Annual Energy Outlook 2009
Early Release Overview

January 2009

Energy Trends to 2030

In preparing the *Annual Energy Outlook 2009* (*AEO-2009*), the Energy Information Administration (EIA) evaluated a wide range of trends and issues that could have major implications for U.S. energy markets. This overview focuses primarily on one case, the *AEO2009* reference case, which is presented and compared with the *Annual Energy Outlook 2008* (*AEO-2008*) reference case (see Table 1); however, because of the great uncertainties in any energy market projection, particularly in periods of high price volatility or rapid market transformation, the reference case results should not be given undue weight. Readers are encouraged to review the alternative cases when the complete *AEO2009* publication is released, to gain perspective on how variations in key assumptions can lead to different outlooks for energy markets.

Trends in energy supply and demand are affected by many factors. The *AEO2009* reference case reflects EIA's current thinking about trends in the economy and in energy markets. For example, the projection of world oil prices (the benchmark is represented by the price of West Texas Intermediate crude oil) is higher in the *AEO2009* reference case than the *AEO2008* projection.

To provide a basis against which alternative cases and policies can be compared, the *AEO2009* reference case generally assumes that current laws and regulations affecting the energy sector remain unchanged throughout the projection. This year's reference case reflects recent changes in law—including the expiration of moratoria on offshore leasing in the Atlantic, Pacific, and Eastern Gulf of Mexico areas of the Outer Continental Shelf (OCS) and provisions in Public Law 110-343, the Energy Improvement and Extension Act of 2008 (EIEA2008), related to production and investment tax credits for renewable energy and designated energy equipment, such as plug-in hybrid electric vehicles (PHEVs)—as well as regulatory changes.[1]

Other key changes in the *AEO2009* projections include:

- Higher projections for delivered energy prices, reflecting both higher wellhead and minemouth prices and higher costs to transport, distribute, and refine fuels per unit supplied
- Revised capital costs for capital-intensive projects to reflect recent sharp increases in those costs
- Revised handling of hybrid vehicles, including PHEVs
- Recognition of the impact of uncertainty about greenhouse gas (GHG) legislation on investment decisions (see box on page 3)
- Updated characterization of unconventional natural gas production, in particular for natural gas shales.

Economic Growth

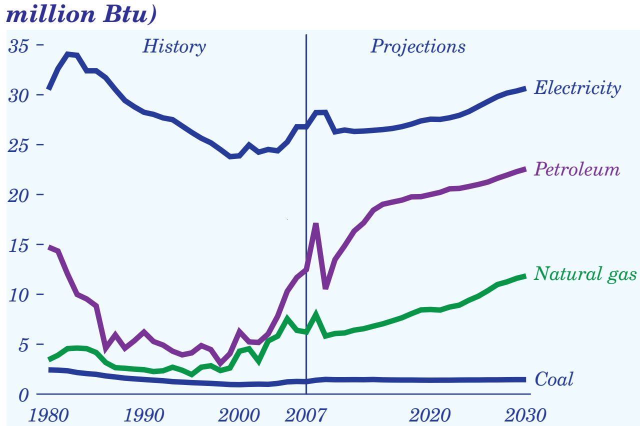
- Real gross domestic product (GDP) grows by 2.5 percent per year from 2007 to 2030 in the *AEO2009* reference case, similar to the growth in the *AEO2008* reference case, with the Nation's population, labor force, and productivity growing at annual rates of 0.9 percent, 0.7 percent, and 1.9 percent, respectively.
- The economic assumptions underlying the *AEO-2009* reference case beyond 2010 reflect trend projections that do not include short-term perturbations. The near-term scenario reflects four consecutive quarters of negative annualized economic growth during the first 2 years of the projection, consistent with EIA's November 2008 *Short-Term Energy Outlook*. GDP growth begins to recover by 2010 and reaches trend growth by 2021.

