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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.

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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

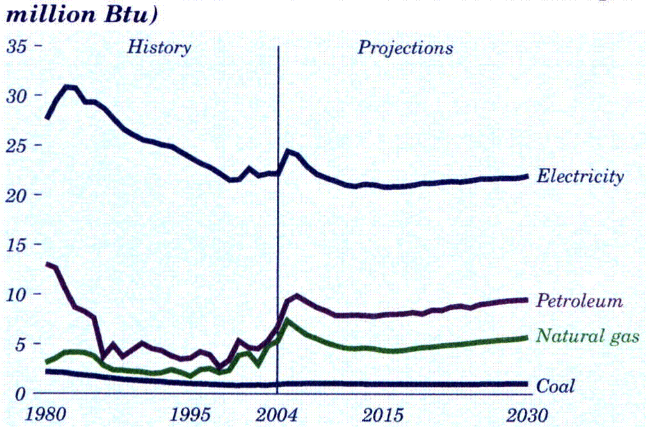
In the reference case—one of several cases included in *AEO2006*—the average world crude oil price continues to rise through 2006 and then declines to $46.90 per barrel in 2014 (2004 dollars) as new supplies enter the market. It then rises slowly to $54.08 per barrel in 2025 (Figure 1), about $21 per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

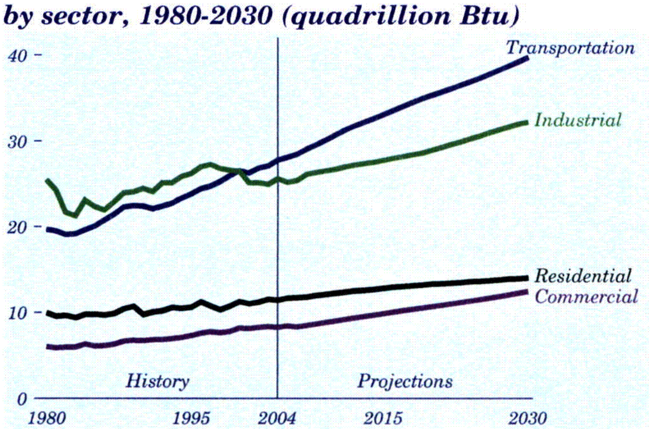
while petroleum and natural gas consumption are lower—in the *AEO2006* reference case than in *AEO-2005*. Among the most important factors accounting for the differences are higher energy prices, particularly for petroleum and natural gas; lower projected growth rates in the manufacturing portion of 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 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*.

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



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)

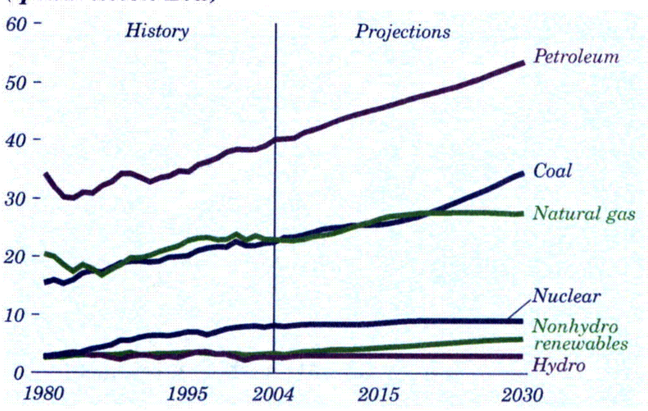
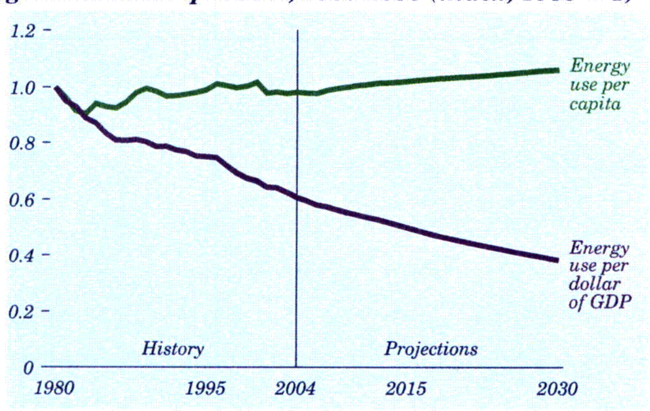


