[32] Non-grid-connected housing units that derive most or all of their energy from renewable sources exist, but most are in remote areas and not designed for year-round living.

[33] Partnership for Advancing Housing Technology (PATH), web site www.pathnet.org.

[34] These are the six high-priority areas for emerging technologies identified in American Council for an Energy-Efficient Economy, *Emerging Energy-Saving Technologies and Practices for the Buildings Sector as of 2004*, Report Number A042 (Washington, DC, October 2004), web site http://aceee.org/pubs/a042full.pdf.

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[37] National Academy of Sciences, National Research Council, *Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000* (Washington, DC: National Academy Press, 2001), web site www.nap.edu/catalog/10165.html.

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[44] M. Kray, "Testimony on Behalf of NuStart Energy Development, LLC, United States Senate, Committee on Environment & Public Works, Subcommittee on Clean Air, Climate Change and Nuclear Safety" (May 20, 2004), web site www.nei.org/documents/Testimony_Kray_05-20-04.pdf; and E.W. Merrow, K.E. Phillips, and C.W. Myers, *Understanding Cost Growth and Performance Shortfalls in Pioneer Process Plants*, R-2569-DOE (Santa Monica, CA: The Rand Corporation, September 1981), web site www.rand.org/pubs/reports/R2569.

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[*60*] J.T. Bartis et al., p. 15.

[*61*] "Fischer-Tropsch Condensate Boosts Lubricity in Synthetic Diesel: New SASOL Study," *World Fuels Today* (October 6, 2005), p. 3.

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Market Trends

[*84*] The energy-intensive manufacturing sectors include food, paper, bulk chemicals, petroleum refining, glass, cement, steel, and aluminum.

[*85*] EIA collects aggregate data on total energy consumption in the industrial sector and detailed energy consumption in the manufacturing sector. The difference between the aggregate industrial sector energy data and the detailed manufacturing sector data is nonmanufacturing industrial energy consumption. Nonmanufacturing energy consumption is allocated to the agriculture, mining, and construction sectors on the basis of information from the Energy Information Administration, the U.S. Census Bureau, and the U.S. Department of Agriculture.

[*86*] The alternative technology cases change technology characterizations only for sectors represented in the NEMS industrial model. Consequently, refining values are unchanged from those in the reference case projections. The reference case projections for the refining sector include considerable cogeneration capacity additions associated with coal-to-liquids production. Excluding the refining sector, cogeneration capacity increases by 2.4 percent per year in the high technology case, as compared with 1.8 percent per year in the reference case.

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[*88*] Unless otherwise noted, the term "capacity" in the discussion of electricity generation indicates utility, nonutility, and combined heat and power capacity. Costs reflect the arithmetic average of regional costs.

[*89*] Avoided cost estimates the incremental cost of fuel and capacity displaced by a unit of the specified resource and more accurately reflects its as-dispatched energy value than comparison to the levelized cost of other individual technologies. It does not reflect system reliability cost, nor does it necessarily indicate the lowest cost alternative for meeting system energy and capacity needs.

[*90*] *AEO2006* does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2003, EIA estimates that as much as 149 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2003, plus an additional 414 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384 (2004) (Washington, DC, August 2005), Table 10.6, "Photovoltaic Cell and Module Shipments by End Use and Market Sector, 1989-2003." 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 overestimates 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 are retired from service or abandoned.

[*91*] Stranded Arctic natural gas and resources in areas where drilling is officially prohibited are not included in Table 17.

[*92*] Resources from the Arctic Offshore Outer Continental shelf and resources in areas where drilling is officially prohibited are not included in Table 18.

[*93*] Energy Information Administration (EIA), Form EIA-767, "Steam-Electric Plant Operation and Design Data"; and EIA, Office of Integrated Analysis and Forecasting, Plant File.

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Notes and Sources

Table Notes and Sources

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

Table 1. Total energy supply and disposition in the *AEO2006* reference case: summary, 2003-2030: AEO2006 National Energy Modeling System, run AEO2006.D111905A. **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.

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Table 12. Economic indicators in the reference, high price, and low price cases, 2005-2030: AEO2006 National Energy Modeling System, runs AEO2006.D111905A, LP2006.D120105A, and HP2006.D113005A.

Table 13. Technologies expected to have significant impacts on new light-duty vehicles: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 14. Nonconventional liquid fuels production in the AEO2006 reference and high price cases, 2030: AEO2006 National Energy Modeling System, runs AEO2006.D111905A and HP2006.D113005A.

Table 15. Projected changes in U.S. greenhouse gas emissions, gross domestic product, and greenhouse gas intensity, 2002-2020: AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Table 16. Costs of producing electricity from new plants, 2015 and 2030: AEO2006 National Energy Modeling System, run AEO2006.D111905A.

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Table 18. Technically recoverable U.S. crude oil resources as of January 1, 2004: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure Notes and Sources

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

Figure 1. Energy prices, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table A1.

Figure 2. Delivered energy consumption by sector, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table A2.

Figure 3. Energy consumption by fuel, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Tables A1 and A18.

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Figure 11. World oil prices in three AEO2006 cases, 1980-2030: Table C1.

Figure 12. Changes in world oil price and U.S. real GDP in the AEO2006 high and low price cases, 2004-2030: AEO2006 National Energy Modeling System, runs LP2006.D120105A and HP2006.D113005A.

Figure 13. GDP elasticities with respect to oil price changes in the high price case, 2006-2030: AEO2006 National Energy Modeling System, run HP2006.D113005A. **Note:** The figure shows profiles of year-by-year and period average GDP elasticities with respect to oil price changes in the high price case. The elasticities are computed as follows: (1) *Year-by-year elasticity* = (*Percentage change from baseline real GDP*) / (*Percentage change from baseline oil price*). (2) *Period average elasticity* = (*percentage change in cumulative high price GDPs from cumulative baseline GDPs*) / (*Percentage change in cumulative high prices from cumulative baseline prices*).

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Figure 17. Market penetration of advanced technologies in new cars, 2004 and 2030: AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 18. Market penetration of advanced technologies in new light trucks, 2004 and 2030: AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 19. System elements for production of synthetic fuels from coal, natural gas, and biomass: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 20. Mercury emissions from the electricity generation sector, 2002-2030: AEO2006 National Energy Modeling System, runs AEO2006.D111905A and ACI2006.D112305A.

Figure 21. Mercury allowance prices, 2010-2030: AEO2006 National Energy Modeling System, runs AEO-2006.D111905A and ACI2006.D112305A.

Figure 22. Coal-fired generating capacity retrofitted with activated carbon injection systems, 2010-2030: AEO2006 National Energy Modeling System, runs AEO-2006.D111905A and ACI2006.D112305A.

Figure 23. Projected change in U.S. greenhouse gas intensity in three cases, 2002-2020: AEO2006 National Energy Modeling System, runs AEO2006.D111905A, LTRKITEN.D121905A, and HTRKITEN.D121905A.

Figure 24. Average annual growth rates of real GDP, labor force, and productivity in three cases, 2004-2030: Table B4.

Figure 25. Average annual unemployment, interest, and inflation rates, 2004-2030: Table A19.

Figure 26. Sectoral composition of output growth rates, 2004-2030: AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 27. Sectoral composition of manufacturing output growth rates, 2004-2030: AEO2006 National Energy Modeling System, run AEO2006.D111905A.

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Figure 29. World oil prices in three cases, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table C1.

Figure 30. U.S. gross petroleum imports by source, 2004-2030: AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 31. Energy use per capita and per dollar of gross domestic product, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections: Energy use per capita:** Calculated from data in Table A2. **Energy use per dollar of GDP:** Table A19.

Figure 32. Primary energy use by fuel, 2004-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Tables A1 and A17.

Figure 33. Delivered energy use by fuel, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table A2.

Figure 34. Primary energy consumption by sector, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table A2.

Figure 35. Delivered residential energy consumption per capita by fuel, 1980-2030: History: Energy Information Administration, *State Energy Data Report 2001*, DOE/EIA-0214(2001) (Washington, DC, November 2004), and *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 36. Delivered residential energy consumption by end use, 2001, 2004, 2015, and 2030: History: Energy Information Administration, "Residential Energy Consumption Survey." **Projections:** Table A4. **Note:** Although 2001 is the last year of historical data for many of the detailed end-use consumption concepts (e.g., space heating, cooling), 2004 data, taken from EIA's *Annual Energy Review 2004*, is used as the base year for the more aggregate statistics shown in *AEO2006*. For illustrative purposes, EIA estimates for the detailed end-use consumption concepts, consistent with this historical information, are used to show growth rates.

Figure 37. Efficiency indicators for selected residential appliances, 2004 and 2030: Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2004); and AEO2006 National Energy Modeling System, run AEO-2006.D111905A.

Figure 38. Variation from reference case delivered residential energy use in three alternative cases, 2004-2030: Table D1.

Figure 39. Delivered commercial energy consumption per capita by fuel, 1980-2030: History: Energy Information Administration, *State Energy Data Report 2001*, DOE/EIA-0214(2001) (Washington, DC, November 2004), and *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 40. Delivered commercial energy intensity by end use, 2004, 2015, and 2030: Table A5.

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Figure 42. Variation from reference case delivered commercial energy intensity in three alternative cases, 2004-2030: Table D1.

Figure 43. Buildings sector electricity generation from advanced technologies in two alternative cases, 2030: AEO2006 National Energy Modeling System, runs AEO2006.D111905A, BLDHIGH.D112205A, and BLDBEST.D112205C.

Figure 44. Industrial energy intensity by two measures, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** AEO2006 National Energy Modeling System, run AEO2006.D111905A.

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Figure 46. Average growth in industrial output and delivered energy consumption by sector, 2004-2030: AEO2006 National Energy Modeling System, run AEO-2006.D111905A.

Figure 47. Projected energy intensity in 2030 relative to 2004, by industry: AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 48. Variation from reference case delivered industrial energy use in two alternative cases, 2004-2030: Table D2.

Figure 49. Transportation energy use per capita, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** AEO2006 National Energy Modeling System, run AEO2006.D111905A.

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Figure 52. Sales of advanced technology light-duty vehicles by fuel type, 2015 and 2030: AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 53. Changes in projected transportation fuel use in two alternative cases, 2010 and 2030: Table D3.

Figure 54. Changes in projected transportation fuel efficiency in two alternative cases, 2010 and 2030: Table D3.

Figure 55. Annual electricity sales by sector, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table A8.

Figure 56. Electricity generation capacity additions by fuel type, including combined heat and power, 2005-2030: Table A9.

Figure 57. Electricity generation capacity additions, including combined heat and power, by region and fuel, 2005-2030: AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 58. Levelized electricity costs for new plants, 2015 and 2030: AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 59. Electricity generation from nuclear power, 1973-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384 (2004) (Washington, DC, August 2005). **Projections:** Table A8.

Figure 60. Additions of renewable generating capacity, 2004-2030: AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 61. Levelized and avoided costs for new renewable plants in the Northwest, 2015 and 2030: AEO2006 National Energy Modeling System, run AEO-2006.D111905A.

Figure 62. Electricity generation by fuel, 2004 and 2030: Table A8.

Figure 63. Grid-connected electricity generation from renewable energy sources, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table A16. **Note:** Data for nonutility producers are not available before 1989.

Figure 64. Nonhydroelectric renewable electricity generation by energy source, 2004-2030: Table A16.

Figure 65. Fuel prices to electricity generators, 1995-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 66. Average U.S. retail electricity prices, 1970-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table A8.

Figure 67. Cumulative new generating capacity by technology type in three economic growth cases, 2004-2030: AEO2006 National Energy Modeling System, runs AEO2006.D111905A, LM2006.D113005A, and HM2006.D112505B.

Figure 68. Cumulative new generating capacity by technology type in three fossil fuel technology cases, 2004-2030: Table D6.

Figure 69. Levelized electricity costs for new plants by fuel type in two nuclear cost cases, 2015 and 2030: AEO2006 National Energy Modeling System, runs AEO2006.D111905A, ADVNUC5A.D120105A, and ADVNUC20.D120105A. **Note:** Includes generation and interconnection costs.

Figure 70. Nonhydroelectric renewable electricity generation by energy source in three cases, 2010 and 2030: Table D7.

Figure 71. Natural gas consumption by sector, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384 (2004) (Washington, DC, August 2005). **Projections:** Table A13.

Figure 72. Increases in natural gas consumption by Census division, 2004-2030: AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 73. Natural gas production by source, 1990-2030: Table A14.

Figure 74. Net U.S. imports of natural gas by source, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** AEO2006 National Energy Modeling System, run AEO2006. D111905A.

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Figure 76. Natural gas prices by end-use sector, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table A13.

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Figure 78. Natural gas production and net imports in three technology cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table D9.

Figure 79. Lower 48 natural gas wellhead prices in three price cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table C1.

Figure 80. Net imports of liquefied natural gas in three price cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** AEO2006 National Energy Modeling System, runs AEO2006.D111905A, LP2006.D120105A, and HP2006.D113005A.

Figure 81. Net imports of liquefied natural gas in three LNG supply cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** AEO2006 National Energy Modeling System, runs AEO2006.D111905A, LOLNG06.D120405A, and HILNG06.D120405.

Figure 82. Lower 48 natural gas wellhead prices in three LNG supply cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table D11.

Figure 83. World oil prices in the reference case, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table A1.

Figure 84. Domestic crude oil production by source, 1990-2030: History: Energy Information Administration, *Petroleum Supply Annual 1990*, DOE/EIA-0340(90) (Washington, DC, May 1991), and Office of Integrated Analysis and Forecasting. **Projections:** AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 85. World oil prices in three cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table C1.

Figure 86. Total U.S. petroleum production in three price cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table C4.

Figure 87. U.S. syncrude production from oil shale in the high price case, 2004-2030: AEO2006 National Energy Modeling System, run HP2006.D113005A.

Figure 88. Total U.S. crude oil production in three technology cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table D10.

Figure 89. Alaskan oil production in the reference and ANWR cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table D12.

Figure 90. U.S. net imports of oil in the reference and ANWR cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table D12.

Figure 91. Consumption of petroleum products, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table A11.

Figure 92. Domestic refinery distillation capacity, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table A11.

Figure 93. U.S. petroleum product demand and domestic petroleum supply, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Tables A11.

Figure 94. Components of retail gasoline prices, 2004, 2015, and 2030: AEO2006 Energy Modeling System, run AEO2006.D111905A.

Figure 95. U.S. ethanol fuel consumption in three price cases, 1995-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** AEO2006 National Energy Modeling System, runs AEO2006.D111905A, LP2006.D120105A, and HP2006.D113005A.

Figure 96. Coal-to-liquids and gas-to-liquids production in two price cases, 2004-2030: Table C4.

Figure 97. Coal production by region, 1970-2030: History: 1970-1990: Energy Information Administration (EIA), *The U.S. Coal Industry, 1970-1990: Two Decades of Change*, DOE/EIA-0559 (Washington, DC, November 2002); **1991-2000:** EIA, *Coal Industry Annual*, DOE/EIA-0584 (various years); **2001-2004:** EIA, *Annual Coal Report 2004*, DOE/EIA-0584(2004) (Washington, DC, November 2005), and previous issues; and EIA, *Short-Term Energy Outlook* (Washington, DC, September 2005). **Projections:** Table A15.

Figure 98. Distribution of domestic coal by demand and supply region, 2003 and 2030: 2003: Energy Information Administration (EIA), Form EIA-6, "Coal Distribution Report—Annual." **Projections:** AEO2006 National Energy Modeling System, run AEO2006.D111905A. **Note:** The Eastern Demand Region includes the New England, Middle Atlantic, South Atlantic, East North Central, and East South Central Census Divisions. The Western Demand Region includes the West North Central, West South Central, Mountain, and Pacific Census Divisions.

Figure 99. U.S. coal mine employment by region, 1970-2030: History: 1970-1976: U.S. Department of the Interior, Bureau of Mines, *Minerals Yearbook* (various years); **1977-1978:** Energy Information Administration (EIA), *Energy Data Report, Coal—Bituminous and Lignite*, DOE/EIA-0118 (Washington, DC, various years), and *Energy Data Report, Coal—Pennsylvania Anthracite*, DOE/EIA-0119 (Washington, DC, various years); **1979-1992:** EIA, *Coal Production*, DOE/EIA-0118 (various years); **1993-2000:** EIA, *Coal Industry Annual*, DOE/EIA-0584 (Washington, DC, various years); **2001-2004:** EIA, *Annual Coal Report 2004*, DOE/EIA-0584(2004) (Washington, DC, November 2005), and previous issues. **Projections:** AEO-2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 100. Average minemouth price of coal by region, 1990-2030: History: 1990-2000: Energy Information Administration (EIA), *Coal Industry Annual*, DOE/EIA-0584 (various years); **2001-2004:** EIA, *Annual Coal Report 2004*, DOE/EIA-0584(2004) (Washington, DC, November 2005), and previous issues. **Projections:** AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 101. Changes in regional coal transportation rates, 2010, 2025, and 2030: AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 102. U.S. coal exports and imports, 1970-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table A15.

Figure 103. Electricity and other coal consumption, 1970-2030: History: Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table A15.

Figure 104. Coal consumption in the industrial and buildings sectors and at coal-to-liquids plants, 2004, 2015, and 2030: Table A15.

Figure 105. Projected variation from the reference case projection of U.S. total coal demand in four cases, 2030: AEO2006 National Energy Modeling System, runs AEO2006.D111905A, LP2006.D120105A, HP2006.D113005A, LM2006.D113005A, and HM2006.D112505B.

Figure 106. Average delivered coal prices in three cost cases, 1990-2030: History: Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2004*, DOE/EIA-0121(2004/4Q) (Washington, DC, March 2005), and previous issues; EIA, *Electric Power Monthly, June 2005*, DOE/EIA-0226(2005/06) (Washington, DC, June 2005); and EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** Table D13. **Note:** Historical prices are weighted by consumption but exclude residential/commercial prices and export free-alongside-ship (f.a.s.) prices. Projected prices are weighted in the same way as historical prices and also exclude import quantities and prices.

Figure 107. Carbon dioxide emissions by sector and fuel, 2004 and 2030: 2004: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2004*, DOE/EIA-0573(2004) (Washington, DC, December 2005). **Projections:** Table A18.

Figure 108. Carbon dioxide emissions in three economic growth cases, 1990-2030: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2004*, DOE/EIA-0573(2004) (Washington, DC, December 2005). **Projections:** Table B2.

Figure 109. Carbon dioxide emissions in three technology cases, 2004, 2020, and 2030: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2004*, DOE/EIA-0573(2004) (Washington, DC, December 2005). **Projections:** Table D4.

Figure 110. Sulfur dioxide emissions from electricity generation, 1990-2030: 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). **2004:** U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 2004*, web site www.epa.gov/airmarkets/emissions/prelimarp/index.html. **Projections:** AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 111. Nitrogen oxide emissions from electricity generation, 1990-2030: 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). **2004:** U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 2004*, web site www.epa.gov/airmarkets/emissions/prelimarp/index.html. **Projections:** AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Figure 112. Mercury emissions from electricity generation, 1995-2030: History: 1995, 2000, and 2004: Energy Information Administration, Office of Integrated Analysis and Forecasting. **Projections:** AEO2006 National Energy Modeling System, run AEO2006.D111905A.

Appendixes

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

Supply, Disposition, and Prices	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Production								
Crude Oil and Lease Condensate	12.05	11.47	12.45	12.37	11.75	10.56	9.68	-0.7%
Natural Gas Plant Liquids	2.34	2.46	2.39	2.57	2.67	2.62	2.57	0.2%
Dry Natural Gas	19.63	19.02	19.13	20.97	22.09	21.80	21.45	0.5%
Coal	22.12	22.86	25.78	25.73	27.30	30.61	34.10	1.6%
Nuclear Power	7.96	8.23	8.44	8.66	9.09	9.09	9.09	0.4%
Renewable Energy[1]	5.69	5.74	7.08	7.43	8.00	8.61	9.02	1.8%
Other[2]	0.72	0.64	2.16	2.85	3.16	3.32	3.44	6.7%
Total	**70.52**	**70.42**	**77.42**	**80.58**	**84.05**	**86.59**	**89.36**	**0.9%**
Imports								
Crude Oil[3]	21.06	22.02	22.01	22.91	24.63	26.96	29.54	1.1%
Petroleum Products[4]	5.16	5.93	6.36	7.29	8.01	8.41	9.27	1.7%
Natural Gas	4.10	4.36	5.01	5.81	5.83	6.37	6.72	1.7%
Other Imports[5]	0.67	0.83	0.45	0.74	1.36	2.02	2.42	4.2%
Total	**30.98**	**33.14**	**33.83**	**36.75**	**39.83**	**43.76**	**47.95**	**1.4%**
Exports								
Petroleum[6]	2.03	2.07	2.15	2.18	2.24	2.26	2.31	0.4%
Natural Gas	0.71	0.86	0.55	0.58	0.68	0.86	1.01	0.6%
Coal	1.12	1.25	1.03	0.54	0.46	0.48	0.40	-4.3%
Total	**3.86**	**4.18**	**3.74**	**3.30**	**3.39**	**3.61**	**3.72**	**-0.5%**
Discrepancy[7]	**-0.40**	**-0.31**	**-0.36**	**-0.16**	**-0.15**	**-0.25**	**-0.30**	**N/A**
Consumption								
Petroleum Products[8]	38.96	40.08	43.14	45.69	48.14	50.57	53.58	1.1%
Natural Gas	23.04	23.07	24.04	26.67	27.70	27.78	27.66	0.7%
Coal	22.38	22.53	25.09	25.66	27.65	30.89	34.49	1.7%
Nuclear Power	7.96	8.23	8.44	8.66	9.09	9.09	9.09	0.4%
Renewable Energy[1]	5.70	5.74	7.08	7.43	8.00	8.61	9.02	1.8%
Other[9]	0.02	0.04	0.07	0.08	0.05	0.05	0.05	0.9%
Total	**98.05**	**99.68**	**107.87**	**114.18**	**120.63**	**126.99**	**133.88**	**1.1%**
Net Imports - Petroleum	**24.19**	**25.88**	**26.22**	**28.02**	**30.39**	**33.11**	**36.49**	**1.3%**
Prices (2004 dollars per unit)								
Imported Low Sulfur Light Crude Oil Price (dollars per barrel)[10]	31.72	40.49	47.29	47.79	50.70	54.08	56.97	1.3%
Imported Crude Oil Price (dollars per barrel)[10]	28.46	35.99	43.99	43.00	44.99	47.99	49.99	1.3%
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	5.08	5.49	5.03	4.52	4.90	5.43	5.92	0.3%
Coal Minemouth Price (dollars per ton)	18.40	20.07	22.23	20.39	20.20	20.63	21.73	0.3%
Average Electricity Price (cents per kilowatthour)	7.6	7.6	7.3	7.1	7.2	7.4	7.5	-0.0%

[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 A17 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]Weighted average price delivered to U.S. refiners.
[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 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2003 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Annual 2003*, DOE/EIA-0131(2003) (Washington, DC, December 2004). 2004 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2005/06) (Washington, DC, June 2005), subtracting 1 billion cubic feet per day to account for carbon dioxide included in production in Texas. 2003 natural gas wellhead price: Mineral Management Service and EIA, *Natural Gas Annual 2003*, DOE/EIA-0131(2003) (Washington, DC, December 2004). 2003 coal minemouth prices: EIA, *Annual Coal Report 2004*, DOE/EIA-0584(2004) (Washington, DC, November 2005). 2004 petroleum supply values and 2003 crude oil and lease condensate production: EIA, *Petroleum Supply Annual 2004*, DOE/EIA-0340(2004)/1 (Washington, DC, June 2005). Other 2003 petroleum supply values: EIA, *Petroleum Supply Annual 2003*, DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). 2003 and 2004 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2003 and 2004 coal values: *Quarterly Coal Report, October-December 2004*, DOE/EIA-0121(2004/4Q) (Washington, DC, March 2005). Other 2003 and 2004 values: EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

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

Sector and Source	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Energy Consumption								
Residential								
Distillate Fuel	0.91	0.94	0.84	0.79	0.73	0.67	0.61	-1.7%
Kerosene	0.08	0.09	0.09	0.09	0.08	0.07	0.07	-1.0%
Liquefied Petroleum Gas	0.52	0.54	0.56	0.59	0.61	0.63	0.65	0.7%
Petroleum Subtotal	1.50	1.57	1.48	1.47	1.43	1.37	1.32	-0.7%
Natural Gas	5.25	5.03	5.33	5.52	5.68	5.74	5.82	0.6%
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.5%
Renewable Energy[1]	0.40	0.41	0.44	0.43	0.43	0.42	0.41	0.1%
Electricity	4.34	4.41	4.99	5.38	5.77	6.10	6.47	1.5%
Delivered Energy	**11.51**	**11.44**	**12.25**	**12.81**	**13.31**	**13.64**	**14.04**	**0.8%**
Electricity Related Losses	9.51	9.60	10.74	11.26	11.85	12.24	12.60	1.1%
Total	**21.02**	**21.04**	**22.99**	**24.07**	**25.17**	**25.88**	**26.64**	**0.9%**
Commercial								
Distillate Fuel	0.48	0.50	0.48	0.49	0.50	0.51	0.52	0.1%
Residual Fuel	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.1%
Kerosene	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.3%
Liquefied Petroleum Gas	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.2%
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.3%
Petroleum Subtotal	0.75	0.79	0.77	0.78	0.79	0.80	0.82	0.1%
Natural Gas	3.32	3.09	3.18	3.46	3.68	3.89	4.11	1.1%
Coal	0.08	0.09	0.09	0.09	0.09	0.09	0.09	-0.0%
Renewable Energy[3]	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.0%
Electricity	4.09	4.19	4.88	5.43	6.01	6.63	7.34	2.2%
Delivered Energy	**8.34**	**8.24**	**9.00**	**9.85**	**10.66**	**11.50**	**12.44**	**1.6%**
Electricity Related Losses	8.96	9.13	10.51	11.37	12.35	13.32	14.29	1.7%
Total	**17.30**	**17.37**	**19.51**	**21.23**	**23.02**	**24.82**	**26.73**	**1.7%**
Industrial[4]								
Distillate Fuel	1.14	1.19	1.20	1.20	1.23	1.26	1.32	0.4%
Liquefied Petroleum Gas	2.12	2.19	2.21	2.26	2.34	2.44	2.54	0.6%
Petrochemical Feedstock	1.37	1.49	1.48	1.49	1.51	1.53	1.55	0.2%
Residual Fuel	0.22	0.24	0.20	0.19	0.20	0.21	0.21	-0.4%
Motor Gasoline[2]	0.31	0.32	0.32	0.32	0.32	0.33	0.34	0.2%
Other Petroleum[5]	4.12	4.16	4.60	4.83	5.05	5.34	5.69	1.2%
Petroleum Subtotal	9.28	9.58	10.01	10.29	10.65	11.10	11.66	0.8%
Natural Gas	7.38	7.64	8.07	8.33	8.52	8.77	9.08	0.7%
Lease and Plant Fuel[6]	1.16	1.14	1.12	1.22	1.28	1.24	1.21	0.2%
Natural Gas Subtotal	8.54	8.78	9.19	9.55	9.80	10.02	10.29	0.6%
Metallurgical Coal	0.67	0.65	0.62	0.61	0.59	0.58	0.58	-0.4%
Other Industrial Coal	1.38	1.38	1.43	1.43	1.43	1.43	1.45	0.2%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.16	0.49	1.22	1.61	33.8%
Net Coal Coke Imports	0.05	0.14	0.02	0.02	0.02	0.01	0.02	-8.1%
Coal Subtotal	2.09	2.16	2.07	2.21	2.53	3.25	3.65	2.0%
Renewable Energy[7]	1.59	1.68	1.79	1.90	2.01	2.14	2.29	1.2%
Electricity	3.44	3.48	3.62	3.76	3.91	4.08	4.31	0.8%
Delivered Energy	**24.94**	**25.68**	**26.67**	**27.72**	**28.91**	**30.58**	**32.19**	**0.9%**
Electricity Related Losses	7.53	7.58	7.79	7.88	8.04	8.19	8.39	0.4%
Total	**32.46**	**33.27**	**34.46**	**35.60**	**36.95**	**38.77**	**40.58**	**0.8%**

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

Sector and Source	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Transportation								
Distillate Fuel[8]	5.67	5.91	6.82	7.48	8.13	8.95	9.98	2.0%
Jet Fuel[9]	3.26	3.35	3.89	4.27	4.53	4.61	4.79	1.4%
Motor Gasoline[2]	16.62	16.93	18.33	19.54	20.73	21.81	22.99	1.2%
Residual Fuel	0.57	0.61	0.62	0.63	0.64	0.65	0.65	0.3%
Liquefied Petroleum Gas	0.02	0.03	0.06	0.07	0.09	0.10	0.11	5.0%
Other Petroleum[10]	0.15	0.18	0.18	0.18	0.18	0.19	0.19	0.3%
Petroleum Subtotal	26.30	27.02	29.91	32.18	34.30	36.30	38.71	1.4%
Pipeline Fuel Natural Gas	0.69	0.69	0.65	0.74	0.80	0.79	0.78	0.5%
Compressed Natural Gas	0.02	0.03	0.05	0.08	0.09	0.11	0.12	6.0%
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.01	0.01	6.4%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	0.08	0.08	0.09	0.09	0.10	0.10	0.11	0.9%
Delivered Energy	**27.09**	**27.82**	**30.70**	**33.09**	**35.30**	**37.31**	**39.72**	**1.4%**
Electricity Related Losses	0.18	0.18	0.19	0.20	0.20	0.21	0.21	0.5%
Total	**27.27**	**28.00**	**30.90**	**33.29**	**35.50**	**37.52**	**39.93**	**1.4%**
Delivered Energy Consumption for All Sectors								
Distillate Fuel	8.19	8.55	9.34	9.96	10.59	11.38	12.43	1.5%
Kerosene	0.11	0.13	0.14	0.13	0.13	0.12	0.11	-0.6%
Jet Fuel[9]	3.26	3.35	3.89	4.27	4.53	4.61	4.79	1.4%
Liquefied Petroleum Gas	2.76	2.85	2.92	3.02	3.14	3.27	3.40	0.7%
Motor Gasoline[2]	16.98	17.30	18.70	19.91	21.10	22.19	23.38	1.2%
Petrochemical Feedstock	1.37	1.49	1.48	1.49	1.51	1.53	1.55	0.2%
Residual Fuel	0.90	0.97	0.94	0.94	0.96	0.98	0.99	0.1%
Other Petroleum[12]	4.26	4.32	4.75	4.99	5.21	5.50	5.86	1.2%
Petroleum Subtotal	37.83	38.96	42.17	44.72	47.17	49.57	52.51	1.2%
Natural Gas	15.96	15.79	16.63	17.39	17.97	18.51	19.13	0.7%
Lease and Plant Fuel[6]	1.16	1.14	1.12	1.22	1.28	1.24	1.21	0.2%
Pipeline Natural Gas	0.69	0.69	0.65	0.74	0.80	0.79	0.78	0.5%
Natural Gas Subtotal	17.81	17.62	18.40	19.35	20.06	20.55	21.11	0.7%
Metallurgical Coal	0.67	0.65	0.62	0.61	0.59	0.58	0.58	-0.4%
Other Coal	1.47	1.47	1.53	1.52	1.53	1.53	1.54	0.2%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.16	0.49	1.22	1.61	33.8%
Net Coal Coke Imports	0.05	0.14	0.02	0.02	0.02	0.01	0.02	-8.1%
Coal Subtotal	2.19	2.26	2.17	2.31	2.63	3.35	3.74	2.0%
Renewable Energy[13]	2.08	2.17	2.32	2.41	2.53	2.66	2.80	1.0%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity	11.96	12.17	13.57	14.67	15.79	16.91	18.22	1.6%
Delivered Energy	**71.87**	**73.18**	**78.62**	**83.46**	**88.19**	**93.04**	**98.40**	**1.1%**
Electricity Related Losses	26.18	26.50	29.24	30.71	32.45	33.95	35.48	1.1%
Total	**98.05**	**99.68**	**107.87**	**114.18**	**120.63**	**126.99**	**133.88**	**1.1%**
Electric Power[14]								
Distillate Fuel	0.29	0.17	0.23	0.23	0.24	0.26	0.27	1.8%
Residual Fuel	0.84	0.95	0.74	0.73	0.73	0.74	0.80	-0.6%
Petroleum Subtotal	1.13	1.12	0.97	0.96	0.97	1.00	1.07	-0.2%
Natural Gas	5.23	5.45	5.65	7.32	7.65	7.23	6.54	0.7%
Steam Coal	20.19	20.26	22.92	23.35	25.02	27.54	30.74	1.6%
Nuclear Power	7.96	8.23	8.44	8.66	9.09	9.09	9.09	0.4%
Renewable Energy[15]	3.62	3.57	4.76	5.01	5.47	5.95	6.22	2.2%
Electricity Imports	0.02	0.04	0.07	0.08	0.05	0.05	0.05	0.9%
Total	**38.14**	**38.67**	**42.82**	**45.38**	**48.24**	**50.86**	**53.71**	**1.3%**

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

Sector and Source	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Total Energy Consumption								
Distillate Fuel	8.48	8.72	9.57	10.19	10.83	11.64	12.70	1.5%
Kerosene	0.11	0.13	0.14	0.13	0.13	0.12	0.11	-0.6%
Jet Fuel[9]	3.26	3.35	3.89	4.27	4.53	4.61	4.79	1.4%
Liquefied Petroleum Gas	2.76	2.85	2.92	3.02	3.14	3.27	3.40	0.7%
Motor Gasoline[2]	16.98	17.30	18.70	19.91	21.10	22.19	23.38	1.2%
Petrochemical Feedstock	1.37	1.49	1.48	1.49	1.51	1.53	1.55	0.2%
Residual Fuel	1.74	1.91	1.68	1.67	1.69	1.72	1.79	-0.3%
Other Petroleum[12]	4.26	4.32	4.75	4.99	5.21	5.50	5.86	1.2%
Petroleum Subtotal	38.96	40.08	43.14	45.69	48.14	50.57	53.58	1.1%
Natural Gas	21.19	21.24	22.28	24.71	25.62	25.75	25.67	0.7%
Lease and Plant Fuel[6]	1.16	1.14	1.12	1.22	1.28	1.24	1.21	0.2%
Pipeline Natural Gas	0.69	0.69	0.65	0.74	0.80	0.79	0.78	0.5%
Natural Gas Subtotal	23.04	23.07	24.04	26.67	27.70	27.78	27.66	0.7%
Metallurgical Coal	0.67	0.65	0.62	0.61	0.59	0.58	0.58	-0.4%
Other Coal	21.66	21.74	24.45	24.88	26.55	29.07	32.29	1.5%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.16	0.49	1.22	1.61	33.8%
Net Coal Coke Imports	0.05	0.14	0.02	0.02	0.02	0.01	0.02	-8.1%
Coal Subtotal	22.38	22.53	25.09	25.66	27.65	30.89	34.49	1.7%
Nuclear Power	7.96	8.23	8.44	8.66	9.09	9.09	9.09	0.4%
Renewable Energy[16]	5.70	5.74	7.08	7.43	8.00	8.61	9.02	1.8%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electricity Imports	0.02	0.04	0.07	0.08	0.05	0.05	0.05	0.9%
Total	**98.05**	**99.68**	**107.87**	**114.18**	**120.63**	**126.99**	**133.88**	**1.1%**
Energy Use and Related Statistics								
Delivered Energy Use	71.87	73.18	78.62	83.46	88.19	93.04	98.40	1.1%
Total Energy Use	98.05	99.68	107.87	114.18	120.63	126.99	133.88	1.1%
Population (millions)	291.39	294.10	310.12	323.55	336.99	350.64	364.79	0.8%
Gross Domestic Product (billion 2000 dollars)	10321	10756	13043	15082	17541	20123	23112	3.0%
Carbon Dioxide Emissions (million metric tons)	5795.5	5899.9	6364.9	6717.6	7119.0	7586.7	8114.5	1.2%

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 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 A17 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[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 for on- and off- road use.
[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 2003 and 2004 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: 2003 and 2004 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). 2003 and 2004 population and gross domestic product: Global Insight macroeconomic model CTL0805. 2003 and 2004 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2004,* DOE/EIA-0573(2004) (Washington, DC, December 2005). **Projections:** EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

Table A3. Energy Prices by Sector and Source
(2004 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Residential	**16.25**	**17.31**	**16.98**	**16.65**	**17.19**	**17.89**	**18.51**	**0.3%**
Primary Energy[1]	9.90	11.39	11.28	10.82	11.31	12.01	12.62	0.4%
Petroleum Products[2]	11.61	14.63	14.77	14.72	15.94	17.31	18.42	0.9%
Distillate Fuel	9.85	13.62	12.85	12.73	13.55	14.23	14.56	0.3%
Liquefied Petroleum Gas	15.00	17.30	18.17	17.91	19.34	21.19	22.68	1.0%
Natural Gas	9.43	10.40	10.33	9.80	10.16	10.76	11.32	0.3%
Electricity	26.14	26.19	24.78	24.24	24.44	24.76	25.02	-0.2%
Commercial	**15.95**	**16.56**	**16.27**	**15.80**	**16.28**	**16.95**	**17.52**	**0.2%**
Primary Energy[1]	8.11	9.20	8.96	8.45	8.74	9.21	9.65	0.2%
Petroleum Products[2]	8.17	10.39	10.56	10.65	11.22	11.78	12.28	0.6%
Distillate Fuel	7.24	9.99	10.15	10.39	10.89	11.33	11.77	0.6%
Residual Fuel	5.11	6.37	6.14	6.04	6.31	6.66	6.91	0.3%
Natural Gas	8.26	9.10	8.76	8.12	8.37	8.83	9.29	0.1%
Electricity	23.90	23.52	22.31	21.66	22.00	22.52	22.90	-0.1%
Industrial[3]	**8.03**	**8.67**	**8.48**	**8.15**	**8.48**	**8.84**	**9.27**	**0.3%**
Primary Energy	6.66	7.42	7.19	6.92	7.24	7.62	8.09	0.3%
Petroleum Products[2]	8.60	9.65	9.46	9.44	9.94	10.63	11.36	0.6%
Distillate Fuel	7.45	10.29	10.75	11.42	11.84	12.35	12.91	0.9%
Liquefied Petroleum Gas	12.93	14.24	12.03	11.80	12.92	14.06	15.25	0.3%
Residual Fuel	4.72	5.88	6.31	6.32	6.70	6.99	7.27	0.8%
Natural Gas[4]	5.59	6.10	5.69	5.16	5.49	5.99	6.45	0.2%
Metallurgical Coal[5]	1.90	2.24	2.36	2.19	2.23	2.28	2.28	0.1%
Other Industrial Coal[5]	1.62	1.74	1.86	1.80	1.81	1.86	1.92	0.4%
Coal to Liquids	N/A	N/A	N/A	0.86	1.04	1.22	1.26	N/A
Electricity	15.49	15.54	15.65	14.95	15.35	15.76	15.95	0.1%
Transportation	**11.83**	**13.81**	**14.83**	**14.82**	**15.38**	**15.84**	**16.32**	**0.6%**
Primary Energy	11.80	13.79	14.82	14.80	15.36	15.83	16.31	0.6%
Petroleum Products[2]	11.80	13.79	14.82	14.82	15.38	15.84	16.32	0.7%
Distillate Fuel[6]	11.24	13.25	14.29	14.56	14.78	15.15	15.65	0.6%
Jet Fuel[7]	6.65	9.02	9.67	9.87	10.49	10.92	11.53	0.9%
Motor Gasoline[8]	13.31	15.34	16.52	16.34	17.02	17.49	17.92	0.6%
Residual Fuel	4.63	4.91	6.43	6.31	6.54	7.05	7.59	1.7%
Liquefied Petroleum Gas[9]	17.14	17.14	16.72	16.33	16.82	18.40	19.25	0.4%
Natural Gas[10]	8.90	9.94	10.09	9.61	9.90	10.32	10.68	0.3%
Ethanol (E85)[11]	16.71	20.24	21.19	20.50	21.10	21.74	22.48	0.4%
Electricity	21.74	21.67	20.76	20.25	20.56	20.86	21.00	-0.1%
Average End-Use Energy	**11.82**	**13.00**	**13.32**	**13.16**	**13.66**	**14.14**	**14.64**	**0.5%**
Primary Energy	9.58	11.04	11.52	11.40	11.89	12.35	12.86	0.6%
Electricity	22.28	22.19	21.43	20.87	21.23	21.69	22.00	-0.0%
Electric Power[12]								
Fossil Fuel Average	2.35	2.46	2.41	2.41	2.46	2.50	2.49	0.0%
Petroleum Products	5.35	5.43	6.50	6.52	6.91	7.37	7.61	1.3%
Distillate Fuel	6.65	9.23	9.04	9.02	9.62	10.05	10.28	0.4%
Residual Fuel	4.90	4.76	5.70	5.72	6.02	6.43	6.73	1.3%
Natural Gas	5.66	5.92	5.46	5.08	5.40	5.87	6.26	0.2%
Steam Coal[5]	1.33	1.36	1.48	1.40	1.39	1.44	1.51	0.4%