Energy Prices

Crude Oil

- Although world oil prices declined sharply at the end of 2008 with the slowing of the U.S. and world economies, the *AEO2009* reference case includes

Figure 1. Energy prices, 1980-2030 (2007 dollars per million Btu)



[1] EIA has examined many proposed policies at the request of Congress; the reports are available on EIA's web site (see "Responses to Congressional and Other Requests," web site www.eia.doe.gov/oiaf/service_ rpts.htm).

Energy Investment Behavior: Impact of Concerns Over Greenhouse Gas Emissions

Energy companies currently are operating in a challenging environment. Beyond the well-known uncertainties with respect to future demand growth and fuel, labor, and new plant costs, they also must consider the potential impact of concerns surrounding energy-related GHG emissions. Even without the enactment of Federal laws and policies limiting U.S. GHG emissions, regulators and the investment community are beginning to push energy companies to shift their investments towards less GHG-intensive technologies.

For example, many State public utility commissions are requiring that the utilities they regulate prepare simulations in their integrated resource plans that include assumed carbon dioxide (CO_2) allowance fees. The utilities often prepare a range of cases, with CO_2 fees ranging widely from $0 to $80 per ton of CO_2 or more. In addition, a number of major financial institutions (e.g., Citicorp, JPMorgan Chase, and Morgan Stanley) have adopted "carbon principles" under which they agree to "(1) encourage their clients to pursue cost-effective energy efficiency, renewable energy, and other low-carbon alternatives to conventional generation, taking into consideration the potential value of avoided CO_2 emissions; (2) ascertain and evaluate the financial and operational risk to fossil fuel generation financings posed by the prospect of domestic CO_2 emissions controls through the application of an 'Enhanced Diligence Process,'[a] and use the results of this diligence as a factor in determining whether a transaction is eligible for financing and under what terms; and (3) educate clients, regulators, and other industry participants regarding the additional diligence required for fossil fuel generation financings, and encourage regulatory and legislative changes consistent with the Principles." [b]

There are two key questions: to what extent are concerns about climate change already affecting operating and investment decisions in energy markets, and how should these impacts be represented in *AEO2009*? Although it appears that existing assets continue to be operated without adjustments for their GHG characteristics, there is considerable evidence that investors and regulators reviewing proposals for new power plants are considering GHG emissions in their investment evaluation process by implicitly (or explicitly) adding a cost to some plants, particularly those that involve GHG-intensive technologies.

To reflect this behavior, the *AEO2009* reference case adds a 3-percentage point increase in the cost of capital when evaluating investments in GHG-intensive technologies, such as coal-fired power plants without carbon control and sequestration (CCS) and coal-to-liquids (CTL) plants. While the 3-percentage adjustment is somewhat arbitrary, in levelized cost terms its impact is similar to that of a $15-per-ton value for CO_2 emissions when investing in a new coal plant without CCS, well within the range of the results of simulations that utilities and regulators have prepared. The adjustment should not be seen as an increase in the actual cost of financing but rather as representing an implicit hurdle being added to GHG-intensive projects to account for the possibility that eventually they may be required to purchase allowances or invest in other GHG-emission-reducing projects to offset their emissions.

In previous *AEO*s the reference cases did not incorporate such an adjustment. Investment decisions in those reference cases were treated in the same way as they would be in a world where the issue of climate change and the role of GHG emissions as a contributing factor did not exist. Current evidence suggests that such a methodology is now inappropriate to reflect business-as-usual behavior under current laws and regulations. To facilitate comparisons with previous *AEO*s, and to provide a measure of the impact of the change in methodology, the complete *AEO2009* will also include an alternative case that does not incorporate the new financing adjustment factor for long-lived investments in GHG-intensive technologies.

[a]An expanded due diligence process that considers the probable risks posed by the costs of CO_2 emissions and seeks to address those risks in financing decisions.