Figure 4. Energy use per capita and per dollar of gross domestic product, 1980-2030 (index, 1980 = 1)



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 *AEO-2006* 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

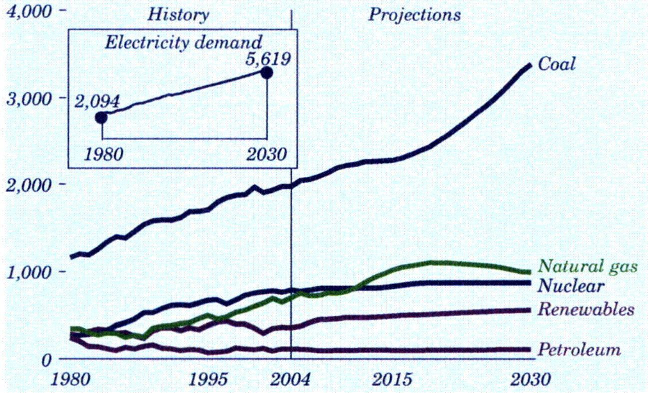
In the *AEO2006* reference case, the projected average prices of natural gas and coal delivered to electricity generators in 2025 are, respectively, 31 cents and 11 cents per million Btu higher than the comparable prices in *AEO2005*. Although the projected levels of coal consumption for electricity 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 *AEO-2006* 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)

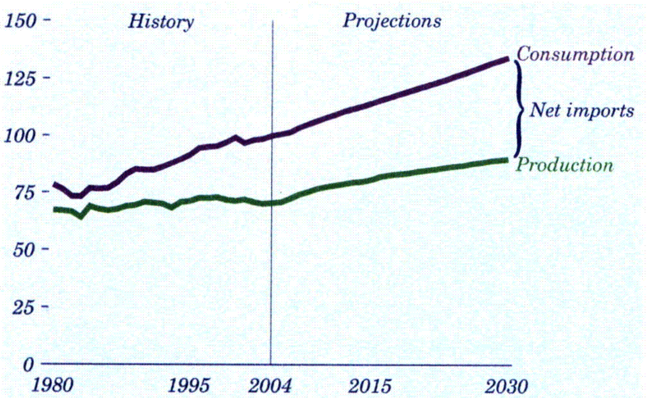
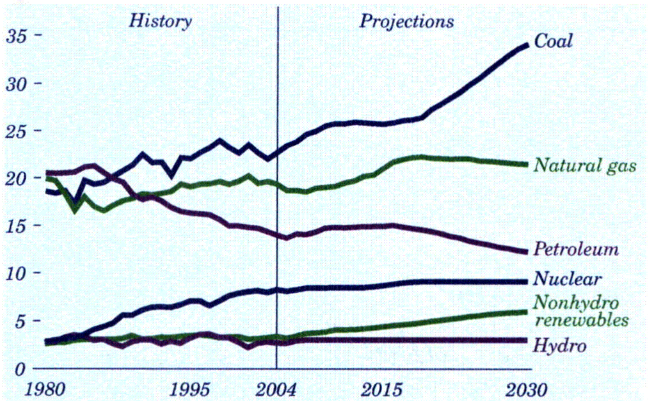


Figure 7. Energy production by fuel, 1980-2030 (quadrillion Btu)



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 *AEO-2005* 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 *AEO-2005*. *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)

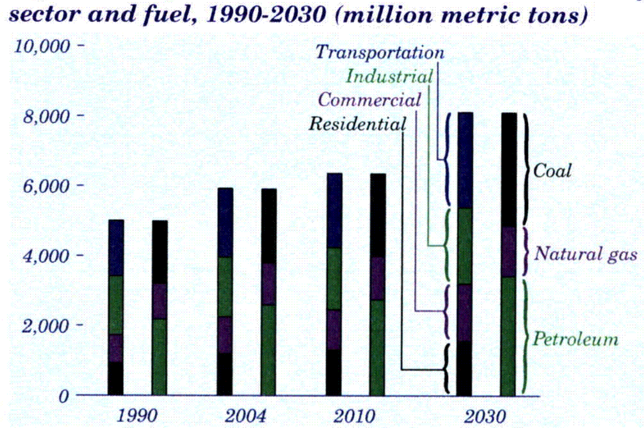


Table 1. Total energy supply and disposition in the *AEO2006* reference case: summary, 2003-2030

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

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

		CO_2 equivalent emissions standard (grams per mile)	
Tier	Model Year	Passenger cars and small light trucks (under 3,751 pounds)	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)

	Vehicle category and footprint range (square feet)					
Model year	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.