Table A3. Energy Prices by Sector and Source (Continued)
(2004 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Average Price to All Users[13]								
Petroleum Products[2]	10.86	12.61	13.41	13.45	14.05	14.61	15.16	0.7%
Distillate Fuel	10.20	12.62	13.30	13.72	14.07	14.52	15.04	0.7%
Jet Fuel	6.65	9.02	9.67	9.87	10.49	10.92	11.53	0.9%
Liquefied Petroleum Gas	13.40	14.89	13.39	13.19	14.38	15.66	16.90	0.5%
Motor Gasoline[8]	13.30	15.33	16.52	16.34	17.02	17.49	17.92	0.6%
Residual Fuel	4.80	5.04	6.07	6.03	6.31	6.75	7.12	1.3%
Natural Gas	6.98	7.52	7.19	6.60	6.93	7.47	7.98	0.2%
Metallurgical Coal[5]	1.90	2.24	2.36	2.19	2.23	2.28	2.28	0.1%
Other Coal[5]	1.35	1.39	1.51	1.43	1.42	1.46	1.53	0.4%
Coal to Liquids	0.00	0.00	0.00	0.86	1.04	1.22	1.26	N/A
Ethanol (E85)[11]	16.71	20.24	21.19	20.50	21.10	21.74	22.48	0.4%
Electricity	22.28	22.19	21.43	20.87	21.23	21.69	22.00	-0.0%
Non-Renewable Energy Expenditures by Sector (billion 2004 dollars)								
Residential	180.52	190.90	200.59	206.16	221.50	236.52	252.12	1.1%
Commercial	131.57	135.07	145.01	154.28	172.19	193.44	216.48	1.8%
Industrial	153.18	170.01	169.60	167.05	179.83	197.21	216.86	0.9%
Transportation	312.29	374.67	445.81	479.43	530.44	578.48	635.46	2.1%
Total Non-Renewable Expenditures	777.56	870.65	961.01	1006.92	1103.97	1205.65	1320.94	1.6%
Transportation Renewable Expenditures	0.02	0.02	0.05	0.08	0.10	0.12	0.13	6.9%
Total Expenditures	**777.58**	**870.67**	**961.06**	**1007.00**	**1104.07**	**1205.76**	**1321.07**	**1.6%**

[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 energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Excludes use for lease and plant fuel.
[5]Excludes imported coal.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[8]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[9]Includes Federal and State taxes while excluding county and local taxes.
[10]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes.
[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 electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[13]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.
N/A = Not applicable.
Note: Data for 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2003 and 2004 prices for motor gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2004*, DOE/EIA-0487(2004) (Washington, DC, August 2005). 2003 residential and commercial natural gas delivered prices: EIA,*Natural Gas Annual 2003*, DOE/EIA-0131(2003) (Washington, DC, December 2004). 2004 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2005/06) (Washington, DC, June 2005). 2003 and 2004 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2003*, DOE/EIA-0131(2003) (Washington, DC, December 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2005/06) (Washington, DC, June 2005). 2003 transportation sector natural gas delivered prices are based on EIA, *Natural Gas Annual 2003*, DOE/EIA-0131(2003) (Washington, DC, December 2004) and estimated state and federal taxes. 2004 transportation sector natural gas delivered prices are model results. 2003 and 2004 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004, Table 4.11.A. 2003 and 2004 coal prices based on: EIA, *Quarterly Coal Report, October-December 2004*, DOE/EIA-0121(2004/4Q) (Washington, DC, March 2005) and EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A. 2003 and 2004 electricity prices: EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). 2003 and 2004 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

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

Key Indicators and Consumption	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Key Indicators								
Households (millions)								
Single-Family	76.15	77.53	84.95	90.49	95.85	100.66	105.20	1.2%
Multifamily	29.51	29.80	31.46	32.72	34.09	35.37	36.81	0.8%
Mobile Homes	6.35	6.32	6.52	6.90	7.25	7.52	7.80	0.8%
Total	**112.01**	**113.65**	**122.93**	**130.11**	**137.19**	**143.55**	**149.81**	**1.1%**
Average House Square Footage	**1728**	**1740**	**1812**	**1861**	**1905**	**1944**	**1977**	**0.5%**
Energy Intensity								
(million Btu per household)								
Delivered Energy Consumption	102.7	100.6	99.6	98.4	97.0	95.0	93.7	-0.3%
Total Energy Consumption	187.7	185.1	187.0	185.0	183.4	180.3	177.8	-0.2%
(thousand Btu per square foot)								
Delivered Energy Consumption	59.5	57.8	55.0	52.9	50.9	48.9	47.4	-0.8%
Total Energy Consumption	108.6	106.4	103.2	99.4	96.3	92.8	89.9	-0.6%
Delivered Energy Consumption by Fuel								
Electricity								
Space Heating	0.40	0.39	0.44	0.46	0.48	0.49	0.49	0.9%
Space Cooling	0.65	0.64	0.70	0.73	0.77	0.80	0.85	1.1%
Water Heating	0.37	0.37	0.38	0.39	0.39	0.39	0.39	0.2%
Refrigeration	0.41	0.40	0.37	0.35	0.36	0.36	0.38	-0.2%
Cooking	0.10	0.10	0.11	0.12	0.13	0.14	0.14	1.2%
Clothes Dryers	0.24	0.24	0.26	0.27	0.28	0.29	0.30	0.8%
Freezers	0.13	0.13	0.12	0.12	0.12	0.13	0.13	0.1%
Lighting	0.76	0.78	0.85	0.93	0.99	1.05	1.11	1.4%
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.6%
Dishwashers[1]	0.02	0.02	0.03	0.03	0.03	0.03	0.03	1.2%
Color Televisions	0.13	0.14	0.19	0.23	0.27	0.28	0.30	3.0%
Personal Computers	0.07	0.07	0.10	0.11	0.13	0.14	0.16	3.1%
Furnace Fans	0.08	0.08	0.09	0.10	0.11	0.11	0.12	1.4%
Other Uses[2]	0.94	1.00	1.31	1.51	1.70	1.86	2.03	2.8%
Delivered Energy	**4.34**	**4.41**	**4.99**	**5.38**	**5.77**	**6.10**	**6.47**	**1.5%**
Natural Gas								
Space Heating	3.69	3.50	3.73	3.87	3.98	4.02	4.06	0.6%
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.9%
Water Heating	1.17	1.15	1.19	1.22	1.25	1.26	1.28	0.4%
Cooking	0.21	0.21	0.23	0.24	0.26	0.27	0.28	1.0%
Clothes Dryers	0.07	0.07	0.08	0.09	0.10	0.11	0.11	1.8%
Other Uses[3]	0.10	0.10	0.09	0.09	0.09	0.09	0.09	-0.4%
Delivered Energy	**5.25**	**5.03**	**5.33**	**5.52**	**5.68**	**5.74**	**5.82**	**0.6%**
Distillate								
Space Heating	0.79	0.82	0.73	0.69	0.64	0.59	0.53	-1.7%
Water Heating	0.11	0.12	0.11	0.10	0.09	0.08	0.08	-1.9%
Other Uses[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Delivered Energy	**0.91**	**0.94**	**0.84**	**0.79**	**0.73**	**0.67**	**0.61**	**-1.7%**
Liquefied Petroleum Gas								
Space Heating	0.29	0.29	0.28	0.28	0.28	0.27	0.26	-0.4%
Water Heating	0.05	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	0.03	0.4%
Other Uses[3]	0.16	0.17	0.20	0.23	0.25	0.28	0.30	2.2%
Delivered Energy	**0.52**	**0.54**	**0.56**	**0.59**	**0.61**	**0.63**	**0.65**	**0.7%**
Marketed Renewables (wood)[5]	0.40	0.41	0.44	0.43	0.43	0.42	0.41	0.1%
Other Fuels[6]	0.09	0.10	0.10	0.10	0.09	0.09	0.08	-1.0%

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

Key Indicators and Consumption	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Delivered Energy Consumption by End Use								
Space Heating	5.66	5.51	5.73	5.84	5.91	5.87	5.84	0.2%
Space Cooling	0.65	0.64	0.70	0.73	0.77	0.80	0.85	1.1%
Water Heating	1.70	1.70	1.73	1.76	1.78	1.78	1.80	0.2%
Refrigeration	0.41	0.40	0.37	0.35	0.36	0.36	0.38	-0.2%
Cooking	0.34	0.35	0.37	0.39	0.42	0.43	0.45	1.0%
Clothes Dryers	0.31	0.32	0.34	0.36	0.38	0.39	0.42	1.1%
Freezers	0.13	0.13	0.12	0.12	0.12	0.13	0.13	0.1%
Lighting	0.76	0.78	0.85	0.93	0.99	1.05	1.11	1.4%
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.6%
Dishwashers	0.02	0.02	0.03	0.03	0.03	0.03	0.03	1.2%
Color Televisions	0.13	0.14	0.19	0.23	0.27	0.28	0.30	3.0%
Personal Computers	0.07	0.07	0.10	0.11	0.13	0.14	0.16	3.1%
Furnace Fans	0.08	0.08	0.09	0.10	0.11	0.11	0.12	1.4%
Other Uses[7]	1.20	1.27	1.60	1.83	2.04	2.22	2.42	2.5%
Delivered Energy	**11.51**	**11.44**	**12.25**	**12.81**	**13.31**	**13.64**	**14.04**	**0.8%**
Electricity Related Losses	**9.51**	**9.60**	**10.74**	**11.26**	**11.85**	**12.24**	**12.60**	**1.1%**
Total Energy Consumption by End Use								
Space Heating	6.55	6.36	6.68	6.81	6.89	6.84	6.80	0.3%
Space Cooling	2.08	2.04	2.22	2.26	2.34	2.42	2.51	0.8%
Water Heating	2.52	2.51	2.55	2.58	2.59	2.57	2.56	0.1%
Refrigeration	1.29	1.27	1.15	1.09	1.08	1.09	1.12	-0.5%
Cooking	0.57	0.57	0.62	0.65	0.68	0.70	0.73	0.9%
Clothes Dryers	0.84	0.85	0.89	0.91	0.94	0.97	1.01	0.7%
Freezers	0.42	0.41	0.37	0.37	0.38	0.38	0.39	-0.2%
Lighting	2.41	2.46	2.69	2.87	3.03	3.15	3.27	1.1%
Clothes Washers	0.10	0.10	0.10	0.09	0.08	0.08	0.08	-0.9%
Dishwashers	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.9%
Color Televisions	0.42	0.45	0.60	0.71	0.82	0.86	0.89	2.7%
Personal Computers	0.22	0.22	0.32	0.35	0.38	0.42	0.46	2.8%
Furnace Fans	0.27	0.26	0.30	0.31	0.33	0.34	0.35	1.2%
Other Uses[7]	3.26	3.46	4.42	4.98	5.52	5.95	6.38	2.4%
Total	**21.02**	**21.04**	**22.99**	**24.07**	**25.17**	**25.88**	**26.64**	**0.9%**
Nonmarketed Renewables								
Geothermal[8]	0.00	0.00	0.01	0.01	0.01	0.01	0.01	7.1%
Solar[9]	0.02	0.02	0.03	0.04	0.04	0.05	0.05	3.0%
Total	**0.02**	**0.03**	**0.04**	**0.04**	**0.05**	**0.06**	**0.06**	**3.5%**

[1]Does not include electric water heating portion of load.
[2]Includes small electric devices, heating elements, and motors not listed above.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as swimming pool and spa 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 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2003 and 2004 based on: Energy Information Administration (EIA), *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

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

Key Indicators and Consumption	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Key Indicators								
Total Floorspace (billion square feet)								
Surviving	71.6	73.1	80.4	86.8	93.7	101.2	109.4	1.6%
New Additions	2.1	2.0	2.0	2.1	2.3	2.4	2.6	1.1%
Total	**73.7**	**75.0**	**82.3**	**88.9**	**96.0**	**103.7**	**112.0**	**1.6%**
Energy Consumption Intensity (thousand Btu per square foot)								
Delivered Energy Consumption	113.2	109.9	109.3	110.8	111.1	111.0	111.0	0.0%
Electricity Related Losses	121.6	121.6	127.7	127.9	128.7	128.5	127.5	0.2%
Total Energy Consumption	234.8	231.5	237.0	238.8	239.8	239.5	238.6	0.1%
Delivered Energy Consumption by Fuel								
Purchased Electricity								
Space Heating[1]	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.7%
Space Cooling[1]	0.43	0.41	0.44	0.46	0.48	0.51	0.55	1.1%
Water Heating[1]	0.14	0.14	0.14	0.15	0.15	0.16	0.16	0.5%
Ventilation	0.16	0.17	0.17	0.18	0.19	0.20	0.21	1.0%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.1%
Lighting	1.09	1.10	1.17	1.27	1.36	1.44	1.52	1.2%
Refrigeration	0.20	0.21	0.22	0.24	0.25	0.27	0.29	1.3%
Office Equipment (PC)	0.13	0.14	0.23	0.26	0.29	0.30	0.30	3.0%
Office Equipment (non-PC)	0.27	0.31	0.46	0.55	0.65	0.76	0.89	4.1%
Other Uses[2]	1.48	1.53	1.84	2.12	2.44	2.80	3.19	2.9%
Delivered Energy	**4.09**	**4.19**	**4.88**	**5.43**	**6.01**	**6.63**	**7.34**	**2.2%**
Natural Gas								
Space Heating[1]	1.27	1.20	1.30	1.40	1.47	1.53	1.60	1.1%
Space Cooling[1]	0.01	0.01	0.01	0.02	0.02	0.03	0.03	4.3%
Water Heating[1]	0.55	0.54	0.53	0.60	0.65	0.71	0.76	1.3%
Cooking	0.26	0.26	0.28	0.32	0.35	0.37	0.40	1.7%
Other Uses[3]	1.23	1.07	1.05	1.13	1.19	1.25	1.32	0.8%
Delivered Energy	**3.32**	**3.09**	**3.18**	**3.46**	**3.68**	**3.89**	**4.11**	**1.1%**
Distillate								
Space Heating[1]	0.21	0.19	0.22	0.23	0.23	0.24	0.25	1.0%
Water Heating[1]	0.07	0.07	0.06	0.06	0.06	0.06	0.06	-0.1%
Other Uses[4]	0.20	0.24	0.20	0.20	0.20	0.20	0.20	-0.7%
Delivered Energy	**0.48**	**0.50**	**0.48**	**0.49**	**0.50**	**0.51**	**0.52**	**0.1%**
Marketed Renewables (biomass)	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.0%
Other Fuels[5]	0.35	0.37	0.37	0.38	0.38	0.38	0.39	0.2%
Delivered Energy Consumption by End Use								
Space Heating[1]	1.63	1.55	1.67	1.79	1.87	1.94	2.02	1.0%
Space Cooling[1]	0.44	0.42	0.46	0.48	0.51	0.54	0.58	1.2%
Water Heating[1]	0.76	0.75	0.73	0.80	0.87	0.93	0.99	1.1%
Ventilation	0.16	0.17	0.17	0.18	0.19	0.20	0.21	1.0%
Cooking	0.29	0.29	0.32	0.35	0.38	0.40	0.43	1.5%
Lighting	1.09	1.10	1.17	1.27	1.36	1.44	1.52	1.2%
Refrigeration	0.20	0.21	0.22	0.24	0.25	0.27	0.29	1.3%
Office Equipment (PC)	0.13	0.14	0.23	0.26	0.29	0.30	0.30	3.0%
Office Equipment (non-PC)	0.27	0.31	0.46	0.55	0.65	0.76	0.89	4.1%
Other Uses[6]	3.36	3.31	3.55	3.93	4.31	4.72	5.19	1.7%
Delivered Energy	**8.34**	**8.24**	**9.00**	**9.85**	**10.66**	**11.50**	**12.44**	**1.6%**

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

Key Indicators and Consumption	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Electricity Related Losses	**8.96**	**9.13**	**10.51**	**11.37**	**12.35**	**13.32**	**14.29**	**1.7%**
Total Energy Consumption by End Use								
Space Heating[1]	1.97	1.87	2.02	2.13	2.21	2.29	2.37	0.9%
Space Cooling[1]	1.39	1.32	1.41	1.44	1.50	1.57	1.66	0.9%
Water Heating[1]	1.06	1.06	1.04	1.11	1.18	1.24	1.30	0.8%
Ventilation	0.52	0.53	0.54	0.56	0.57	0.60	0.63	0.7%
Cooking	0.36	0.36	0.38	0.42	0.44	0.46	0.49	1.2%
Lighting	3.48	3.51	3.70	3.94	4.15	4.33	4.49	1.0%
Refrigeration	0.65	0.66	0.71	0.74	0.78	0.82	0.86	1.0%
Office Equipment (PC)	0.41	0.44	0.74	0.82	0.88	0.89	0.89	2.7%
Office Equipment (non-PC)	0.86	0.99	1.46	1.71	1.98	2.29	2.63	3.8%
Other Uses[6]	6.61	6.64	7.52	8.37	9.33	10.34	11.41	2.1%
Total	**17.30**	**17.37**	**19.51**	**21.23**	**23.02**	**24.82**	**26.73**	**1.7%**
Nonmarketed Renewable Fuels								
Solar[7]	0.02	0.03	0.03	0.03	0.03	0.03	0.04	1.6%

[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 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2003 and 2004 based on: Energy Information Administration (EIA), *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

Table A6. Industrial Sector Key Indicators and Consumption

Key Indicators and Consumption	Reference Case 2003	2004	2010	2015	2020	2025	2030	Annual Growth 2004-2030 (percent)
Key Indicators								
Value of Shipments (billion 2000 dollars)								
Manufacturing	3985	4204	4783	5347	5969	6664	7509	2.3%
Nonmanufacturing	1393	1439	1572	1689	1808	1926	2069	1.4%
Total	**5378**	**5643**	**6355**	**7036**	**7778**	**8589**	**9578**	**2.1%**
Energy Prices (2004 dollars per million Btu)								
Distillate Oil	7.45	10.29	10.75	11.42	11.84	12.35	12.91	0.9%
Liquefied Petroleum Gas	12.93	14.24	12.03	11.80	12.92	14.06	15.25	0.3%
Residual Oil	4.72	5.88	6.31	6.32	6.70	6.99	7.27	0.8%
Motor Gasoline	13.16	15.18	16.46	16.29	16.97	17.43	17.87	0.6%
Natural Gas	5.59	6.10	5.69	5.16	5.49	5.99	6.45	0.2%
Metallurgical Coal	1.90	2.24	2.36	2.19	2.23	2.28	2.28	0.1%
Other Industrial Coal	1.62	1.74	1.86	1.80	1.81	1.86	1.92	0.4%
Coal to Liquids	N/A	N/A	N/A	0.86	1.04	1.22	1.26	N/A
Electricity	15.49	15.54	15.65	14.95	15.35	15.76	15.95	0.1%
Energy Consumption (quadrillion Btu)[1]								
Distillate	1.14	1.19	1.20	1.20	1.23	1.26	1.32	0.4%
Liquefied Petroleum Gas	2.12	2.19	2.21	2.26	2.34	2.44	2.54	0.6%
Petrochemical Feedstocks	1.37	1.49	1.48	1.49	1.51	1.53	1.55	0.2%
Residual Fuel	0.22	0.24	0.20	0.19	0.20	0.21	0.21	-0.4%
Motor Gasoline	0.31	0.32	0.32	0.32	0.32	0.33	0.34	0.2%
Petroleum Coke	0.83	0.94	1.12	1.18	1.24	1.26	1.34	1.4%
Still Gas	1.55	1.55	1.78	1.94	2.07	2.27	2.44	1.8%
Asphalt and Road Oil	1.22	1.24	1.22	1.23	1.25	1.30	1.39	0.4%
Miscellaneous Petroleum[2]	0.53	0.43	0.48	0.48	0.49	0.50	0.52	0.7%
Petroleum Subtotal	9.28	9.58	10.01	10.29	10.65	11.10	11.66	0.8%
Natural Gas	7.38	7.64	8.07	8.33	8.52	8.77	9.08	0.7%
Lease and Plant Fuel[3]	1.16	1.14	1.12	1.22	1.28	1.24	1.21	0.2%
Natural Gas Subtotal	8.54	8.78	9.19	9.55	9.80	10.02	10.29	0.6%
Metallurgical Coal and Coke[4]	0.72	0.79	0.64	0.62	0.61	0.59	0.59	-1.1%
Other Industrial Coal	1.38	1.38	1.43	1.43	1.43	1.43	1.45	0.2%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.16	0.49	1.22	1.61	33.8%
Coal Subtotal	2.09	2.16	2.07	2.21	2.53	3.25	3.65	2.0%
Renewables[5]	1.59	1.68	1.79	1.90	2.01	2.14	2.29	1.2%
Purchased Electricity	3.44	3.48	3.62	3.76	3.91	4.08	4.31	0.8%
Delivered Energy	**24.94**	**25.68**	**26.67**	**27.72**	**28.91**	**30.58**	**32.19**	**0.9%**
Electricity Related Losses	7.53	7.58	7.79	7.88	8.04	8.19	8.39	0.4%
Total	**32.46**	**33.27**	**34.46**	**35.60**	**36.95**	**38.77**	**40.58**	**0.8%**
Energy Consumption per dollar of Shipment (thousand Btu per 2000 dollars)								
Distillate	0.21	0.21	0.19	0.17	0.16	0.15	0.14	-1.6%
Liquefied Petroleum Gas	0.39	0.39	0.35	0.32	0.30	0.28	0.27	-1.4%
Petrochemical Feedstocks	0.25	0.26	0.23	0.21	0.19	0.18	0.16	-1.9%
Residual Fuel	0.04	0.04	0.03	0.03	0.03	0.02	0.02	-2.4%
Motor Gasoline	0.06	0.06	0.05	0.05	0.04	0.04	0.04	-1.8%
Petroleum Coke	0.15	0.17	0.18	0.17	0.16	0.15	0.14	-0.7%
Still Gas	0.29	0.28	0.28	0.28	0.27	0.26	0.25	-0.3%
Asphalt and Road Oil	0.23	0.22	0.19	0.17	0.16	0.15	0.15	-1.6%
Miscellaneous Petroleum[2]	0.10	0.08	0.08	0.07	0.06	0.06	0.05	-1.3%
Petroleum Subtotal	1.73	1.70	1.57	1.46	1.37	1.29	1.22	-1.3%
Natural Gas	1.37	1.35	1.27	1.18	1.09	1.02	0.95	-1.4%
Lease and Plant Fuel[3]	0.22	0.20	0.18	0.17	0.16	0.14	0.13	-1.8%
Natural Gas Subtotal	1.59	1.56	1.45	1.36	1.26	1.17	1.07	-1.4%
Metallurgical Coal and Coke[4]	0.13	0.14	0.10	0.09	0.08	0.07	0.06	-3.1%
Other Industrial Coal	0.26	0.24	0.23	0.20	0.18	0.17	0.15	-1.8%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.02	0.06	0.14	0.17	31.1%
Coal Subtotal	0.39	0.38	0.33	0.31	0.33	0.38	0.38	-0.0%
Renewables[5]	0.30	0.30	0.28	0.27	0.26	0.25	0.24	-0.8%
Purchased Electricity	0.64	0.62	0.57	0.53	0.50	0.47	0.45	-1.2%
Delivered Energy	**4.64**	**4.55**	**4.20**	**3.94**	**3.72**	**3.56**	**3.36**	**-1.2%**
Electricity Related Losses	1.40	1.34	1.23	1.12	1.03	0.95	0.88	-1.6%
Total	**6.04**	**5.89**	**5.42**	**5.06**	**4.75**	**4.51**	**4.24**	**-1.3%**

Table A6. Industrial Sector Key Indicators and Consumption (Continued)

Key Indicators and Consumption	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Industrial Combined Heat and Power								
Capacity (gigawatts)	26.74	27.53	30.09	34.56	41.70	53.64	60.83	3.1%
Generation (billion kilowatthours)	149.85	149.23	178.58	212.43	266.77	356.08	412.59	4.0%

[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 lubricants 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.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2003 and 2004 prices for motor gasoline and distillate are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2004*, DOE/EIA-0487(2004) (Washington, DC, August 2005). 2003 and 2004 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2004*, DOE/EIA-0121(2004/4Q) (Washington, DC, March 2005) and EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A. 2003 and 2004 electricity prices: EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). 2003 and 2004 natural gas prices based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2003*, DOE/EIA-0131(2003) (Washington, DC, December 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2005/06) (Washington, DC, June 2005). 2003 and 2004 consumption values based on: EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). 2003 and 2004 shipments: Global Insight industry model, July 2004. **Projections:** EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Key Indicators								
Level of Travel								
(billion vehicle miles traveled)								
Light-Duty Vehicles less than 8,500 pounds	2594	2632	2890	3171	3474	3791	4132	1.8%
Commercial Light Trucks[1]	66	69	77	85	94	103	115	2.0%
Freight Trucks greater than 10,000 pounds	216	226	261	292	328	367	413	2.3%
(billion seat miles available)								
Air	919	980	1192	1340	1452	1507	1567	1.8%
(billion ton miles traveled)								
Rail	1489	1539	1721	1825	1983	2188	2403	1.7%
Domestic Shipping	597	629	683	727	767	792	824	1.0%
Energy Efficiency Indicators								
(miles per gallon)								
New Light-Duty Vehicle[2]	25.0	24.9	26.7	27.4	28.0	28.8	29.2	0.6%
New Car[2]	29.4	29.3	31.4	32.2	32.7	33.5	33.8	0.6%
New Light Truck[2]	21.6	21.5	23.2	24.0	24.9	25.8	26.4	0.8%
Light-Duty Stock[3]	20.2	20.2	20.4	20.8	21.4	22.0	22.5	0.4%
New Commercial Light Truck[1]	14.4	14.5	15.4	15.8	16.3	16.9	17.1	0.6%
Stock Commercial Light Truck[1]	14.0	14.1	14.6	15.2	15.7	16.2	16.7	0.7%
Freight Truck	6.0	6.0	6.0	6.2	6.4	6.6	6.8	0.5%
(seat miles per gallon)								
Aircraft	55.3	55.5	59.0	63.0	67.6	72.4	76.0	1.2%
(ton miles per thousand Btu)								
Rail	2.9	2.9	2.9	2.9	3.0	3.0	3.0	0.1%
Domestic Shipping	2.1	2.1	2.2	2.2	2.2	2.2	2.2	0.2%
Energy Use by Mode								
(quadrillion Btu)								
Light-Duty Vehicles	15.90	16.21	17.71	19.00	20.30	21.56	22.98	1.4%
Commercial Light Trucks[1]	0.59	0.61	0.66	0.70	0.75	0.80	0.86	1.3%
Bus Transportation	0.26	0.27	0.28	0.29	0.29	0.29	0.30	0.4%
Freight Trucks	4.50	4.70	5.42	5.92	6.37	6.90	7.57	1.9%
Rail, Passenger	0.13	0.13	0.14	0.15	0.15	0.16	0.17	0.8%
Rail, Freight	0.51	0.53	0.59	0.62	0.67	0.74	0.80	1.6%
Shipping, Domestic	0.28	0.30	0.32	0.33	0.35	0.36	0.37	0.8%
Shipping, International	0.51	0.55	0.55	0.56	0.56	0.57	0.57	0.1%
Recreational Boats	0.16	0.17	0.17	0.17	0.18	0.18	0.19	0.5%
Air	2.76	2.82	3.32	3.68	3.92	3.98	4.15	1.5%
Military Use	0.67	0.71	0.76	0.78	0.81	0.82	0.84	0.7%
Lubricants	0.15	0.15	0.15	0.15	0.15	0.16	0.16	0.4%
Pipeline Fuel	0.69	0.69	0.65	0.74	0.80	0.79	0.78	0.5%
Total	**27.12**	**27.82**	**30.70**	**33.09**	**35.30**	**37.31**	**39.72**	**1.4%**

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption (Continued)

Key Indicators and Consumption	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Energy Use by Mode (million barrels per day oil equivalent)								
Light-Duty Vehicles	8.36	8.51	9.40	10.13	10.83	11.49	12.23	1.4%
Commercial Light Trucks[1]	0.31	0.32	0.35	0.37	0.40	0.43	0.46	1.4%
Bus Transportation	0.12	0.13	0.13	0.14	0.14	0.14	0.14	0.5%
Freight Trucks	2.15	2.24	2.59	2.84	3.05	3.31	3.63	1.9%
Rail, Passenger	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.8%
Rail, Freight	0.24	0.25	0.28	0.30	0.32	0.35	0.38	1.6%
Shipping, Domestic	0.13	0.14	0.15	0.16	0.16	0.17	0.17	0.9%
Shipping, International	0.22	0.24	0.24	0.24	0.25	0.25	0.25	0.1%
Recreational Boats	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.5%
Air	1.33	1.37	1.60	1.78	1.90	1.93	2.01	1.5%
Military Use	0.32	0.34	0.36	0.38	0.39	0.40	0.40	0.7%
Lubricants	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.4%
Pipeline Fuel	0.35	0.35	0.33	0.37	0.41	0.40	0.39	0.5%
Total	**13.76**	**14.09**	**15.67**	**16.94**	**18.08**	**19.10**	**20.32**	**1.4%**

[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.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2003 and 2004: Energy Information Administration (EIA), *Natural Gas Annual 2003*, DOE/EIA-0131(2003) (Washington, DC, December 2004); Federal Highway Administration, *Highway Statistics 2003* (Washington, DC, December 2004); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 24 and Annual* (Oak Ridge, TN, December 2004); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, March 2004); 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 2004*, http://www.eia.doe.gov/fuelrenewable.html; EIA, *State Energy Data Report 2001*, DOE/EIA-0214(2001) (Washington, DC, December 2004) U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2004/2003* (Washington, DC, 2004); EIA, *Fuel Oil and Kerosene Sales 2003*, DOE/EIA-0535(2003) (Washington, DC, November 2004); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

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

Supply, Disposition, and Prices	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Generation by Fuel Type								
Electric Power Sector[1]								
Power Only[2]								
Coal	1916	1916	2164	2209	2405	2728	3178	2.0%
Petroleum	111	110	90	89	90	93	99	-0.4%
Natural Gas[3]	439	486	533	743	814	775	691	1.4%
Nuclear Power	764	789	809	829	871	871	871	0.4%
Pumped Storage/Other	-9	-8	-9	-9	-9	-9	-9	0.3%
Renewable Sources[4]	322	319	432	445	465	486	500	1.7%
Distributed Generation (Natural Gas)	0	0	0	0	1	1	2	N/A
Total	**3543**	**3612**	**4020**	**4306**	**4638**	**4945**	**5332**	**1.5%**
Combined Heat and Power[5]								
Coal	37	38	30	30	30	29	27	-1.3%
Petroleum	5	5	2	2	2	2	2	-2.8%
Natural Gas	129	132	140	159	153	141	131	-0.1%
Renewable Sources	4	4	4	4	4	4	4	-0.3%
Total	**177**	**182**	**176**	**195**	**189**	**177**	**164**	**-0.4%**
Total Net Generation	**3720**	**3794**	**4196**	**4501**	**4827**	**5121**	**5497**	**1.4%**
Less Direct Use	27	26	28	28	28	28	28	0.3%
Net Available to the Grid	**3694**	**3768**	**4168**	**4473**	**4799**	**5093**	**5469**	**1.4%**
End-Use Generation[6]								
Coal	21	23	23	38	70	139	175	8.2%
Petroleum	5	5	12	13	14	13	13	3.9%
Natural Gas	83	83	101	116	134	152	169	2.8%
Other Gaseous Fuels[7]	7	5	4	4	5	5	5	0.3%
Renewable Sources[4]	35	35	40	43	46	50	55	1.8%
Other[8]	11	12	12	12	12	12	12	-0.0%
Total	**162**	**161**	**192**	**226**	**280**	**370**	**429**	**3.8%**
Less Direct Use	137	135	149	163	186	224	250	2.4%
Total Sales to the Grid	**24**	**26**	**43**	**62**	**94**	**146**	**179**	**7.7%**
Total Electricity Generation	**3882**	**3955**	**4388**	**4727**	**5108**	**5491**	**5926**	**1.6%**
Total Net Generation to the Grid	**3718**	**3793**	**4211**	**4536**	**4893**	**5240**	**5648**	**1.5%**
Net Imports	**6**	**11**	**22**	**23**	**14**	**15**	**14**	**0.9%**
Electricity Sales by Sector								
Residential	1273	1293	1461	1576	1691	1787	1897	1.5%
Commercial	1200	1229	1430	1592	1762	1944	2151	2.2%
Industrial	1008	1021	1060	1103	1147	1195	1262	0.8%
Transportation	25	25	26	28	29	30	31	0.9%
Total	**3505**	**3567**	**3978**	**4300**	**4629**	**4956**	**5341**	**1.6%**
Direct Use	164	161	177	192	214	252	278	2.1%
Total Electricity Use	**3669**	**3729**	**4155**	**4491**	**4844**	**5208**	**5619**	**1.6%**
End-Use Prices (2004 cents per kilowatthour)								
Residential	8.9	8.9	8.5	8.3	8.3	8.4	8.5	-0.2%
Commercial	8.2	8.0	7.6	7.4	7.5	7.7	7.8	-0.1%
Industrial	5.3	5.3	5.3	5.1	5.2	5.4	5.4	0.1%
Transportation	7.4	7.4	7.1	6.9	7.0	7.1	7.2	-0.1%
All Sectors Average	**7.6**	**7.6**	**7.3**	**7.1**	**7.2**	**7.4**	**7.5**	**-0.0%**
Prices by Service Category (2004 cents per kilowatthour)								
Generation	5.0	5.0	4.7	4.6	4.8	5.0	5.1	0.1%
Transmission	0.6	0.5	0.6	0.6	0.7	0.7	0.7	0.9%
Distribution	2.1	2.1	2.0	1.9	1.9	1.8	1.8	-0.6%

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

Supply, Disposition, and Prices	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Electric Power Sector Emissions[1]								
Sulfur Dioxide (million tons)	10.60	10.89	5.91	4.63	4.04	3.80	3.72	-4.0%
Nitrogen Oxide (million tons)	4.12	3.74	2.34	2.10	2.13	2.16	2.17	-2.1%
Mercury (tons)	50.70	53.31	37.73	24.04	18.74	16.59	15.31	-4.7%

[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 North American Industry Classification System code 22).
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[7]Other gaseous fuels include refinery and still gas.
[8]Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2003 and 2004 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 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005), and supporting databases. 2003 and 2004 commercial and transportation electricity sales based on: EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005), and Oak Ridge National Laboratory, *Transportation Energy Data Book 24* (Oak Ridge, TN, December 2004). 2003 and 2004 prices: EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A. **Projections**: EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

Table A9. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Electric Power Sector[2]								
Power Only[3]								
Coal Steam	305.5	305.0	313.7	315.0	340.9	385.7	453.1	1.5%
Other Fossil Steam[4]	128.8	123.8	121.8	85.9	79.8	78.8	74.8	-1.9%
Combined Cycle	110.4	126.3	151.5	157.0	181.4	193.4	198.3	1.7%
Combustion Turbine/Diesel	125.2	127.2	136.1	136.3	146.1	155.9	170.8	1.1%
Nuclear Power[5]	99.5	99.6	100.9	104.0	108.8	108.8	108.8	0.3%
Pumped Storage	20.7	20.8	20.8	20.8	20.8	20.8	20.8	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[6]	91.4	91.9	102.3	104.6	107.8	111.4	113.7	0.8%
Distributed Generation[7]	0.0	0.0	0.2	0.6	1.4	2.4	5.5	N/A
Total	**881.5**	**894.6**	**947.4**	**924.2**	**986.9**	**1057.2**	**1145.7**	**1.0%**
Combined Heat and Power[8]								
Coal Steam	4.9	4.9	4.9	4.3	4.3	4.3	4.3	-0.4%
Other Fossil Steam[4]	0.5	0.5	0.5	0.5	0.5	0.5	0.5	N/A
Combined Cycle	31.7	32.4	32.3	32.3	32.3	32.3	32.3	-0.0%
Combustion Turbine/Diesel	2.9	2.9	2.9	2.9	2.9	2.9	2.9	-0.0%
Renewable Sources[6]	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.2%
Total	**40.4**	**41.0**	**41.0**	**40.5**	**40.5**	**40.5**	**40.5**	**-0.0%**
Cumulative Planned Additions[9]								
Coal Steam	0.0	0.0	8.3	9.3	9.3	9.3	9.3	N/A
Other Fossil Steam[4]	0.0	0.0	0.1	0.1	0.1	0.1	0.1	N/A
Combined Cycle	0.0	0.0	25.7	25.7	25.7	25.7	25.7	N/A
Combustion Turbine/Diesel	0.0	0.0	5.3	5.3	5.3	5.3	5.3	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[6]	0.0	0.0	10.0	11.0	11.1	11.2	11.4	N/A
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Total	**0.0**	**0.0**	**49.4**	**51.5**	**51.6**	**51.7**	**51.8**	**N/A**
Cumulative Unplanned Additions[9]								
Coal Steam	0.0	0.0	3.4	7.0	32.9	77.7	145.1	N/A
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Combined Cycle	0.0	0.0	0.0	5.5	29.9	41.9	46.8	N/A
Combustion Turbine/Diesel	0.0	0.0	4.7	11.6	21.5	31.3	46.2	N/A
Nuclear Power	0.0	0.0	0.0	2.2	6.0	6.0	6.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[6]	0.0	0.0	0.4	1.7	4.8	8.3	10.4	N/A
Distributed Generation[7]	0.0	0.0	0.2	0.6	1.4	2.4	5.5	N/A
Total	**0.0**	**0.0**	**8.8**	**28.6**	**96.5**	**167.7**	**260.0**	**N/A**
Cumulative Electric Power Sector	**0.0**	**0.0**	**58.2**	**80.1**	**148.1**	**219.3**	**311.8**	**N/A**
Cumulative Retirements[10]								
Coal Steam	0.0	0.0	3.0	6.8	6.8	6.8	6.8	N/A
Other Fossil Steam[4]	0.0	0.0	2.0	37.9	44.0	45.1	49.0	N/A
Combined Cycle	0.0	0.0	0.6	0.6	0.6	0.6	0.6	N/A
Combustion Turbine/Diesel	0.0	0.0	1.4	8.2	8.2	8.2	8.2	N/A
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Renewable Sources[6]	0.0	0.0	0.1	0.1	0.1	0.1	0.1	N/A
Total	**0.0**	**0.0**	**7.1**	**53.6**	**59.8**	**60.8**	**64.7**	**N/A**
Total Electric Power Sector Capacity	**921.9**	**935.6**	**988.4**	**964.7**	**1027.4**	**1097.7**	**1186.2**	**0.9%**

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

Net Summer Capacity[1]	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
End-Use Generators[11]								
Coal	4.2	4.1	4.2	6.2	10.2	19.2	23.6	6.9%
Petroleum	0.8	1.6	1.8	1.8	2.0	1.8	1.9	0.7%
Natural Gas	15.7	15.8	17.7	19.6	22.1	24.5	26.7	2.0%
Other Gaseous Fuels	1.8	1.8	1.5	1.5	1.5	1.5	1.6	-0.5%
Renewable Sources[6]	5.3	5.4	6.6	7.1	7.7	8.4	9.9	2.4%
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	N/A
Total	**28.5**	**29.3**	**32.4**	**36.9**	**44.2**	**56.3**	**64.3**	**3.1%**
Cumulative Capacity Additions[9]	**0.0**	**0.0**	**3.1**	**7.6**	**14.8**	**26.9**	**35.0**	**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 includes 3 gigawatts of uprates through 2030.
[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 North American Industry Classification System code 22).
[9]Cumulative additions after December 31, 2004.
[10]Cumulative retirements after December 31, 2004.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2003 and 2004 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

Table A10. Electricity Trade

(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Interregional Electricity Trade								
Gross Domestic Sales								
Firm Power	136.7	142.4	105.5	82.4	50.6	37.9	37.9	-5.0%
Economy	215.1	233.2	231.5	200.4	168.3	165.4	158.2	-1.5%
Total	**351.8**	**375.6**	**336.9**	**282.8**	**218.9**	**203.3**	**196.1**	**-2.5%**
Gross Domestic Sales (million 2004 dollars)								
Firm Power	7129.0	7428.5	5500.9	4298.7	2639.5	1975.9	1975.9	-5.0%
Economy	9070.8	9820.2	9433.0	8328.1	7360.0	7381.2	7234.1	-1.2%
Total	**16199.8**	**17248.6**	**14933.9**	**12626.8**	**9999.5**	**9357.1**	**9210.0**	**-2.4%**
International Electricity Trade								
Imports from Canada and Mexico								
Firm Power	11.3	12.5	2.5	1.9	0.8	0.4	0.4	-12.5%
Economy	19.0	21.6	39.7	39.3	28.6	27.1	26.5	0.8%
Total	**30.3**	**34.1**	**42.3**	**41.1**	**29.4**	**27.5**	**26.9**	**-0.9%**
Exports to Canada and Mexico								
Firm Power	5.5	7.4	1.0	0.7	0.2	0.0	0.0	N/A
Economy	18.7	15.6	19.6	17.2	14.8	12.9	12.9	-0.7%
Total	**24.1**	**23.0**	**20.6**	**17.8**	**15.0**	**12.9**	**12.9**	**-2.2%**

N/A = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2003 and 2004 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: 2003 and 2004 interregional firm electricity trade data: North American Electric Reliability Council (NERC), Electricity Sales and Demand Database 2003. 2003 and 2004 Mexican electricity trade data: DOE Form FE-718R, “Annual Report of International Electrical Export/Import Data.” 2003 Canadian international electricity trade data: National Energy Board, *Annual Report 2003*. 2004 Canadian electricity trade data: National Energy Board, *Annual Report 2004*. **Projections:** Energy Information Administration, AEO2006 National Energy Modeling System run AEO2006.D111905A.