[b]See Morgan Stanley, "Leading Wall Street Banks Establish The Carbon Principles" (Press Release, February 4, 2008), web site www.morganstanley.com/about/press/articles/6017.html.

higher world oil prices by 2030, based on a reevaluation of long-term fundamentals that support higher prices than expected in earlier *AEO*s. Prices begin to rise in 2010 (Figure 1) as the economy rebounds and global demand is expected to once again grow more rapidly than liquids supplies from producers outside the Organization of the Petroleum Exporting Countries (OPEC). In 2030, the average real price of crude oil in the reference case is $130 per barrel in 2007 dollars, or about $189 per barrel in nominal dollars. Alternative *AEO2009* cases address higher and lower world crude oil prices.

- The *AEO2009* reference case assumes that access limitations restrain the growth of non-OPEC conventional liquids production between 2007 and 2030, and that OPEC targets a relatively constant market share of about 40 percent of total world liquids production.
- Contributing to world oil price uncertainty is the degree to which non-OPEC countries and countries outside the Organization for Economic Cooperation and Development (OECD), such as Russia, restrict economic access to potentially productive resources. Other uncertain factors, including OPEC investment decisions, will affect the world oil price and the economic viability of unconventional liquids.
- The *AEO2009* reference case also includes significant long-term potential for supply from non-OPEC producers. In several resource-rich regions (including Brazil, Azerbaijan, and Kazakhstan), high oil prices, expanded infrastructure, and new exploration and drilling technologies contribute additional non-OPEC oil production. Also, with the economic viability of Canada's oil sands enhanced by higher world oil prices and advances in production technology, oil sands production reaches 4 million barrels per day in 2030.

Liquid Products

- Real prices (in 2007 dollars) for motor gasoline and diesel in the *AEO2009* reference case are $3.90 per gallon and $3.91 per gallon in 2030—$1.39 and $1.16 per gallon higher, respectively, than in the *AEO2008* reference case, largely as a result of higher crude oil prices. Despite being almost equal in 2030, diesel prices generally are higher than gasoline prices throughout the projection because of continued strong growth in world demand.
- Retail prices for E85 (a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume), including the discounts on an energy-equivalent basis relative to motor gasoline that are required to meet the renewable fuels standard (RFS) legislated in Public Law 110-140, the Energy Independence and Security Act of 2007 (EISA2007), decline to $2.39 per gallon in 2015, then rise gradually with the cost of building additional E85 infrastructure to expand its availability.

Natural Gas

- After declining at the end of 2008, natural gas prices stabilize through 2011, with Henry Hub spot prices just above $6.50 per million British thermal units (Btu). After 2011, Henry Hub spot prices (in 2007 dollars) begin to increase, reaching $9.25 per million Btu in 2030.
- The price of natural gas is generally higher in the *AEO2009* reference case than was projected in the *AEO2008* reference case, as a result of higher exploration and development costs and a requirement for increased natural gas production (to meet increased consumption while imports are decreasing), particularly during the last 10 years of the projection. Total natural gas consumption is about 7 percent higher in 2030 as a result of a 40-percent increase in natural gas use for power generation, and net imports are 78 percent lower. The wellhead price of natural gas in 2030 is 23 percent higher in the *AEO2009* reference case than in the *AEO2008* reference case.

Coal

- Coal prices are expected to moderate somewhat in the near term from their recent very high levels, but they remain well above the price projections of recent *AEO*s and rise toward the end of the projection as consumption grows. Average real minemouth coal prices (in 2007 dollars) in the *AEO2009* reference case increase from $1.27 per million Btu ($25.82 per short ton) in 2007 to $1.47 per million Btu ($30.01 per short ton) in 2009, then level off and even decline somewhat, bottoming out at $1.39 per million Btu ($27.94 per short ton) in 2020. Much of the moderation in coal prices after 2009 is attributable to a shift from more expensive coal production from the Central Appalachian supply region to regions with lower production costs, such as Northern Appalachia, the Eastern Interior, and Wyoming's Powder

River Basin. After 2020, coal prices rise to $1.45 per million Btu ($28.94 per short ton) in 2030.