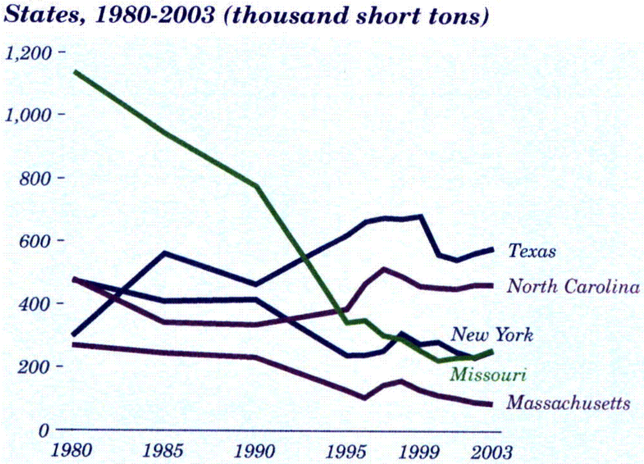
Federal Air Emissions Regulations

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.

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



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

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

		Projections		
Emissions	***2003***	***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).

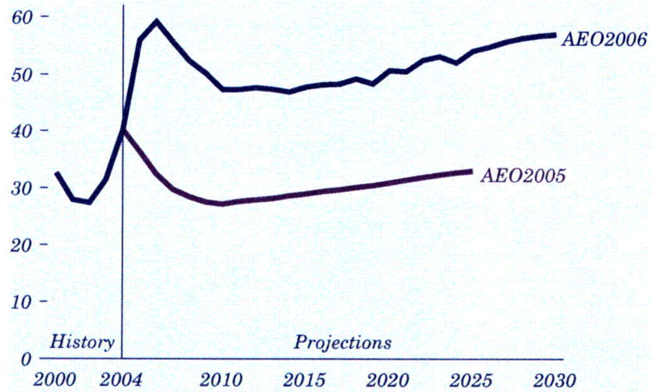
The oil price path in the *AEO2006* reference case reflects a reassessment of the willingness of oil-rich countries to expand production capacity as aggressively as envisioned last year. It does not represent a change in the assessment of the ultimate size of the world's petroleum resources but rather 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.

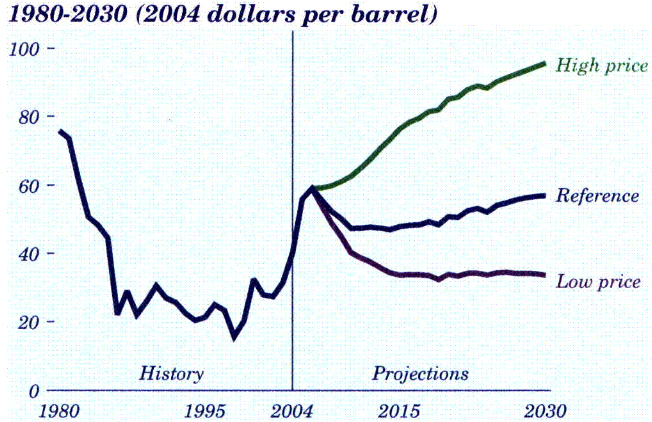
Figure 11 shows the three price projections. As compared with the reference case, the world oil price in 2030 is 68 percent higher in the high price case and 41 percent lower in the low price case. As a result, world oil consumption in 2030 is 13 percent lower in the high price case and 8 percent higher 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

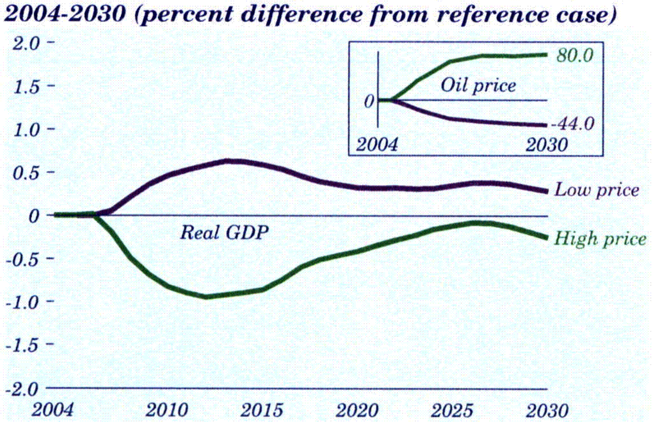
The key feature of the *AEO2006* high and low world oil price paths is that they are not characterized by disruption, but rather represent a gradual and sustained movement relative to the reference case path. Keeping this distinction in mind, the Macroeconomic Activity Module in NEMS, which contains 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

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)



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.