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

Supply and Disposition	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Crude Oil								
Domestic Crude Production[1]	5.69	5.42	5.88	5.84	5.55	4.99	4.57	-0.7%
Alaska	0.99	0.91	0.83	0.89	0.76	0.47	0.27	-4.5%
Lower 48 States	4.71	4.51	5.05	4.95	4.79	4.52	4.30	-0.2%
Net Imports	9.65	10.06	10.05	10.47	11.26	12.33	13.51	1.1%
Gross Imports	9.66	10.09	10.08	10.50	11.28	12.35	13.53	1.1%
Exports	0.01	0.03	0.03	0.03	0.03	0.02	0.02	-0.7%
Other Crude Supply[2]	-0.03	-0.00	0.00	0.00	0.00	0.00	0.00	N/A
Total Crude Supply	**15.32**	**15.48**	**15.93**	**16.31**	**16.81**	**17.32**	**18.08**	**0.6%**
Other Petroleum Supply								
Natural Gas Plant Liquids	1.72	1.81	1.75	1.88	1.94	1.90	1.87	0.1%
Net Product Imports	1.60	2.05	2.28	2.76	3.16	3.35	3.73	2.3%
Gross Refined Product Imports[3]	1.85	2.07	2.39	2.83	3.13	3.25	3.56	2.1%
Unfinished Oil Imports	0.34	0.49	0.41	0.44	0.54	0.60	0.66	1.2%
Blending Component Imports	0.41	0.41	0.46	0.49	0.52	0.55	0.57	1.3%
Exports	0.96	0.96	0.98	1.00	1.03	1.04	1.07	0.4%
Refinery Processing Gain[4]	0.97	1.05	1.31	1.37	1.44	1.63	1.82	2.1%
Other Inputs	0.44	0.35	0.94	1.25	1.52	1.92	2.16	7.2%
Liquids from Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Liquids from Coal	0.00	0.00	0.00	0.08	0.23	0.58	0.76	N/A
Other[5]	0.44	0.35	0.94	1.18	1.28	1.34	1.39	5.4%
Total Primary Supply[6]	**20.05**	**20.74**	**22.21**	**23.57**	**24.87**	**26.12**	**27.65**	**1.1%**
Refined Petroleum Products Supplied								
by Fuel								
Motor Gasoline[7]	8.94	9.10	9.94	10.63	11.28	11.86	12.49	1.2%
Jet Fuel[8]	1.58	1.63	1.88	2.06	2.19	2.23	2.31	1.4%
Distillate Fuel[9]	3.93	4.06	4.61	4.91	5.21	5.59	6.09	1.6%
Residual Fuel	0.77	0.87	0.73	0.73	0.74	0.75	0.78	-0.4%
Other[10]	4.84	5.10	5.01	5.20	5.40	5.62	5.89	0.6%
by Sector								
Residential and Commercial	1.24	1.29	1.25	1.26	1.25	1.23	1.22	-0.2%
Industrial[11]	4.86	5.02	5.23	5.37	5.55	5.78	6.06	0.7%
Transportation	13.34	13.69	15.27	16.48	17.57	18.59	19.81	1.4%
Electric Power[12]	0.50	0.49	0.43	0.43	0.43	0.44	0.47	-0.1%
Total	**20.05**	**20.76**	**22.17**	**23.53**	**24.81**	**26.05**	**27.57**	**1.1%**
Discrepancy[13]	**-0.01**	**-0.02**	**0.03**	**0.04**	**0.05**	**0.07**	**0.09**	**N/A**

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

Supply and Disposition	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Imported Low Sulfur Light Crude Oil Price (2004 dollars per barrel)[14]	31.72	40.49	47.29	47.79	50.70	54.08	56.97	1.3%
Imported Crude Oil Price (2004 dollars per barrel)[14]	28.46	35.99	43.99	43.00	44.99	47.99	49.99	1.3%
Import Share of Product Supplied	0.56	0.58	0.56	0.56	0.58	0.60	0.62	0.3%
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2004 dollars)	117.53	152.36	189.84	201.18	231.71	268.22	310.15	2.8%
Domestic Refinery Distillation Capacity[15]	16.8	16.9	17.6	17.9	18.1	18.5	19.3	0.5%
Capacity Utilization Rate (percent)[16]	93.0	93.0	91.9	92.2	94.1	95.1	94.8	0.1%

[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 other hydrocarbons and alcohols.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes petroleum product stock withdrawals; domestic sources of blending components, other hydrocarbons, alcohols, and ethers.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes only kerosene type.
[9]Includes distillate and kerosene.
[10]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[11]Includes consumption for combined heat and power (CHP), which produces electricity and other useful thermal energy.
[12]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.
[13]Balancing item. Includes unaccounted for supply, losses, and gains.
[14]Weighted average price delivered to U.S. refiners.
[15]End-of-year operable capacity.
[16]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2003 and 2004 imported crude oil price and petroleum product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). 2003 and 2004 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2003 data: EIA, *Petroleum Supply Annual 2003,* DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). Other 2004 data: EIA, *Petroleum Supply Annual 2004,* DOE/EIA-0340(2004)/1 (Washington, DC, June 2005). **Projections:** EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

Table A12. Petroleum Product Prices
(2004 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Crude Oil Prices (2004 dollars per barrel)								
Imported Low Sulfur Light Crude Oil Price[1]	31.72	40.49	47.29	47.79	50.70	54.08	56.97	1.3%
Imported Crude Oil Price[1]	28.46	35.99	43.99	43.00	44.99	47.99	49.99	1.3%
Delivered Sector Product Prices								
Residential								
Distillate Fuel	136.6	188.8	178.2	176.6	188.0	197.4	202.0	0.3%
Liquefied Petroleum Gas	129.7	149.1	156.5	154.3	166.6	182.6	195.4	1.0%
Commercial								
Distillate Fuel	100.2	138.3	140.0	143.2	150.1	156.3	162.2	0.6%
Residual Fuel	76.5	95.3	91.8	90.5	94.4	99.7	103.5	0.3%
Residual Fuel (2004 dollars per barrel)	32.13	40.03	38.57	38.00	39.66	41.88	43.47	0.3%
Industrial[2]								
Distillate Fuel	103.2	142.5	147.8	156.8	162.5	169.6	177.2	0.8%
Liquefied Petroleum Gas	111.7	122.7	103.6	101.7	111.3	121.1	131.4	0.3%
Residual Fuel	70.7	87.9	94.4	94.6	100.2	104.6	108.9	0.8%
Residual Fuel (2004 dollars per barrel)	29.69	36.94	39.67	39.74	42.10	43.95	45.72	0.8%
Transportation								
Diesel Fuel (distillate)[3]	154.8	182.4	195.9	199.5	202.5	207.6	214.4	0.6%
Jet Fuel[4]	89.7	121.8	130.6	133.2	141.6	147.4	155.6	0.9%
Motor Gasoline[5]	165.0	190.4	202.7	199.6	207.6	213.4	218.8	0.5%
Liquid Petroleum Gas	148.1	147.7	144.0	140.7	144.9	158.5	165.8	0.4%
Residual Fuel	69.2	73.5	96.3	94.5	97.8	105.5	113.6	1.7%
Residual Fuel (2004 dollars per barrel)	29.08	30.89	40.43	39.68	41.09	44.31	47.70	1.7%
Ethanol (E85)[6]	156.9	190.2	198.3	191.5	197.1	203.1	210.0	0.4%
Ethanol Wholesale Price	134.2	171.5	157.5	146.1	164.1	169.0	167.2	-0.1%
Electric Power[7]								
Distillate Fuel	92.2	128.0	125.4	125.2	133.5	139.4	142.6	0.4%
Residual Fuel	73.4	71.2	85.3	85.6	90.1	96.3	100.7	1.3%
Residual Fuel (2004 dollars per barrel)	30.82	29.90	35.84	35.95	37.84	40.44	42.29	1.3%
Refined Petroleum Product Prices[8]								
Distillate Fuel	140.8	174.2	182.8	188.3	193.1	199.2	206.3	0.7%
Jet Fuel[4]	89.7	121.8	130.6	133.2	141.6	147.4	155.6	0.9%
Liquefied Petroleum Gas	115.8	128.3	115.4	113.7	123.9	134.9	145.6	0.5%
Motor Gasoline[5]	164.9	190.4	202.7	199.6	207.6	213.4	218.8	0.5%
Residual Fuel	71.9	75.5	90.9	90.3	94.5	101.0	106.6	1.3%
Residual Fuel (2004 dollars per barrel)	30.19	31.71	38.19	37.94	39.70	42.42	44.75	1.3%
Average	**140.6**	**164.3**	**173.2**	**173.4**	**181.1**	**187.9**	**194.7**	**0.7%**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[4]Includes only kerosene type.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]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.
[7]Includes 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.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2003 and 2004 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” 2003 and 2004 imported crude oil price: EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). 2003 and 2004 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2004*, DOE/EIA-0487(2004) (Washington, DC, August 2005). 2003 and 2004 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.” 2003 and 2004 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.” 2003 and 2004 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2003 and 2004 wholesale ethanol prices derived from Bloomburg U.S. average rack price. **Projections:** EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

Table A13. Natural Gas Supply, Disposition, and Prices
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Production								
Dry Gas Production[1]	19.04	18.46	18.58	20.36	21.44	21.16	20.83	0.5%
Supplemental Natural Gas[2]	0.07	0.06	0.07	0.07	0.07	0.07	0.07	1.1%
Net Imports	**3.29**	**3.40**	**4.35**	**5.10**	**5.02**	**5.37**	**5.57**	**1.9%**
Pipeline	2.85	2.81	2.28	2.05	1.32	1.24	1.22	-3.2%
Liquefied Natural Gas[3]	0.44	0.59	2.07	3.05	3.70	4.13	4.36	8.0%
Total Supply	**22.40**	**21.92**	**23.00**	**25.54**	**26.54**	**26.60**	**26.48**	**0.7%**
Consumption by Sector								
Residential	5.08	4.88	5.17	5.36	5.51	5.57	5.64	0.6%
Commercial	3.22	3.00	3.08	3.36	3.57	3.77	3.99	1.1%
Industrial[4]	7.14	7.41	7.82	8.08	8.26	8.51	8.81	0.7%
Electric Power[5]	5.10	5.32	5.51	7.14	7.46	7.05	6.38	0.7%
Transportation[6]	0.02	0.02	0.05	0.08	0.09	0.11	0.12	6.2%
Pipeline Fuel	0.66	0.67	0.63	0.71	0.78	0.77	0.75	0.5%
Lease and Plant Fuel[7]	1.13	1.11	1.09	1.18	1.25	1.20	1.17	0.2%
Total	**22.34**	**22.41**	**23.35**	**25.91**	**26.92**	**26.99**	**26.86**	**0.7%**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Discrepancy[8]	**0.06**	**-0.49**	**-0.36**	**-0.37**	**-0.38**	**-0.38**	**-0.39**	**N/A**
Natural Gas Prices (2004 dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[9]	**5.08**	**5.49**	**5.03**	**4.52**	**4.90**	**5.43**	**5.92**	**0.3%**
Delivered Prices								
Residential	9.74	10.72	10.65	10.11	10.48	11.10	11.67	0.3%
Commercial	8.53	9.38	9.03	8.37	8.63	9.11	9.58	0.1%
Industrial[4]	5.77	6.29	5.86	5.32	5.66	6.18	6.65	0.2%
Electric Power[5]	5.81	6.07	5.60	5.21	5.53	6.02	6.41	0.2%
Transportation[10]	9.20	10.25	10.40	9.91	10.21	10.64	11.01	0.3%
Average[11]	**7.20**	**7.74**	**7.41**	**6.80**	**7.14**	**7.69**	**8.22**	**0.2%**

[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 any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]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.
[6]Compressed natural gas used as vehicle fuel.
[7]Represents natural gas used in field gathering and processing plant machinery.
[8]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, 2003 and 2004 values include net storage injections.
[9]Represents lower 48 onshore and offshore supplies.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2003 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), *Natural Gas Annual 2003*, DOE/EIA-0131(2003) (Washington, DC, December 2004). 2004 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2005/06) (Washington, DC, June 2005), subtracting 1 billion cubic feet per day to account for carbon dioxide included in production in Texas. Other 2003 and 2004 consumption based on: EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). 2003 wellhead price: Mineral Management Service and EIA, *Natural Gas Annual 2003*, DOE/EIA-0131(2003) (Washington, DC, December 2004). 2003 residential and commercial delivered prices: EIA, *Natural Gas Annual 2003*, DOE/EIA-0131(2003) (Washington, DC, December 2004). 2004 residential and commercial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2005/06) (Washington, DC, June 2005). 2003 and 2004 electric power sector prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2004 through April 2005. 2003 and 2004 industrial delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2003*, DOE/EIA-0131(2003) (Washington, DC, December 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2005/06) (Washington, DC, June 2005). 2003 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2003*, DOE/EIA-0131(2003) (Washington, DC, December 2004) and estimated state and federal taxes. 2004 transportation sector delivered prices are model results. **Projections:** EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

Table A14. Oil and Gas Supply

Production and Supply	Reference Case 2003	2004	2010	2015	2020	2025	2030	Annual Growth 2004-2030 (percent)
Crude Oil								
Lower 48 Average Wellhead Price[1] (2004 dollars per barrel)	**29.68**	**38.06**	**43.49**	**44.98**	**47.50**	**50.41**	**53.16**	**1.3%**
Production (million barrels per day)[2]								
U.S. Total	5.69	5.40	5.88	5.84	5.55	4.99	4.57	-0.6%
Lower 48 Onshore	2.99	2.90	2.62	2.48	2.42	2.36	2.27	-0.9%
Lower 48 Offshore	1.72	1.59	2.42	2.47	2.36	2.15	2.03	0.9%
Alaska	0.99	0.91	0.83	0.89	0.76	0.47	0.27	-4.5%
Lower 48 End of Year Reserves[2] (billion barrels)	**18.66**	**18.21**	**19.83**	**19.98**	**19.61**	**18.74**	**17.91**	**-0.1%**
Natural Gas								
Lower 48 Average Wellhead Price[1] (2004 dollars per thousand cubic feet)	**5.08**	**5.49**	**5.03**	**4.52**	**4.90**	**5.43**	**5.92**	**0.3%**
Dry Production (trillion cubic feet)[3]								
U.S. Total	19.04	18.46	18.58	20.36	21.44	21.16	20.83	0.5%
Lower 48 Onshore	13.82	13.76	14.03	14.23	14.52	14.73	14.72	0.3%
Associated-Dissolved[4]	1.49	1.51	1.34	1.26	1.20	1.15	1.10	-1.2%
Non-Associated	12.33	12.26	12.69	12.97	13.33	13.58	13.62	0.4%
Conventional	5.49	4.79	5.01	4.86	4.66	4.44	4.17	-0.5%
Unconventional	6.84	7.47	7.68	8.11	8.66	9.14	9.45	0.9%
Lower 48 Offshore	4.76	4.26	4.31	5.08	4.71	4.25	3.97	-0.3%
Associated-Dissolved[4]	0.95	0.85	1.08	1.40	1.34	1.20	1.15	1.2%
Non-Associated	3.81	3.41	3.23	3.68	3.37	3.05	2.82	-0.7%
Alaska	0.46	0.44	0.24	1.06	2.21	2.19	2.14	6.3%
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**180.76**	**183.64**	**214.35**	**228.95**	**229.52**	**226.85**	**222.72**	**0.7%**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.07**	**0.06**	**0.07**	**0.07**	**0.07**	**0.07**	**0.07**	**1.1%**
Total Lower 48 Wells Drilled (thousands)	**30.62**	**33.74**	**32.31**	**27.86**	**26.95**	**26.40**	**26.42**	**-0.9%**

[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 reservoirs 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 2003 and 2004 are model results and may differ slightly from official EIA data reports.

Sources: 2003 and 2004 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2004,* DOE/EIA-0340(2004)/1 (Washington, DC, June 2005). 2003 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2003) (Washington, DC, November 2004). 2003 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2003*, DOE/EIA-0131(2003) (Washington, DC, December 2004). 2003 natural gas lower 48 average wellhead price: Mineral Management Service and EIA, *Natural Gas Annual 2003*, DOE/EIA-0131(2003) (Washington, DC, December 2004). 2004 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2005/06) (Washington, DC, June 2005), subtracting 1 billion cubic feet per day to account for carbon dioxide included in production in Texas. 2003 and 2004 crude oil lower 48 average wellhead price: EIA, *Petroleum Marketing Annual 2004*, DOE/EIA-0487(2004) (Washington, DC, August 2005). Other 2003 and 2004 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

Table A15. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Production[1]								
Appalachia	388	403	426	389	379	391	412	0.1%
Interior	146	146	190	209	219	236	281	2.5%
West	549	575	645	674	758	904	1010	2.2%
East of the Mississippi	481	497	559	538	542	570	633	0.9%
West of the Mississippi	603	627	702	734	813	960	1070	2.1%
Total	**1083**	**1125**	**1261**	**1272**	**1355**	**1530**	**1703**	**1.6%**
Net Imports								
Imports	25	27	15	27	55	82	99	5.1%
Exports	43	48	41	22	19	20	17	-4.0%
Total	**-18**	**-21**	**-26**	**5**	**36**	**63**	**83**	**N/A**
Total Supply[2]	**1065**	**1104**	**1235**	**1277**	**1391**	**1593**	**1785**	**1.9%**
Consumption by Sector								
Residential and Commercial	4	4	4	4	4	4	4	0.0%
Coke Plants	24	24	23	22	22	21	21	-0.4%
Other Industrial[3]	61	61	66	66	66	67	67	0.4%
Coal-to-Liquids Heat and Power	0	0	0	11	31	74	96	N/A
Coal-to-Liquids Liquids Production	0	0	0	11	31	72	94	N/A
Electric Power[4]	1005	1015	1140	1161	1235	1354	1502	1.5%
Total Coal Use	**1095**	**1104**	**1233**	**1276**	**1390**	**1592**	**1784**	**1.9%**
Discrepancy and Stock Change[5]	**-30**	**-0**	**2**	**1**	**1**	**1**	**1**	**N/A**
Average Minemouth Price								
(2004 dollars per short ton)	18.40	20.07	22.23	20.39	20.20	20.63	21.73	0.3%
(2004 dollars per million Btu)	0.89	0.98	1.09	1.01	1.00	1.03	1.09	0.4%
Delivered Prices (2004 dollars per short ton)[6]								
Coke Plants	51.96	61.50	64.63	60.06	61.12	62.64	62.67	0.1%
Other Industrial[3]	36.22	39.53	39.99	38.48	38.76	39.83	41.05	0.1%
Coal to Liquids	N/A	N/A	N/A	12.74	16.28	20.07	21.06	N/A
Electric Power								
(2004 dollars per short ton)	26.99	27.43	29.74	28.12	28.07	29.02	30.58	0.4%
(2004 dollars per million Btu)	1.33	1.36	1.48	1.40	1.39	1.44	1.51	0.4%
Average	**28.06**	**28.81**	**30.90**	**28.93**	**28.55**	**29.06**	**30.30**	**0.2%**
Exports[7]	40.85	54.11	54.45	46.68	47.86	48.94	46.91	-0.5%

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 11.6 million tons in 2003 and 12.5 million tons in 2004.
[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. Excludes all coal use in the coal-to-liquids process.
[4]Includes all electricity-only and combined heat and power 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]Prices weighted by consumption tonnage less imports; weighted average excludes residential and commercial prices, import 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 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2003 and 2004 data based on: Energy Information Administration (EIA), *Annual Coal Report 2004*, DOE/EIA-0584(2004) (Washington, DC, November 2005); EIA, *Quarterly Coal Report, October-December 2004*, DOE/EIA-0121(2004/4Q) (Washington, DC, March 2005); and EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A. **Projections:** EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

Table A16. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Electric Power Sector[1]								
Net Summer Capacity								
Conventional Hydropower	77.69	77.64	77.67	77.72	77.87	77.87	77.87	0.0%
Geothermal[2]	2.11	2.11	2.56	3.19	4.61	6.02	6.64	4.5%
Municipal Solid Waste[3]	3.19	3.22	3.52	3.65	3.76	3.84	3.87	0.7%
Wood and Other Biomass[4,5]	2.00	2.00	2.15	2.15	2.46	3.45	4.63	3.3%
Solar Thermal	0.39	0.39	0.47	0.48	0.50	0.53	0.55	1.3%
Solar Photovoltaic[6]	0.03	0.03	0.07	0.14	0.22	0.31	0.39	10.5%
Wind	6.39	6.87	16.27	17.71	18.81	19.80	20.10	4.2%
Total	**91.80**	**92.26**	**102.69**	**105.03**	**108.23**	**111.81**	**114.06**	**0.8%**
Generation (billion kilowatthours)								
Conventional Hydropower	270.26	264.50	296.98	297.40	298.46	298.64	298.85	0.5%
Geothermal[2]	14.42	14.36	17.51	22.84	34.01	46.74	52.70	5.1%
Municipal Solid Waste[3]	20.84	19.86	24.89	25.96	26.83	27.52	27.79	1.3%
Wood and Other Biomass[5]	9.53	9.49	44.67	44.80	48.59	51.30	57.83	7.2%
Dedicated Plants	9.53	8.00	10.39	9.98	13.03	22.05	31.67	5.4%
Cofiring	0.00	1.49	34.29	34.82	35.55	29.25	26.16	11.7%
Solar Thermal	0.53	0.58	0.84	0.89	0.96	1.03	1.11	2.5%
Solar Photovoltaic[6]	0.00	0.00	0.18	0.34	0.54	0.76	0.98	26.9%
Wind	11.19	14.15	50.87	55.98	59.82	63.48	64.51	6.0%
Total	**326.78**	**322.93**	**435.94**	**448.23**	**469.21**	**489.47**	**503.77**	**1.7%**
End-Use Generators[7]								
Net Summer Capacity								
Conventional Hydropower[8]	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Municipal Solid Waste	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.0%
Biomass	4.32	4.33	5.01	5.48	6.02	6.60	7.29	2.0%
Solar Photovoltaic[6]	0.08	0.12	0.63	0.68	0.75	0.87	1.68	10.6%
Total	**5.32**	**5.38**	**6.57**	**7.09**	**7.70**	**8.40**	**9.89**	**2.4%**
Generation (billion kilowatthours)								
Conventional Hydropower[8]	4.29	4.45	4.42	4.42	4.42	4.42	4.42	-0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Municipal Solid Waste	2.22	2.12	2.24	2.24	2.24	2.24	2.24	0.2%
Biomass	28.00	27.81	31.81	34.52	37.69	41.05	45.09	1.9%
Solar Photovoltaic[6]	0.17	0.26	1.34	1.46	1.60	1.89	3.62	10.7%
Total	**34.69**	**34.63**	**39.80**	**42.63**	**45.94**	**49.59**	**55.37**	**1.8%**

[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]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). Based on annual PV shipments from 1989 through 2003, EIA estimates that as much as 149 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2003, plus an additional 414 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005), Table 10.6 (annual PV shipments, 1989-2003). 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.
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Represents own-use industrial hydroelectric power.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2003 and 2004 capacity: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2003 and 2004 generation: EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

Table A17. Renewable Energy, Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Marketed Renewable Energy[2]								
Residential (wood)	**0.40**	**0.41**	**0.44**	**0.43**	**0.43**	**0.42**	**0.41**	**0.1%**
Commercial (biomass)	**0.09**	**0.09**	**0.09**	**0.09**	**0.09**	**0.09**	**0.09**	**0.0%**
Industrial[3]	**1.59**	**1.68**	**1.79**	**1.90**	**2.01**	**2.14**	**2.29**	**1.2%**
Conventional Hydroelectric	0.04	0.04	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	0.01	N/A
Biomass	1.53	1.62	1.74	1.84	1.96	2.09	2.24	1.3%
Transportation	**0.23**	**0.28**	**0.66**	**0.87**	**0.96**	**1.00**	**1.01**	**5.0%**
Ethanol used in E85[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.4%
Ethanol used in Gasoline Blending	0.23	0.28	0.65	0.87	0.95	0.99	1.00	5.0%
Electric Power[5]	**3.62**	**3.57**	**4.76**	**5.01**	**5.47**	**5.95**	**6.22**	**2.2%**
Conventional Hydroelectric	2.77	2.67	2.98	2.99	2.99	2.99	2.99	0.4%
Geothermal	0.30	0.30	0.39	0.57	0.92	1.33	1.54	6.5%
Municipal Solid Waste[6]	0.30	0.31	0.33	0.35	0.36	0.37	0.37	0.8%
Biomass	0.12	0.14	0.52	0.52	0.57	0.58	0.63	6.1%
Dedicated Plants	0.12	0.11	0.11	0.10	0.14	0.24	0.34	4.4%
Cofiring	0.00	0.03	0.41	0.42	0.43	0.34	0.30	9.6%
Solar Thermal	0.01	0.01	0.01	0.01	0.02	0.02	0.02	5.1%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Wind	0.11	0.14	0.52	0.58	0.62	0.65	0.66	6.1%
Total Marketed Renewable Energy	**5.93**	**6.02**	**7.73**	**8.30**	**8.96**	**9.60**	**10.02**	**2.0%**
Sources of Ethanol								
From Corn	0.23	0.28	0.61	0.80	0.87	0.91	0.92	4.6%
From Cellulose	0.00	0.00	0.01	0.02	0.02	0.02	0.02	N/A
Imports	0.00	0.00	0.04	0.06	0.06	0.07	0.07	N/A
Total	**0.23**	**0.28**	**0.66**	**0.87**	**0.96**	**1.00**	**1.01**	**5.0%**
Nonmarketed Renewable Energy[7] Selected Consumption								
Residential	**0.02**	**0.03**	**0.04**	**0.04**	**0.05**	**0.06**	**0.06**	**3.5%**
Solar Hot Water Heating	0.02	0.02	0.03	0.03	0.04	0.04	0.05	2.8%
Geothermal Heat Pumps	0.00	0.00	0.01	0.01	0.01	0.01	0.01	7.1%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.8%
Commercial	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**1.6%**
Solar Thermal	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.5%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.01	10.2%

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table A8.
[3]Includes all electricity production by industrial and other 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 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 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2003 and 2004 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). 2003 and 2004 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2003 and 2004 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

Table A18. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Residential								
Petroleum	103.3	108.1	102.0	100.5	97.5	93.0	89.3	-0.7%
Natural Gas	276.9	265.5	281.4	291.6	299.7	303.3	307.3	0.6%
Coal	1.0	1.0	1.1	1.0	1.0	1.0	0.9	-0.4%
Electricity	827.8	833.2	930.5	975.8	1035.6	1100.1	1178.4	1.3%
Total	**1209.0**	**1207.8**	**1315.0**	**1369.0**	**1433.9**	**1497.4**	**1575.9**	**1.0%**
Commercial								
Petroleum	53.9	57.9	55.2	56.4	57.1	57.8	58.7	0.1%
Natural Gas	175.4	162.7	167.9	182.7	194.6	205.4	217.1	1.1%
Coal	8.0	8.2	8.2	8.2	8.2	8.2	8.2	-0.0%
Electricity	779.8	791.6	910.6	985.6	1079.2	1197.1	1335.9	2.0%
Total	**1017.1**	**1020.4**	**1141.8**	**1232.9**	**1339.0**	**1468.5**	**1620.0**	**1.8%**
Industrial[1]								
Petroleum	409.4	440.6	441.5	456.9	475.1	497.5	523.8	0.7%
Natural Gas[2]	428.8	441.9	477.9	497.1	510.4	521.8	535.9	0.7%
Coal	188.9	186.8	192.9	206.4	236.2	303.4	340.6	2.3%
Electricity	655.2	657.7	674.9	682.8	702.6	735.8	784.1	0.7%
Total	**1682.3**	**1727.1**	**1787.2**	**1843.2**	**1924.3**	**2058.4**	**2184.5**	**0.9%**
Transportation								
Petroleum[3]	1833.8	1891.3	2067.1	2212.4	2356.6	2496.3	2667.1	1.3%
Natural Gas[4]	37.3	37.4	37.1	43.0	47.4	47.5	47.5	0.9%
Electricity	15.9	16.0	16.7	17.1	17.7	18.6	19.6	0.8%
Total	**1887.0**	**1944.7**	**2121.0**	**2272.4**	**2421.8**	**2562.4**	**2734.1**	**1.3%**
Electric Power[5]								
Petroleum	97.1	97.4	74.5	73.6	74.5	76.4	81.8	-0.7%
Natural Gas	277.6	295.9	297.4	385.7	402.8	380.7	344.3	0.6%
Coal	1892.4	1893.9	2147.8	2188.4	2343.5	2579.4	2876.6	1.6%
Other[6]	11.7	11.4	13.0	13.6	14.3	15.0	15.3	1.1%
Total	**2278.8**	**2298.6**	**2532.7**	**2661.3**	**2835.2**	**3051.6**	**3318.0**	**1.4%**
Carbon Dioxide Emissions by Primary Fuel[7]								
Petroleum[3]	2497.5	2595.2	2740.3	2899.8	3060.8	3221.0	3420.8	1.1%
Natural Gas	1196.0	1203.4	1261.6	1400.1	1454.9	1458.7	1452.1	0.7%
Coal	2090.2	2089.9	2350.0	2404.0	2589.0	2892.0	3226.3	1.7%
Other[6]	11.7	11.4	13.0	13.6	14.3	15.0	15.3	1.1%
Total	**5795.5**	**5899.9**	**6364.9**	**6717.6**	**7119.0**	**7586.7**	**8114.5**	**1.2%**
Carbon Dioxide Emissions (ton per person)	**19.9**	**20.1**	**20.5**	**20.8**	**21.1**	**21.6**	**22.2**	**0.4%**

[1]Fuel consumption includes energy for combined heat and power plants (CHP), 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 carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2003, international bunker fuels accounted for 83 to 115 million metric tons annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes electricity-only and combined heat and power 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.
[6]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
[7]Emissions from the electric power sector are distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2003 and 2004 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2004,* DOE/EIA-0573(2004) (Washington, DC, December 2005). **Projections:** EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

Table A19. Macroeconomic Indicators
(Billion 2000 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	Reference Case 2003	2004	2010	2015	2020	2025	2030	Annual Growth 2004-2030 (percent)
Real Gross Domestic Product	**10321**	**10756**	**13043**	**15082**	**17541**	**20123**	**23112**	**3.0%**
Real Potential Gross Domestic Product	**10686**	**11030**	**13367**	**15073**	**17176**	**19765**	**22738**	**2.8%**
Components of Real Gross Domestic Product								
Real Consumption	7307	7589	9128	10373	11916	13555	15352	2.7%
Real Investment	1617	1810	2259	2713	3293	4025	4985	4.0%
Real Government Spending	1911	1952	2150	2296	2464	2631	2838	1.4%
Real Exports	1031	1118	1831	2671	3776	5083	6833	7.2%
Real Imports	1553	1719	2295	2857	3659	4734	6156	5.0%
Energy Intensity (thousand Btu per 2000 dollar of GDP)								
Delivered Energy	6.97	6.81	6.03	5.54	5.03	4.63	4.26	-1.8%
Total Energy	9.51	9.27	8.28	7.58	6.88	6.32	5.80	-1.8%
Price Indices								
GDP Chain-Type Price Index (2000=1.000)	1.063	1.091	1.235	1.398	1.597	1.818	2.048	2.5%
Consumer Price Index (1982-4=1)								
All-Urban	1.84	1.89	2.15	2.46	2.86	3.31	3.78	2.7%
Energy Commodities and Services	1.36	1.51	1.67	1.86	2.19	2.57	2.96	2.6%
Wholesale Price Index (1982=1.00)								
All Commodities	1.38	1.47	1.55	1.66	1.82	1.98	2.13	1.5%
Fuel and Power	1.13	1.27	1.36	1.49	1.77	2.12	2.49	2.6%
Interest Rates (percent, nominal)								
Federal Funds Rate	1.13	1.35	5.30	5.46	5.24	5.01	5.04	N/A
10-Year Treasury Note	4.01	4.27	5.92	6.11	6.21	6.14	6.13	N/A
AA Utility Bond Rate	6.39	6.04	7.55	7.69	8.15	8.35	8.52	N/A
Value of Shipments (billion 2000 dollars)								
Total Industrial	5378	5643	6355	7036	7778	8589	9578	2.1%
Non-manufacturing	1393	1439	1572	1689	1808	1926	2069	1.4%
Manufacturing	3985	4204	4783	5347	5969	6664	7509	2.3%
Energy-Intensive	1117	1161	1265	1350	1441	1529	1627	1.3%
Non-Energy Intensive	2868	3044	3518	3997	4528	5135	5882	2.6%
Population and Employment (millions)								
Population, with Armed Forces Overseas	291.4	294.1	310.1	323.5	337.0	350.6	364.8	0.8%
Population, aged 16 and over	226.5	229.1	244.1	254.5	265.3	276.6	288.5	0.9%
Population, over age 65	36.0	36.4	40.4	47.0	54.9	63.8	71.6	2.6%
Employment, Nonfarm	129.9	131.4	142.1	147.6	156.2	164.2	173.6	1.1%
Employment, Manufacturing	14.5	14.3	14.0	13.5	13.3	12.9	12.6	-0.5%
Key Labor Indicators								
Labor Force (millions)	146.5	147.4	158.9	162.9	167.7	173.1	180.8	0.8%
Non-farm Labor Productivity (1992=1.00)	1.29	1.34	1.52	1.73	1.93	2.15	2.42	2.3%
Unemployment Rate (percent)	5.99	5.53	4.69	4.58	4.37	4.80	4.90	N/A
Key Indicators for Energy Demand								
Real Disposable Personal Income	7742	8004	9622	11058	13057	15182	17562	3.1%
Housing Starts (millions)	1.98	2.08	1.97	1.95	1.89	1.83	1.82	-0.5%
Commercial Floorspace (billion square feet)	73.7	75.0	82.3	88.9	96.0	103.7	112.0	1.6%
Unit Sales of Light-Duty Vehicles (millions)	16.64	16.87	17.61	18.00	18.90	20.31	21.75	1.0%

GDP = Gross domestic product.
Btu = British thermal unit.
N/A = Not applicable.
Sources: 2003 and 2004: Global Insight macroeconomic model CTL0805 and Global Insight industry model, July 2004. **Projections:** Energy Information Administration, AEO2006 National Energy Modeling System run AEO2006.D111905A.