- In dollars per million Btu, the coal price projections for both 2020 and 2030 are 19 percent higher than those in the *AEO2008* reference case. Key factors include a less optimistic outlook for coal mining productivity and expected higher costs for equipment, fuel, and explosives used at mines, especially in the early years of the projection.

Electricity

- From a peak of 9.6 cents per kilowatthour (2007 dollars) in 2009, average delivered electricity prices in *AEO2009* decline to 9.0 cents per kilowatthour in 2012 and then increase to 10.5 cents per kilowatthour in 2030. In the *AEO2008* reference case, with lower delivered fuel prices and construction costs for all new technologies, electricity prices reached 9.1 cents per kilowatthour (2007 dollars) in 2030.
- Higher costs for fuel and new plant construction in the *AEO2009* reference case lead to higher electricity prices than in *AEO2008*. In the early years of the projection, real electricity prices decline slightly as the recent rapid increase in fuel and new plant costs begins to wane. Over the longer run, real electricity prices rise as demand grows and the price of delivered fuels increases, leading to higher production costs.

Energy Consumption by Sector

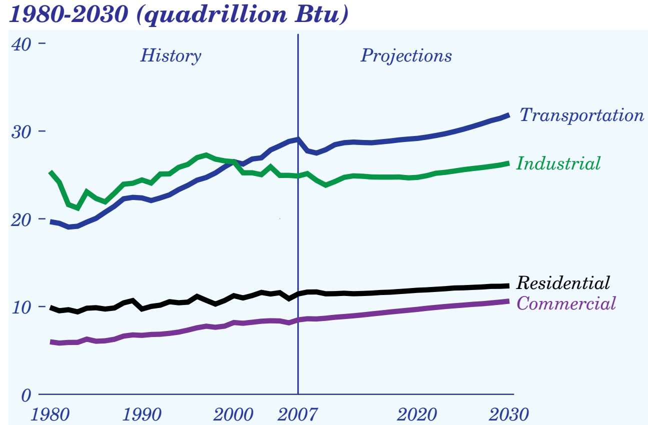
Residential

- The incorporation of tax credits for renewable systems and energy-efficient appliances in EIEA-2008, along with higher prices for natural gas and heating oil, contributes to a reduction in energy use in the *AEO2009* reference case relative to the *AEO2008* reference case (0.5 quadrillion Btu or 4 percent of delivered energy). Residential delivered energy consumption in the *AEO2009* reference case grows from 11.4 quadrillion Btu in 2007 to 12.4 quadrillion Btu in 2030 (Figure 2).
- Increased use of compact fluorescent lamps and the incorporation of efficiency standards for residential lighting from EISA2007 that promote the widespread use of light-emitting diode (LED) bulbs later in the projection significantly reduce electricity demand in the residential sector.
- EIEA2008 removes the existing tax credit cap for the installation of solar photovoltaic systems, causing the installed stock of the systems to increase to 1.65 million (from fewer than 75,000 in a case without the tax credit) in 2016, the last year in which the credit is available.
- Ground-source (geothermal) heat pumps also benefit from a large increase in the allowable credit in EIEA2008 (from $300 to $2,000 per unit), fostering nearly a threefold increase in the stock of very efficient heat pumps by 2016, relative to a case without the tax credit. Even though the tax credit spurs additional purchases of ground-source heat pumps, however, their market share remains low, reaching 1.0 percent of the single-family heating market by 2016.

Commercial

- Despite faster growth in commercial square footage, higher energy prices lead to slower growth in commercial energy consumption in the *AEO2009* reference case relative to the *AEO2008* reference case, along with increased adoption of energy conservation and efficiency measures. Delivered commercial energy consumption grows from 8.5 quadrillion Btu in 2007 to 10.6 quadrillion Btu in 2030, about 0.7 quadrillion Btu less than in the *AEO2008* reference case.
- The 8-year extension of investment tax credits for solar, fuel cell, and microturbine technologies and the addition of tax credits for wind, conventional combined heat and power (CHP) systems, and ground-source heat pumps in EIEA2008 lead to increased adoption of the technologies in the commercial sector.
- Higher electricity prices lead to an overall increase in commercial distributed generation and CHP in the *AEO2009* reference case. The EIEA-2008 tax credits for those systems spur additional adoption.