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

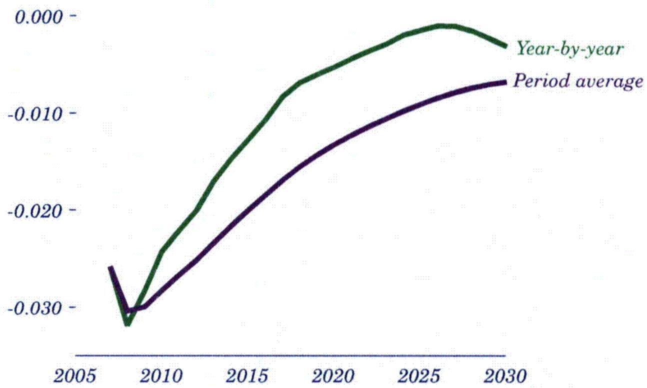


Table 12. Economic indicators in the reference, high price, and low price cases, 2005-2030 (percent)

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)

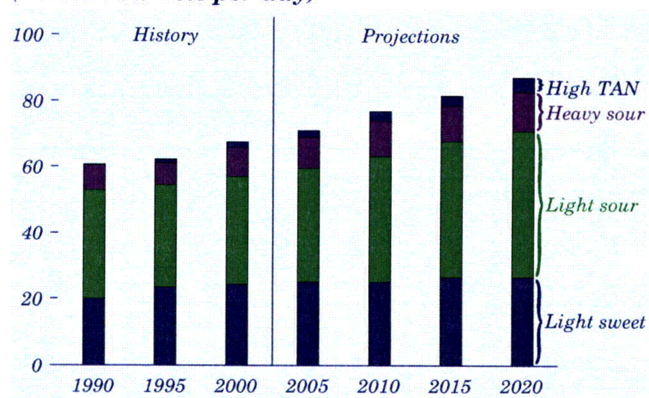


Figure 15. Sulfur content specifications for U.S. petroleum products, 1990-2014 (parts per million)

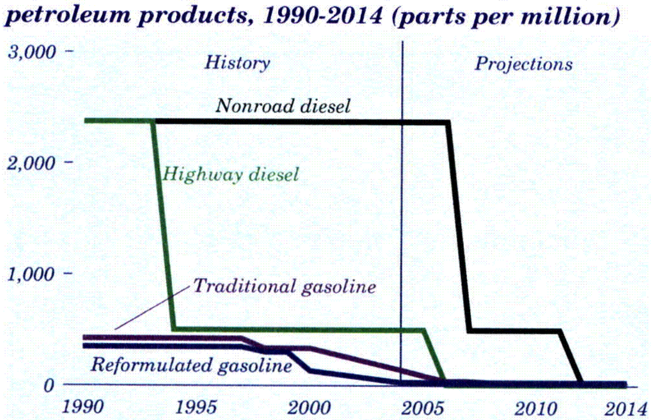
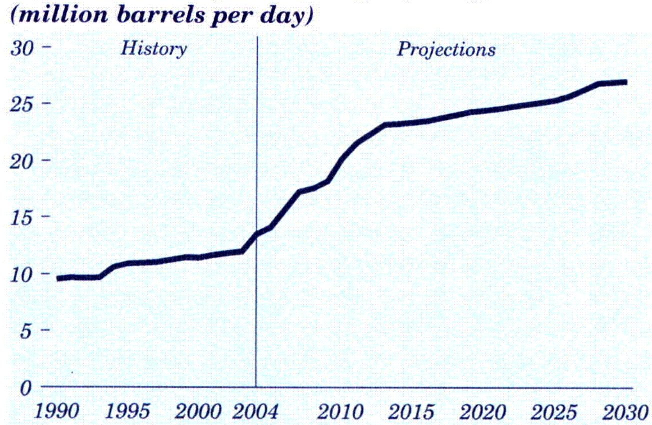


Figure 16. U.S. hydrotreating capacity, 1990-2030 (million barrels per day)



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)