Table A20. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Crude Oil Prices (2004 dollars per barrel)								
Imported Low Sulfur Light Crude Oil Price[1]	31.72	40.49	47.29	47.79	50.70	54.08	56.97	1.3%
Imported Crude Oil Price[1]	28.46	35.99	43.99	43.00	44.99	47.99	49.99	1.3%
Production (Conventional)[2]								
Mature Market Economies								
United States (50 states)	8.64	8.41	9.39	9.62	9.51	9.13	8.92	0.2%
Canada	2.37	2.40	1.66	1.43	1.45	1.45	1.43	-2.0%
Mexico	4.00	4.10	3.97	4.19	4.48	4.78	5.01	0.8%
Western Europe[3]	7.04	6.85	5.88	5.32	5.22	4.83	4.37	-1.7%
Japan	0.14	0.14	0.09	0.07	0.07	0.07	0.07	-2.8%
Australia and New Zealand	0.70	0.67	0.89	0.83	0.84	0.83	0.81	0.7%
Total Mature Market Economies	**22.88**	**22.57**	**21.88**	**21.46**	**21.58**	**21.09**	**20.60**	**-0.3%**
Transitional Economies								
Former Soviet Union								
Russia	8.81	9.29	9.50	9.88	10.66	11.06	11.26	0.7%
Caspian Area[4]	1.92	2.32	2.99	4.18	5.16	6.25	7.43	4.6%
Eastern Europe[5]	0.24	0.25	0.31	0.34	0.39	0.44	0.48	2.5%
Total Transitional Economies	**10.96**	**11.86**	**12.80**	**14.40**	**16.21**	**17.74**	**19.17**	**1.9%**
Emerging Economies								
OPEC[6]								
Asia	1.33	1.39	1.49	1.39	1.26	1.17	1.09	-0.9%
Middle East	20.25	21.25	24.76	25.57	26.99	28.88	31.07	1.5%
North Africa	2.89	2.98	3.48	3.53	3.70	3.59	3.50	0.6%
West Africa	1.91	1.96	2.39	2.51	2.61	2.81	3.05	1.7%
South America	2.75	2.82	3.38	3.63	3.70	3.90	4.14	1.5%
Non-OPEC								
China	3.26	3.25	3.38	3.18	3.33	3.30	3.22	-0.0%
Other Asia	2.73	2.88	2.48	2.53	2.61	2.58	2.51	-0.5%
Middle East[7]	1.90	1.76	2.09	2.24	2.45	2.69	2.91	1.9%
Africa	3.10	3.54	3.62	4.49	5.41	6.65	8.03	3.2%
South and Central America	4.14	4.22	4.34	5.04	5.83	6.45	7.00	2.0%
Total Emerging Economies	**44.26**	**46.07**	**51.41**	**54.12**	**57.89**	**62.03**	**66.52**	**1.4%**
Total Production (Conventional)	**78.10**	**80.50**	**86.09**	**89.98**	**95.68**	**100.87**	**106.29**	**1.1%**
Production (Nonconventional)[8]								
United States (50 states)	0.18	0.22	0.48	0.72	0.94	1.31	1.50	7.6%
Other North America	0.79	0.92	1.79	2.32	2.67	3.16	3.58	5.4%
Western Europe	0.03	0.03	0.09	0.11	0.12	0.12	0.13	6.4%
Asia	0.20	0.20	0.68	1.07	1.25	1.54	2.06	9.4%
Middle East[7]	0.01	0.01	0.53	0.64	0.73	0.86	1.08	18.3%
Africa.	0.08	0.08	0.21	0.41	0.53	0.67	0.85	9.4%
South and Central America	0.49	0.49	1.13	1.65	1.78	2.07	2.31	6.1%
Total Production (Nonconventional)	**1.79**	**1.96**	**4.91**	**6.92**	**8.02**	**9.73**	**11.52**	**7.1%**
Total Production	**79.89**	**82.46**	**91.00**	**96.90**	**103.70**	**110.60**	**117.80**	**1.4%**

Table A20. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2004-2030 (percent)
	2003	2004	2010	2015	2020	2025	2030	
Consumption[9]								
Mature Market Economies								
United States (50 states)	20.05	20.76	22.17	23.53	24.81	26.05	27.57	1.1%
United States Territories	0.31	0.33	0.34	0.35	0.38	0.41	0.45	1.2%
Canada	2.11	2.15	2.13	2.18	2.25	2.30	2.34	0.3%
Mexico	1.98	2.00	2.13	2.18	2.24	2.27	2.29	0.5%
Western Europe[3]	13.66	13.63	13.44	13.37	13.52	13.95	14.27	0.2%
Japan	5.24	5.22	4.85	4.57	4.40	4.27	4.13	-0.9%
Australia and New Zealand	1.04	1.07	1.16	1.21	1.28	1.37	1.45	1.2%
Total Mature Market Economies	**44.40**	**45.16**	**46.22**	**47.39**	**48.89**	**50.62**	**52.50**	**0.6%**
Transitional Economies								
Former Soviet Union	4.11	4.14	4.55	4.66	4.93	5.19	5.41	1.0%
Eastern Europe[5]	1.41	1.42	1.58	1.72	1.87	2.01	2.15	1.6%
Total Transitional Economies	**5.52**	**5.56**	**6.13**	**6.38**	**6.81**	**7.20**	**7.57**	**1.2%**
Emerging Economies								
China	5.87	6.63	8.64	9.82	11.38	13.08	14.93	3.2%
India	2.29	2.42	2.92	3.33	3.81	4.30	4.85	2.7%
South Korea	2.20	2.23	2.41	2.50	2.57	2.62	2.66	0.7%
Other Asia	5.84	6.10	7.64	8.69	9.85	10.93	12.05	2.6%
Middle East[7]	5.86	6.09	7.16	7.75	8.34	8.85	9.34	1.7%
Africa	2.81	2.96	3.63	4.00	4.31	4.56	4.81	1.9%
South and Central America	5.11	5.30	6.25	7.02	7.75	8.42	9.10	2.1%
Total Emerging Economies	**29.98**	**31.74**	**38.65**	**43.13**	**48.01**	**52.78**	**57.74**	**2.3%**
Total Consumption	**79.89**	**82.46**	**91.00**	**96.90**	**103.70**	**110.60**	**117.80**	**1.4%**
OPEC Production[10]	29.50	30.78	36.67	38.34	40.27	42.82	45.82	1.5%
Non-OPEC Production[10]	50.39	51.68	54.33	58.56	63.43	67.78	71.98	1.3%
Net Eurasia Exports	5.44	6.31	6.67	8.02	9.40	10.54	11.60	2.4%
OPEC Market Share	0.37	0.37	0.40	0.40	0.39	0.39	0.39	0.2%

[1]Weighted average price delivered to U.S. refiners.
[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, 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 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2003 and 2004 low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2003 and 2004 imported crude oil price: EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). 2003 quantities derived from: EIA, *International Energy Annual 2003*, DOE/EIA-0219(2003) (Washington, DC, May-July 2005). **2004 quantities and projections:** EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

Economic Growth Case Comparisons

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

Supply, Disposition, and Prices	2004	Projections								
		2010			2020			2030		
		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	11.47	12.44	12.45	12.46	11.66	11.75	11.73	9.61	9.68	9.73
Natural Gas Plant Liquids	2.46	2.35	2.39	2.42	2.61	2.67	2.71	2.50	2.57	2.64
Dry Natural Gas	19.02	18.79	19.13	19.48	21.51	22.09	22.64	20.75	21.45	22.15
Coal	22.86	25.27	25.78	26.09	25.70	27.30	29.07	29.78	34.10	38.77
Nuclear Power	8.23	8.44	8.44	8.44	8.93	9.09	9.09	8.94	9.09	9.09
Renewable Energy[1]	5.74	6.98	7.08	7.15	7.55	8.00	8.42	8.34	9.02	9.83
Other[2]	0.64	2.12	2.16	2.20	3.06	3.16	3.26	3.23	3.44	3.69
Total	**70.42**	**76.39**	**77.42**	**78.23**	**81.03**	**84.05**	**86.91**	**83.15**	**89.36**	**95.89**
Imports										
Crude Oil[3]	22.02	21.93	22.01	22.81	23.07	24.63	26.72	26.25	29.54	32.70
Petroleum Products[4]	5.93	5.29	6.36	6.82	6.97	8.01	8.95	7.58	9.27	11.08
Natural Gas	4.36	4.75	5.01	5.30	4.96	5.83	6.27	6.07	6.72	7.49
Other Imports[5]	0.83	0.44	0.45	0.45	1.24	1.36	1.57	2.08	2.42	2.58
Total	**33.14**	**32.41**	**33.83**	**35.38**	**36.24**	**39.83**	**43.50**	**41.97**	**47.95**	**53.84**
Exports										
Petroleum[6]	2.07	2.11	2.15	2.19	2.15	2.24	2.32	2.19	2.31	2.44
Natural Gas	0.86	0.56	0.55	0.55	0.71	0.68	0.65	1.08	1.01	0.92
Coal	1.25	1.03	1.03	1.03	0.47	0.46	0.46	0.39	0.40	0.40
Total	**4.18**	**3.71**	**3.74**	**3.77**	**3.33**	**3.39**	**3.43**	**3.66**	**3.72**	**3.77**
Discrepancy[7]	**-0.31**	**-0.33**	**-0.36**	**-0.36**	**-0.06**	**-0.15**	**-0.27**	**-0.08**	**-0.30**	**-0.42**
Consumption										
Petroleum Products[8]	40.08	41.93	43.14	44.45	45.11	48.14	51.46	47.89	53.58	59.33
Natural Gas	23.07	23.43	24.04	24.68	26.22	27.70	28.73	26.20	27.66	29.23
Coal	22.53	24.58	25.09	25.40	26.13	27.65	29.50	30.13	34.49	38.86
Nuclear Power	8.23	8.44	8.44	8.44	8.93	9.09	9.09	8.94	9.09	9.09
Renewable Energy[1]	5.74	6.98	7.08	7.15	7.55	8.00	8.42	8.34	9.02	9.83
Other[9]	0.04	0.07	0.07	0.08	0.05	0.05	0.05	0.04	0.05	0.05
Total	**99.68**	**105.42**	**107.87**	**110.19**	**114.00**	**120.63**	**127.25**	**121.54**	**133.88**	**146.39**
Net Imports - Petroleum	**25.88**	**25.11**	**26.22**	**27.43**	**27.89**	**30.39**	**33.34**	**31.64**	**36.49**	**41.34**
Prices (2004 dollars per unit)										
Imported Low Sulfur Light Crude Oil Price (dollars per barrel)[10]	40.49	47.29	47.29	47.29	50.70	50.70	50.78	56.97	56.97	56.97
Imported Crude Oil Price (dollars per barrel)[10]	35.99	43.99	43.99	43.99	44.99	44.99	44.99	49.99	49.99	49.99
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	5.49	4.87	5.03	5.20	4.76	4.90	5.10	5.61	5.92	6.22
Coal Minemouth Price (dollars per ton)	20.07	21.79	22.23	22.02	19.60	20.20	20.85	19.96	21.73	23.05
Average Electricity Price (cents per kilowatthour)	7.6	7.2	7.3	7.4	7.0	7.2	7.5	7.2	7.5	7.8

[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] 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] Weighted average price delivered to U.S. refiners. Crude oil prices were held constant in alternative economic growth cases.
[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 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2004 natural gas supply values and natural gas wellhead price: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2005/06) (Washington, DC, June 2005), subtracting 1 billion cubic feet per day to account for carbon dioxide included in production in Texas. 2004 petroleum supply values: EIA, *Petroleum Supply Annual 2004*, DOE/EIA-0340(2004)/1 (Washington, DC, June 2005). 2004 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2004 coal values: *Quarterly Coal Report, October-December 2004*, DOE/EIA-0121(2004/4Q) (Washington, DC, March 2005). Other 2004 values: EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** EIA, AEO2006 National Energy Modeling System runs LM2006.D113005A, AEO2006.D111905A, and HM2006.D112505B.

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

Sector and Source	2004	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Energy Consumption										
Residential										
Distillate Fuel	0.94	0.84	0.84	0.84	0.73	0.73	0.74	0.60	0.61	0.62
Kerosene	0.09	0.09	0.09	0.09	0.08	0.08	0.08	0.07	0.07	0.07
Liquefied Petroleum Gas	0.54	0.55	0.56	0.56	0.60	0.61	0.63	0.61	0.65	0.68
Petroleum Subtotal	1.57	1.48	1.48	1.49	1.41	1.43	1.45	1.28	1.32	1.36
Natural Gas	5.03	5.29	5.33	5.37	5.49	5.68	5.87	5.45	5.82	6.19
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.41	0.43	0.44	0.44	0.42	0.43	0.44	0.40	0.41	0.43
Electricity	4.41	4.94	4.99	5.04	5.55	5.77	5.99	6.00	6.47	6.95
Delivered Energy	**11.44**	**12.16**	**12.25**	**12.34**	**12.88**	**13.31**	**13.75**	**13.13**	**14.04**	**14.94**
Electricity Related Losses	9.60	10.62	10.74	10.79	11.55	11.85	12.15	12.03	12.60	13.15
Total	**21.04**	**22.78**	**22.99**	**23.14**	**24.43**	**25.17**	**25.90**	**25.16**	**26.64**	**28.08**
Commercial										
Distillate Fuel	0.50	0.48	0.48	0.48	0.49	0.50	0.51	0.49	0.52	0.54
Residual Fuel	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.13
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.02	0.03	0.03
Liquefied Petroleum Gas	0.10	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	0.79	0.77	0.77	0.77	0.78	0.79	0.81	0.78	0.82	0.85
Natural Gas	3.09	3.17	3.18	3.19	3.54	3.68	3.83	3.76	4.11	4.46
Coal	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Renewable Energy[3]	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Electricity	4.19	4.86	4.88	4.90	5.77	6.01	6.22	6.71	7.34	7.96
Delivered Energy	**8.24**	**8.97**	**9.00**	**9.03**	**10.26**	**10.66**	**11.03**	**11.42**	**12.44**	**13.45**
Electricity Related Losses	9.13	10.46	10.51	10.50	12.00	12.35	12.63	13.45	14.29	15.07
Total	**17.37**	**19.43**	**19.51**	**19.53**	**22.26**	**23.02**	**23.67**	**24.88**	**26.73**	**28.51**
Industrial[4]										
Distillate Fuel	1.19	1.13	1.20	1.27	1.11	1.23	1.35	1.15	1.32	1.50
Liquefied Petroleum Gas	2.19	2.07	2.21	2.35	2.06	2.34	2.64	2.10	2.54	2.97
Petrochemical Feedstock	1.49	1.38	1.48	1.57	1.32	1.51	1.72	1.27	1.55	1.87
Residual Fuel	0.24	0.19	0.20	0.21	0.19	0.20	0.21	0.19	0.21	0.23
Motor Gasoline[2]	0.32	0.31	0.32	0.34	0.30	0.32	0.35	0.30	0.34	0.37
Other Petroleum[5]	4.16	4.41	4.60	4.83	4.60	5.05	5.66	4.85	5.69	6.54
Petroleum Subtotal	9.58	9.49	10.01	10.57	9.57	10.65	11.93	9.85	11.66	13.49
Natural Gas	7.64	7.80	8.07	8.32	7.89	8.52	9.06	8.11	9.08	10.09
Lease and Plant Fuel[6]	1.14	1.10	1.12	1.13	1.26	1.28	1.31	1.17	1.21	1.24
Natural Gas Subtotal	8.78	8.90	9.19	9.45	9.15	9.80	10.36	9.29	10.29	11.33
Metallurgical Coal	0.65	0.60	0.62	0.64	0.55	0.59	0.64	0.51	0.58	0.64
Other Industrial Coal	1.38	1.41	1.43	1.45	1.39	1.43	1.47	1.38	1.45	1.52
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.26	0.49	0.62	1.28	1.61	2.07
Net Coal Coke Imports	0.14	0.02	0.02	0.02	0.01	0.02	0.02	0.01	0.02	0.02
Coal Subtotal	2.16	2.02	2.07	2.12	2.21	2.53	2.74	3.18	3.65	4.25
Renewable Energy[7]	1.68	1.73	1.79	1.86	1.86	2.01	2.17	1.99	2.29	2.60
Electricity	3.48	3.45	3.62	3.79	3.55	3.91	4.29	3.66	4.31	4.96
Delivered Energy	**25.68**	**25.59**	**26.67**	**27.78**	**26.34**	**28.91**	**31.51**	**27.97**	**32.19**	**36.63**
Electricity Related Losses	7.58	7.42	7.79	8.11	7.39	8.04	8.71	7.34	8.39	9.38
Total	**33.27**	**33.02**	**34.46**	**35.89**	**33.73**	**36.95**	**40.22**	**35.31**	**40.58**	**46.01**

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

Sector and Source	2004	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Transportation										
Distillate Fuel[8]	5.91	6.53	6.82	7.14	7.41	8.13	8.89	8.67	9.98	11.38
Jet Fuel[9]	3.35	3.82	3.89	3.97	4.35	4.53	4.70	4.36	4.79	5.26
Motor Gasoline[2]	16.93	18.03	18.33	18.65	19.77	20.73	21.71	21.08	22.99	24.88
Residual Fuel	0.61	0.62	0.62	0.63	0.63	0.64	0.65	0.64	0.65	0.67
Liquefied Petroleum Gas	0.03	0.06	0.06	0.06	0.08	0.09	0.09	0.10	0.11	0.11
Other Petroleum[10]	0.18	0.18	0.18	0.18	0.18	0.18	0.19	0.18	0.19	0.20
Petroleum Subtotal	27.02	29.23	29.91	30.63	32.43	34.30	36.22	35.03	38.71	42.50
Pipeline Fuel Natural Gas	0.69	0.64	0.65	0.66	0.77	0.80	0.82	0.75	0.78	0.81
Compressed Natural Gas	0.03	0.05	0.05	0.06	0.09	0.09	0.10	0.10	0.12	0.13
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.11
Delivered Energy	**27.82**	**30.01**	**30.70**	**31.44**	**33.39**	**35.30**	**37.25**	**35.99**	**39.72**	**43.56**
Electricity Related Losses	0.18	0.19	0.19	0.19	0.20	0.20	0.21	0.21	0.21	0.21
Total	**28.00**	**30.20**	**30.90**	**31.64**	**33.59**	**35.50**	**37.46**	**36.19**	**39.93**	**43.78**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	8.55	8.98	9.34	9.73	9.74	10.59	11.49	10.90	12.43	14.04
Kerosene	0.13	0.14	0.14	0.14	0.13	0.13	0.13	0.11	0.11	0.12
Jet Fuel[9]	3.35	3.82	3.89	3.97	4.35	4.53	4.70	4.36	4.79	5.26
Liquefied Petroleum Gas	2.85	2.78	2.92	3.07	2.84	3.14	3.47	2.91	3.40	3.87
Motor Gasoline[2]	17.30	18.39	18.70	19.03	20.12	21.10	22.10	21.43	23.38	25.30
Petrochemical Feedstock	1.49	1.38	1.48	1.57	1.32	1.51	1.72	1.27	1.55	1.87
Residual Fuel	0.97	0.93	0.94	0.96	0.94	0.96	0.98	0.95	0.99	1.03
Other Petroleum[12]	4.32	4.56	4.75	4.99	4.76	5.21	5.83	5.01	5.86	6.71
Petroleum Subtotal	38.96	40.97	42.17	43.46	44.19	47.17	50.41	46.93	52.51	58.19
Natural Gas	15.79	16.32	16.63	16.93	17.01	17.97	18.85	17.42	19.13	20.87
Lease and Plant Fuel Plant[6]	1.14	1.10	1.12	1.13	1.26	1.28	1.31	1.17	1.21	1.24
Pipeline Natural Gas	0.69	0.64	0.65	0.66	0.77	0.80	0.82	0.75	0.78	0.81
Natural Gas Subtotal	17.62	18.06	18.40	18.72	19.03	20.06	20.98	19.34	21.11	22.93
Metallurgical Coal	0.65	0.60	0.62	0.64	0.55	0.59	0.64	0.51	0.58	0.64
Other Coal	1.47	1.50	1.53	1.55	1.48	1.53	1.57	1.47	1.54	1.61
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.26	0.49	0.62	1.28	1.61	2.07
Net Coal Coke Imports	0.14	0.02	0.02	0.02	0.01	0.02	0.02	0.01	0.02	0.02
Coal Subtotal	2.26	2.12	2.17	2.21	2.30	2.63	2.84	3.28	3.74	4.35
Renewable Energy[13]	2.17	2.25	2.32	2.39	2.37	2.53	2.70	2.49	2.80	3.13
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.17	13.33	13.57	13.82	14.96	15.79	16.60	16.47	18.22	19.97
Delivered Energy	**73.18**	**76.73**	**78.62**	**80.60**	**82.86**	**88.19**	**93.55**	**88.52**	**98.40**	**108.57**
Electricity Related Losses	26.50	28.69	29.24	29.60	31.14	32.45	33.70	33.02	35.48	37.81
Total	**99.68**	**105.42**	**107.87**	**110.19**	**114.00**	**120.63**	**127.25**	**121.54**	**133.88**	**146.39**
Electric Power[14]										
Distillate Fuel	0.17	0.23	0.23	0.24	0.23	0.24	0.26	0.25	0.27	0.30
Residual Fuel	0.95	0.73	0.74	0.75	0.69	0.73	0.79	0.71	0.80	0.84
Petroleum Subtotal	1.12	0.96	0.97	0.99	0.91	0.97	1.05	0.96	1.07	1.14
Natural Gas	5.45	5.37	5.65	5.96	7.19	7.65	7.74	6.85	6.54	6.30
Steam Coal	20.26	22.46	22.92	23.18	23.83	25.02	26.66	26.85	30.74	34.51
Nuclear Power	8.23	8.44	8.44	8.44	8.93	9.09	9.09	8.94	9.09	9.09
Renewable Energy[15]	3.57	4.73	4.76	4.76	5.19	5.47	5.72	5.85	6.22	6.70
Electricity Imports	0.04	0.07	0.07	0.08	0.05	0.05	0.05	0.04	0.05	0.05
Total	**38.67**	**42.03**	**42.82**	**43.41**	**46.10**	**48.24**	**50.31**	**49.50**	**53.71**	**57.79**

Table B2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2004	Projections								
		2010			2020			2030		
		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	8.72	9.21	9.57	9.97	9.96	10.83	11.75	11.15	12.70	14.34
Kerosene	0.13	0.14	0.14	0.14	0.13	0.13	0.13	0.11	0.11	0.12
Jet Fuel[9]	3.35	3.82	3.89	3.97	4.35	4.53	4.70	4.36	4.79	5.26
Liquefied Petroleum Gas	2.85	2.78	2.92	3.07	2.84	3.14	3.47	2.91	3.40	3.87
Motor Gasoline[2]	17.30	18.39	18.70	19.03	20.12	21.10	22.10	21.43	23.38	25.30
Petrochemical Feedstock	1.49	1.38	1.48	1.57	1.32	1.51	1.72	1.27	1.55	1.87
Residual Fuel	1.91	1.66	1.68	1.70	1.63	1.69	1.77	1.66	1.79	1.86
Other Petroleum[12]	4.32	4.56	4.75	4.99	4.76	5.21	5.83	5.01	5.86	6.71
Petroleum Subtotal	40.08	41.93	43.14	44.45	45.11	48.14	51.46	47.89	53.58	59.33
Natural Gas	21.24	21.69	22.28	22.89	24.19	25.62	26.60	24.28	25.67	27.18
Lease and Plant Fuel[6]	1.14	1.10	1.12	1.13	1.26	1.28	1.31	1.17	1.21	1.24
Pipeline Natural Gas	0.69	0.64	0.65	0.66	0.77	0.80	0.82	0.75	0.78	0.81
Natural Gas Subtotal	23.07	23.43	24.04	24.68	26.22	27.70	28.73	26.20	27.66	29.23
Metallurgical Coal	0.65	0.60	0.62	0.64	0.55	0.59	0.64	0.51	0.58	0.64
Other Coal	21.74	23.97	24.45	24.74	25.31	26.55	28.23	28.32	32.29	36.13
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.26	0.49	0.62	1.28	1.61	2.07
Net Coal Coke Imports	0.14	0.02	0.02	0.02	0.01	0.02	0.02	0.01	0.02	0.02
Coal Subtotal	22.53	24.58	25.09	25.40	26.13	27.65	29.50	30.13	34.49	38.86
Nuclear Power	8.23	8.44	8.44	8.44	8.93	9.09	9.09	8.94	9.09	9.09
Renewable Energy[16]	5.74	6.98	7.08	7.15	7.55	8.00	8.42	8.34	9.02	9.83
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.04	0.07	0.07	0.08	0.05	0.05	0.05	0.04	0.05	0.05
Total	**99.68**	**105.42**	**107.87**	**110.19**	**114.00**	**120.63**	**127.25**	**121.54**	**133.88**	**146.39**
Energy Use and Related Statistics										
Delivered Energy Use	73.18	76.73	78.62	80.60	82.86	88.19	93.55	88.52	98.40	108.57
Total Energy Use	99.68	105.42	107.87	110.19	114.00	120.63	127.25	121.54	133.88	146.39
Population (millions)	294.10	307.61	310.12	312.62	322.74	336.99	351.24	334.11	364.79	395.48
Gross Domestic Product (billion 2000 dollars)	10756	12529	13043	13561	16022	17541	19073	19771	23112	26471
Carbon Dioxide Emissions (million metric tons)	5899.9	6219.0	6364.9	6501.9	6720.4	7119.0	7542.4	7283.7	8114.5	8956.8

[1]Includes wood used for residential heating.
[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.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[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 for on- and off- road use.
[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 2004 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: 2004 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). 2004 population and gross domestic product: Global Insight macroeconomic model CTL0805. 2004 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2004,* DOE/EIA-0573(2004) (Washington, DC, December 2005). **Projections:** EIA, AEO2006 National Energy Modeling System runs LM2006.D113005A, AEO2006.D111905A, and HM2006.D112505B.

Table B3. Energy Prices by Sector and Source
(2004 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2004	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential	**17.31**	**16.65**	**16.98**	**17.25**	**16.69**	**17.19**	**17.74**	**17.85**	**18.51**	**19.19**
Primary Energy[1]	11.39	11.05	11.28	11.46	11.06	11.31	11.58	12.26	12.62	13.01
Petroleum Products[2]	14.63	14.27	14.77	14.95	15.36	15.94	16.39	17.92	18.42	19.15
Distillate Fuel	13.62	12.39	12.85	12.88	13.46	13.55	13.63	14.56	14.56	14.66
Liquefied Petroleum Gas	17.30	17.62	18.17	18.59	18.15	19.34	20.23	21.79	22.68	23.92
Natural Gas	10.40	10.17	10.33	10.51	9.98	10.16	10.41	10.95	11.32	11.68
Electricity	26.19	24.36	24.78	25.15	23.69	24.44	25.26	24.12	25.02	25.92
Commercial	**16.56**	**15.87**	**16.27**	**16.60**	**15.75**	**16.28**	**16.87**	**16.74**	**17.52**	**18.35**
Primary Energy[1]	9.20	8.79	8.96	9.11	8.59	8.74	8.94	9.41	9.65	9.94
Petroleum Products[2]	10.39	10.30	10.56	10.63	10.99	11.22	11.37	12.17	12.28	12.66
Distillate Fuel	9.99	9.85	10.15	10.18	10.75	10.89	10.99	11.75	11.77	12.12
Residual Fuel	6.37	6.13	6.14	6.14	6.29	6.31	6.29	6.89	6.91	6.96
Natural Gas	9.10	8.61	8.76	8.93	8.22	8.37	8.58	9.01	9.29	9.57
Electricity	23.52	21.74	22.31	22.78	21.22	22.00	22.90	21.80	22.90	24.06
Industrial[3]	**8.67**	**8.23**	**8.48**	**8.67**	**8.18**	**8.48**	**8.85**	**8.84**	**9.27**	**9.85**
Primary Energy	7.42	6.99	7.19	7.33	7.01	7.24	7.54	7.75	8.09	8.62
Petroleum Products[2]	9.65	9.24	9.46	9.55	9.58	9.94	10.26	11.01	11.36	12.21
Distillate Fuel	10.29	10.44	10.75	10.79	11.66	11.84	11.97	12.92	12.91	13.39
Liquefied Petroleum Gas	14.24	11.70	12.03	12.30	11.87	12.92	13.67	14.38	15.25	16.42
Residual Fuel	5.88	6.30	6.31	6.35	6.61	6.70	6.59	7.16	7.27	7.51
Natural Gas[4]	6.10	5.53	5.69	5.85	5.35	5.49	5.70	6.17	6.45	6.72
Metallurgical Coal[5]	2.24	2.34	2.36	2.37	2.19	2.23	2.27	2.22	2.28	2.34
Other Industrial Coal[5]	1.74	1.84	1.86	1.87	1.76	1.81	1.86	1.82	1.92	2.00
Coal to Liquids	N/A	N/A	N/A	N/A	0.86	1.04	1.11	1.23	1.26	1.32
Electricity	15.54	15.17	15.65	16.08	14.69	15.35	16.05	15.15	15.95	16.77
Transportation	**13.81**	**14.56**	**14.83**	**14.92**	**15.10**	**15.38**	**15.52**	**16.17**	**16.32**	**16.79**
Primary Energy	13.79	14.54	14.82	14.90	15.08	15.36	15.51	16.16	16.31	16.78
Petroleum Products[2]	13.79	14.55	14.82	14.91	15.10	15.38	15.52	16.17	16.32	16.80
Distillate Fuel[6]	13.25	13.98	14.29	14.36	14.49	14.78	15.06	15.52	15.65	16.38
Jet Fuel[7]	9.02	9.35	9.67	9.71	10.25	10.49	10.69	11.24	11.53	11.94
Motor Gasoline[8]	15.34	16.26	16.52	16.62	16.73	17.02	17.09	17.78	17.92	18.32
Residual Fuel	4.91	6.31	6.43	6.45	6.56	6.54	6.62	7.45	7.59	7.68
Liquefied Petroleum Gas[9]	17.14	16.19	16.72	17.03	15.83	16.82	17.96	18.37	19.25	20.48
Natural Gas[10]	9.94	9.91	10.09	10.26	9.68	9.90	10.19	10.31	10.68	11.06
Ethanol (E85)[11]	20.24	20.90	21.19	21.37	20.67	21.10	21.52	21.99	22.48	23.00
Electricity	21.67	20.30	20.76	21.15	19.84	20.56	21.33	20.12	21.00	21.79
Average End-Use Energy	**13.00**	**13.08**	**13.32**	**13.45**	**13.39**	**13.66**	**13.91**	**14.34**	**14.64**	**15.13**
Primary Energy	11.04	11.30	11.52	11.61	11.69	11.89	12.06	12.68	12.86	13.27
Electricity	22.19	21.00	21.43	21.80	20.58	21.23	21.97	21.16	22.00	22.88
Electric Power[12]										
Fossil Fuel Average	2.46	2.34	2.41	2.48	2.39	2.46	2.51	2.49	2.49	2.52
Petroleum Products	5.43	6.41	6.50	6.53	6.90	6.91	6.89	7.67	7.61	7.77
Distillate Fuel	9.23	8.75	9.04	9.07	9.52	9.62	9.66	10.24	10.28	10.43
Residual Fuel	4.76	5.67	5.70	5.71	6.05	6.02	5.97	6.76	6.73	6.82
Natural Gas	5.92	5.28	5.46	5.67	5.24	5.40	5.60	5.98	6.26	6.55
Steam Coal[5]	1.36	1.46	1.48	1.48	1.36	1.39	1.44	1.41	1.51	1.61

Table B3. Energy Prices by Sector and Source (Continued)
(2004 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2004	Projections								
		2010			2020			2030		
		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[13]										
Petroleum Products[2]	12.61	13.17	13.41	13.47	13.80	14.05	14.19	15.02	15.16	15.68
Distillate Fuel	12.62	12.96	13.30	13.37	13.81	14.07	14.31	14.93	15.04	15.69
Jet Fuel	9.02	9.35	9.67	9.71	10.25	10.49	10.69	11.24	11.53	11.94
Liquefied Petroleum Gas	14.89	13.07	13.39	13.64	13.41	14.38	15.06	16.20	16.90	17.95
Motor Gasoline[8]	15.33	16.26	16.52	16.62	16.73	17.02	17.09	17.78	17.92	18.32
Residual Fuel	5.04	6.02	6.07	6.09	6.33	6.31	6.31	7.08	7.12	7.22
Natural Gas	7.52	7.06	7.19	7.34	6.80	6.93	7.14	7.65	7.98	8.30
Metallurgical Coal[5]	2.24	2.34	2.36	2.37	2.19	2.23	2.27	2.22	2.28	2.34
Other Coal[5]	1.39	1.48	1.51	1.51	1.39	1.42	1.46	1.43	1.53	1.63
Coal to Liquids	N/A	N/A	N/A	N/A	0.86	1.04	1.11	1.23	1.26	1.32
Ethanol (E85)[11]	20.24	20.90	21.19	21.37	20.67	21.10	21.52	21.99	22.48	23.00
Electricity	22.19	21.00	21.43	21.80	20.58	21.23	21.97	21.16	22.00	22.88
Non-Renewable Energy Expenditures by Sector (billion 2004 dollars)										
Residential	190.90	195.27	200.59	205.38	207.93	221.50	236.10	227.28	252.12	278.41
Commercial	135.07	141.03	145.01	148.51	160.17	172.19	184.74	189.81	216.48	245.17
Industrial	170.01	156.56	169.60	182.01	156.14	179.83	205.96	177.33	216.86	264.94
Transportation	374.67	427.60	445.81	459.08	492.36	530.44	565.50	569.70	635.46	717.72
Total Non-Renewable Expenditures	870.65	920.45	961.01	994.97	1016.60	1103.97	1192.30	1164.11	1320.94	1506.24
Transportation Renewable Expenditures	0.02	0.05	0.05	0.05	0.09	0.10	0.10	0.12	0.13	0.15
Total Expenditures	**870.67**	**920.50**	**961.06**	**995.03**	**1016.69**	**1104.07**	**1192.40**	**1164.23**	**1321.07**	**1506.39**

[1]Weighted average price includes fuels below as well as coal.
[2]This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Excludes use for lease and plant fuel.
[5]Excludes imported coal.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[8]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[9]Includes Federal and State taxes while excluding county and local taxes.
[10]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes.
[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 electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[13]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 2004 are model results and may differ slightly from official EIA data reports.

Sources: 2004 prices for motor gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2004*, DOE/EIA-0487(2004) (Washington, DC, August 2005). 2004 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2005/06) (Washington, DC, June 2005). 2004 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2003*, DOE/EIA-0131(2003) (Washington, DC, December 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2005/06) (Washington, DC, June 2005). 2004 transportation sector natural gas delivered prices are model results. 2004 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004, Table 4.11.A. 2004 coal prices based on: EIA, *Quarterly Coal Report, October-December 2004*, DOE/EIA-0121(2004/4Q) (Washington, DC, March 2005) and EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A. 2004 electricity prices: EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). 2004 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2006 National Energy Modeling System runs LM2006.D113005A, AEO2006.D111905A, and HM2006.D112505B.

Table B4. Macroeconomic Indicators
(Billion 2000 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2004	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Real Gross Domestic Product	**10756**	**12529**	**13043**	**13561**	**16022**	**17541**	**19073**	**19771**	**23112**	**26471**
Real Potential Gross Domestic Product	**11030**	**13153**	**13367**	**13583**	**15886**	**17176**	**18469**	**19756**	**22738**	**25731**
Components of Real Gross Domestic Product										
Real Consumption	7589	8831	9128	9429	11016	11916	12826	13416	15352	17306
Real Investment	1810	2033	2259	2487	2858	3293	3730	3960	4985	6001
Real Government Spending	1952	2097	2150	2204	2288	2464	2640	2471	2838	3204
Real Exports	1118	1823	1831	1839	3589	3776	3967	6252	6833	7421
Real Imports	1719	2219	2295	2366	3479	3659	3788	5775	6156	6492
Energy Intensity (thousand Btu per 2000 dollar of GDP)										
Delivered Energy	6.81	6.13	6.03	5.95	5.18	5.03	4.91	4.48	4.26	4.11
Total Energy	9.27	8.42	8.28	8.13	7.12	6.88	6.68	6.15	5.80	5.53
Price Indices										
GDP Chain-Type Price Index (2000=1.000)	1.091	1.265	1.235	1.204	1.741	1.597	1.453	2.326	2.048	1.778
Consumer Price Index (1982-4=1)										
All-Urban	1.89	2.21	2.15	2.10	3.12	2.86	2.61	4.29	3.78	3.30
Energy Commodities and Services	1.51	1.68	1.67	1.64	2.34	2.19	2.03	3.31	2.96	2.66
Wholesale Price Index (1982=1.00)										
All Commodities	1.47	1.59	1.55	1.50	2.02	1.82	1.62	2.50	2.13	1.79
Fuel and Power	1.27	1.36	1.36	1.34	1.89	1.77	1.65	2.75	2.49	2.24
Interest Rates (percent, nominal)										
Federal Funds Rate	1.35	5.69	5.30	4.90	5.74	5.24	4.74	5.56	5.04	4.60
10-Year Treasury Note	4.27	6.44	5.92	5.38	6.82	6.21	5.62	6.76	6.13	5.57
AA Utility Bond Rate	6.04	7.91	7.55	7.17	8.79	8.15	7.54	9.20	8.52	7.91
Value of Shipments (billion 2000 dollars)										
Total Industrial	5643	6015	6355	6704	6936	7778	8636	7989	9578	11201
Non-manufacturing	1439	1437	1572	1710	1579	1808	2040	1746	2069	2392
Manufacturing	4204	4578	4783	4994	5357	5969	6596	6243	7509	8809
Energy-Intensive	1161	1226	1265	1310	1335	1441	1550	1436	1627	1819
Non-Energy Intensive	3044	3352	3518	3684	4022	4528	5046	4807	5882	6990
Population and Employment (millions)										
Population with Armed Forces Overseas	294.1	307.6	310.1	312.6	322.7	337.0	351.2	334.1	364.8	395.5
Population (aged 16 and over)	229.1	241.7	244.1	246.5	256.0	265.3	274.6	268.5	288.5	308.5
Population, over age 65	36.4	40.2	40.4	40.6	53.9	54.9	55.8	69.1	71.6	74.1
Employment, Nonfarm	131.4	135.2	142.1	148.9	145.3	156.2	167.1	157.3	173.6	189.8
Employment, Manufacturing	14.3	13.6	14.0	14.3	12.8	13.3	13.7	11.9	12.6	13.2
Key Labor Indicators										
Labor Force (millions)	147.4	156.7	158.9	161.7	161.5	167.7	174.4	171.3	180.8	190.7
Non-farm Labor Productivity (1992=1.00)	1.34	1.50	1.52	1.55	1.80	1.93	2.06	2.15	2.42	2.68
Unemployment Rate (percent)	5.53	4.70	4.69	4.67	4.46	4.37	4.27	4.98	4.90	4.83
Key Indicators for Energy Demand										
Real Disposable Personal Income	8004	9325	9622	9926	12205	13057	13923	15703	17562	19450
Housing Starts (millions)	2.08	1.64	1.97	2.30	1.45	1.89	2.34	1.21	1.82	2.43
Commercial Floorspace (billion square feet)	75.0	81.7	82.3	83.0	91.5	96.0	100.4	101.2	112.0	123.0
Unit Sales of Light-Duty Vehicles (millions)	16.87	17.02	17.61	18.50	17.40	18.90	20.55	19.15	21.75	24.70

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2004: Global Insight macroeconomic model CTL0805, and Global Insight industry model, July 2005. **Projections:** Energy Information Administration, AEO2006 National Energy Modeling System runs LM2006.D113005A, AEO2006.D111905A, and HM2006.D112505B.

Price Case Comparisons

Table C1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2004	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Production										
Crude Oil and Lease Condensate	11.47	12.71	12.45	12.24	11.77	11.75	11.91	9.51	9.68	10.50
Natural Gas Plant Liquids	2.46	2.43	2.39	2.35	2.61	2.67	2.65	2.65	2.57	2.62
Dry Natural Gas	19.02	19.58	19.13	18.67	21.66	22.09	21.90	22.09	21.45	21.83
Coal	22.86	25.38	25.78	25.91	24.81	27.30	29.53	27.86	34.10	39.52
Nuclear Power	8.23	8.44	8.44	8.44	9.03	9.09	9.09	9.03	9.09	9.09
Renewable Energy[1]	5.74	7.00	7.08	7.25	7.64	8.00	8.15	8.73	9.02	9.12
Other[2]	0.64	2.13	2.16	2.20	3.04	3.16	3.37	3.15	3.44	3.91
Total	**70.42**	**77.67**	**77.42**	**77.05**	**80.57**	**84.05**	**86.61**	**83.00**	**89.36**	**96.57**
Imports										
Crude Oil[3]	22.02	22.25	22.01	21.23	27.19	24.63	22.09	33.90	29.54	24.59
Petroleum Products[4]	5.93	6.55	6.36	5.90	9.08	8.01	6.31	11.68	9.27	5.88
Natural Gas	4.36	5.19	5.01	4.74	8.32	5.83	3.33	10.75	6.72	3.63
Other Imports[5]	0.83	0.45	0.45	0.46	1.49	1.36	1.61	2.09	2.42	2.69
Total	**33.14**	**34.43**	**33.83**	**32.33**	**46.08**	**39.83**	**33.35**	**58.43**	**47.95**	**36.79**
Exports										
Petroleum[6]	2.07	2.17	2.15	2.11	2.68	2.24	2.16	2.86	2.31	2.24
Natural Gas	0.86	0.57	0.55	0.53	0.83	0.68	0.50	1.35	1.01	0.57
Coal	1.25	1.03	1.03	1.03	0.46	0.46	0.46	0.39	0.40	0.40
Total	**4.18**	**3.78**	**3.74**	**3.67**	**3.97**	**3.39**	**3.11**	**4.61**	**3.72**	**3.21**
Discrepancy[7]	**-0.31**	**-0.32**	**-0.36**	**-0.49**	**-0.10**	**-0.15**	**-0.24**	**0.00**	**-0.30**	**0.07**
Consumption										
Petroleum Products[8]	40.08	43.78	43.14	41.88	50.67	48.14	44.72	57.55	53.58	48.87
Natural Gas	23.07	24.65	24.04	23.34	29.62	27.70	25.05	31.97	27.66	24.71
Coal	22.53	24.68	25.09	25.22	25.77	27.65	30.01	29.49	34.49	38.25
Nuclear Power	8.23	8.44	8.44	8.44	9.03	9.09	9.09	9.03	9.09	9.09
Renewable Energy[1]	5.74	7.00	7.08	7.25	7.64	8.00	8.16	8.73	9.02	9.12
Other[9]	0.04	0.07	0.07	0.08	0.04	0.05	0.06	0.05	0.05	0.05
Total	**99.68**	**108.64**	**107.87**	**106.21**	**122.78**	**120.63**	**117.09**	**136.82**	**133.88**	**130.09**
Net Imports - Petroleum	**25.88**	**26.62**	**26.22**	**25.02**	**33.59**	**30.39**	**26.25**	**42.72**	**36.49**	**28.23**
Prices (2004 dollars per unit)										
Imported Low Sulfur Light Crude Oil Price (dollars per barrel)[10]	40.49	40.29	47.29	62.65	33.99	50.70	85.06	33.73	56.97	95.71
Imported Crude Oil Price (dollars per barrel)[10]	35.99	37.00	43.99	58.99	27.99	44.99	79.98	27.99	49.99	89.98
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	5.49	4.55	5.03	5.95	4.09	4.90	5.94	4.97	5.92	7.71
Coal Minemouth Price (dollars per ton)	20.07	21.74	22.23	22.53	19.19	20.20	21.54	20.66	21.73	22.66
Average Electricity Price (cents per kilowatthour)	7.6	7.1	7.3	7.6	7.0	7.2	7.6	7.3	7.5	7.9

[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.
[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]Weighted average price delivered to U.S. refiners.
[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 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2004 natural gas supply values and natural gas wellhead price: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2005/06) (Washington, DC, June 2005), subtracting 1 billion cubic feet per day to account for carbon dioxide included in production in Texas. 2004 petroleum supply values: EIA, *Petroleum Supply Annual 2004,* DOE/EIA-0340(2004)/1 (Washington, DC, June 2005). 2004 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2004 coal values: *Quarterly Coal Report, October-December 2004*, DOE/EIA-0121(2004/4Q) (Washington, DC, March 2005). Other 2004 values: EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** EIA, AEO2006 National Energy Modeling System runs LP2006.D120105A, AEO2006.D111905A, and HP2006.D113005A.