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



Industrial

- About one-third of delivered energy in the United States is consumed in the industrial sector, and one-half of that is consumed in just three industries: bulk chemicals, petroleum refining, and paper products. Petroleum refining, which includes heat and power for coal- and natural-gas-based petroleum liquids and ethanol, becomes the single largest energy-consuming industry in 2030 in the *AEO2009* reference case, overtaking bulk chemicals.
- Collectively, the energy-intensive manufacturing industries—bulk chemicals, refineries, paper products, primary metals, food, glass, and cement—produce about one-fifth of the dollar value of industrial shipments while accounting for more than two-thirds of delivered energy consumption. With strong growth in refinery-related fuel use, the share of industrial energy use by the energy-intensive industries increases slightly, from 71 percent in 2007 to 77 percent in 2030.
- Industrial delivered energy consumption increases by just 4 percent from 2007 to 2030 in the *AEO2009* reference case, while industrial shipments increase by 47 percent. Cumulative economic growth in energy-intensive manufacturing industries (23 percent) is much slower, reflecting increased foreign competition from regions with lower energy costs. Most significant is the 10-percent decline in bulk chemical industry shipments, currently the largest energy-consuming industry in the United States. The composition of the chemical industry also shifts to less energy-intensive products and becomes more efficient. As a result, energy consumption in bulk chemicals, including feedstock usage, declines by 25 percent from 2007 to 2030.
- Energy consumption in the refining industry runs counter to the trends in the rest of the industrial sector, increasing by more than one-half while shipments are largely unchanged, as the industry becomes more energy-intensive to meet environmental requirements and increasingly produces synthetic fuels in the latter half of the projection period.

Transportation

- Delivered energy consumption in the transportation sector grows to 31.9 quadrillion Btu in 2030 in the *AEO2009* reference case, 1.1 quadrillion Btu less than in the *AEO2008* reference case, due to higher energy prices and the revised handling of the EISA2007 corporate average fuel economy (CAFE) standards.
- Growth in industrial output is expected to increase energy demand for heavy truck travel, which accounts for a majority of the growth in transportation energy demand in the reference case.
- Recent changes in airfare pricing and their impact on the cost of air travel diminish growth in air travel in *AEO2009* relative to *AEO2008*.
- EIEA2008 provides tax credits for PHEVs between 2009 and 2014. In the *AEO2009* reference case, the PHEV credit increases sales of those vehicles to the cumulative maximum by 2014 and increases market penetration of PHEVs throughout the projection.
- The proposal by the National Highway Traffic Safety Administration (NHTSA) for implementation of the EISA2007 CAFE standard, which has been adopted in *AEO2009*, reflects a more rapid increase in light-duty vehicle CAFE than was anticipated in *AEO2008*. To attain the mandated fuel economy levels, the *AEO2009* reference case includes a sharp increase in sales of unconventional vehicle technologies,[2] such as flex-fuel, hybrid, and diesel vehicles, and a slowdown in the growth of new light truck sales. Hybrid vehicle sales, including PHEVs, increase from 2 percent of new light-duty vehicle sales in 2007 to 38 percent in 2030. PHEV sales grow rapidly as a result of the EIEA2008 tax credits, increasing to 90,000 vehicles annually in 2014. In 2030, PHEVs account for 2 percent of new light-duty vehicle sales.