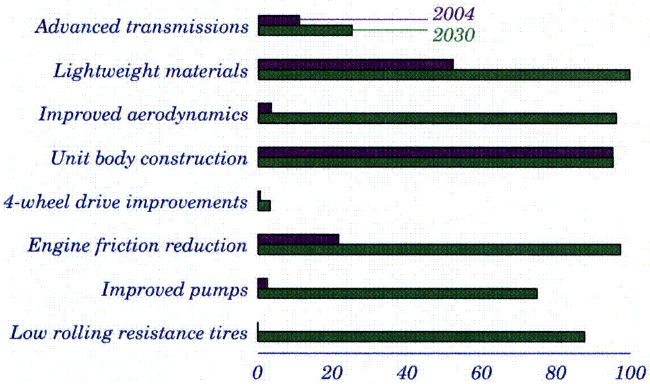
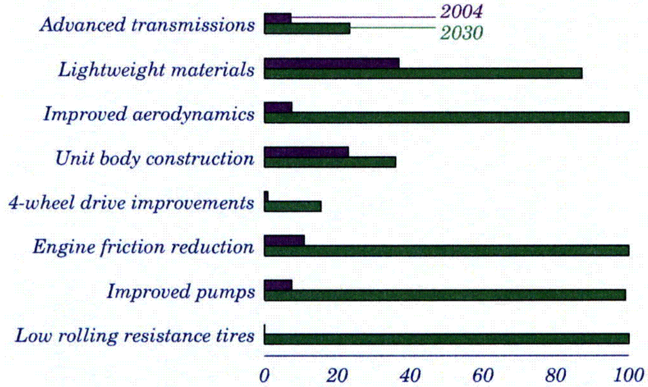


Figure 18. Market penetration of advanced technologies in new light trucks, 2004 and 2030 (percent of total new light trucks sold)



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

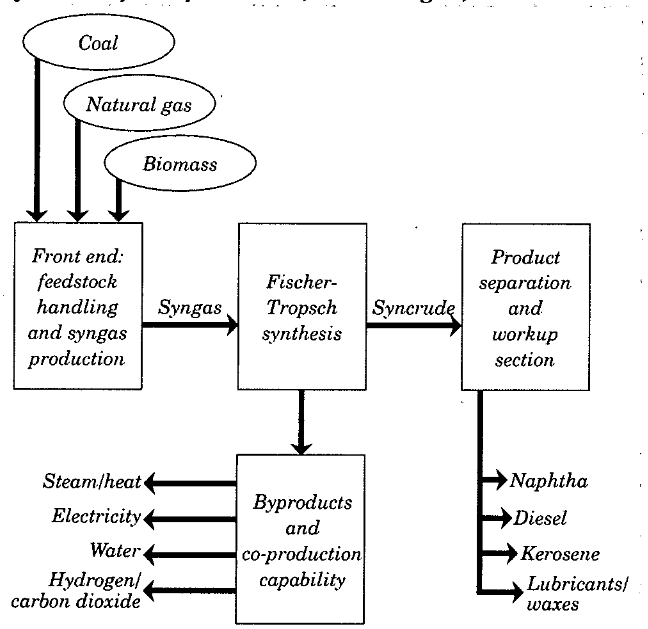
Synfuels can be produced from coal, natural gas, or biomass feedstocks through chemical conversion into syncrude and/or synthetic liquid products. Huge industrial facilities gasify the feedstocks to produce synthesis gas (carbon monoxide and hydrogen) as an initial step. Synfuel plants commonly employ 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

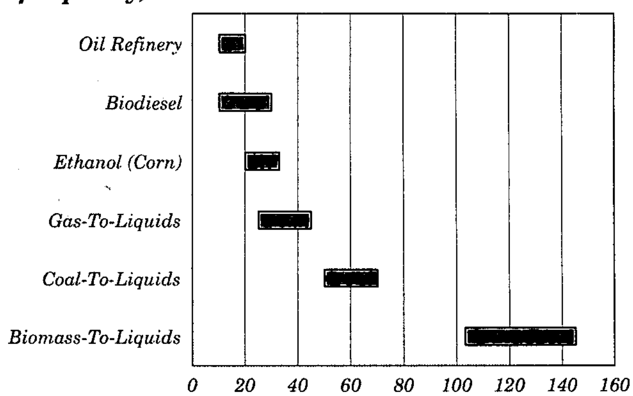
The chart below shows the range of capital investment costs for the synthetic fuel technologies. A traditional crude oil refinery is shown as a point of reference. Each of the alternative fuel technologies is more expensive than an oil refinery, with a range of capital costs for each technology resulting 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)