Table C2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2004	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Energy Consumption										
Residential										
Distillate Fuel	0.94	0.86	0.84	0.79	0.81	0.73	0.64	0.69	0.61	0.51
Kerosene	0.09	0.09	0.09	0.09	0.09	0.08	0.07	0.08	0.07	0.06
Liquefied Petroleum Gas	0.54	0.57	0.56	0.53	0.68	0.61	0.53	0.74	0.65	0.55
Petroleum Subtotal	1.57	1.52	1.48	1.41	1.57	1.43	1.25	1.51	1.32	1.12
Natural Gas	5.03	5.38	5.33	5.25	5.76	5.68	5.59	5.90	5.82	5.71
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.41	0.43	0.44	0.46	0.39	0.43	0.47	0.38	0.41	0.45
Electricity	4.41	5.00	4.99	4.96	5.80	5.77	5.74	6.49	6.47	6.45
Delivered Energy	**11.44**	**12.34**	**12.25**	**12.10**	**13.54**	**13.31**	**13.06**	**14.29**	**14.04**	**13.73**
Electricity Related Losses	9.60	10.69	10.74	10.78	11.78	11.85	12.03	12.69	12.60	12.46
Total	**21.04**	**23.03**	**22.99**	**22.88**	**25.31**	**25.17**	**25.09**	**26.98**	**26.64**	**26.19**
Commercial										
Distillate Fuel	0.50	0.50	0.48	0.45	0.55	0.50	0.44	0.60	0.52	0.46
Residual Fuel	0.12	0.12	0.12	0.11	0.13	0.12	0.11	0.13	0.12	0.11
Kerosene	0.02	0.02	0.02	0.02	0.03	0.02	0.02	0.03	0.03	0.02
Liquefied Petroleum Gas	0.10	0.10	0.10	0.09	0.10	0.10	0.09	0.11	0.10	0.09
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	0.79	0.79	0.77	0.73	0.86	0.79	0.72	0.91	0.82	0.74
Natural Gas	3.09	3.23	3.18	3.10	3.80	3.68	3.54	4.25	4.11	3.89
Coal	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Renewable Energy[3]	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Electricity	4.19	4.90	4.88	4.84	6.08	6.01	5.90	7.45	7.34	7.20
Delivered Energy	**8.24**	**9.09**	**9.00**	**8.84**	**10.91**	**10.66**	**10.33**	**12.79**	**12.44**	**12.00**
Electricity Related Losses	9.13	10.48	10.51	10.51	12.34	12.35	12.37	14.56	14.29	13.91
Total	**17.37**	**19.57**	**19.51**	**19.35**	**23.26**	**23.02**	**22.70**	**27.34**	**26.73**	**25.91**
Industrial[4]										
Distillate Fuel	1.19	1.21	1.20	1.17	1.26	1.23	1.20	1.40	1.32	1.30
Liquefied Petroleum Gas	2.19	2.23	2.21	2.17	2.46	2.34	2.22	2.64	2.54	2.39
Petrochemical Feedstock	1.49	1.49	1.48	1.45	1.55	1.51	1.46	1.62	1.55	1.52
Residual Fuel	0.24	0.21	0.20	0.17	0.23	0.20	0.16	0.26	0.21	0.15
Motor Gasoline[2]	0.32	0.33	0.32	0.32	0.32	0.32	0.32	0.34	0.34	0.33
Other Petroleum[5]	4.16	4.65	4.60	4.48	5.37	5.05	4.70	6.09	5.69	5.17
Petroleum Subtotal	9.58	10.12	10.01	9.77	11.19	10.65	10.06	12.34	11.66	10.87
Natural Gas	7.64	8.15	8.07	7.95	8.66	8.52	8.36	9.41	9.08	8.71
Lease and Plant Fuel[6]	1.14	1.14	1.12	1.09	1.27	1.28	1.30	1.24	1.21	1.39
Natural Gas Subtotal	8.78	9.29	9.19	9.05	9.92	9.80	9.67	10.65	10.29	10.10
Metallurgical Coal	0.65	0.63	0.62	0.60	0.61	0.59	0.57	0.60	0.58	0.56
Other Industrial Coal	1.38	1.44	1.43	1.42	1.44	1.43	1.42	1.45	1.45	1.44
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.49	0.62	0.00	1.61	3.57
Net Coal Coke Imports	0.14	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.02	0.02
Coal Subtotal	2.16	2.08	2.07	2.03	2.07	2.53	2.61	2.06	3.65	5.58
Renewable Energy[7]	1.68	1.80	1.79	1.77	2.05	2.01	1.97	2.33	2.29	2.26
Electricity	3.48	3.65	3.62	3.56	3.97	3.91	3.88	4.27	4.31	4.37
Delivered Energy	**25.68**	**26.94**	**26.67**	**26.18**	**29.20**	**28.91**	**28.18**	**31.64**	**32.19**	**33.18**
Electricity Related Losses	7.58	7.80	7.79	7.73	8.07	8.04	8.13	8.34	8.39	8.45
Total	**33.27**	**34.74**	**34.46**	**33.91**	**37.27**	**36.95**	**36.31**	**39.99**	**40.58**	**41.63**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2004	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Transportation										
Distillate Fuel[8]	5.91	6.90	6.82	6.71	8.25	8.13	7.90	10.10	9.98	9.93
Jet Fuel[9]	3.35	3.93	3.89	3.83	4.58	4.53	4.44	4.82	4.79	4.33
Motor Gasoline[2]	16.93	18.62	18.33	17.72	21.98	20.73	18.60	25.33	22.99	20.00
Residual Fuel	0.61	0.62	0.62	0.62	0.64	0.64	0.64	0.66	0.65	0.65
Liquefied Petroleum Gas	0.03	0.06	0.06	0.06	0.09	0.09	0.07	0.12	0.11	0.09
Other Petroleum[10]	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.19	0.19	0.19
Petroleum Subtotal	27.02	30.30	29.91	29.11	35.73	34.30	31.83	41.21	38.71	35.18
Pipeline Fuel Natural Gas	0.69	0.66	0.65	0.64	0.80	0.80	0.76	0.85	0.78	0.74
Compressed Natural Gas	0.03	0.06	0.05	0.05	0.09	0.09	0.09	0.12	0.12	0.12
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.10
Delivered Energy	**27.82**	**31.11**	**30.70**	**29.89**	**36.73**	**35.30**	**32.78**	**42.29**	**39.72**	**36.15**
Electricity Related Losses	0.18	0.19	0.19	0.19	0.21	0.20	0.20	0.22	0.21	0.20
Total	**28.00**	**31.30**	**30.90**	**30.08**	**36.94**	**35.50**	**32.98**	**42.51**	**39.93**	**36.35**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	8.55	9.46	9.34	9.13	10.87	10.59	10.18	12.78	12.43	12.20
Kerosene	0.13	0.14	0.14	0.13	0.13	0.13	0.12	0.12	0.11	0.10
Jet Fuel[9]	3.35	3.93	3.89	3.83	4.58	4.53	4.44	4.82	4.79	4.33
Liquefied Petroleum Gas	2.85	2.97	2.92	2.85	3.33	3.14	2.92	3.61	3.40	3.12
Motor Gasoline[2]	17.30	18.99	18.70	18.08	22.35	21.10	18.97	25.71	23.38	20.37
Petrochemical Feedstock	1.49	1.49	1.48	1.45	1.55	1.51	1.46	1.62	1.55	1.52
Residual Fuel	0.97	0.96	0.94	0.91	1.00	0.96	0.91	1.04	0.99	0.92
Other Petroleum[12]	4.32	4.81	4.75	4.64	5.53	5.21	4.86	6.26	5.86	5.34
Petroleum Subtotal	38.96	42.74	42.17	41.02	49.35	47.17	43.85	55.97	52.51	47.91
Natural Gas	15.79	16.80	16.63	16.36	18.31	17.97	17.59	19.68	19.13	18.42
Lease and Plant Fuel Plant[6]	1.14	1.14	1.12	1.09	1.27	1.28	1.30	1.24	1.21	1.39
Pipeline Natural Gas	0.69	0.66	0.65	0.64	0.80	0.80	0.76	0.85	0.78	0.74
Natural Gas Subtotal	17.62	18.60	18.40	18.09	20.38	20.06	19.66	21.77	21.11	20.56
Metallurgical Coal	0.65	0.63	0.62	0.60	0.61	0.59	0.57	0.60	0.58	0.56
Other Coal	1.47	1.53	1.53	1.52	1.54	1.53	1.51	1.55	1.54	1.53
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.49	0.62	0.00	1.61	3.57
Net Coal Coke Imports	0.14	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.02	0.02
Coal Subtotal	2.26	2.18	2.17	2.13	2.17	2.63	2.71	2.16	3.74	5.68
Renewable Energy[13]	2.17	2.32	2.32	2.32	2.54	2.53	2.53	2.80	2.80	2.81
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.17	13.64	13.57	13.44	15.95	15.79	15.60	18.31	18.22	18.12
Delivered Energy	**73.18**	**79.48**	**78.62**	**77.00**	**90.38**	**88.19**	**84.35**	**101.02**	**98.40**	**95.07**
Electricity Related Losses	26.50	29.15	29.24	29.21	32.39	32.45	32.73	35.80	35.48	35.01
Total	**99.68**	**108.64**	**107.87**	**106.21**	**122.78**	**120.63**	**117.09**	**136.82**	**133.88**	**130.09**
Electric Power[14]										
Distillate Fuel	0.17	0.23	0.23	0.23	0.29	0.24	0.25	0.32	0.27	0.28
Residual Fuel	0.95	0.81	0.74	0.63	1.03	0.73	0.63	1.26	0.80	0.67
Petroleum Subtotal	1.12	1.05	0.97	0.86	1.32	0.97	0.88	1.58	1.07	0.96
Natural Gas	5.45	6.05	5.65	5.25	9.24	7.65	5.39	10.19	6.54	4.15
Steam Coal	20.26	22.50	22.92	23.09	23.60	25.02	27.30	27.33	30.74	32.57
Nuclear Power	8.23	8.44	8.44	8.44	9.03	9.09	9.09	9.03	9.09	9.09
Renewable Energy[15]	3.57	4.68	4.76	4.93	5.10	5.47	5.62	5.93	6.22	6.32
Electricity Imports	0.04	0.07	0.07	0.08	0.04	0.05	0.06	0.05	0.05	0.05
Total	**38.67**	**42.79**	**42.82**	**42.65**	**48.35**	**48.24**	**48.34**	**54.12**	**53.71**	**53.13**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2004	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Total Energy Consumption										
Distillate Fuel	8.72	9.70	9.57	9.36	11.16	10.83	10.43	13.10	12.70	12.49
Kerosene	0.13	0.14	0.14	0.13	0.13	0.13	0.12	0.12	0.11	0.10
Jet Fuel[9]	3.35	3.93	3.89	3.83	4.58	4.53	4.44	4.82	4.79	4.33
Liquefied Petroleum Gas	2.85	2.97	2.92	2.85	3.33	3.14	2.92	3.61	3.40	3.12
Motor Gasoline[2]	17.30	18.99	18.70	18.08	22.35	21.10	18.97	25.71	23.38	20.37
Petrochemical Feedstock	1.49	1.49	1.48	1.45	1.55	1.51	1.46	1.62	1.55	1.52
Residual Fuel	1.91	1.77	1.68	1.54	2.03	1.69	1.53	2.31	1.79	1.60
Other Petroleum[12]	4.32	4.81	4.75	4.64	5.53	5.21	4.86	6.26	5.86	5.34
Petroleum Subtotal	40.08	43.78	43.14	41.88	50.67	48.14	44.72	57.55	53.58	48.87
Natural Gas	21.24	22.85	22.28	21.61	27.55	25.62	22.99	29.88	25.67	22.58
Lease and Plant Fuel[6]	1.14	1.14	1.12	1.09	1.27	1.28	1.30	1.24	1.21	1.39
Pipeline Natural Gas	0.69	0.66	0.65	0.64	0.80	0.80	0.76	0.85	0.78	0.74
Natural Gas Subtotal	23.07	24.65	24.04	23.34	29.62	27.70	25.05	31.97	27.66	24.71
Metallurgical Coal	0.65	0.63	0.62	0.60	0.61	0.59	0.57	0.60	0.58	0.56
Other Coal	21.74	24.03	24.45	24.61	25.14	26.55	28.81	28.88	32.29	34.10
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.49	0.62	0.00	1.61	3.57
Net Coal Coke Imports	0.14	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.02	0.02
Coal Subtotal	22.53	24.68	25.09	25.22	25.77	27.65	30.01	29.49	34.49	38.25
Nuclear Power	8.23	8.44	8.44	8.44	9.03	9.09	9.09	9.03	9.09	9.09
Renewable Energy[16]	5.74	7.00	7.08	7.25	7.64	8.00	8.16	8.73	9.02	9.12
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.04	0.07	0.07	0.08	0.04	0.05	0.06	0.05	0.05	0.05
Total	**99.68**	**108.64**	**107.87**	**106.21**	**122.78**	**120.63**	**117.09**	**136.82**	**133.88**	**130.09**
Energy Use and Related Statistics										
Delivered Energy Use	73.18	79.48	78.62	77.00	90.38	88.19	84.35	101.02	98.40	95.07
Total Energy Use	99.68	108.64	107.87	106.21	122.78	120.63	117.09	136.82	133.88	130.09
Population (millions)	294.10	310.12	310.12	310.12	336.99	336.99	336.99	364.79	364.79	364.79
Gross Domestic Product (billion 2000 dollars)	10756	13103	13043	12935	17597	17541	17469	23178	23112	23054
Carbon Dioxide Emissions (million metric tons)	5899.9	6403.1	6364.9	6255.6	7223.1	7119.0	6961.9	8158.5	8114.5	7974.7

[1]Includes wood used for residential heating.
[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.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[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 for on- and off- road use.
[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 2004 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: 2004 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). 2004 population and gross domestic product: Global Insight macroeconomic model CTL0805. 2004 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2004,* DOE/EIA-0573(2004) (Washington, DC, December 2005). **Projections:** EIA, AEO2006 National Energy Modeling System runs LP2006.D120105A, AEO2006.D111905A, and HP2006.D113005A.

Table C3. Energy Prices by Sector and Source
(2004 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2004	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Residential	**17.31**	**16.24**	**16.98**	**18.37**	**15.84**	**17.19**	**19.14**	**17.12**	**18.51**	**20.73**
Primary Energy[1]	11.39	10.41	11.28	13.01	9.65	11.31	13.96	10.58	12.62	15.75
Petroleum Products[2]	14.63	12.61	14.77	19.35	11.13	15.94	26.03	11.86	18.42	29.03
Distillate Fuel	13.62	11.13	12.85	16.64	9.57	13.55	21.46	9.82	14.56	22.18
Liquefied Petroleum Gas	17.30	15.18	18.17	24.28	13.27	19.34	32.77	14.04	22.68	36.63
Natural Gas	10.40	9.81	10.33	11.33	9.25	10.16	11.30	10.27	11.32	13.17
Electricity	26.19	24.30	24.78	25.58	23.68	24.44	25.32	24.60	25.02	26.00
Commercial	**16.56**	**15.58**	**16.27**	**17.52**	**15.06**	**16.28**	**17.95**	**16.29**	**17.52**	**19.74**
Primary Energy[1]	9.20	8.30	8.96	10.27	7.51	8.74	10.70	8.21	9.65	12.17
Petroleum Products[2]	10.39	9.18	10.56	13.54	8.13	11.22	17.86	8.44	12.28	18.93
Distillate Fuel	9.99	8.89	10.15	12.94	7.94	10.89	17.11	8.28	11.77	17.67
Residual Fuel	6.37	5.24	6.14	8.15	4.41	6.31	10.93	4.49	6.91	12.17
Natural Gas	9.10	8.25	8.76	9.74	7.49	8.37	9.46	8.28	9.29	11.11
Electricity	23.52	21.69	22.31	23.38	20.97	22.00	23.30	21.99	22.90	24.71
Industrial[3]	**8.67**	**7.67**	**8.48**	**10.07**	**7.04**	**8.48**	**11.49**	**7.68**	**9.27**	**11.81**
Primary Energy	7.42	6.32	7.19	8.93	5.65	7.24	10.65	6.24	8.09	10.93
Petroleum Products[2]	9.65	8.10	9.46	12.23	7.10	9.94	16.36	7.50	11.36	17.80
Distillate Fuel	10.29	9.46	10.75	13.60	8.87	11.84	18.41	9.26	12.91	19.25
Liquefied Petroleum Gas	14.24	10.00	12.03	15.91	8.98	12.92	21.89	9.71	15.25	24.32
Residual Fuel	5.88	5.42	6.31	8.48	4.31	6.70	11.91	4.73	7.27	13.12
Natural Gas[4]	6.10	5.19	5.69	6.62	4.67	5.49	6.53	5.51	6.45	8.24
Metallurgical Coal[5]	2.24	2.36	2.36	2.36	2.23	2.23	2.23	2.29	2.28	2.29
Other Industrial Coal[5]	1.74	1.84	1.86	1.89	1.73	1.81	1.89	1.80	1.92	1.99
Coal to Liquids	N/A	N/A	N/A	N/A	N/A	1.04	1.16	N/A	1.26	1.50
Electricity	15.54	15.19	15.65	16.37	14.67	15.35	16.03	15.69	15.95	16.91
Transportation	**13.81**	**13.53**	**14.83**	**17.57**	**12.34**	**15.38**	**21.62**	**12.36**	**16.32**	**23.06**
Primary Energy	13.79	13.51	14.82	17.56	12.32	15.36	21.62	12.34	16.31	23.06
Petroleum Products[2]	13.79	13.51	14.82	17.57	12.33	15.38	21.65	12.34	16.32	23.10
Distillate Fuel[6]	13.25	13.01	14.29	17.05	11.86	14.78	21.43	11.98	15.65	22.28
Jet Fuel[7]	9.02	8.53	9.67	12.23	7.79	10.49	15.76	7.82	11.53	17.25
Motor Gasoline[8]	15.34	15.14	16.52	19.34	13.76	17.02	23.55	13.61	17.92	25.15
Residual Fuel	4.91	5.44	6.43	8.68	4.04	6.54	11.98	4.16	7.59	13.47
Liquefied Petroleum Gas[9]	17.14	14.31	16.72	21.26	12.39	16.82	26.89	12.70	19.25	29.37
Natural Gas[10]	9.94	9.60	10.09	11.05	9.07	9.90	10.98	9.72	10.68	12.46
Ethanol (E85)[11]	20.24	19.59	21.19	24.57	17.58	21.10	28.92	17.73	22.48	26.66
Electricity	21.67	20.27	20.76	21.58	19.75	20.56	21.44	20.51	21.00	21.89
Average End-Use Energy	**13.00**	**12.34**	**13.32**	**15.29**	**11.62**	**13.66**	**17.59**	**12.20**	**14.64**	**18.59**
Primary Energy	11.04	10.44	11.52	13.71	9.62	11.89	16.46	10.02	12.86	17.42
Electricity	22.19	20.90	21.43	22.32	20.38	21.23	22.22	21.44	22.00	23.27
Electric Power[12]										
Fossil Fuel Average	2.46	2.34	2.41	2.59	2.35	2.46	2.54	2.60	2.49	2.60
Petroleum Products	5.43	5.47	6.50	8.86	4.33	6.91	12.32	4.47	7.61	13.16
Distillate Fuel	9.23	7.84	9.04	11.74	6.70	9.62	15.44	7.05	10.28	15.13
Residual Fuel	4.76	4.79	5.70	7.83	3.68	6.02	11.09	3.82	6.73	12.33
Natural Gas	5.92	5.06	5.46	6.33	4.68	5.40	6.28	5.56	6.26	7.89
Steam Coal[5]	1.36	1.46	1.48	1.50	1.33	1.39	1.49	1.39	1.51	1.61

Table C3. Energy Prices by Sector and Source (Continued)
(2004 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2004	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Average Price to All Users[13]										
Petroleum Products[2]	12.61	12.05	13.41	16.23	10.96	14.05	20.43	11.12	15.16	21.89
Distillate Fuel	12.62	11.98	13.30	16.19	11.03	14.07	20.76	11.29	15.04	21.62
Jet Fuel	9.02	8.53	9.67	12.23	7.79	10.49	15.76	7.82	11.53	17.25
Liquefied Petroleum Gas	14.89	11.17	13.39	17.71	10.01	14.38	24.16	10.76	16.90	26.82
Motor Gasoline[8]	15.33	15.13	16.52	19.34	13.75	17.02	23.55	13.61	17.92	25.15
Residual Fuel	5.04	5.12	6.07	8.27	3.91	6.31	11.53	4.06	7.12	12.86
Natural Gas	7.52	6.68	7.19	8.15	6.03	6.93	8.10	6.88	7.98	9.94
Metallurgical Coal[5]	2.24	2.36	2.36	2.36	2.23	2.23	2.23	2.29	2.28	2.29
Other Coal[5]	1.39	1.48	1.51	1.53	1.36	1.42	1.51	1.42	1.53	1.63
Coal to Liquids	N/A	N/A	N/A	N/A	N/A	1.04	1.16	N/A	1.26	1.50
Ethanol (E85)[11]	20.24	19.59	21.19	24.57	17.58	21.10	28.92	17.73	22.48	26.66
Electricity	22.19	20.90	21.43	22.32	20.38	21.23	22.22	21.44	22.00	23.27
Non-Renewable Energy Expenditures by Sector (billion 2004 dollars)										
Residential	190.90	193.52	200.59	213.78	208.19	221.50	240.85	238.21	252.12	275.34
Commercial	135.07	140.38	145.01	153.30	163.10	172.19	183.90	206.87	216.48	235.28
Industrial	170.01	156.00	169.60	195.61	153.11	179.83	231.32	180.93	216.86	280.30
Transportation	374.67	411.84	445.81	513.93	443.45	530.44	691.99	512.03	635.46	816.38
Total Non-Renewable Expenditures	870.65	901.73	961.01	1076.61	967.86	1103.97	1348.07	1138.04	1320.94	1607.30
Transportation Renewable Expenditures	0.02	0.05	0.05	0.06	0.08	0.10	0.12	0.11	0.13	0.22
Total Expenditures	**870.67**	**901.77**	**961.06**	**1076.67**	**967.94**	**1104.07**	**1348.19**	**1138.15**	**1321.07**	**1607.52**

[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 energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Excludes use for lease and plant fuel.
[5]Excludes imported coal.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[8]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[9]Includes Federal and State taxes while excluding county and local taxes.
[10]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes.
[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 electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[13]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 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2004 prices for motor gasoline, distillate, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2004*, DOE/EIA-0487(2004) (Washington, DC, August 2005). 2004 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2005/06) (Washington, DC, June 2005). 2004 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2003*, DOE/EIA-0131(2003) (Washington, DC, December 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2005/06) (Washington, DC, June 2005). 2004 transportation sector natural gas delivered prices are model results. 2004 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004, Table 4.11.A. 2004 coal prices based on: EIA, *Quarterly Coal Report, October-December 2004*, DOE/EIA-0121(2004/4Q) (Washington, DC, March 2005) and EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A. 2004 electricity prices: EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). 2004 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2006 National Energy Modeling System runs LP2006.D120105A, AEO2006.D111905A, and HP2006.D113005A.

Table C4. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2004	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Crude Oil										
Domestic Crude Production[1]	5.42	6.00	5.88	5.78	5.56	5.55	5.63	4.49	4.57	4.96
Alaska	0.91	0.86	0.83	0.80	0.83	0.76	0.69	0.29	0.27	0.26
Lower 48 States	4.51	5.14	5.05	4.98	4.73	4.79	4.94	4.20	4.30	4.70
Net Imports	10.06	10.16	10.05	9.70	12.43	11.26	10.09	15.51	13.51	11.24
Gross Imports	10.09	10.19	10.08	9.73	12.46	11.28	10.12	15.53	13.53	11.26
Exports	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02
Other Crude Supply[2]	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.48**	**16.17**	**15.93**	**15.48**	**17.99**	**16.81**	**15.72**	**20.00**	**18.08**	**16.20**
Other Petroleum Supply										
Natural Gas Plant Liquids	1.81	1.78	1.75	1.72	1.90	1.94	1.92	1.92	1.87	1.89
Net Product Imports	2.05	2.39	2.28	2.03	3.51	3.16	2.26	4.70	3.73	2.04
Gross Refined Product Imports[3]	2.07	2.49	2.39	2.18	3.55	3.13	2.39	4.52	3.56	2.12
Unfinished Oil Imports	0.49	0.42	0.41	0.36	0.63	0.54	0.39	0.86	0.66	0.44
Blending Components	0.41	0.46	0.46	0.44	0.55	0.52	0.47	0.63	0.57	0.50
Exports	0.96	0.99	0.98	0.96	1.22	1.03	0.99	1.31	1.07	1.03
Refinery Processing Gain[4]	1.05	1.28	1.31	1.35	1.48	1.44	1.48	1.75	1.82	1.66
Other Supply	0.35	0.93	0.94	0.96	1.26	1.52	1.69	1.30	2.16	3.43
Liquids from Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.19
Liquids from Coal	0.00	0.00	0.00	0.00	0.00	0.23	0.29	0.00	0.76	1.69
Other[5]	0.35	0.93	0.94	0.96	1.26	1.28	1.36	1.30	1.39	1.55
Total Primary Supply[6]	**20.74**	**22.54**	**22.21**	**21.54**	**26.14**	**24.87**	**23.08**	**29.68**	**27.65**	**25.22**
Refined Petroleum Products Supplied										
by Fuel										
Motor Gasoline[7]	9.10	10.09	9.94	9.62	11.92	11.28	10.18	13.68	12.49	10.96
Jet Fuel[8]	1.63	1.90	1.88	1.85	2.21	2.19	2.14	2.33	2.31	2.09
Distillate Fuel[9]	4.06	4.67	4.61	4.51	5.37	5.21	5.01	6.29	6.09	5.99
Residual Fuel	0.87	0.77	0.73	0.67	0.89	0.74	0.67	1.01	0.78	0.70
Other[10]	5.10	5.07	5.01	4.90	5.70	5.40	5.05	6.26	5.89	5.44
by Sector										
Residential and Commercial	1.29	1.29	1.25	1.18	1.37	1.25	1.10	1.39	1.22	1.06
Industrial[11]	5.02	5.28	5.23	5.11	5.83	5.55	5.25	6.40	6.06	5.67
Transportation	13.69	15.47	15.27	14.86	18.30	17.57	16.31	21.08	19.81	18.01
Electric Power[12]	0.49	0.46	0.43	0.38	0.58	0.43	0.39	0.70	0.47	0.43
Total	**20.76**	**22.50**	**22.17**	**21.54**	**26.08**	**24.81**	**23.05**	**29.57**	**27.57**	**25.17**
Discrepancy[13]	**-0.02**	**0.03**	**0.03**	**0.00**	**0.05**	**0.05**	**0.02**	**0.11**	**0.09**	**0.05**

Table C4. Petroleum Supply and Disposition Balance (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2004	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Imported Low Sulfur Light Crude Oil Price (2004 dollars per barrel)[14]	40.49	40.29	47.29	62.65	33.99	50.70	85.06	33.73	56.97	95.71
Imported Crude Oil Price (2004 dollars per barrel)[14]	35.99	37.00	43.99	58.99	27.99	44.99	79.98	27.99	49.99	89.98
Import Share of Product Supplied	0.58	0.56	0.56	0.54	0.61	0.58	0.54	0.68	0.62	0.53
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2004 dollars)	152.36	162.94	189.84	242.97	161.48	231.71	347.85	208.01	310.15	420.97
Domestic Refinery Distillation Capacity[15]	16.9	17.6	17.6	17.3	19.2	18.1	17.6	21.3	19.3	17.9
Capacity Utilization Rate (percent)[16]	93.0	93.1	91.9	90.8	95.2	94.1	90.8	95.3	94.8	91.8

[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 other hydrocarbons and alcohols.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes petroleum product stock withdrawals; domestic sources of blending components, other hydrocarbons, alcohols, and ethers.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes only kerosene type.
[9]Includes distillate and kerosene.
[10]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[11]Includes consumption for combined heat and power (CHP), which produces electricity and other useful thermal energy.
[12]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.
[13]Balancing item. Includes unaccounted for supply, losses, and gains.
[14]Weighted average price delivered to U.S. refiners.
[15]End-of-year operable capacity.
[16]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2004 imported crude oil price and petroleum product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). 2004 imported low sulfur light crude oil price: EIA, Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” Other 2004 data: EIA, *Petroleum Supply Annual 2004,* DOE/EIA-0340(2004)/1 (Washington, DC, June 2005). **Projections:** EIA, AEO2006 National Energy Modeling System runs LP2006.D120105A, AEO2006.D111905A, and HP2006.D113005A.

Table C5. Petroleum Product Prices
(2004 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2004	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Crude Oil Prices (2004 dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[1]	40.49	40.29	47.29	62.65	33.99	50.70	85.06	33.73	56.97	95.71
Imported Crude Oil[1]	35.99	37.00	43.99	58.99	27.99	44.99	79.98	27.99	49.99	89.98
Delivered Sector Product Prices										
Residential										
Distillate Fuel	188.8	154.3	178.2	230.8	132.7	188.0	297.6	136.1	202.0	307.6
Liquefied Petroleum Gas	149.1	130.8	156.5	209.2	114.3	166.6	282.4	120.9	195.4	315.5
Commercial										
Distillate Fuel	138.3	122.6	140.0	178.5	109.5	150.1	236.0	114.1	162.2	243.6
Residual Fuel	95.3	78.4	91.8	122.1	66.0	94.4	163.7	67.2	103.5	182.2
Residual Fuel (2004 dollars per barrel)	40.03	32.91	38.57	51.26	27.71	39.66	68.75	28.23	43.47	76.50
Industrial[2]										
Distillate Fuel	142.5	130.1	147.8	187.0	121.8	162.5	252.7	127.1	177.2	264.2
Liquefied Petroleum Gas	122.7	86.1	103.6	137.1	77.4	111.3	188.6	83.7	131.4	209.5
Residual Fuel	87.9	81.2	94.4	126.9	64.6	100.2	178.2	70.8	108.9	196.4
Residual Fuel (2004 dollars per barrel)	36.94	34.09	39.67	53.29	27.11	42.10	74.86	29.72	45.72	82.49
Transportation										
Diesel Fuel (distillate)[3]	182.4	178.4	195.9	233.8	162.6	202.5	293.6	164.2	214.4	305.2
Jet Fuel[4]	121.8	115.2	130.6	165.1	105.2	141.6	212.7	105.6	155.6	232.8
Motor Gasoline[5]	190.4	185.8	202.7	237.2	168.2	207.6	286.2	166.8	218.8	305.1
Liquid Petroleum Gas	147.7	123.3	144.0	183.2	106.7	144.9	231.6	109.4	165.8	253.0
Residual Fuel	73.5	81.4	96.3	129.9	60.5	97.8	179.3	62.3	113.6	201.7
Residual Fuel (2004 dollars per barrel)	30.89	34.19	40.43	54.57	25.43	41.09	75.30	26.16	47.70	84.70
Ethanol (E85)[6]	190.2	183.3	198.3	229.9	164.3	197.1	269.7	165.8	210.0	248.5
Ethanol Wholesale Price	171.5	146.3	157.5	165.6	141.0	164.1	189.7	143.3	167.2	204.9
Electric Power[7]										
Distillate Fuel	128.0	108.8	125.4	162.9	92.9	133.5	214.1	97.7	142.6	209.8
Residual Fuel	71.2	71.7	85.3	117.2	55.0	90.1	166.0	57.2	100.7	184.5
Residual Fuel (2004 dollars per barrel)	29.90	30.10	35.84	49.22	23.11	37.84	69.72	24.01	42.29	77.50
Refined Petroleum Product Prices[8]										
Distillate Fuel	174.2	164.6	182.8	222.5	151.5	193.1	284.8	154.9	206.3	296.7
Jet Fuel[4]	121.8	115.2	130.6	165.1	105.2	141.6	212.7	105.6	155.6	232.8
Liquefied Petroleum Gas	128.3	96.3	115.4	152.6	86.2	123.9	208.1	92.7	145.6	231.0
Motor Gasoline[5]	190.4	185.8	202.7	237.2	168.2	207.6	286.2	166.8	218.8	305.1
Residual Fuel	75.5	76.7	90.9	123.8	58.5	94.5	172.6	60.7	106.6	192.5
Residual Fuel (2004 dollars per barrel)	31.71	32.21	38.19	51.98	24.59	39.70	72.50	25.50	44.75	80.86
Average	**164.3**	**156.2**	**173.2**	**208.7**	**142.2**	**181.1**	**260.9**	**144.0**	**194.7**	**279.6**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[4]Includes only kerosene type.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]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.
[7]Includes 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.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2004 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2004 imported crude oil price: EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). 2004 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2004*, DOE/EIA-0487(2004) (Washington, DC, August 2005). 2004 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." 2004 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2004 wholesale ethanol prices derived from Bloomburg U.S. average rack price. **Projections:** EIA, AEO2006 National Energy Modeling System runs LP2006.D120105A, AEO2006.D111905A, and HP2006.D113005A.

Table C6. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2004	2010 Low Price	2010 Reference	2010 High Price	2020 Low Price	2020 Reference	2020 High Price	2030 Low Price	2030 Reference	2030 High Price
Crude Oil Prices (2004 dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[1]	40.49	40.29	47.29	62.65	33.99	50.70	85.06	33.73	56.97	95.71
Imported Crude Oil Price[1]	35.99	37.00	43.99	58.99	27.99	44.99	79.98	27.99	49.99	89.98
Production (Conventional)[2]										
Mature Market Economies										
United States (50 states)	8.41	9.51	9.39	9.33	9.55	9.51	9.53	8.83	8.92	8.76
Canada	2.40	1.72	1.66	1.61	1.70	1.45	1.34	1.80	1.43	1.09
Mexico	4.10	4.10	3.97	3.91	4.96	4.48	4.30	5.76	5.01	4.16
Western Europe[3]	6.85	6.08	5.88	5.75	5.90	5.22	4.89	5.17	4.37	3.53
Japan	0.14	0.09	0.09	0.09	0.07	0.07	0.08	0.08	0.07	0.06
Australia and New Zealand	0.67	0.92	0.89	0.87	0.94	0.84	0.80	0.94	0.81	0.66
Total Mature Market Economies	**22.57**	**22.42**	**21.88**	**21.57**	**23.13**	**21.58**	**20.92**	**22.57**	**20.60**	**18.25**
Transitional Economies										
Former Soviet Union										
Russia	9.29	9.79	9.50	9.37	11.75	10.66	10.29	12.86	11.26	9.41
Caspian Area[4]	2.32	3.08	2.99	2.95	5.66	5.16	5.01	8.43	7.43	6.25
Eastern Europe[5]	0.25	0.32	0.31	0.31	0.44	0.39	0.37	0.56	0.48	0.39
Total Transitional Economies	**11.86**	**13.19**	**12.80**	**12.63**	**17.84**	**16.21**	**15.67**	**21.85**	**19.17**	**16.05**
Emerging Economies										
OPEC[6]										
Asia	1.39	1.55	1.49	1.31	1.37	1.26	0.86	1.25	1.09	0.68
Middle East	21.25	25.67	24.76	21.80	29.36	26.99	18.48	35.65	31.07	19.36
North Africa	2.98	3.61	3.48	3.06	4.02	3.70	2.53	4.02	3.50	2.18
West Africa	1.96	2.47	2.39	2.10	2.84	2.61	1.79	3.50	3.05	1.90
South America	2.82	3.50	3.38	2.98	4.02	3.70	2.53	4.75	4.14	2.58
Non-OPEC										
China	3.25	3.49	3.38	3.32	3.72	3.33	3.15	3.75	3.22	2.63
Other Asia	2.88	2.56	2.48	2.44	2.90	2.61	2.49	2.91	2.51	2.07
Middle East[7]	1.76	2.15	2.09	2.05	2.74	2.45	2.32	3.39	2.91	2.38
Africa	3.54	3.73	3.62	3.58	5.91	5.41	5.29	9.05	8.03	6.80
South and Central America	4.22	4.47	4.34	4.28	6.40	5.83	5.66	7.95	7.00	5.89
Total Emerging Economies	**46.07**	**53.20**	**51.41**	**46.93**	**63.29**	**57.89**	**45.11**	**76.22**	**66.52**	**46.48**
Total Production (Conventional)	**80.50**	**88.81**	**86.09**	**81.12**	**104.26**	**95.68**	**81.70**	**120.64**	**106.29**	**80.78**
Production[6] (Nonconventional)										
United States (50 states)	0.22	0.48	0.48	0.48	0.65	0.94	1.19	0.64	1.50	3.18
Other North America	0.92	1.12	1.79	1.86	2.33	2.67	3.54	2.67	3.58	4.88
Western Europe	0.03	0.09	0.09	0.10	0.10	0.12	0.15	0.10	0.13	0.17
Asia	0.20	0.60	0.68	0.79	0.81	1.25	2.33	0.91	2.06	5.09
Middle East[7]	0.01	0.06	0.53	0.69	0.19	0.73	1.13	0.30	1.08	1.49
Africa	0.08	0.20	0.21	0.30	0.38	0.53	1.07	0.57	0.85	2.09
South and Central America	0.49	1.14	1.13	1.65	1.69	1.78	3.07	1.85	2.31	4.22
Total Production (Nonconventional)	**1.96**	**3.69**	**4.91**	**5.88**	**6.14**	**8.02**	**12.50**	**7.06**	**11.52**	**21.12**
Total Production	**82.46**	**92.50**	**91.00**	**87.00**	**110.40**	**103.70**	**94.20**	**127.70**	**117.80**	**101.90**

Table C6. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2004	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Consumption[8]										
Mature Market Economies										
United States (50 states)	20.76	22.50	22.17	21.54	26.08	24.81	23.05	29.57	27.57	25.17
United States Territories	0.33	0.35	0.34	0.31	0.44	0.38	0.30	0.55	0.45	0.34
Canada	2.15	2.20	2.13	1.98	2.58	2.25	1.85	2.80	2.34	1.79
Mexico	2.00	2.18	2.13	1.97	2.61	2.24	1.73	3.03	2.29	1.37
Western Europe[3]	13.63	13.67	13.44	12.80	14.37	13.52	12.30	15.32	14.27	12.34
Japan	5.22	4.99	4.85	4.48	5.23	4.40	3.39	5.43	4.13	2.66
Australia and New Zealand	1.07	1.17	1.16	1.11	1.35	1.28	1.18	1.53	1.45	1.26
Total Mature Market Economies	**45.16**	**47.06**	**46.22**	**44.18**	**52.66**	**48.89**	**43.80**	**58.22**	**52.50**	**44.93**
Transitional Economies										
Former Soviet Union	4.14	4.61	4.55	4.35	5.17	4.93	4.57	5.70	5.41	4.79
Eastern Europe[5]	1.42	1.60	1.58	1.53	1.93	1.87	1.78	2.22	2.15	1.98
Total Transitional Economies	**5.56**	**6.21**	**6.13**	**5.88**	**7.10**	**6.81**	**6.35**	**7.92**	**7.57**	**6.78**
Emerging Economies										
China	6.63	8.84	8.64	8.15	12.41	11.38	10.02	16.58	14.93	12.51
India	2.42	2.98	2.92	2.75	4.13	3.81	3.32	5.43	4.85	3.82
South Korea	2.23	2.47	2.41	2.26	2.84	2.57	2.21	3.03	2.66	2.10
Other Asia	6.10	7.74	7.64	7.34	10.24	9.85	9.21	12.56	12.05	10.72
Middle East[7]	6.09	7.22	7.16	6.94	8.52	8.34	8.00	9.52	9.34	8.67
Africa	2.96	3.67	3.63	3.46	4.48	4.31	3.99	5.01	4.81	4.12
South and Central America	5.30	6.32	6.25	6.03	8.02	7.75	7.30	9.43	9.10	8.27
Total Emerging Economies	**31.74**	**39.23**	**38.65**	**36.94**	**50.64**	**48.01**	**44.05**	**61.55**	**57.74**	**50.19**
Total Consumption	**82.46**	**92.50**	**91.00**	**87.00**	**110.40**	**103.70**	**94.20**	**127.70**	**117.80**	**101.90**
OPEC Production[10]	30.78	37.50	36.67	32.99	42.95	40.27	29.58	50.77	45.82	31.66
Non-OPEC Production[10]	51.68	55.00	54.33	54.01	67.45	63.43	64.62	76.93	71.98	70.24
Net Eurasia Exports	6.31	6.98	6.67	6.74	10.74	9.40	9.32	13.93	11.60	9.28
OPEC Market Share	0.37	0.41	0.40	0.38	0.39	0.39	0.31	0.40	0.39	0.31

[1]Weighted average price delivered to U.S. refiners.
[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, 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 2003 and 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2004 low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2004 imported crude oil price: EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **2004 quantities and projections:** Energy Information Administration, AEO2006 National Energy Modeling System runs LP2006.D120105A, AEO2006.D111905A, and HP2006.D113005A.

Results from Side Cases

Table D1. Key Results for Residential and Commercial Sector Technology Cases

Energy Consumption	2004	2010				2020			
		2005 Technology	Reference	High Technology	Best Available Technology	2005 Technology	Reference	High Technology	Best Available Technology
Residential									
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.94	0.86	0.83	0.83	0.81	0.78	0.73	0.71	0.67
Kerosene	0.09	0.10	0.09	0.09	0.09	0.09	0.08	0.08	0.07
Liquefied Petroleum Gas	0.54	0.56	0.56	0.55	0.54	0.63	0.61	0.60	0.57
Petroleum Subtotal	1.57	1.51	1.48	1.47	1.44	1.50	1.43	1.39	1.32
Natural Gas	5.03	5.39	5.33	5.30	5.25	5.86	5.68	5.43	5.25
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy	0.41	0.44	0.44	0.43	0.43	0.45	0.43	0.41	0.40
Electricity	4.41	5.01	4.99	4.92	4.62	5.88	5.77	5.52	4.88
Delivered Energy	**11.44**	**12.37**	**12.25**	**12.13**	**11.76**	**13.69**	**13.31**	**12.77**	**11.86**
Electricity Related Losses	9.60	10.80	10.74	10.60	9.96	12.07	11.85	11.35	10.02
Total	**21.04**	**23.17**	**22.99**	**22.73**	**21.72**	**25.77**	**25.17**	**24.12**	**21.88**
Delivered Energy Intensity (million Btu per household)	**100.6**	**100.7**	**99.6**	**98.7**	**95.6**	**99.8**	**97.0**	**93.1**	**86.4**
Nonmarketed Renewables Consumption (quadrillion Btu)	**0.03**	**0.04**	**0.04**	**0.04**	**0.03**	**0.05**	**0.05**	**0.07**	**0.06**
Commercial									
Energy Consumption (quadrillion Btu)									
Distillate Fuel	0.50	0.49	0.48	0.48	0.49	0.53	0.50	0.50	0.54
Residual Fuel	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.10	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	0.79	0.77	0.77	0.77	0.78	0.83	0.79	0.79	0.84
Natural Gas	3.09	3.19	3.18	3.17	3.12	3.68	3.68	3.65	3.48
Coal	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Renewable Energy	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Electricity	4.19	4.94	4.88	4.77	4.41	6.35	6.01	5.79	5.01
Delivered Energy	**8.24**	**9.07**	**9.00**	**8.88**	**8.47**	**11.03**	**10.66**	**10.41**	**9.50**
Electricity Related Losses	9.13	10.64	10.51	10.27	9.49	13.04	12.35	11.90	10.29
Total	**17.37**	**19.71**	**19.51**	**19.15**	**17.97**	**24.07**	**23.02**	**22.31**	**19.78**
Delivered Energy Intensity (thousand Btu per square foot)	**109.9**	**110.2**	**109.3**	**107.9**	**102.9**	**115.0**	**111.1**	**108.5**	**99.0**
Commercial Sector Generation									
Net Summer Generation Capacity (megawatts)									
Natural Gas	561	569	570	570	570	570	587	587	587
Solar Photovoltaic	111	453	491	491	505	528	577	577	1093
Electricity Generation (billion kilowatthours)									
Natural Gas	4.04	4.10	4.10	4.10	4.10	4.10	4.23	4.23	4.23
Solar Photovoltaic	0.23	0.96	1.04	1.04	1.07	1.12	1.22	1.22	2.34
Nonmarketed Renewables Consumption (quadrillion Btu)	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2004 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, AEO2006 National Energy Modeling System, runs BLDFRZN.D112205A, BLDDEF.D112205A, BLDHIGH.D112205A, and BLDBEST.D112205C.

2030				Annual Growth 2004-2030 (percent)			
2005 Technology	Reference	High Technology	Best Available Technology	2005 Technology	Reference	High Technology	Best Available Technology
0.67	0.61	0.58	0.53	-1.3%	-1.7%	-1.9%	-2.2%
0.08	0.07	0.07	0.06	-0.6%	-1.0%	-1.2%	-1.8%
0.67	0.65	0.62	0.60	0.8%	0.7%	0.5%	0.4%
1.42	1.32	1.27	1.18	-0.4%	-0.7%	-0.8%	-1.1%
6.13	5.82	5.39	5.08	0.8%	0.6%	0.3%	0.0%
0.01	0.01	0.01	0.01	-0.1%	-0.5%	-0.6%	-0.7%
0.46	0.41	0.39	0.38	0.4%	0.1%	-0.1%	-0.3%
6.68	6.47	6.16	5.29	1.6%	1.5%	1.3%	0.7%
14.70	**14.04**	**13.22**	**11.93**	**1.0%**	**0.8%**	**0.6%**	**0.2%**
13.01	12.60	11.99	10.30	1.2%	1.1%	0.9%	0.3%
27.72	**26.64**	**25.22**	**22.23**	**1.1%**	**0.9%**	**0.7%**	**0.2%**
98.1	**93.7**	**88.3**	**79.7**	**-0.1%**	**-0.3%**	**-0.5%**	**-0.9%**
0.06	**0.06**	**0.13**	**0.12**	**3.6%**	**3.5%**	**6.4%**	**6.0%**
0.58	0.52	0.52	0.60	0.6%	0.1%	0.1%	0.7%
0.12	0.12	0.12	0.12	0.1%	0.1%	0.1%	0.1%
0.03	0.03	0.03	0.03	0.3%	0.3%	0.3%	0.3%
0.10	0.10	0.10	0.10	0.2%	0.2%	0.2%	0.2%
0.05	0.05	0.05	0.05	0.3%	0.3%	0.3%	0.3%
0.88	0.82	0.82	0.90	0.4%	0.1%	0.1%	0.5%
4.11	4.11	4.06	3.81	1.1%	1.1%	1.0%	0.8%
0.09	0.09	0.09	0.09	-0.0%	-0.0%	-0.0%	-0.0%
0.09	0.09	0.09	0.09	0.0%	0.0%	0.0%	0.0%
7.98	7.34	7.05	6.03	2.5%	2.2%	2.0%	1.4%
13.15	**12.44**	**12.09**	**10.92**	**1.8%**	**1.6%**	**1.5%**	**1.1%**
15.55	14.29	13.72	11.74	2.1%	1.7%	1.6%	1.0%
28.69	**26.73**	**25.82**	**22.66**	**1.9%**	**1.7%**	**1.5%**	**1.0%**
117.3	**111.0**	**107.9**	**97.5**	**0.3%**	**0.0%**	**-0.1%**	**-0.5%**
581	696	701	749	0.1%	0.8%	0.9%	1.1%
616	1357	1774	4769	6.8%	10.1%	11.3%	15.6%
4.19	5.02	5.05	5.41	0.1%	0.8%	0.9%	1.1%
1.31	2.92	3.79	9.81	6.9%	10.2%	11.3%	15.5%
0.03	**0.04**	**0.04**	**0.06**	**1.0%**	**1.6%**	**1.8%**	**3.5%**

Table D2. Key Results for Industrial Sector Technology Cases

Consumption	2004	2010			2020			2030		
		2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology
Value of Shipments (billion 2000 dollars)										
Manufacturing	4204	4783	4783	4783	5969	5969	5969	7509	7509	7509
Nonmanufacturing	1439	1572	1572	1572	1808	1808	1808	2069	2069	2069
Total	**5643**	**6355**	**6355**	**6355**	**7778**	**7778**	**7778**	9578	9578	9578
Energy Consumption (quadrillion Btu)[1]										
Distillate Fuel	1.19	1.25	1.20	1.16	1.37	1.23	1.11	1.53	1.32	1.18
Liquefied Petroleum Gas	2.19	2.27	2.21	2.16	2.50	2.34	2.21	2.75	2.54	2.38
Petrochemical Feedstocks	1.49	1.52	1.48	1.44	1.62	1.51	1.41	1.71	1.55	1.45
Residual Fuel	0.24	0.20	0.20	0.20	0.20	0.20	0.18	0.23	0.21	0.19
Motor Gasoline	0.32	0.34	0.32	0.31	0.36	0.32	0.29	0.38	0.34	0.30
Petroleum Coke	0.94	1.13	1.12	1.10	1.29	1.24	1.19	1.41	1.34	1.28
Still Gas	1.55	1.78	1.78	1.78	2.07	2.07	2.07	2.44	2.44	2.44
Asphalt and Road Oil	1.24	1.33	1.22	1.14	1.53	1.25	1.04	1.76	1.39	1.14
Miscellaneous Petroleum[2]	0.43	0.50	0.48	0.46	0.53	0.49	0.44	0.57	0.52	0.45
Petroleum Subtotal	9.58	10.32	10.01	9.73	11.46	10.65	9.95	12.78	11.66	10.80
Natural Gas	7.64	8.30	8.07	7.93	9.12	8.51	8.07	9.78	9.08	8.32
Lease and Plant Fuel[3]	1.14	1.12	1.12	1.12	1.28	1.28	1.28	1.21	1.21	1.21
Natural Gas Subtotal	8.78	9.42	9.19	9.05	10.41	9.80	9.36	10.99	10.28	9.53
Metallurgical Coal and Coke[4]	0.79	0.67	0.64	0.60	0.68	0.61	0.52	0.68	0.59	0.47
Other Industrial Coal	1.38	1.45	1.43	1.41	1.47	1.43	1.38	1.51	1.45	1.37
Coal to Liquids Heat and Power	0.00	0.00	0.00	0.00	0.49	0.49	0.49	1.61	1.61	1.61
Coal Subtotal	2.16	2.12	2.07	2.01	2.64	2.53	2.39	3.80	3.65	3.45
Renewable Energy[5]	1.68	1.79	1.79	1.83	2.00	2.01	2.17	2.26	2.29	2.61
Purchased Electricity	3.48	3.71	3.62	3.50	4.18	3.91	3.61	4.76	4.31	3.82
Delivered Energy	**25.68**	**27.35**	**26.67**	**26.12**	**30.70**	**28.91**	**27.48**	**34.59**	**32.19**	**30.21**
Electricity Related Losses	7.58	7.99	7.79	7.54	8.59	8.04	7.41	9.27	8.39	7.43
Total	**33.27**	**35.34**	**34.46**	**33.66**	**39.29**	**36.95**	**34.89**	**43.86**	**40.58**	**37.64**
Delivered Energy Use per Dollar of Shipments (thousand Btu per 2000 dollar)	**5.89**	**5.56**	**5.42**	**5.30**	**5.05**	**4.75**	**4.49**	**4.58**	**4.24**	**3.93**
Industrial Combined Heat and Power										
Capacity (gigawatts)	27.53	30.11	30.09	31.36	41.40	41.69	45.12	59.28	60.79	65.72
Generation (billion kilowatthours)	149.23	178.82	178.57	187.10	265.31	266.65	288.81	402.96	412.28	442.53

[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]Includes lubricants 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 2004 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, AEO2006 National Energy Modeling System runs INDFRZN.D120505A, INDDEF.D120505A, and INDHIGH.D120505A.

Table D3. Key Results for Transportation Sector Technology Cases

Consumption and Indicators	2004	2010			2020			2030		
		2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology
Level of Travel										
(billion vehicle miles traveled)										
Light-Duty Vehicles less than 8,500	2632	2887	2889	2895	3450	3474	3509	4066	4132	4198
Commercial Light Trucks[1]	69	77	77	77	93	94	94	114	114	115
Freight Trucks greater than 10,000	226	261	261	261	328	328	329	414	414	414
(billion seat miles available)										
Air	980	1192	1192	1192	1452	1452	1452	1567	1567	1567
(billion ton miles traveled)										
Rail	1539	1723	1723	1724	1985	1985	1987	2406	2406	2408
Domestic Shipping	629	684	684	684	768	768	768	825	825	825
Energy Efficiency Indicators										
(miles per gallon)										
New Light-Duty Vehicle[2]	24.9	26.1	26.7	28.2	26.0	28.0	30.5	26.2	29.2	32.1
New Car[2]	29.3	30.5	31.4	33.4	30.6	32.7	35.5	30.7	33.8	36.9
New Light Truck[2]	21.5	22.8	23.2	24.3	22.9	24.9	27.1	23.4	26.4	29.0
Light-Duty Stock[3]	20.2	20.3	20.3	20.6	20.5	21.4	22.6	20.7	22.5	24.4
New Commercial Light Truck[1]	14.5	15.1	15.4	16.2	14.7	16.3	18.0	14.7	17.1	19.1
Stock Commercial Light Truck[1]	14.1	14.6	14.6	14.8	14.9	15.7	16.8	14.7	16.7	18.5
Freight Truck	6.0	6.0	6.0	6.1	6.1	6.4	6.5	6.1	6.8	6.9
(seat miles per gallon)										
Aircraft	55.5	58.5	59.0	64.5	61.0	67.6	83.8	61.6	76.0	99.6
(ton miles per thousand Btu)										
Rail	2.9	2.9	2.9	3.0	2.9	3.0	3.3	2.9	3.0	3.6
Domestic Shipping	2.1	2.1	2.2	2.2	2.1	2.2	2.3	2.1	2.2	2.4
Energy Use by Mode (quadrillion Btu)										
Light-Duty Vehicles	16.21	17.75	17.69	17.46	20.94	20.26	19.37	24.57	22.94	21.47
Commercial Light Trucks[1]	0.61	0.66	0.66	0.65	0.79	0.75	0.70	0.97	0.86	0.78
Bus Transportation	0.27	0.28	0.28	0.28	0.30	0.29	0.29	0.33	0.30	0.30
Freight Trucks	4.70	5.42	5.42	5.39	6.76	6.38	6.31	8.47	7.58	7.50
Rail, Passenger	0.13	0.14	0.14	0.14	0.16	0.15	0.14	0.17	0.17	0.14
Rail, Freight	0.53	0.59	0.59	0.57	0.68	0.67	0.60	0.83	0.81	0.68
Shipping, Domestic	0.30	0.32	0.32	0.31	0.36	0.35	0.33	0.39	0.37	0.34
Shipping, International	0.55	0.56	0.55	0.55	0.57	0.56	0.56	0.57	0.57	0.57
Recreational Boats	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.19	0.19	0.19
Air	2.82	3.35	3.32	3.04	4.34	3.92	3.16	5.12	4.15	3.16
Military Use	0.71	0.76	0.76	0.76	0.81	0.81	0.80	0.84	0.84	0.84
Lubricants	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.16	0.16	0.16
Pipeline Fuel	0.69	0.65	0.65	0.65	0.80	0.80	0.80	0.78	0.78	0.78
Total	**27.82**	**30.80**	**30.69**	**30.11**	**36.85**	**35.27**	**33.40**	**43.38**	**39.69**	**36.91**
Energy Use by Fuel (quadrillion Btu)										
Distillate Fuel[4]	5.91	6.84	6.83	6.76	8.57	8.14	7.92	10.96	10.00	9.60
Jet Fuel[5]	3.35	3.92	3.89	3.61	4.96	4.53	3.77	5.76	4.79	3.80
Motor Gasoline[6]	16.93	18.38	18.31	18.09	21.41	20.69	19.82	24.68	22.95	21.58
Residual Fuel	0.61	0.62	0.62	0.62	0.65	0.64	0.63	0.66	0.65	0.64
Liquefied Petroleum Gas	0.03	0.06	0.06	0.06	0.09	0.09	0.08	0.11	0.11	0.10
Other Petroleum[7]	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.19	0.19	0.19
Petroleum Subtotal	27.02	30.00	29.90	29.32	35.84	34.27	32.41	42.36	38.68	35.92
Pipeline Fuel Natural Gas	0.69	0.65	0.65	0.65	0.80	0.80	0.80	0.78	0.78	0.78
Compressed Natural Gas	0.03	0.05	0.05	0.05	0.09	0.09	0.09	0.12	0.12	0.11
Renewable Energy (E85)[8]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.09	0.09	0.10	0.10	0.09	0.11	0.11	0.09
Delivered Energy	**27.82**	**30.80**	**30.69**	**30.11**	**36.85**	**35.27**	**33.40**	**43.38**	**39.69**	**36.91**
Electricity Related Losses	0.18	0.19	0.19	0.19	0.20	0.20	0.18	0.21	0.21	0.18
Total	**28.00**	**30.99**	**30.88**	**30.30**	**37.05**	**35.47**	**33.59**	**43.59**	**39.90**	**37.09**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[2]Combined car and light truck "on-the-road" estimate.
[4]Diesel fuel for on- and off- road use.
[5]Includes only kerosene type.
[6]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[7]Includes aviation gasoline and lubricants.
[8]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.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 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, AEO2006 National Energy Modeling System runs LOTEK_06.D113005A, REF.D120505A, and HITEK_06.D120805B.

Table D4. Key Results for Integrated Technology Cases

Consumption and Emissions	2004	2010			2020			2030		
		2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology	2005 Technology	Reference	High Technology
Consumption by Sector (quadrillion Btu)										
Residential	21.0	23.1	23.0	22.8	25.7	25.2	24.3	27.7	26.6	25.2
Commercial	17.4	19.6	19.5	19.2	23.9	23.0	22.5	28.4	26.7	25.9
Industrial	33.3	35.3	34.5	33.7	39.4	37.0	34.7	44.6	40.6	37.4
Transportation	28.0	31.0	30.9	30.4	37.0	35.5	33.7	43.5	39.9	37.2
Total	**99.7**	**109.1**	**107.9**	**106.1**	**125.9**	**120.6**	**115.2**	**144.2**	**133.9**	**125.7**
Consumption by Fuel (quadrillion Btu)										
Petroleum Products	40.1	43.6	43.1	42.3	50.7	48.1	45.5	58.7	53.6	49.7
Natural Gas	23.1	24.6	24.0	23.5	28.5	27.7	26.4	28.8	27.7	26.7
Coal	22.5	25.3	25.1	24.7	29.7	27.6	26.0	38.1	34.5	30.2
Nuclear Power	8.2	8.4	8.4	8.4	9.1	9.1	8.9	9.7	9.1	9.5
Renewable Energy	5.7	7.1	7.1	7.1	7.8	8.0	8.3	8.8	9.0	9.6
Other	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.0
Total	**99.7**	**109.1**	**107.9**	**106.1**	**125.9**	**120.6**	**115.2**	**144.2**	**133.9**	**125.7**
Energy Intensity (thousand Btu per 2000 dollar of GDP)	**9.3**	**8.4**	**8.3**	**8.1**	**7.2**	**6.9**	**6.6**	**6.3**	**5.8**	**5.4**
Carbon Dioxide Emissions by Sector (million metric tons)										
Residential	1207.8	1323.9	1315.0	1301.2	1487.3	1433.9	1366.1	1653.2	1575.9	1432.1
Commercial	1020.4	1151.5	1141.8	1123.2	1418.2	1339.0	1292.8	1748.5	1620.0	1502.2
Industrial	1727.1	1831.0	1787.2	1744.8	2073.2	1924.3	1778.1	2444.8	2184.5	1945.6
Transportation	1944.7	2127.6	2121.0	2083.4	2527.8	2421.8	2296.9	2985.0	2734.1	2541.0
Total	**5899.9**	**6433.9**	**6364.9**	**6252.6**	**7506.5**	**7119.0**	**6733.8**	**8831.5**	**8114.5**	**7420.8**
Carbon Dioxide Emissions by End-Use Fuel (million metric tons)										
Petroleum	2497.8	2685.1	2665.8	2619.8	3135.3	2986.3	2829.1	3653.9	3339.0	3102.9
Natural Gas	907.5	979.6	964.2	955.6	1089.9	1052.1	1015.1	1158.1	1107.8	1042.1
Coal	196.1	206.3	202.2	197.4	266.4	245.4	212.9	434.0	349.7	318.8
Electricity	2298.6	2562.8	2532.7	2479.8	3014.8	2835.2	2676.8	3585.5	3318.0	2957.1
Total	**5899.9**	**6433.9**	**6364.9**	**6252.6**	**7506.5**	**7119.0**	**6733.8**	**8831.5**	**8114.5**	**7420.8**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)										
Petroleum	97.4	75.3	74.5	73.1	77.5	74.5	70.4	91.0	81.8	75.2
Natural Gas	295.9	311.3	297.4	276.6	408.5	402.8	372.9	352.9	344.3	361.2
Coal	1893.9	2163.3	2147.8	2117.1	2514.6	2343.5	2219.3	3127.0	2876.6	2505.7
Other	11.4	13.0	13.0	13.0	14.2	14.3	14.2	14.6	15.3	15.0
Total	**2298.6**	**2562.8**	**2532.7**	**2479.8**	**3014.8**	**2835.2**	**2676.8**	**3585.5**	**3318.0**	**2957.1**
Carbon Dioxide Emissions by Primary Fuel (million metric tons)										
Petroleum	2595.2	2760.5	2740.3	2692.9	3212.8	3060.8	2899.5	3744.9	3420.8	3178.1
Natural Gas	1203.4	1290.9	1261.6	1232.2	1498.5	1454.9	1388.0	1511.0	1452.1	1403.2
Coal	2089.9	2369.6	2350.0	2314.5	2781.0	2589.0	2432.1	3561.0	3226.3	2824.5
Other	11.4	13.0	13.0	13.0	14.2	14.3	14.2	14.6	15.3	15.0
Total	**5899.9**	**6433.9**	**6364.9**	**6252.6**	**7506.5**	**7119.0**	**6733.8**	**8831.5**	**8114.5**	**7420.8**

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 2004 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2006 National Energy Modeling System runs LTRKITEN.D121905A, AEO2006.D111905A, and HTRKITEN.D121905A.

Table D5. Key Results for Advanced Nuclear Cost Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation, Emissions, and Fuel Prices	2004	2010			2020			2030		
		Reference	Vendor Estimate	Advanced Nuclear Cost	Reference	Vendor Estimate	Advanced Nuclear Cost	Reference	Vendor Estimate	Advanced Nuclear Cost
Capacity										
Coal Steam	309.9	318.6	318.7	318.7	345.3	337.0	342.0	457.4	390.5	437.3
Other Fossil Steam	124.3	122.4	122.4	122.4	80.3	78.3	78.6	75.3	73.1	72.9
Combined Cycle	158.7	183.8	183.8	183.8	213.8	210.2	212.8	230.6	223.2	222.8
Combustion Turbine/Diesel	130.1	139.0	139.0	139.0	149.0	153.8	151.8	173.7	184.2	179.5
Nuclear Power	99.6	100.9	100.9	100.9	108.8	116.1	111.7	108.8	179.5	136.8
Pumped Storage	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	92.3	102.7	102.7	102.7	108.2	107.2	108.2	114.1	110.8	112.4
Distributed Generation (Natural Gas)	0.0	0.2	0.2	0.2	1.4	1.3	1.4	5.5	7.1	6.7
Combined Heat and Power[1]	29.3	32.4	32.4	32.4	44.2	44.1	44.2	64.3	64.3	63.7
Total	**964.9**	**1020.8**	**1021.0**	**1021.0**	**1071.6**	**1068.8**	**1071.4**	**1250.5**	**1253.5**	**1252.7**
Cumulative Additions										
Coal Steam	0.0	11.7	11.9	11.9	42.2	34.1	38.8	154.4	87.6	134.1
Other Fossil Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combined Cycle	0.0	25.7	25.7	25.7	55.7	52.1	54.7	72.5	65.1	64.7
Combustion Turbine/Diesel	0.0	10.0	10.0	10.0	26.8	31.6	29.8	51.5	62.0	57.4
Nuclear Power	0.0	0.0	0.0	0.0	6.0	13.3	8.9	6.0	76.7	34.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	10.4	10.4	10.4	16.0	14.9	15.9	21.8	18.6	20.1
Distributed Generation	0.0	0.2	0.2	0.2	1.4	1.3	1.4	5.5	7.1	6.7
Combined Heat and Power[1]	0.0	3.1	3.1	3.1	14.8	14.8	14.8	35.0	34.9	34.4
Total	**0.0**	**61.3**	**61.4**	**61.5**	**162.9**	**162.3**	**164.4**	**346.8**	**352.1**	**351.5**
Cumulative Retirements	**0.0**	**7.1**	**7.1**	**7.1**	**59.8**	**61.9**	**61.5**	**64.7**	**67.1**	**67.2**
Generation by Fuel (billion kilowatthours)										
Coal	1954	2195	2194	2199	2435	2385	2416	3205	2737	3065
Petroleum	115	93	92	93	92	93	93	101	94	99
Natural Gas	619	673	674	672	968	970	970	822	786	779
Nuclear Power	789	809	809	809	871	924	889	871	1412	1086
Pumped Storage	-8	-9	-9	-9	-9	-9	-9	-9	-9	-9
Renewable Sources	323	436	436	433	469	462	467	504	482	493
Distributed Generation	0	0	0	0	1	1	1	2	3	3
Combined Heat and Power[1]	161	192	192	192	280	280	279	429	429	425
Total	**3955**	**4388**	**4389**	**4388**	**5108**	**5106**	**5107**	**5926**	**5935**	**5942**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Petroleum	97.4	74.5	74.3	74.5	74.5	75.4	75.1	81.8	76.1	79.9
Natural Gas	295.9	297.4	298.0	297.1	402.8	405.2	403.8	344.3	335.0	331.3
Coal	1893.9	2147.8	2145.8	2150.9	2343.5	2311.5	2331.4	2876.6	2566.2	2782.5
Other	11.4	13.0	13.0	13.0	14.3	14.3	14.3	15.3	15.1	15.2
Total	**2298.6**	**2532.7**	**2531.0**	**2535.5**	**2835.2**	**2806.4**	**2824.7**	**3318.0**	**2992.4**	**3209.0**
Prices to the Electric Power Sector[2] (2004 dollars per million Btu)										
Petroleum	5.43	6.50	6.50	6.50	6.91	6.85	6.87	7.61	7.75	7.65
Natural Gas	5.92	5.46	5.47	5.46	5.40	5.43	5.41	6.26	6.21	6.17
Coal	1.36	1.48	1.48	1.48	1.39	1.38	1.39	1.51	1.43	1.48

[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.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2006 National Energy Modeling System runs AEO2006.D111905A, ADVNUC5A.D120105A, and ADVNUC20.D120105A.

Table D6. Key Results for Electric Power Sector Fossil Technology Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation Consumption, and Emissions	2004	2010			2020			2030		
		Low Fossil	Reference	High Fossil	Low Fossil	Reference	High Fossil	Low Fossil	Reference	High Fossil
Capacity										
Pulverized Coal	309.5	317.9	317.9	317.9	349.7	334.7	330.2	449.0	372.6	340.0
Coal Gasification Combined-Cycle	0.3	0.3	0.7	0.3	0.3	10.6	9.9	0.3	84.8	90.6
Conventional Natural Gas Combined-Cycle	158.7	183.8	183.8	183.8	186.0	184.9	183.8	194.0	185.8	184.0
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	8.7	28.8	54.7	18.4	44.9	102.9
Conventional Combustion Turbine	130.1	138.1	138.1	137.9	135.8	134.4	131.8	144.0	134.6	131.8
Advanced Combustion Turbine	0.0	0.9	0.9	1.1	17.9	14.6	9.6	36.1	39.1	32.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	99.6	100.9	100.9	100.9	108.8	108.8	108.8	112.4	108.8	108.8
Oil and Gas Steam	124.3	122.4	122.4	122.4	85.9	80.3	70.6	75.9	75.3	59.4
Renewable Sources/Pumped Storage	113.0	123.4	123.4	123.4	129.8	129.0	127.5	137.1	134.8	130.0
Distributed Generation	0.0	0.2	0.2	0.2	2.9	1.4	1.1	13.1	5.5	3.8
Combined Heat and Power[1]	29.3	32.5	32.4	32.5	45.8	44.2	44.1	66.2	64.3	65.1
Total	**964.9**	**1020.5**	**1020.8**	**1020.5**	**1071.6**	**1071.6**	**1072.0**	**1246.6**	**1250.5**	**1248.3**
Cumulative Additions										
Pulverized Coal	0.0	11.3	11.3	11.3	46.7	31.9	27.4	146.0	69.9	37.2
Coal Gasification Combined-Cycle	0.0	0.0	0.4	0.0	0.0	10.3	9.6	0.0	84.5	90.3
Conventional Natural Gas Combined-Cycle	0.0	25.7	25.7	25.7	27.9	26.8	25.7	35.9	27.7	25.9
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	8.7	28.8	54.7	18.4	44.9	102.9
Conventional Combustion Turbine	0.0	9.1	9.1	9.0	13.8	12.2	10.4	22.0	12.4	10.4
Advanced Combustion Turbine	0.0	0.9	0.9	1.1	17.9	14.6	9.6	36.1	39.1	32.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	6.0	6.0	6.0	9.6	6.0	6.0
Oil and Gas Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Renewable Sources	0.0	10.4	10.4	10.4	16.8	16.0	14.5	24.1	21.8	17.0
Distributed Generation	0.0	0.2	0.2	0.2	2.9	1.4	1.1	13.1	5.5	3.8
Combined Heat and Power[1]	0.0	3.1	3.1	3.1	16.4	14.8	14.7	36.9	35.0	35.7
Total	**0.0**	**61.0**	**61.3**	**61.0**	**157.3**	**162.9**	**173.7**	**342.3**	**346.8**	**361.2**
Cumulative Retirements	**0.0**	**7.1**	**7.1**	**7.1**	**54.2**	**59.8**	**70.1**	**64.1**	**64.7**	**81.4**
Generation by Fuel (billion kilowatthours)										
Coal	1954.0	2197.9	2194.8	2192.4	2460.5	2435.2	2399.1	3152.4	3205.4	3049.9
Petroleum	115.2	92.8	92.6	92.4	90.7	92.4	93.1	101.1	101.3	98.9
Natural Gas	618.6	672.5	672.6	676.0	922.4	967.8	1016.5	791.0	821.8	996.4
Nuclear Power	788.6	808.7	808.7	808.7	870.7	870.7	870.7	897.2	870.6	870.6
Renewable Sources/Pumped Storage	314.8	423.9	427.2	426.5	466.5	460.5	452.3	513.2	495.0	469.2
Distributed Generation	0.0	0.1	0.1	0.1	1.3	0.6	0.5	5.7	2.4	1.6
Combined Heat and Power[1]	161.3	192.1	191.8	192.2	292.0	280.3	279.7	442.8	429.0	434.1
Total	**3954.9**	**4388.1**	**4387.7**	**4388.2**	**5104.0**	**5107.5**	**5111.9**	**5903.4**	**5925.6**	**5920.7**
Fuel Consumption by the Electric Power Sector (quadrillion Btu)[2]										
Coal	20.26	22.96	22.92	22.89	25.32	25.02	24.67	31.22	30.74	28.96
Petroleum	1.12	0.97	0.97	0.97	0.95	0.97	0.98	1.05	1.07	1.05
Natural Gas	5.45	5.65	5.65	5.67	7.52	7.65	7.60	6.56	6.54	7.17
Nuclear Power	8.23	8.44	8.44	8.44	9.09	9.09	9.09	9.37	9.09	9.09
Renewable Sources	3.57	4.73	4.76	4.75	5.54	5.47	5.39	6.37	6.22	5.83
Total	**38.63**	**42.76**	**42.74**	**42.73**	**48.41**	**48.19**	**47.73**	**54.57**	**53.66**	**52.10**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Coal	1893.9	2152.0	2147.8	2145.5	2372.1	2343.5	2311.5	2922.8	2876.6	2711.1
Petroleum	97.4	74.7	74.5	74.3	72.8	74.5	75.4	80.1	81.8	80.7
Natural Gas	295.9	297.4	297.4	298.6	396.0	402.8	400.3	345.6	344.3	377.4
Other	11.4	13.0	13.0	13.0	14.3	14.3	14.1	14.9	15.3	14.4
Total	**2298.6**	**2537.0**	**2532.7**	**2531.4**	**2855.2**	**2835.2**	**2801.1**	**3363.4**	**3318.0**	**3183.7**

[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 2004 are model results and may differ slightly from official EIA data reports.

Source: Energy Information Administration, AEO2006 National Energy Modeling System runs LFOSS06.D120105A, AEO2006.D111905A, and HFOSS06.D120105B.

Table D7. Key Results for Renewable Technology Cases

Capacity, Generation, and Emissions	2004	2010			2020			2030		
		Low Technology	Reference	High Technology	Low Technology	Reference	High Technology	Low Technology	Reference	High Technology
Net Summer Capacity (gigawatts)										
Electric Power Sector[1]										
Conventional Hydropower	77.64	77.67	77.67	77.67	77.80	77.87	77.75	77.80	77.87	78.10
Geothermal[2]	2.11	2.56	2.56	2.80	3.83	4.61	6.19	5.11	6.64	9.14
Municipal Solid Waste[3]	3.22	3.52	3.52	3.52	3.71	3.76	3.76	3.87	3.87	3.87
Wood and Other Biomass[4]	2.00	2.15	2.15	2.20	2.41	2.46	3.96	3.84	4.63	10.55
Solar Thermal	0.39	0.47	0.47	0.47	0.50	0.50	0.50	0.55	0.55	0.55
Solar Photovoltaic	0.03	0.07	0.07	0.07	0.22	0.22	0.22	0.39	0.39	0.39
Wind	6.87	16.27	16.27	16.27	17.13	18.81	18.87	17.18	20.10	22.63
Total	**92.26**	**102.69**	**102.69**	**103.00**	**105.59**	**108.23**	**111.24**	**108.74**	**114.06**	**125.24**
End-Use Sector										
Conventional Hydropower	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
Wood and Other Biomass	4.33	4.98	5.01	5.27	5.88	6.02	6.89	7.03	7.29	9.00
Solar Photovoltaic	0.12	0.58	0.63	0.63	0.68	0.75	0.75	0.80	1.68	1.93
Total	**5.38**	**6.48**	**6.57**	**6.82**	**7.49**	**7.70**	**8.57**	**8.75**	**9.89**	**11.85**
Generation (billion kilowatthours)										
Electric Power Sector[1]										
Coal	1954	2200	2195	2191	2441	2435	2424	3222	3205	3162
Petroleum	115	92	93	93	94	92	92	103	101	101
Natural Gas	619	673	673	673	972	968	955	828	822	804
Total Fossil	**2688**	**2966**	**2960**	**2957**	**3507**	**3495**	**3471**	**4153**	**4129**	**4067**
Conventional Hydropower	264.50	296.98	296.98	296.98	298.07	298.46	297.73	298.46	298.85	300.04
Geothermal	14.36	17.51	17.51	19.16	27.65	34.01	47.91	39.74	52.70	73.01
Municipal Solid Waste[3]	19.86	24.89	24.89	24.89	26.47	26.83	26.84	27.78	27.79	27.80
Wood and Other Biomass[4]	9.49	40.64	44.67	45.45	48.73	48.59	59.94	54.86	57.83	95.96
Dedicated Plants	8.00	10.92	10.39	10.79	12.52	13.03	25.28	25.27	31.67	78.99
Cofiring	1.49	29.72	34.29	34.66	36.21	35.55	34.66	29.59	26.16	16.96
Solar Thermal	0.58	0.84	0.84	0.84	0.96	0.96	0.96	1.11	1.11	1.11
Solar Photovoltaic	0.00	0.18	0.18	0.18	0.54	0.54	0.54	0.98	0.98	0.98
Wind	14.15	50.87	50.87	50.87	53.91	59.82	59.97	54.08	64.51	73.90
Total Renewable	**322.93**	**431.91**	**435.94**	**438.38**	**456.32**	**469.21**	**493.88**	**477.00**	**503.77**	**572.79**
End-Use Sector[5]										
Total Fossil	111	136	136	136	219	218	217	357	357	353
Conventional Hydropower[6]	4.45	4.42	4.42	4.42	4.42	4.42	4.42	4.42	4.42	4.42
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	2.12	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24
Wood and Other Biomass	27.81	31.58	31.81	33.28	36.87	37.69	42.78	43.56	45.09	55.06
Solar Photovoltaic	0.26	1.23	1.34	1.34	1.45	1.60	1.60	1.70	3.62	4.16
Total Renewables	**34.63**	**39.47**	**39.80**	**41.27**	**44.98**	**45.94**	**51.03**	**51.92**	**55.37**	**65.88**
Sources of Ethanol										
From Corn	0.28	0.61	0.61	0.61	0.87	0.87	0.87	0.92	0.92	0.91
From Cellulose	0.00	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.05
Imports	0.00	0.04	0.04	0.04	0.06	0.06	0.06	0.07	0.07	0.07
Total	**0.28**	**0.66**	**0.66**	**0.67**	**0.96**	**0.96**	**0.96**	**1.01**	**1.01**	**1.03**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[1]										
Coal	1893.9	2152.0	2147.8	2145.5	2350.5	2343.5	2336.8	2896.4	2876.6	2842.7
Petroleum	97.4	74.3	74.5	74.6	76.0	74.5	74.1	82.7	81.8	81.8
Natural Gas	295.9	297.6	297.4	297.5	404.0	402.8	398.2	346.5	344.3	337.5
Other	11.4	13.0	13.0	13.0	14.0	14.3	14.7	14.9	15.3	15.8
Total	**2298.6**	**2536.9**	**2532.7**	**2530.6**	**2844.6**	**2835.2**	**2823.9**	**3340.6**	**3318.0**	**3277.7**

[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; and 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.
[6]Represents own-use industrial hydroelectric power.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2006 National Energy Modeling System runs LOREN06.D120505A, AEO2006.D111905A, and HIREN06.D120605A.

Table D8. Total Energy Supply and Disposition, Oil and Gas Technological Progress Cases
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2004	2010			2020			2030		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Production										
Crude Oil and Lease Condensate	11.47	12.21	12.45	12.65	11.05	11.75	12.32	8.91	9.68	10.38
Natural Gas Plant Liquids	2.46	2.37	2.39	2.40	2.55	2.67	2.79	2.38	2.57	2.85
Dry Natural Gas	19.02	18.91	19.13	19.27	20.87	22.09	23.55	19.34	21.45	25.18
Coal	22.86	25.97	25.78	25.75	28.04	27.30	26.84	34.99	34.10	32.53
Nuclear Power	8.23	8.44	8.44	8.44	9.09	9.09	9.09	9.09	9.09	9.09
Renewable Energy[1]	5.74	7.07	7.08	7.04	8.02	8.00	7.78	9.12	9.02	8.85
Other[2]	0.64	2.16	2.16	2.16	3.17	3.16	3.15	3.42	3.44	3.45
Total	**70.42**	**77.12**	**77.42**	**77.71**	**82.79**	**84.05**	**85.52**	**87.26**	**89.36**	**92.32**
Imports										
Crude Oil[3]	22.02	22.18	22.01	21.93	25.33	24.63	24.14	30.47	29.54	28.75
Petroleum Products[4]	5.93	6.44	6.36	6.24	8.09	8.01	7.83	9.39	9.27	8.96
Natural Gas	4.36	4.94	5.01	5.06	5.99	5.83	5.16	7.42	6.72	5.69
Other Imports[5]	0.83	0.44	0.45	0.45	1.56	1.36	1.36	2.51	2.42	2.24
Total	**33.14**	**34.00**	**33.83**	**33.67**	**40.96**	**39.83**	**38.50**	**49.79**	**47.95**	**45.63**
Exports										
Petroleum[6]	2.07	2.15	2.15	2.15	2.26	2.24	2.23	2.31	2.31	2.31
Natural Gas	0.86	0.55	0.55	0.56	0.65	0.68	0.72	0.90	1.01	1.12
Coal	1.25	1.03	1.03	1.03	0.46	0.46	0.46	0.40	0.40	0.39
Total	**4.18**	**3.73**	**3.74**	**3.75**	**3.37**	**3.39**	**3.41**	**3.61**	**3.72**	**3.82**
Consumption										
Petroleum Products[7]	40.08	43.13	43.14	43.16	48.17	48.14	48.15	53.60	53.58	53.51
Natural Gas	23.07	23.76	24.04	24.22	26.68	27.70	28.46	26.36	27.66	30.21
Coal	22.53	25.28	25.09	25.05	28.50	27.65	27.24	35.46	34.49	32.78
Nuclear Power	8.23	8.44	8.44	8.44	9.09	9.09	9.09	9.09	9.09	9.09
Renewable Energy[1]	5.74	7.07	7.08	7.04	8.02	8.00	7.78	9.12	9.02	8.86
Other[8]	0.04	0.07	0.07	0.07	0.05	0.05	0.05	0.05	0.05	0.05
Total	**99.68**	**107.75**	**107.87**	**107.99**	**120.51**	**120.63**	**120.77**	**133.69**	**133.88**	**134.50**
Net Imports - Petroleum	**25.88**	**26.47**	**26.22**	**26.01**	**31.16**	**30.39**	**29.74**	**37.54**	**36.49**	**35.40**
Prices (2004 dollars per unit)										
Imported Low Sulfur Light Crude Oil Price (dollars per barrel)[9]	40.49	47.29	47.29	47.29	50.70	50.70	50.70	56.97	56.97	56.97
Imported Crude Oil Price (dollars per barrel)[9]	35.99	43.99	43.99	43.99	44.99	44.99	44.99	49.99	49.99	49.99
Natural Gas Wellhead Price (dollars per thousand cubic feet)[10]	5.49	5.19	5.03	4.88	5.17	4.90	4.76	6.36	5.92	5.20
Coal Minemouth Price (dollars per ton)	20.07	22.21	22.23	22.30	20.35	20.20	19.95	21.76	21.73	20.99
Average Electricity Price (cents per kilowatthour)	7.6	7.3	7.3	7.2	7.3	7.2	7.2	7.5	7.5	7.4
Carbon Dioxide Emissions (million metric tons)	**5899.9**	**6368.5**	**6364.9**	**6372.2**	**7148.2**	**7119.0**	**7121.4**	**8140.7**	**8114.5**	**8082.3**

[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.
[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]Weighted average price delivered to U.S. refiners.
[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 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2004 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2005/06) (Washington, DC, June 2005). 2004 petroleum supply values: EIA, *Petroleum Supply Annual 2004,* DOE/EIA-0340(2004)/1 (Washington, DC, June 2005). 2004 carbon dioxide emission values: EIA, *Emissions of Greenhouse Gases in the United States 2004,* DOE/EIA-0573(2004) (Washington, DC, December 2005). 2004 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2004 values: EIA,*Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005) and EIA,*Quarterly Coal Report, October-December 2004*, DOE/EIA-0121(2004/4Q) (Washington, DC, March 2005). **Projections:** EIA, AEO2006 National Energy Modeling System runs OGLTEC06.D121605A, AEO2006.D111905A, and OGHTEC06.D121605A.