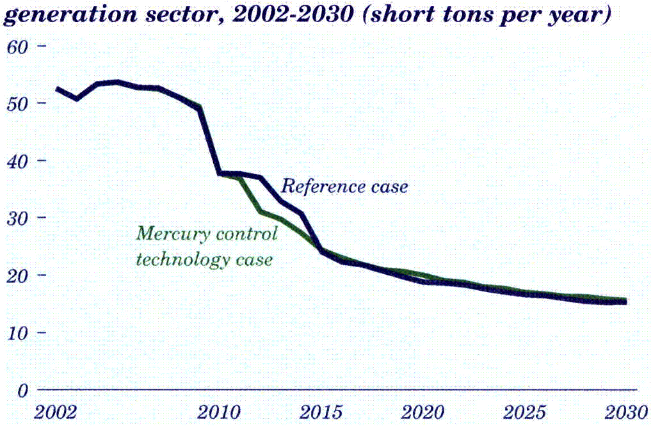
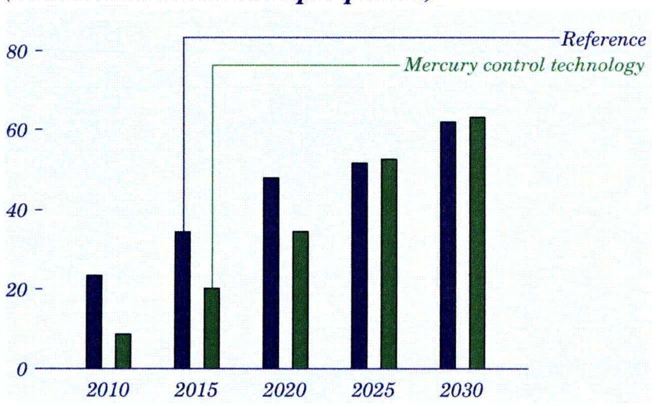


Figure 21. Mercury allowance prices, 2010-2030 (thousand 2004 dollars per pound)

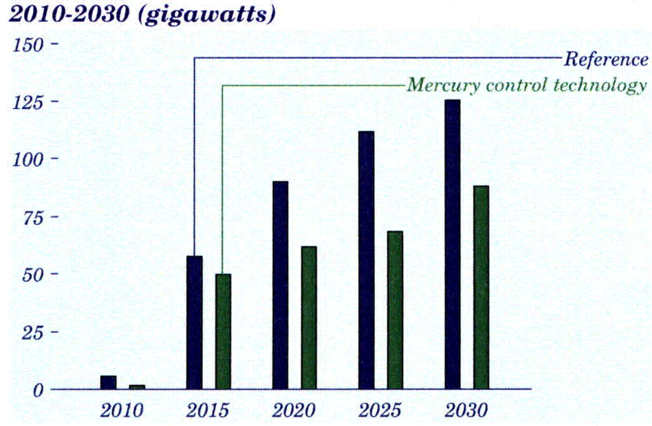


The mercury control technology case assumes that brominated ACI will be commercially available before 2010 (CAMR Phase I), and that the cost and performance levels seen in the initial DOE-sponsored tests will be replicable in the systems being offered commercially. Under these assumptions, comparison 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)

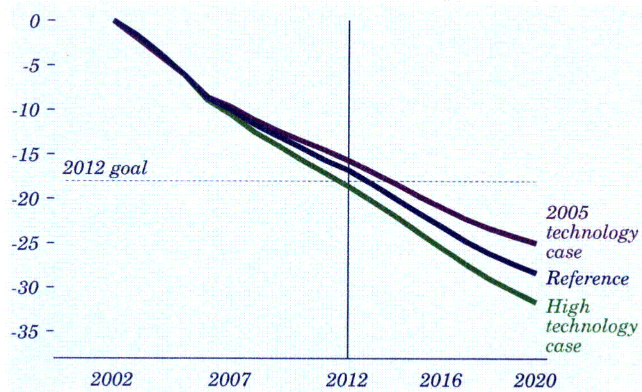


Table 15. Projected changes in U.S. greenhouse gas emissions, gross domestic product, and greenhouse gas intensity, 2002-2020

Measure	Projection			Percent Change	
	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