Table D9. Natural Gas Supply and Disposition, Oil and Gas Technological Progress Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2004	2010			2020			2030		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Lower 48 Average Wellhead Price (2004 dollars per thousand cubic feet)	**5.49**	**5.19**	**5.03**	**4.88**	**5.17**	**4.90**	**4.76**	**6.36**	**5.92**	**5.20**
Dry Gas Production[1]	**18.46**	**18.36**	**18.58**	**18.71**	**20.26**	**21.44**	**22.87**	**18.78**	**20.83**	**24.44**
Lower 48 Onshore	13.76	13.89	14.03	14.12	13.74	14.52	15.71	12.92	14.72	18.08
Associated-Dissolved	1.51	1.33	1.34	1.35	1.17	1.20	1.22	1.07	1.10	1.12
Non-Associated	12.26	12.57	12.69	12.77	12.57	13.33	14.49	11.85	13.62	16.96
Conventional	4.79	5.02	5.01	5.00	4.59	4.66	4.76	4.05	4.17	4.16
Unconventional	7.47	7.55	7.68	7.77	7.98	8.66	9.73	7.80	9.45	12.80
Lower 48 Offshore	4.26	4.22	4.31	4.35	4.32	4.71	4.94	3.72	3.97	4.22
Associated-Dissolved	0.85	1.07	1.08	1.10	1.25	1.34	1.40	1.06	1.15	1.26
Non-Associated	3.41	3.16	3.23	3.25	3.06	3.37	3.54	2.65	2.82	2.96
Alaska	0.44	0.24	0.24	0.24	2.21	2.21	2.21	2.14	2.14	2.14
Supplemental Natural Gas[2]	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Net Imports	**3.40**	**4.29**	**4.35**	**4.39**	**5.21**	**5.02**	**4.34**	**6.36**	**5.57**	**4.45**
Pipeline	2.81	2.10	2.28	2.42	1.23	1.32	1.53	1.02	1.22	1.29
Liquefied Natural Gas[3]	0.59	2.19	2.07	1.97	3.97	3.70	2.80	5.34	4.36	3.16
Total Supply	**21.92**	**22.72**	**23.00**	**23.17**	**25.54**	**26.54**	**27.28**	**25.22**	**26.48**	**28.97**
Consumption by Sector										
Residential	4.88	5.15	5.17	5.19	5.48	5.51	5.53	5.60	5.64	5.73
Commercial	3.00	3.07	3.08	3.10	3.55	3.57	3.60	3.94	3.99	4.08
Industrial[4]	7.41	7.77	7.82	7.87	8.13	8.26	8.37	8.59	8.81	9.15
Electric Power[5]	5.32	5.33	5.51	5.60	6.73	7.46	7.95	5.57	6.38	8.12
Transportation[6]	0.02	0.05	0.05	0.05	0.09	0.09	0.09	0.12	0.12	0.12
Pipeline Fuel	0.67	0.62	0.63	0.63	0.75	0.78	0.80	0.72	0.75	0.83
Lease and Plant Fuel[7]	1.11	1.07	1.09	1.09	1.19	1.25	1.31	1.08	1.17	1.33
Total	**22.41**	**23.08**	**23.35**	**23.53**	**25.92**	**26.92**	**27.66**	**25.60**	**26.86**	**29.36**
Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[8]	**-0.49**	**-0.36**	**-0.36**	**-0.36**	**-0.38**	**-0.38**	**-0.38**	**-0.39**	**-0.39**	**-0.39**
Lower 48 End of Year Reserves	**183.64**	**209.30**	**214.35**	**219.01**	**210.18**	**229.52**	**254.49**	**187.07**	**222.72**	**295.89**

[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 any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]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.
[6]Compressed natural gas used as vehicle fuel.
[7]Represents natural gas used in field gathering and processing plant machinery.
[8]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, 2004 values include net storage injections.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2004 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2005/06) (Washington, DC, June 2005). 2004 consumption based on: EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** EIA, AEO2006 National Energy Modeling System runs OGLTEC06.D121605A, AEO2006.D111905A, and OGHTEC06.D121605A.

Table D10. Petroleum Supply and Disposition, Oil and Gas Technological Progress Cases
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2004	2010			2020			2030		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Prices (2004 dollars per barrel)										
Imported Low Sulfur Light Crude Oil[1]	**40.49**	**47.29**	**47.29**	**47.29**	**50.70**	**50.70**	**50.70**	**56.97**	**56.97**	**56.97**
Imported Crude Oil[1]	**35.99**	**43.99**	**43.99**	**43.99**	**44.99**	**44.99**	**44.99**	**49.99**	**49.99**	**49.99**
Crude Oil Supply										
Domestic Crude Oil Production[2]	5.40	5.77	5.88	5.98	5.22	5.55	5.82	4.21	4.57	4.90
Lower 48 Onshore	2.90	2.57	2.62	2.68	2.27	2.42	2.57	2.12	2.27	2.40
Lower 48 Offshore	1.59	2.37	2.42	2.46	2.19	2.36	2.49	1.82	2.03	2.23
Alaska	0.91	0.83	0.83	0.84	0.75	0.76	0.77	0.27	0.27	0.28
Net Crude Oil Imports	10.06	10.13	10.05	10.02	11.58	11.26	11.03	13.94	13.51	13.15
Other Crude Oil Supply	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Oil Supply	**15.48**	**15.90**	**15.93**	**15.99**	**16.80**	**16.81**	**16.85**	**18.15**	**18.08**	**18.05**
Other Petroleum Supply										
Natural Gas Plant Liquids	1.81	1.74	1.75	1.76	1.86	1.94	2.03	1.73	1.87	2.07
Net Petroleum Product Imports[3]	2.05	2.32	2.28	2.22	3.20	3.16	3.08	3.78	3.73	3.58
Refinery Processing Gain[4]	1.05	1.31	1.31	1.30	1.46	1.44	1.43	1.85	1.82	1.79
Other Supply[5]	0.35	0.94	0.94	0.94	1.56	1.52	1.49	2.16	2.16	2.14
Total Primary Supply[6]	**20.74**	**22.20**	**22.21**	**22.22**	**24.87**	**24.87**	**24.87**	**27.66**	**27.65**	**27.63**
Refined Petroleum Products Supplied										
Residential and Commercial	1.29	1.25	1.25	1.25	1.25	1.25	1.25	1.22	1.22	1.22
Industrial[7]	5.02	5.23	5.23	5.23	5.56	5.55	5.56	6.06	6.06	6.05
Transportation	13.69	15.26	15.27	15.28	17.56	17.57	17.59	19.79	19.81	19.85
Electric Power[8]	0.49	0.44	0.43	0.43	0.46	0.43	0.42	0.49	0.47	0.42
Total	**20.76**	**22.17**	**22.17**	**22.18**	**24.82**	**24.81**	**24.82**	**27.57**	**27.57**	**27.55**
Discrepancy[9]	**-0.02**	**0.03**	**0.03**	**0.03**	**0.05**	**0.05**	**0.06**	**0.09**	**0.09**	**0.08**
Lower 48 End of Year Reserves (billion barrels)[2]	**18.21**	**19.28**	**19.83**	**20.32**	**18.33**	**19.61**	**20.70**	**16.50**	**17.91**	**19.26**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes lease condensate.
[3]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]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.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[8]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.
[9]Balancing item. Includes unaccounted for supply, losses and gains.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2004 product supplied data based on: Energy Information Administration (EIA), *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). 2004 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2004 data: EIA, *Petroleum Supply Annual 2004,* DOE/EIA-0340(2004)/1 (Washington, DC, June 2005). **Projections:** EIA, AEO2006 National Energy Modeling System runs OGLTEC06.D121605A, AEO2006.D111905A, and OGHTEC06.D121605A.

Table D11. Natural Gas Supply and Disposition, Liquefied Natural Gas Supply Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2004	2010			2020			2030		
		Low LNG	Reference	High LNG	Low LNG	Reference	High LNG	Low LNG	Reference	High LNG
Production										
Dry Gas Production[1]	18.46	18.95	18.58	18.19	22.55	21.44	19.30	21.99	20.83	19.10
Lower 48 Onshore	13.76	14.33	14.03	13.70	15.51	14.52	13.09	15.67	14.72	13.08
Associated-Dissolved	1.51	1.34	1.34	1.34	1.20	1.20	1.20	1.10	1.10	1.10
Non-Associated	12.26	12.99	12.69	12.37	14.31	13.33	11.89	14.57	13.62	11.99
Conventional	4.79	5.13	5.01	4.88	4.88	4.66	4.31	4.36	4.17	3.95
Unconventional	7.47	7.86	7.68	7.48	9.42	8.66	7.58	10.21	9.45	8.04
Lower 48 Offshore	4.26	4.37	4.31	4.24	4.83	4.71	4.36	4.18	3.97	3.88
Associated-Dissolved	0.85	1.08	1.08	1.08	1.35	1.34	1.30	1.18	1.15	1.15
Non-Associated	3.41	3.29	3.23	3.16	3.48	3.37	3.06	3.01	2.82	2.73
Alaska	0.44	0.24	0.24	0.24	2.21	2.21	1.86	2.14	2.14	2.14
Supplemental Natural Gas[2]	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Net Imports	**3.40**	**3.73**	**4.35**	**4.94**	**2.59**	**5.02**	**8.61**	**2.80**	**5.57**	**10.53**
Pipeline	2.81	2.41	2.28	2.13	1.49	1.32	1.08	1.50	1.22	0.95
Liquefied Natural Gas[3]	0.59	1.33	2.07	2.80	1.10	3.70	7.52	1.30	4.36	9.58
Total Supply	**21.92**	**22.75**	**23.00**	**23.20**	**25.21**	**26.54**	**27.98**	**24.87**	**26.48**	**29.70**
Consumption by Sector										
Residential	4.88	5.15	5.17	5.19	5.46	5.51	5.59	5.59	5.64	5.73
Commercial	3.00	3.06	3.08	3.10	3.53	3.57	3.65	3.94	3.99	4.06
Industrial[4]	7.41	7.79	7.82	7.87	8.15	8.26	8.42	8.60	8.81	9.12
Electric Power[5]	5.32	5.32	5.51	5.65	6.29	7.46	8.70	5.03	6.38	9.17
Transportation[6]	0.02	0.05	0.05	0.05	0.09	0.09	0.09	0.12	0.12	0.12
Pipeline Fuel	0.67	0.63	0.63	0.63	0.77	0.78	0.76	0.75	0.75	0.80
Lease and Plant Fuel[7]	1.11	1.10	1.09	1.07	1.30	1.25	1.14	1.22	1.17	1.09
Total	**22.41**	**23.11**	**23.35**	**23.55**	**25.59**	**26.92**	**28.36**	**25.25**	**26.86**	**30.09**
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[8]	**-0.49**	**-0.36**	**-0.36**	**-0.36**	**-0.38**	**-0.38**	**-0.38**	**-0.39**	**-0.39**	**-0.39**
Lower 48 End of Year Reserves	**183.64**	**216.33**	**214.35**	**212.33**	**239.57**	**229.52**	**214.88**	**234.12**	**222.72**	**202.44**
Natural Gas Prices (2004 dollars per thousand cubic feet)										
Average Lower 48 Wellhead Price[9]	**5.49**	**5.24**	**5.03**	**4.81**	**5.30**	**4.90**	**4.22**	**6.36**	**5.92**	**5.35**
Delivered Prices										
Residential	10.72	10.86	10.65	10.43	10.90	10.48	9.72	12.11	11.67	11.05
Commercial	9.38	9.24	9.03	8.81	9.03	8.63	7.89	10.01	9.58	8.99
Industrial[4]	6.29	6.09	5.86	5.63	6.07	5.66	4.94	7.10	6.65	6.08
Electric Power[5]	6.07	5.77	5.60	5.40	5.84	5.53	4.92	6.76	6.41	6.05
Transportation[10]	10.25	10.60	10.40	10.19	10.59	10.21	9.51	11.42	11.01	10.46
Average[11]	**7.74**	**7.63**	**7.41**	**7.17**	**7.60**	**7.14**	**6.37**	**8.75**	**8.22**	**7.53**

[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 any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]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.
[6]Compressed natural gas used as vehicle fuel.
[7]Represents natural gas used in field gathering and processing plant machinery.
[8]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, 2004 values include net storage injections.
[9]Represents lower 48 onshore and offshore supplies.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2004 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2005/06) (Washington, DC, June 2005). 2004 consumption based on: EIA, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). **Projections:** EIA, AEO2006 National Energy Modeling System runs LOLNG06.D120405A, AEO2006.D111905A, and HILNG06.D120405A.

Table D12. Petroleum Supply and Disposition, ANWR Drilling Case
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2004	2010		2020		2030	
		Reference	ANWR	Reference	ANWR	Reference	ANWR
Crude Oil							
Domestic Crude Production[1]	5.42	5.88	5.88	5.55	6.15	4.57	5.22
Alaska	0.91	0.83	0.83	0.76	1.37	0.27	0.93
Lower 48 States	4.51	5.05	5.05	4.79	4.78	4.30	4.30
Net Imports	10.06	10.05	10.05	11.26	10.68	13.51	12.90
Other Crude Supply[2]	-0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.48**	**15.93**	**15.93**	**16.81**	**16.84**	**18.08**	**18.13**
Other Petroleum Supply							
Natural Gas Plant Liquids	1.81	1.75	1.75	1.94	1.95	1.87	1.90
Net Product Imports[3]	2.05	2.28	2.28	3.16	3.21	3.73	3.74
Refinery Processing Gain[4]	1.05	1.31	1.31	1.44	1.45	1.82	1.81
Other Inputs	0.35	0.94	0.94	1.52	1.48	2.16	2.14
Liquids from Coal	0.00	0.00	0.00	0.23	0.20	0.76	0.75
Other[5]	0.35	0.94	0.94	1.28	1.28	1.39	1.39
Total Primary Supply[6]	**20.74**	**22.21**	**22.21**	**24.87**	**24.92**	**27.65**	**27.71**
Refined Petroleum Products Supplied by Fuel							
Motor Gasoline[7]	9.10	9.94	9.94	11.28	11.31	12.49	12.52
Jet Fuel[8]	1.63	1.88	1.88	2.19	2.19	2.31	2.31
Distillate Fuel[9]	4.06	4.61	4.61	5.21	5.22	6.09	6.11
Residual Fuel	0.87	0.73	0.73	0.74	0.74	0.78	0.78
Other[10]	5.10	5.01	5.01	5.40	5.41	5.89	5.90
by Sector							
Residential and Commercial	1.29	1.25	1.25	1.25	1.26	1.22	1.22
Industrial[11]	5.02	5.23	5.23	5.55	5.57	6.06	6.07
Transportation	13.69	15.27	15.27	17.57	17.61	19.81	19.85
Electric Power[12]	0.49	0.43	0.43	0.43	0.44	0.47	0.48
Total	**20.76**	**22.17**	**22.18**	**24.81**	**24.87**	**27.57**	**27.62**
Discrepancy[13]	**-0.02**	**0.03**	**0.03**	**0.05**	**0.05**	**0.09**	**0.09**
Imported Low Sulfur Light Crude Oil Price (2004 dollars per barrel)[14]	40.49	47.29	47.29	50.70	50.35	56.97	56.29
Imported Crude Oil Price (2004 dollars per barrel)[14]	35.99	43.99	43.99	44.99	44.35	49.99	49.31
Import Share of Product Supplied	0.58	0.56	0.56	0.58	0.56	0.62	0.60
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2004 dollars)	152.36	189.84	189.86	231.71	219.94	310.15	295.23

[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 other hydrocarbons and alcohols.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes petroleum product stock withdrawals; domestic sources of blending components, other hydrocarbons, alcohols, and ethers.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes only kerosene type.
[9]Includes distillate and kerosene.
[10]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[11]Includes consumption for combined heat and power (CHP), which produces electricity and other useful thermal energy.
[12]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.
[13]Balancing item. Includes unaccounted for supply, losses, and gains.
[14]Weighted average price delivered to U.S. refiners.
[15]End-of-year operable capacity.
[16]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2004 imported crude oil price and petroleum product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005). 2004 imported low sulfur light crude oil price: EIA, Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” Other 2004 data: EIA, *Petroleum Supply Annual 2004,* DOE/EIA-0340(2004)/1 (Washington, DC, June 2005). **Projections:** EIA, AEO2006 National Energy Modeling System runs AEO2006.D111905A and ANWR2006.D120605A.

Table D13. Key Results for Coal Cost Cases
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2004	2015			2030			Growth Rate, 2004-2030		
		Low Cost	Reference	High Cost	Low Cost	Reference	High Cost	Low Cost	Reference	High Cost
Production[1]	**1124.6**	**1300.5**	**1272.2**	**1248.2**	**1876.1**	**1702.7**	**1420.0**	**2.0%**	**1.6%**	**0.9%**
Appalachia	403.2	398.6	389.2	378.7	461.7	412.0	367.5	0.5%	0.1%	-0.4%
Interior	146.3	209.5	208.9	214.5	299.2	280.8	289.1	2.8%	2.5%	2.7%
West	575.2	692.4	674.1	655.0	1115.2	1009.9	763.4	2.6%	2.2%	1.1%
Net Imports	**-20.7**	**4.6**	**4.8**	**5.5**	**69.5**	**82.7**	**81.5**	**N/A**	**N/A**	**N/A**
Total Supply[2]	**1103.9**	**1305.1**	**1277.0**	**1253.8**	**1945.6**	**1785.4**	**1501.5**	**2.2%**	**1.9%**	**1.2%**
Consumption by Sector										
Residential and Commercial	4.2	4.3	4.3	4.3	4.3	4.3	4.3	0.0%	0.0%	0.0%
Coke Plants	23.7	22.2	22.1	22.0	21.2	21.1	20.7	-0.4%	-0.4%	-0.5%
Other Industrial[3]	61.2	66.1	66.2	66.1	67.5	67.2	66.6	0.4%	0.4%	0.3%
Coal-to-Liquids Heat and Power	0.0	13.6	10.9	10.1	155.1	96.4	25.4	N/A	N/A	N/A
Coal-to-Liquids Liquids Production	0.0	13.2	10.6	9.8	150.6	93.6	24.6	N/A	N/A	N/A
Electric Power[4]	1015.1	1184.1	1161.3	1139.8	1545.6	1501.6	1358.9	1.6%	1.5%	1.1%
Total Coal Use	**1104.2**	**1303.5**	**1275.5**	**1252.1**	**1944.3**	**1784.2**	**1500.4**	**2.2%**	**1.9%**	**1.2%**
Average Minemouth Price										
(2004 dollars per short ton)	20.07	16.84	20.39	24.98	13.10	21.73	37.65	-1.6%	0.3%	2.4%
(2004 dollars per million Btu)	0.98	0.83	1.01	1.24	0.65	1.09	1.88	-1.5%	0.4%	2.5%
Delivered Prices (2004 dollars per short ton)[5]										
Coke Plants	61.50	52.35	60.06	69.90	44.38	62.67	94.11	-1.2%	0.1%	1.6%
Other Industrial[3]	39.53	34.34	38.48	43.72	30.68	41.05	56.50	-1.0%	0.1%	1.4%
Coal to Liquids	N/A	10.25	12.74	16.02	14.36	21.06	26.11	N/A	N/A	N/A
Electric Power										
(2004 dollars per short ton)	27.43	24.57	28.12	32.57	22.16	30.58	44.83	-0.8%	0.4%	1.9%
(2004 dollars per million Btu)	1.36	1.22	1.40	1.64	1.07	1.51	2.24	-0.9%	0.4%	1.9%
Average	**28.81**	**25.22**	**28.93**	**33.52**	**21.42**	**30.30**	**45.39**	**-1.1%**	**0.2%**	**1.8%**
Exports[6]	54.11	40.73	46.68	54.16	32.88	46.91	68.22	-1.9%	-0.5%	0.9%
Cumulative Electricity Generating Capacity Additions (gigawatts)[7]										
Coal	0.0	22.1	18.4	17.1	199.7	173.9	111.1	N/A	N/A	N/A
Conventional: Pulverized Coal	0.0	16.5	13.3	12.2	120.7	69.9	43.4	N/A	N/A	N/A
Advanced: IGCC	0.0	5.5	5.1	4.9	79.0	104.0	67.7	N/A	N/A	N/A
Petroleum	0.0	0.3	0.3	0.3	0.3	0.3	0.3	N/A	N/A	N/A
Natural Gas	0.0	52.0	52.6	53.3	132.5	140.5	168.1	N/A	N/A	N/A
Nuclear	0.0	2.2	2.2	2.2	6.0	6.0	19.1	N/A	N/A	N/A
Renewables[8]	0.0	13.8	14.5	14.8	22.9	26.3	34.5	N/A	N/A	N/A
Other	0.0	-0.3	-0.3	-0.3	-0.2	-0.2	-0.2	N/A	N/A	N/A
Total	**0.0**	**90.1**	**87.7**	**87.4**	**361.3**	**346.8**	**333.0**	**N/A**	**N/A**	**N/A**
Liquids from Coal (million barrels per day)	0.00	0.10	0.08	0.07	1.17	0.76	0.18	N/A	N/A	N/A
Labor Productivity										
Coal Mining (short tons per miner per hour)	6.80	8.84	6.90	5.34	14.20	7.56	3.67	2.9%	0.4%	-2.3%
Rail: Eastern Railroads (billion freight ton-miles per employee per year)	7.43	11.43	8.91	6.90	19.79	10.61	5.59	3.8%	1.4%	-1.1%
Rail: Western Railroads (billion freight ton-miles per employee per year)	11.94	18.58	14.49	11.23	32.50	17.43	9.20	3.9%	1.5%	-1.0%

Table D13. Key Results for Coal Cost Cases (Continued)
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2004	2015			2030			Growth Rate, 2004-2030		
		Low Cost	Reference	High Cost	Low Cost	Reference	High Cost	Low Cost	Reference	High Cost
Cost Indices										
(constant dollar index, 2004=1.000)										
Transportation Rate Multipliers										
Eastern Railroads	1.000	1.023	1.050	1.078	0.952	1.033	1.121	-0.2%	0.1%	0.4%
Western Railroads	1.000	1.015	1.035	1.057	0.958	1.022	1.089	-0.2%	0.1%	0.3%
Equipment Costs										
Mining	1.000	0.904	1.000	1.104	0.778	1.000	1.282	-1.0%	0.0%	1.0%
Railroads	1.000	0.875	0.968	1.070	0.705	0.908	1.166	-1.3%	-0.4%	0.6%
Average Coal Miner Wage										
(2004 dollars per hour)	**21.57**	**19.71**	**21.57**	**23.83**	**16.95**	**21.57**	**27.65**	**-0.9%**	**-0.0%**	**1.0%**

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 12.5 million tons in 2004.
[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. Excludes all coal use in the coal to liquids process.
[4]Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Prices weighted by consumption tonnage less imports; weighted average excludes residential and commercial prices, import prices, and export free-alongside-ship (f.a.s.) prices.
[6]F.a.s. price at U.S. port of exit.
[7]Cumulative additions after December 31, 2004. Includes all additions of electricity only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[8]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.
N/A = Not applicable.
Btu = British thermal unit.
IGCC = Integrated gas combined cycle.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 are model results and may differ slightly from official EIA data reports.
Sources: 2004 data based on: Energy Information Administration (EIA), *Annual Coal Report 2004*, DOE/EIA-0584(2004) (Washington, DC, November 2005); EIA, *Quarterly Coal Report, October-December 2004*, DOE/EIA-0121(2004/4Q) (Washington, DC, March 2005); Securities and Exchange Commission Form 10K filings (BNSF, Norfolk Southern, and Union Pacific), web site www.sec.com; CSX Corporation, web site www.csx.com; U.S. Department of Labor, Bureau of Labor Statistics, Average Hourly Earnings of Productive Workers: Coal Mining, Series ID : ceu1021210006; and EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A. **Projections:** EIA, AEO2006 National Energy Modeling System runs HCCST06.D113005A, AEO2006.D111905A, and LCCST06.D113005A.

NEMS Overview and Brief Description of Cases

The National Energy Modeling System

The projections in the *Annual Energy Outlook 2006* (*AEO2006*) are generated from the National Energy Modeling System (NEMS) [*1*], 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, the White House, and other offices within the Department of Energy. The *AEO* projections 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 long-term period through 2030, approximately 25 years into the future. In order to represent 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 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 fuel prices 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.

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, and permits 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 long-term horizon. Other variables are also evaluated for convergence, such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

Each NEMS component 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 October 31, 2005, such as the Energy Policy Acts of 2005 [*2*] and 1992 [*3*], the Clean Air Act Amendments (CAAA), and the costs of compliance with regulations, such as the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR), both of which were finalized and published on the U.S. Environmental Protection Agency web page in March 2005 and in the *Federal Register* in May 2005.

In general, the historical data used for the *AEO2006* projections were based on EIA's *Annual Energy Review 2004*, published in August 2005 [*4*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2004. Carbon dioxide emissions were calculated by using carbon dioxide coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 2004*, published in December 2005 [*5*].

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 projections. For example, the transportation demand sector in *AEO2006* 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 historical data.

The *AEO2006* projections for 2005 and 2006 incorporate short-term projections from EIA's September 2005 *Short-Term Energy Outlook* (*STEO*). For short-term energy projections, readers are referred to monthly updates of the *STEO* [*6*].

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 or expenditures 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, new housing starts, new light-duty vehicle sales, and employment. The module uses the following models from Global Insight, Inc. (GII): Macroeconomic Model of the U.S. Economy, national Industry Model, and national Employment Model. In addition, EIA has constructed a Regional Economic and Industry Model to project regional economic drivers and a Commercial Floorspace Model to project 13 floorspace types in 9 Census divisions. The accounting framework for industrial output uses the North American Industry Classification System (NAICS).

International Module

The International Module represents world oil markets, calculating the average world oil price and computing supply curves for 5 categories of imported crude oil for the Petroleum Market Module (PMM) of NEMS. The module allows changes in U.S. import requirements. In addition, 17 international petroleum product supply curves, including supply curves for oxygenates and unfinished oils, are also calculated and provided to the PMM. A world oil supply/demand balance is created, including estimates for 16 oil consumption regions and 19 oil production regions. The oil production estimates include both conventional and nonconventional supply recovery technologies.

Residential and Commercial Demand Modules

The Residential Demand Module projects energy consumption in the residential sector 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 projects energy consumption in the commercial sector by building type 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 Demand Module incorporates combined heat and power (CHP) technology. The modules also include projections of distributed generation. Both modules incorporate changes to "normal" heating and cooling degree-days by Census division, based on State-level population projections. The Residential Demand Module projects that the average square footage of both new construction and existing structures is increasing based on trends in the size of new construction and the remodeling of existing homes.

Industrial Demand Module

The Industrial Demand Module projects 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. As noted in the description of the Macroeconomic Module, the value of shipments is based on NAICS. The industries are classified into three groups—energy-intensive manufacturing, non-energy-intensive manufacturing, and nonmanufacturing. Of the 8 energy-intensive industries, 7 are modeled in the Industrial Demand Module, with components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. Bulk chemicals are further disaggregated to organic, inorganic, resins, and agricultural chemicals. 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 projects consumption of fuels in the transportation sector, 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 CAAA and other legislative proposals.

The module also includes a component to assess the penetration of alternative-fuel vehicles explicitly. The air transportation module explicitly represents the industry practice of parking aircraft to reduce operating costs and the movement of aircraft from passenger to cargo markets as aircraft age [7]. For air freight shipments, the model employs narrow-body and wide-body aircraft only. The model also uses an infrastructure constraint that limits growth in air travel to levels commensurate with industry-projected infrastructure expansion and capacity growth.

Electricity Market Module

The Electricity Market Module (EMM) represents 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 cost of uranium fuel for nuclear generation is incorporated directly in the EMM.

All specifically identified CAAA compliance options that have been promulgated by the 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). All specifically identified EPACT2005 financial incentives for power generation expansion and dispatch have been implemented. 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 *AEO2006*.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing renewable resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (wood, energy crops, and biomass co-firing), geothermal, landfill gas, solar thermal electricity, solar photovoltaics, and wind energy. The RFM contains renewable resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits for renewable fuels are incorporated, as currently legislated in the EPACT1992 and EPACT2005. EPACT1992 provides a 10-percent tax credit for business investment in solar energy (thermal non-power uses as well as power uses) and geothermal power. EPACT2005 increases the tax credit to 30 percent for solar energy systems installed before January 1, 2008. The credits have no expiration dates.

Production tax credits for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants are also represented. They provide a tax credit of up to 1.9 cents per kilowatthour for electricity produced in the first 10 years of plant operation. New plants that come on line before January 1, 2008, are eligible to receive the credit. Significant changes made for *AEO2006* in the accounting of new renewable energy capacity resulting from State renewable portfolio standards, mandates, and goals are described in *Assumptions to the Annual Energy Outlook 2006* [*8*].

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships among the various sources of supply: onshore, offshore, and Alaska by both conventional and nonconventional techniques, including natural 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 Petroleum Market Module in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are input to the Natural Gas Transmission and Distribution Module for use in determining 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 international gas supply, liquefaction, transportation, and regasification and world 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 capacity expansion requirements. The flow of natural gas is determined for both a peak and off-peak period in the year. Key components of pipeline and distributor tariffs are included in separate pricing algorithms.

Petroleum Market Module

The Petroleum Market Module (PMM) projects 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 and biodiesel fuels. The module represents refining activities in the five Petroleum Administration for Defense Districts (PADDs), using the same crude oil types represented in the International Energy Module. It explicitly models the requirements of CAAA and the costs of automotive fuels, such as conventional and reformulated gasoline, and includes biofuels production for blending in gasoline and diesel.

AEO2006 reflects State legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in Arizona, California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Maine, Michigan, Minnesota, Missouri, Montana, Nebraska, New Hampshire, New Jersey, New York, North Carolina, Ohio, Rhode Island, South Dakota, Vermont, Washington, and Wisconsin. Furthermore, MTBE is assumed to be phased out by the end of 2008 as a result of EPACT2005, which allows refiners to discontinue use of oxygenates in reformulated gasoline, and because of concern about MTBE contamination of surface water and groundwater resources.

The nationwide phase-in of gasoline with an annual average sulfur content of 30 ppm between 2005 and 2007, regulations that limit the sulfur content of highway diesel fuel to 15 ppm starting in mid-2006 and of all nonroad and locomotive/marine diesel to 15 ppm by mid-2012, and the renewable fuels standard of 7.5 billion gallons by 2012 are represented in *AEO2006*. Growth in demand and the costs of the regulations lead to capacity expansion for refinery-processing units, assuming a financing ratio of 60 percent equity and 40 percent debt, with a hurdle rate and an after-tax return on investment of about 9 percent [*9*]. End-use prices are based on the marginal costs of production, plus markups representing product and distribution costs and State and Federal taxes [*10*]. Expansion of refinery capacity at existing sites is permitted in all of the five refining regions modeled.

Fuel ethanol and biodiesel are included in the PMM, because they are commonly blended into petroleum products. The module allows ethanol blending into gasoline at 10 percent by volume or less, as well as limited quantities of E85, a blend of up to 85 percent ethanol by volume. Ethanol is produced primarily in the Midwest from corn or other starchy crops, and it is expected to be produced from cellulosic material in other regions in the future. Biodiesel is produced from soybean oil or yellow grease (primarily, recycled cooking oil). Both soybean oil biodiesel and yellow grease biodiesel are assumed to be blended into highway diesel.

Alternative fuels such as coal-to-liquids (CTL) and gas-to-liquids (GTL) are modeled in the PMM, based on their economics relative to competing feedstocks and products. CTL facilities are likely to be built at locations close to coal supply sources, where liquid products and electricity could also be distributed to nearby demand regions. GTL facilities may be built on the North Slope of Alaska but would compete with the Alaska Natural Gas Transportation System (ANGTS) for available natural gas resources. Both CTL and GTL are discussed in more detail in "Issues in Focus."

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. U.S. coal production is represented in the CMM using 40 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves include a response to capacity utilization of mines, mining capacity, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Projections of U.S. coal distribution are determined in the CMM through the use of a linear programming algorithm that determines the least-cost supplies of coal for a given set of coal demands by demand region and sector, accounting for minemouth prices, transportation costs, existing coal supply contracts, and sulfur and mercury allowance costs. Over the projection horizon, coal transportation costs in the CMM are projected to vary in response to changes in railroad productivity and the user cost of rail transportation equipment.

The CMM produces projections of U.S. steam and metallurgical coal exports and imports, in the context of world coal trade. The CMM's linear programming algorithm determines the pattern of world coal trade flows that minimizes the production and transportation costs of meeting a pre-specified set of regional world coal import demands, subject to constraints on export capacities and trade flows. The international coal market component of the module computes trade in 3 types of coal for 16 export and 20 import regions. U.S. coal production and distribution are computed for 14 supply and 14 demand regions.

Annual Energy Outlook 2006 Cases

Table E1 provides a summary of the cases used to derive the *AEO2006* projections. 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. The following sections describe the cases listed in Table E1. The reference case assumptions for each sector are described 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/.

Macroeconomic Growth Cases

In addition to the *AEO2006* reference case, the *low economic growth* and *high economic growth cases* were developed to reflect the uncertainty in projections of economic growth. The alternative cases are intended to show the effects of alternative growth assumptions on energy market projections. The cases are described as follows:

- The low economic growth case assumes lower growth rates for population (0.5 percent per year), nonfarm employment (0.7 percent per year), and productivity (1.8 percent per year), resulting in higher prices and interest rates and lower growth in industrial output. In the low economic growth case, economic output increases by 2.4 percent per year from 2004 through 2030, and growth in GDP per capita averages 1.9 percent per year.
- The high economic growth case assumes higher growth rates for population (1.1 percent per year), nonfarm employment (1.4 percent per year), and productivity (2.7 percent per year). With higher productivity gains and employment growth, inflation and interest rates are lower than in the reference case, and consequently economic output grows at a higher rate (3.5 percent per year) than in the reference case (3.0 percent). GDP per capita grows by 2.4 percent per year, compared with 2.2 percent in the reference case.

Price Cases

The world oil price in *AEO2006* is represented by the average U.S. refiners acquisition costs of imported low-sulfur light crude oil, in order to be more consistent with prices typically reported in the media. The low-sulfur light crude oil price is similar to the West Texas Intermediate (WTI) crude oil price. *AEO2006* also includes a projection of the annual average U.S.

Table E1. Summary of the *AEO2006* cases

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Reference	Baseline economic growth (3.0 percent per year), world oil price, and technology assumptions. Complete projection tables in Appendix A.	Fully integrated	—	—
Low Economic Growth	Gross domestic product grows at an average annual rate of 2.4 percent from 2004 through 2030. Subset of projection tables in Appendix B.	Fully integrated	p. 62	p. 203
High Economic Growth	Gross domestic product grows at an average annual rate of 3.5 percent from 2004 through 2030. Subset of projection tables in Appendix B.	Fully integrated	p. 62	p. 203
Low Price	More optimistic assumptions for worldwide crude oil and natural gas resources than in the reference case. World oil prices are $28 per barrel in 2030, compared with $50 per barrel in the reference case, and lower 48 wellhead natural gas prices $4.96 per thousand cubic feet in 2030, compared with $5.92 in the reference case. Subset of projection tables in Appendix C.	Fully integrated	p. 64	p. 206
High Price	More pessimistic assumptions for worldwide crude oil and natural gas resources than in the reference case. World oil prices are about $90 per barrel in 2030 and lower 48 wellhead natural gas prices $7.72 per thousand cubic feet in 2030. Subset of projection tables in Appendix C.	Fully integrated	p. 64	p. 206
Residential: 2005 Technology	Future equipment purchases based on equipment available in 2005. Existing building shell efficiencies fixed at 2005 levels. Partial projection tables in Appendix D.	With commercial	p. 68	p. 206
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Building shell efficiencies increase by 22 percent from 2003 values by 2030. Partial projection tables in Appendix D.	With commercial	p. 68	p. 207
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available. Building shell efficiencies increase by 26 percent from 2003 values by 2030. Partial projection tables in Appendix D.	With commercial	p. 68	p. 207
Commercial: 2005 Technology	Future equipment purchases based on equipment available in 2005. Building shell efficiencies fixed at 2005 levels. Partial projection tables in Appendix D.	With residential	p. 70	p. 207
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Building shell efficiencies for new and existing buildings increase by 10.4 and 7.4 percent, respectively, from 1999 values by 2030. Partial projection tables in Appendix D.	With residential	p. 70	p. 207
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available. Building shell efficiencies for new and existing buildings increase by 12.4 and 8.9 percent, respectively, from 1999 values by 2030. Partial projection tables in Appendix D.	With residential	p. 70	p. 207
Industrial: 2005 Technology	Efficiency of plant and equipment fixed at 2005 levels. Partial projection tables in Appendix D.	Standalone	p. 73	p. 207
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Partial projection tables in Appendix D.	Standalone	p. 73	p. 207
Transportation: 2005 Technology	Efficiencies for new equipment in all modes of travel fixed at 2005 levels. Partial projection tables in Appendix D.	Standalone	p. 76	p. 208

Table E1. Summary of the *AEO2006* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Transportation: High Technology	Reduced costs and improved efficiencies assumed for advanced technologies. Partial projection tables in Appendix D.	Standalone	p. 76	p. 208
Transportation: Alternative CAFE	Assumes that manufacturers adhere to the proposed fleetwide increases in light truck CAFE standards to 24 miler per gallon for model year 2011.	Standalone	p. 24	p. 208
Integrated 2005 Technology	Combination of the residential, commercial, industrial, and transportation 2005 technology cases, electricity low fossil technology case, and assumption of renewable technologies fixed at 2005 levels. Partial projection tables in Appendix D.	Fully integrated	p. 60	—
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. Partial projection tables in Appendix D.	Fully integrated	p. 60	—
Electricity: Advanced Nuclear Cost	New nuclear capacity assumed to have 20 percent lower capital and operating costs in 2030 than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 84	p. 208
Electricity: Nuclear Vendor Estimate	New nuclear capacity assumed to have lower capital costs based on vendor goals. Partial projection tables in Appendix D.	Fully integrated	p. 84	p. 208
Electricity: Low Fossil Technology	New advanced fossil generating technologies assumed not to improve over time from 2006. Partial projection tables in Appendix D.	Fully integrated	p. 83	p. 209
Electricity: High Fossil Technology	Costs and efficiencies for advanced fossil-fired generating technologies improve by 10 percent in 2030 from reference case values. Partial projection tables in Appendix D.	Fully integrated	p. 83	p. 208
Electricity: Mercury Control Technologies	Cost and performance for halogenated activated carbon injection technology used to determine its impact on mercury removal requirements from coal-fired power plants.	Fully integrated	p. 59	p. 209
Renewables: Low Renewables	New renewable generating technologies assumed not to improve over time from 2006. Partial projection tables in Appendix D.	Fully integrated	p. 84	p. 209
Renewables: High Renewables	Levelized cost of energy for nonhydropower renewable generating technologies declines by 10 percent in 2030 from reference case values. Lower capital cost for cellulose ethanol plants. Partial projection tables in Appendix D.	Fully integrated	p. 84	p. 209
Oil and Gas: Slow Technology	Cost, finding rate, and success rate parameters adjusted for 50-percent slower improvement than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 88	p. 210
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate parameters adjusted for 50-percent more rapid improvement than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 88	p. 209
Oil and Gas: Low LNG	LNG imports exogenously set to 30 percent less than the results from the high price case, with remaining assumptions from the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 90	p. 210

Table E1. Summary of the *AEO2006* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Oil and Gas: High LNG	LNG imports exogenously set to 30 percent more than the results from the low price case, with remaining assumptions from the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 90	p. 210
Oil and Gas: ANWR	Federal oil and gas leasing permitted in the Arctic National Wildlife Refuge starting in 2005. Partial projection tables in Appendix D.	Fully integrated	p. 94	p. 210
Coal: Low Cost	Productivity for coal mining and coal transportation assumed to increase more rapidly than in the reference case. Coal mining wages, mine equipment and coal transportation equipment costs assumed to be lower than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 102	p. 210
Coal: High Cost	Productivity for coal mining and coal transportation assumed to increase more slowly than in the reference case. Coal mining wages, mine equipment and coal transportation equipment costs assumed to be higher than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 102	p. 210

refiners acquisition cost of imported crude oil (IRAC), which is more representative of the average cost of all crude oil used by refiners.

The historical record shows substantial variability in world oil prices, and there is arguably even more uncertainty about future prices in the long term. *AEO2006* considers three price cases (*reference* case, *low price case*, and *high price case*) to allow an assessment of alternative views on the course of future oil and natural gas prices. In the reference case, world oil prices moderate from current levels through 2015 before beginning to rise to $57 per barrel in 2030 (2004 dollars). The low and high price cases define a wide range of potential price paths (from $34 to $96 per barrel in 2030). The two cases reflect different assumptions about the availability of world oil and natural gas resources and production costs; they do not assume changes in OPEC behavior. Because the low and high price cases are not directly integrated with a world economic model, the impact of world oil prices on international economies is not directly accounted for in this analysis.

- The reference case represents EIA's current judgment regarding the expected behavior of OPEC producers in the long term, adjusting production to keep world oil prices in a range of $40 to $50 per barrel, in keeping with OPEC's stated goal of keeping potential competitors from eroding its market share. Because OPEC (and particularly the Persian Gulf nations) is expected to be the dominant supplier of oil in the international market over the long term, its production choices will significantly affect world oil prices.
- The low price case assumes greater world crude oil and natural gas resources which are less expensive to produce and a future market where all oil and natural gas production becomes more competitive and plentiful than the reference case.
- The high price case assumes that world crude oil and natural gas resources, including OPEC's, are lower and require greater cost to produce than assumed in the reference case.

Buildings Sector Cases

In addition to the *AEO2006* reference case, three standalone technology-focused cases using the Residential and Commercial Demand Modules of NEMS were developed to examine the effects of changes to equipment and building shell efficiencies.

For the residential sector, the three technology-focused cases are as follows:

- The *2005 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2005. Existing building shell efficiencies are assumed to be fixed at 2005 levels.

- The *high technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [*11*]. Building shell efficiency in 2030 is assumed to be 22 percent higher than the 2003 level.
- 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. Building shell efficiency in 2030 is assumed to be 26 percent higher than the 2003 level.

For the commercial sector, the three technology-focused cases are as follows:

- The *2005 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2005. Building shell efficiencies are assumed to be fixed at 2005 levels.
- The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than in the reference case [*12*]. Building shell efficiencies for new and existing buildings in 2030 are assumed to be 10.4 percent and 7.4 percent higher, respectively, than their 1999 levels—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, regardless of cost. Building shell efficiencies for new and existing buildings in 2030 are assumed to be 12.4 percent and 8.9 percent higher, respectively, than their 1999 values—a 50-percent improvement relative to the reference case.

Two additional integrated cases were developed, in combination with assumptions for electricity generation from renewable fuels, to analyze the sensitivity of the projections to changes in generating technologies that use renewable fuels and in the availability of renewable energy sources. For the Residential and Commercial Demand Modules:

- 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 2030 that are approximately 10 percent lower than reference case costs for distributed photovoltaic technologies.
- The *low renewables case* assumes that costs and performance levels for residential and commercial photovoltaic systems remain constant at 2005 levels through 2030.

Industrial Sector Cases

In addition to the *AEO2006* reference case, two standalone cases using the Industrial Demand Module of NEMS were developed to examine the effects of less rapid and more rapid technology change and adoption. The Industrial Demand Module was also used as part of an integrated high renewables case. For the industrial sector:

- The *2005 technology case* holds the energy efficiency of plant and equipment constant at the 2005 level over the projection period. In this case, delivered energy intensity falls by 0.9 percent annually. Because the level and composition of industrial output are the same in the reference, 2005 technology, and high technology cases, any change in primary energy intensity in the two technology cases is attributable to efficiency changes. The 2005 technology case was run with only the Industrial Demand Module, rather than in fully integrated NEMS runs. Consequently, no potential feedback effects from energy market interactions were captured.
- The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*13*] and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes (0.7 percent per year, as compared with 0.4 percent per year in the reference case). The same assumption is also incorporated in the integrated high renewables case, which focuses on electricity generation. While the choice of 0.7 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, delivered energy intensity falls by 1.4 percent annually in the high technology case. In the reference case, delivered energy intensity falls by 1.2 percent annually between 2004 and 2030.

Transportation Sector Cases

In addition to the *AEO2006* reference case, two standalone cases using the Transportation Demand Module of NEMS were developed to examine the effects of less rapid technology change and adoption and more rapid technology change and adoption. For the transportation sector:

- The *2005 technology case* assumes that new vehicle fuel efficiencies remain constant at 2005 levels through the projection horizon, unless emissions and/or efficiency regulations require the implementation of technology that affects vehicle efficiency. For example, the new light truck corporate average fuel economy (CAFE) standards require an increase in fuel economy through 2007, and increases in heavy truck emissions standards are required through 2010. As a result, the technology available for light truck efficiency improvement is frozen at 2007 levels, and the technology available to heavy trucks is frozen at 2010 levels.
- In the *high technology case*, the characteristics of light-duty conventional and alternative-fuel vehicles reflect more optimistic assumptions about incremental improvements in fuel economy and costs [*14*]. In the air travel sector, the high technology case reflects lower costs for improved thermodynamics, advanced aerodynamics, and weight-reducing materials, providing a 25-percent improvement in new aircraft efficiency relative to the reference case in 2025. In the freight truck sector, the high technology case assumes more incremental improvement in fuel efficiency for engine and emissions control technologies [*15*]. 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.

In addition to these standalone cases, EIA also developed an *alternative CAFE case* designed to examine the potential energy impacts of proposed reforms to the structure of CAFE standards for light trucks and increases in light truck CAFE standards for model years 2008 through 2011 [*16*]. The alternative CAFE case assumes that manufacturers will adhere to the proposed fleet-wide increases in light truck CAFE standards, to 24 miles per gallon for model year 2011.

Electricity Sector Cases

In addition to the reference case, four integrated cases with alternative electric power assumptions were developed to analyze uncertainties about the future costs and performance of new generating technologies. Two of the cases examine alternative assumptions for nuclear power technologies, and two examine alternative assumptions for fossil fuel technologies. Reference case values for technology characteristics are determined in consultation with industry and government specialists; however, there is always uncertainty surrounding newer, untested designs. The electricity cases analyze what could happen if costs of advanced designs are either higher or lower than assumed in the reference case. The cases are fully integrated to allow feedback between the potential shifts in fuel consumption and fuel prices.

Nuclear Technology Cases

- The cost assumptions for the *advanced nuclear cost case* reflect a 20-percent reduction in the capital and operating costs for advanced nuclear technology in 2030, relative to the reference case. The reference case, which assumes that some learning occurs regardless of new orders and construction, projects a 14-percent reduction in the capital costs of nuclear power plants between 2006 and 2030. The advanced nuclear cost case assumes a 31-percent reduction between 2006 and 2030.
- The *nuclear vendor estimate case* uses assumptions that are consistent with estimates from British Nuclear Fuels Limited (Westinghouse) for the manufacture of its AP1000 advanced pressurized-water reactor. In this case, the overnight capital cost of a new advanced nuclear unit is assumed to be 18 percent lower initially than assumed in the reference case and 44 percent lower in 2030. In both of the alternative nuclear cases, cost and performance characteristics for all other technologies are as assumed in the reference case.

Fossil Technology Cases

- In the *high fossil technology case*, capital costs, heat rates, and operating costs for advanced coal and natural gas generating technologies are assumed to be 10 percent lower than reference case levels in 2030. Because learning is assumed to occur 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 technology case* fall to between 16 and 22 percent below initial levels, and capital costs are reduced by 22 to 26 percent between 2006 and 2030, depending on the technology.

- 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 projection period but remain fixed at the 2006 values assumed in the reference case.

Details about annual capital costs, operating and maintenance costs, plant efficiencies, and other factors used in the high and low fossil technology cases are described in the detailed assumptions, which are available at web site www.eia.doe.gov/oiaf/aeo/assumption/.

An additional integrated case was also run to analyze the potential impacts of improved mercury control technologies to comply with CAMR. A detailed description of the rule is included in "Legislation and Regulations."

- In the *mercury control technology case*, the cost and performance for halogenated activated carbon injection technology are used to determine its impact on mercury removal requirements from coal-fired power plants. Conventional activated carbon injection has not been effective in achieving high mercury removal rates from subbituminous and lignite coals, but preliminary tests show that high levels of mercury removal can be achieved with relatively low rates of brominated activated carbon injection. If brominated activated carbon becomes commercially available by 2018, it could have significant impacts on the cost of achieving mercury removal targets.

Renewable Fuels Cases

In addition to the *AEO2006* reference case, two integrated cases with alternative assumptions about renewable fuels were developed to examine the effects of less aggressive and more aggressive improvement in renewable technologies. The cases are as follows:

- 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 2006 levels through 2030.
- In 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 resources in 2030. 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 a combination of performance improvement (increased capacity factor) and capital cost reductions. Biomass supplies are also assumed to be 10 percent greater for each supply step. Annual limits are placed on the development of geothermal sites, because they require incremental development to assure that the resource is viable. In the high renewables case, the annual limits on capacity additions at geothermal sites are raised from 25 megawatts per year through 2015 to 50 megawatts per year for all projection years. All other cases are assumed to retain the 25-megawatt limit through 2015. Other generating technologies and projection assumptions remain unchanged from those in the reference case. In the high renewables case, the rate of improvement in recovery of biomass byproducts from industrial processes is also increased. More rapid improvement in cellulosic ethanol production technology is also assumed, resulting in lower cost for cellulose ethanol at any level of output than in the reference case.

Oil and Gas Supply Cases

Two alternative technology 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. In addition, high and low LNG supply cases were developed to examine the impacts of variations in LNG supply on the domestic natural gas market.

- In the *rapid technology case*, the parameters representing the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates for conventional oil and natural gas drilling in the reference case were increased by 50 percent. A number of key exploration and production technologies for unconventional natural gas were also increased by 50 percent in the rapid technology case. Key Canadian supply parameters were also modified to simulate the assumed impacts of more rapid oil and natural gas technology penetration on the 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 LNG 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 2006*, available at web site www. eia.doe.gov/oiaf/aeo/assumption/.

- In the *slow technology case*, the parameters representing the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates for conventional oil and natural gas drilling in the *AEO2006* reference case were reduced by 50 percent. A number of key exploration and production technologies for unconventional natural gas were also reduced by 50 percent in the slow technology case. Key Canadian supply parameters were also modified to simulate the assumed impacts of slow oil and natural gas technology penetration on Canadian supply potential. All other parameters in the model were kept at the reference case values.
- The *high LNG case* exogenously specifies LNG imports at levels 30 percent higher than projected in the low price case. The intent is to project the potential impact on domestic markets if LNG imports turn out to be higher than projected in the reference case.
- The *low LNG case* exogenously specifies LNG imports at levels 30 percent lower than projected in the high price case. The intent is to project the potential impact on domestic markets if LNG imports turn out to be lower than projected in the reference case.
- The *ANWR case* assumes that the U.S. Congress will approve leasing in the 1002 Area Federal lands in the Arctic National Wildlife Refuge for oil and natural gas exploration and production.

Petroleum Market Cases

In addition to the *AEO2006* reference case, a case that is part of the integrated high renewable case evaluates the impact of more optimistic assumptions about biomass supplies on the production and use of cellulosic ethanol.

- 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 projection year relative to the reference case, making larger quantities available at any given price earlier than in the reference case. More rapid improvement in cellulosic ethanol production technology is also assumed, resulting in lower cost for cellulose ethanol at any level of output than in the reference case.

Coal Market Cases

Two alternative coal cost cases examine the impacts on U.S. coal supply, demand, distribution, and prices that result from alternative assumptions about mining productivity, labor costs, and mine equipment costs on the production side, and railroad productivity and rail equipment costs on the transportation side. For the coal cost cases, adjustments to the reference case assumptions for coal mining and railroad productivity were based on variations in growth rates observed in the data for these industries since 1980. The low and high coal cost cases represent fully integrated NEMS runs, with feedback from the macroeconomic activity, international, supply, conversion, and end-use demand modules.

- In the *low coal cost case*, average annual productivity growth rates for coal mining and railroad productivity are 2.5 percent and 2.6 percent higher, respectively, than in the *AEO2006* reference case. On the mining side, adjustments to reference case productivity are applied at the supply curve level, while adjustments to railroad productivity are made at the regional level. Coal mining wages and mine equipment costs, which remain constant in real dollars in the reference case, are assumed to decline by 1.0 percent per year in real terms in the low coal cost case. Railroad equipment costs, which are projected to increase by 2.1 percent per year in constant dollars in the reference case, are assumed to increase at a slower rate of 1.1 percent per year.
- In the *high coal cost case*, average annual productivity growth rates for coal mining and railroad productivity are 2.5 percent and 2.6 percent lower, respectively, than in the *AEO2006* reference case. Coal mining wages and mine equipment costs are assumed to increase by 1.0 percent per year in real terms. Railroad equipment costs are assumed to increase by 3.1 percent per year.

Additional details about the productivity, wage, and equipment cost assumptions for the reference and alternative coal cost cases are provided in Appendix D.

Notes

[1]Energy Information Administration, The *National Energy Modeling System: An Overview 2003*, DOE/EIA-0581(2003) (Washington, DC, March 2003).

[2]Energy Policy Act of 2005, P.L. 109-58.

[3]Energy Policy Act of 1992, P.L. 102-486, Title III, Section 303, and Title V, Sections 501 and 507.

[4]Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005).

[5]Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2004*, DOE/EIA-0573(2004) (Washington, DC, December 2005).

[6]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 NEMS Petroleum Market Module projection.

[7]Jet Information Services, Inc., *World Jet Inventory Year-End 2003* (Woodinville, WA, March 2004), and personal communication from Bill Francoins (Jet Information Services) and Thomas C. Hoang (Boeing).

[8]Energy Information Administration, *Assumptions to the Annual Energy Outlook 2006*, DOE/EIA-0554(2006) (Washington, DC, to be published).

[9]The hurdle rate for a coal-to-liquids (CTL) plant is assumed to be 12.3 percent because of the higher economic risk involved in this technology.

[10]For gasoline blended with ethanol, the tax credit of 51 cents (nominal) per gallon of ethanol is assumed to be extended through 2030, based on the fact that the ethanol tax credit has been continuously in force for the past 25 years and was recently extended from 2007 to 2010 by the American Jobs Creation Act of 2004.

[11]High technology assumptions are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2004).

[12]High technology assumptions are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2004).

[13]These assumptions are based in part on Energy Information Administration, *Industrial Technology and Data Analysis Supporting the NEMS Industrial Model* (FOCIS Associates, October 2005).

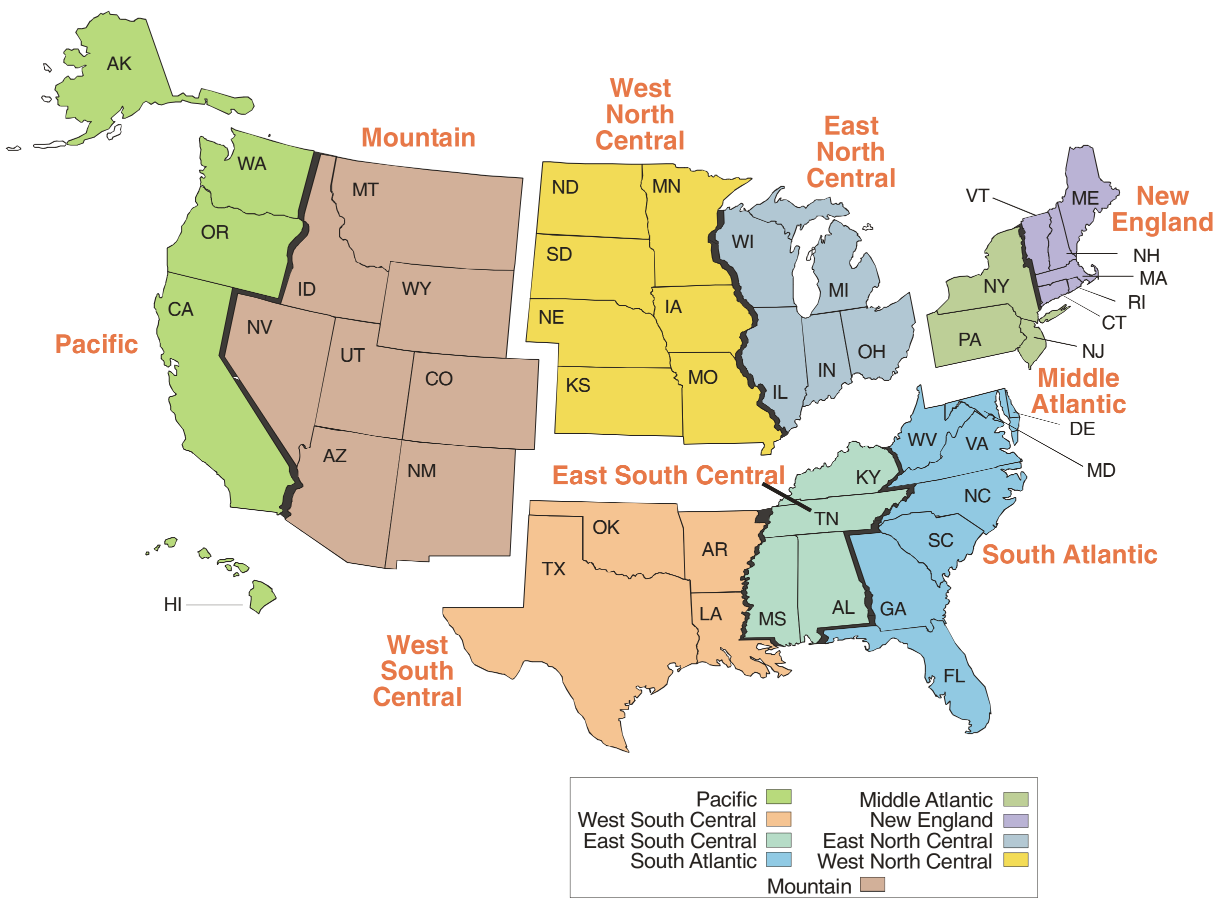
[14]Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (Energy and Environmental Analysis, September 2003).

[15]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).

[16]National Highway Traffic Safety Administration, *Average Fuel Economy Standards for Light Trucks Model Years 2008-2011*, 49 CFR Parts 523, 533, and 537, Docket No. 2005-22223, RIN 2127-AJ61 (Washington, DC, August 2005).

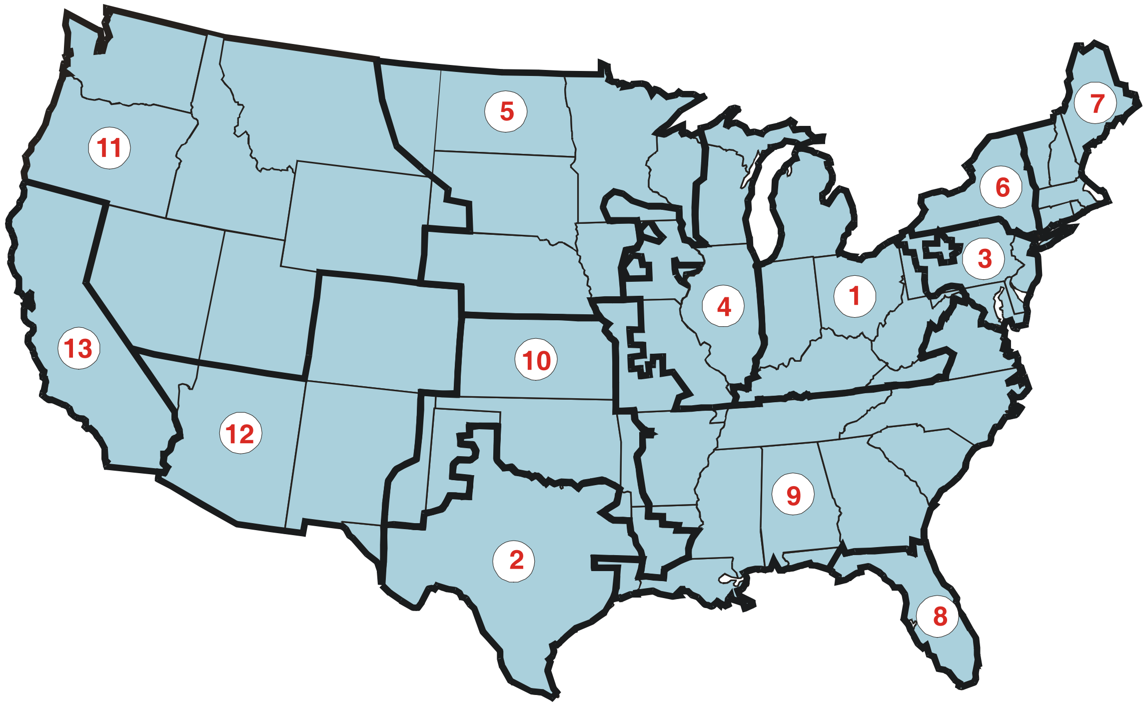
Regional Maps

F1. United States Census Divisions



Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F2. Electricity Market Module Regions



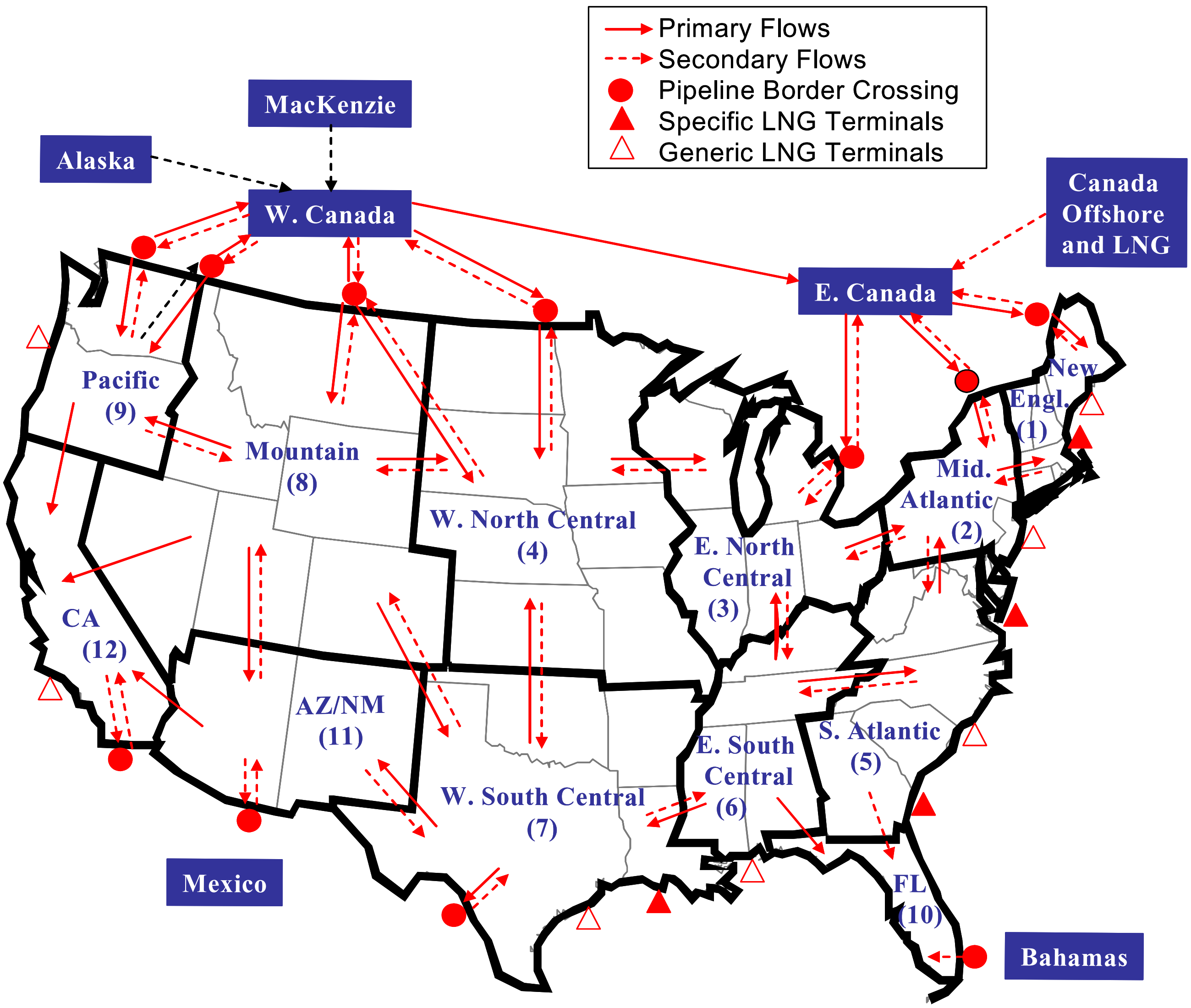
1 East Central Area Reliability Coordination Agreement (ECAR)
2 Electric Reliability Council of Texas (ERCOT)
3 Mid-Atlantic Area Council (MAAC)
4 Mid-America Interconnected Network (MAIN)
5 Mid-Continent Area Power Pool (MAPP)
6. New York (NY)
7. New England (NE)
8. Florida Reliability Coordinating Council (FL)
9. Southeastern Electric Reliability Council (SERC)
10. Southwest Power Pool (SPP)
11. Northwest Power Pool (NWP)
12. Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA)
13. California (CA)

Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F3. Oil and Gas Supply Model Regions

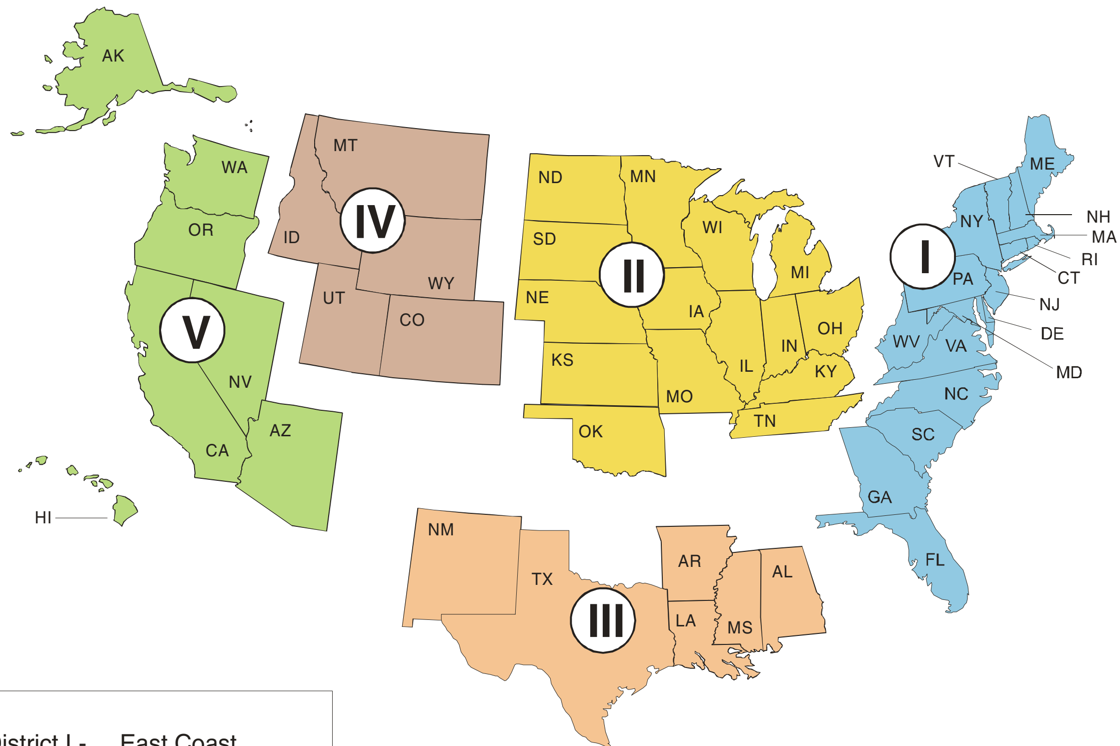
Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F4. Natural Gas Transmission and Distribution Model Regions



Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

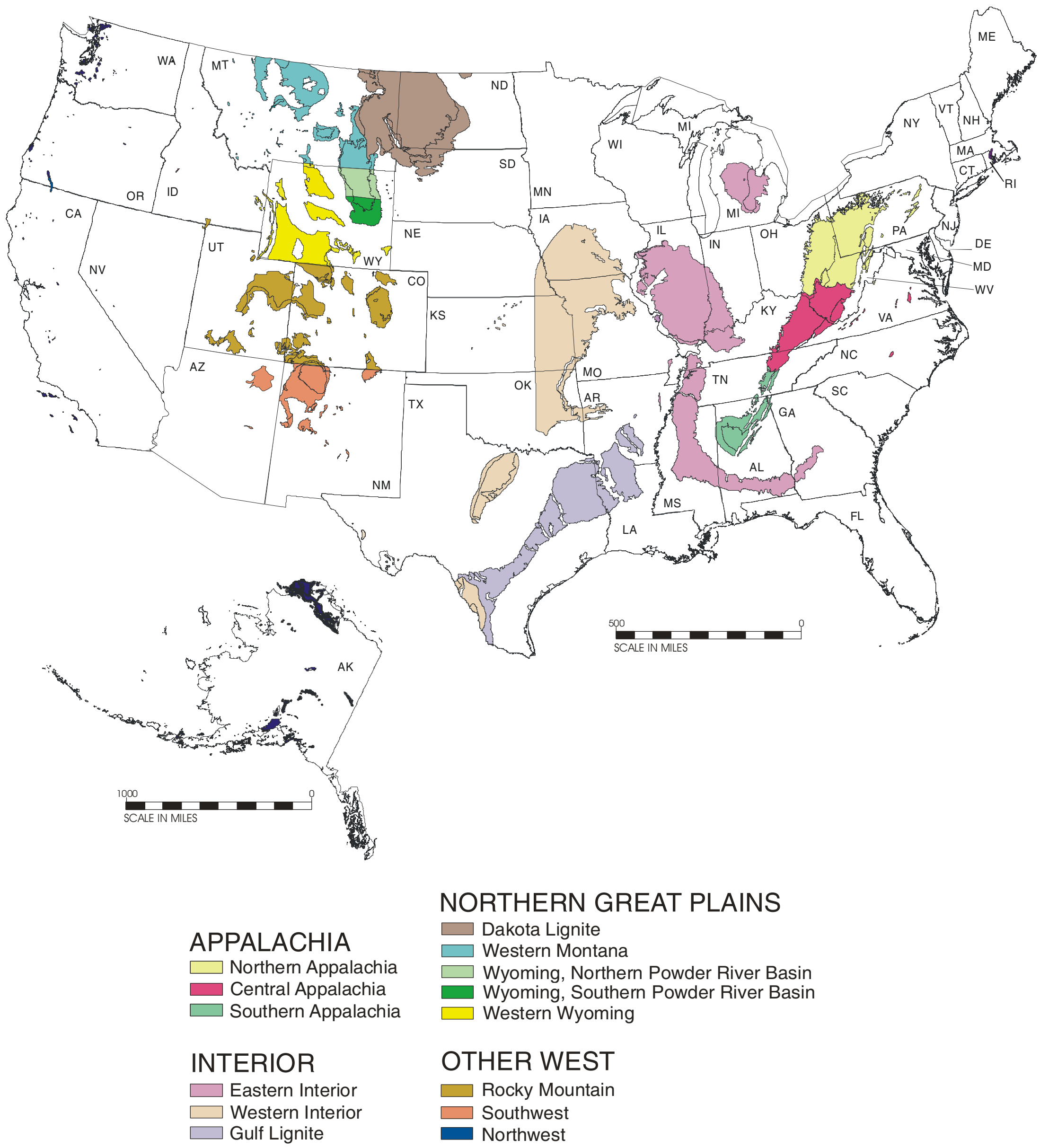
F5. Petroleum Administration for Defense Districts



PAD District I - East Coast
PAD District II - Midwest
PAD District III - Gulf Coast
PAD District IV - Rocky Mountain
PAD District V - West Coast

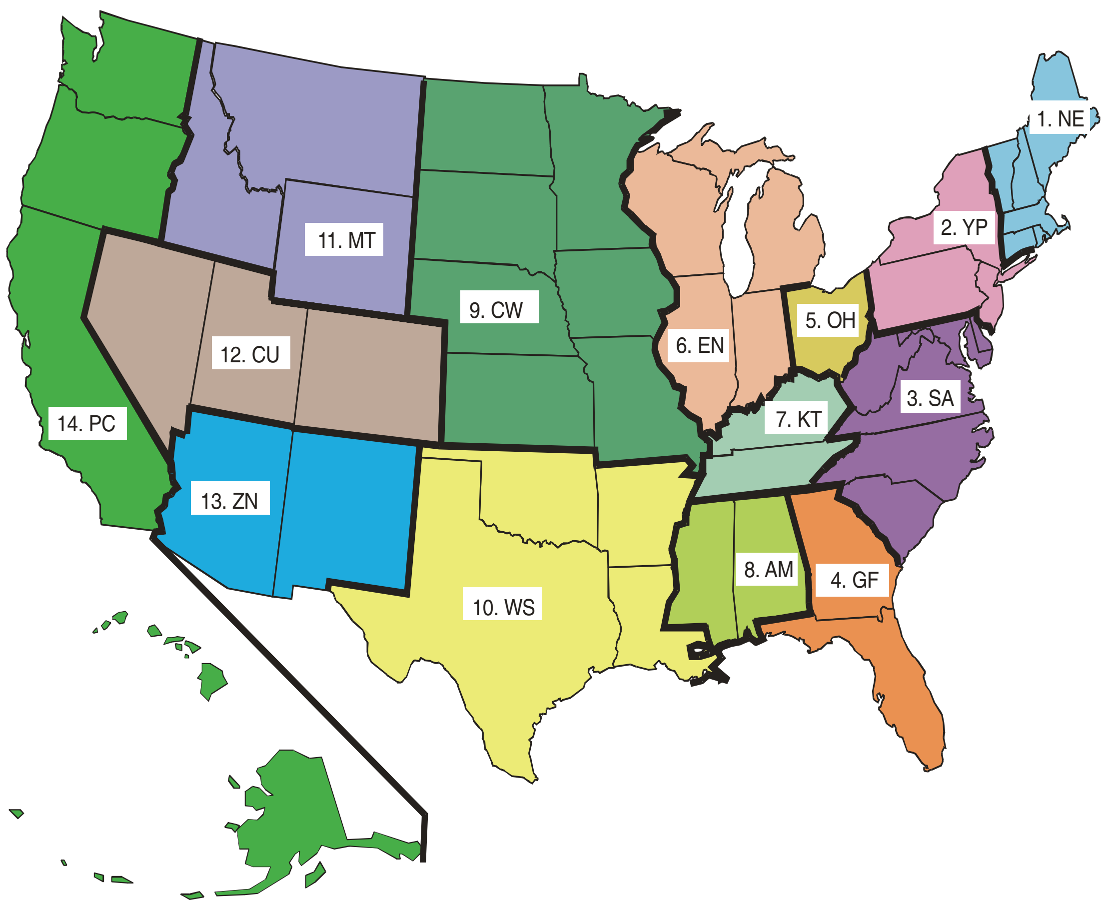
Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F6. Coal Supply Regions



Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F7. Coal Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. SA	WV,MD,DC,DE,VA,NC,SC
4. GF	GA,FL
5. OH	OH
6. EN	IN,IL,MI,WI
7. KT	KY,TN

Region Code	Region Content
8. AM	AL,MS
9. CW	MN,IA,ND,SD,NE,MO,KS
10. WS	TX,LA,OK,AR
11. MT	MT,WY,ID
12. CU	CO,UT,NV
13. ZN	AZ,NM
14. PC	AK,HI,WA,OR,CA

Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

Appendix G
Conversion Factors

Table G1. Heat Rates

Fuel	Units	Approximate Heat Content
Coal[1]		
Production	million Btu per short ton	20.411
Consumption	million Btu per short ton	20.276
Coke Plants	million Btu per short ton	27.426
Industrial	million Btu per short ton	22.473
Residential and Commercial	million Btu per short ton	22.948
Electric Power Sector	million Btu per short ton	19.966
Imports	million Btu per short ton	25.000
Exports	million Btu per short ton	26.108
Coal Coke	million Btu per short ton	24.800
Crude Oil		
Production	million Btu per barrel	5.800
Imports[1]	million Btu per barrel	5.980
Petroleum Products		
Consumption[1]	million Btu per barrel	5.357
Motor Gasoline[1]	million Btu per barrel	5.215
Jet Fuel	million Btu per barrel	5.670
Distillate Fuel Oil[1]	million Btu per barrel	5.799
Residual Fuel Oil	million Btu per barrel	6.287
Liquefied Petroleum Gas[1]	million Btu per barrel	3.618
Kerosene	million Btu per barrel	5.670
Petrochemical Feedstocks[1]	million Btu per barrel	5.527
Unfinished Oils	million Btu per barrel	5.825
Imports[1]	million Btu per barrel	5.473
Exports[1]	million Btu per barrel	5.753
Natural Gas Plant Liquids		
Production[1]	million Btu per barrel	3.724
Natural Gas[1]		
Production, Dry	Btu per cubic foot	1,027
Consumption	Btu per cubic foot	1,030
End-Use Sectors	Btu per cubic foot	1,031
Electric Power Sector	Btu per cubic foot	1,025
Imports	Btu per cubic foot	1,023
Exports	Btu per cubic foot	1,009
Electricity Consumption	Btu per kilowatthour	3,412

Btu = British thermal unit.
[1]Conversion factors vary from year to year. Values correspond to those published by EIA for 2004 and may differ slightly from model results.
Sources: Energy Information Administration (EIA), *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005), and EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

The Energy Information Administration
2006 EIA Energy Outlook and Modeling Conference

Renaissance Hotel, Washington, DC ***March 27, 2006***

8:30 a.m. - 8:45	**Opening Remarks - *Guy F. Caruso***, *Administrator*, Energy Information Administration
8:50 a.m. - 9:20	**Overview of the *Annual Energy Outlook 2006* - *John Conti***, *Director*, Office of Integrated Analysis and Forecasting, Energy Information Administration
9:25 a.m. - 10:25	**Keynote Address: International Oil Markets - *Speaker to be announced***
10:40 a.m. - 12:10	**Concurrent Sessions A** **1. Global Oil Market Outlook: Short-Term Issues** **2. The Future Relationship of Oil and Natural Gas Prices in the U.S.** **3. Nuclear—Is EPACT Enough?**
1:40 p.m. - 3:10	**Concurrent Sessions B** **1. World Outlook for Unconventional Oil Production** **2. Globalization of the Natural Gas Market** **3. Return to Coal—From Where and at What Price?**
3:25 p.m. - 4:55	**Concurrent Sessions C** **1. How Far Ethanol?** **2. Unconventional Natural Gas: Industry Savior or Bridge?** **3. If Not Natural Gas Then . . . ?**

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Information

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Phone: (202) 586-8845
Fax: (202) 586-3045

Or register by e-mail to peggy.wells@eia.doe.gov.

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Please indicate which sessions you will be attending:

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Concurrent Sessions A

❒ Global Oil Market Outlook: Short-Term Issues
❒ The Future Relationship of Oil and Natural Gas Prices in the U.S.
❒ Nuclear—Is EPACT Enough?

Concurrent Sessions B

❒ World Outlook for Unconventional Oil Production
❒ Globalization of the Natural Gas Market
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Concurrent Sessions C

❒ How Far Ethanol?
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❒ If Not Natural Gas Then . . . ?

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