Energy Consumption by Primary Fuel

- Coal, oil, and natural gas meet 79 percent of total U.S. primary energy supply requirements in 2030—down from 85 percent in 2007, reflecting higher energy prices that reduce consumption, the incorporation of the EIEA2008 and EISA2007 provisions, and increased use of renewable energy when compared with the *AEO2008* reference case.
- Total U.S. consumption of liquid fuels, including both fossil liquids and biofuels, grows from 40.8 quadrillion Btu (20.6 million barrels per day) in

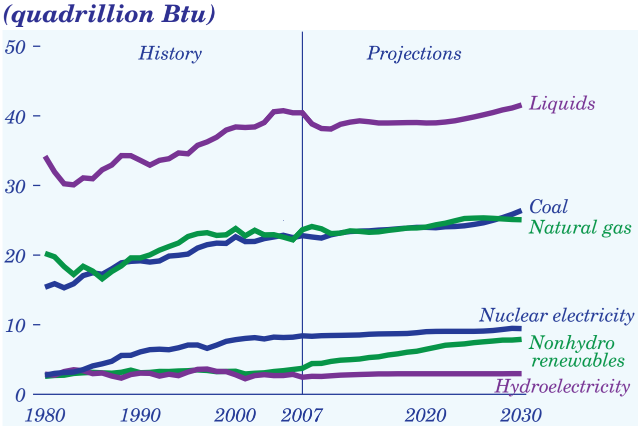
[2]Vehicles that can use alternative fuels or employ electric motors and advanced electricity storage, advanced engine controls, or other new technologies.

2007 to 41.6 quadrillion Btu (21.6 million barrels per day) in 2030 in the *AEO2009* reference case (Figure 3). Excluding growth in biofuel consumption, consumption of petroleum-based liquids is essentially flat. The transportation sector dominates demand for liquid fuels, which grows from a 69-percent share of total consumption in 2007 to a 75-percent share in 2030.

- Rapid growth in the consumption of renewable fuels results mainly from the implementation of the Federal RFS for transportation fuels and State renewable portfolio standard (RPS) programs for electricity generation. Given the anticipated level of technology improvement, the rate of investment, and the current schedule of mandates in the RFS, the requirement for cellulosic biofuels will be met at a level lower than the original EISA-2007 mandate through the implementation of waivers and adjustments. Growth in renewable electricity other than hydropower provides 33 percent of the growth in electricity demand between 2007 and 2030, and its share in meeting demand growth probably would be higher if existing production tax credits scheduled to expire in 2009 were extended, or if policies were implemented to limit GHG emissions.

Total primary energy consumption in the *AEO2009* reference case grows by 11.2 percent, from 101.9 quadrillion Btu in 2007 to 113.3 quadrillion Btu in 2030 (4.7 quadrillion Btu less than in the *AEO2008* reference case). Among the most important factors leading to lower total energy demand in the *AEO2009* reference case are significantly higher energy prices and greater use of more efficient appliances and vehicles in response to the requirements of EISA2007 and EIEA2008.

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



In the *AEO2009* reference case, natural gas consumption ranges between 22.5 and 23.4 trillion cubic feet through 2020 before increasing gradually to 24.4 trillion cubic feet in 2030—1.7 trillion cubic feet more than projected in the *AEO2008* reference case. Despite higher natural gas prices, electric power sector consumption in 2030 is 2.0 trillion cubic feet higher in the *AEO2009* reference case than in the *AEO2008* reference case, in part because uncertainty about potential GHG regulations and their impact on coal use leads to an increase in natural gas use for electric power generation, offsetting lower consumption in the residential, commercial, and industrial sectors.

Total coal consumption increases from 22.7 quadrillion Btu (1,129 million short tons) in 2007 to 26.4 quadrillion Btu (1,358 million short tons) in 2030 in the *AEO2009* reference case. Coal consumption, mostly for electric power generation, grows gradually through 2020 as existing plants are used more intensively and new plants that are already under construction are completed and enter service. In the *AEO2009* reference case, coal consumption in the electric power sector increases from 22.0 quadrillion Btu in 2020 to 24.1 quadrillion Btu in 2030, much lower than the projection of 27.5 quadrillion Btu in 2030 in the *AEO2008* reference case.

The moderate increase in coal consumption from 2007 to 2030 also reflects growth in coal use at CTL plants. In 2030, 1.1 quadrillion Btu of coal is used at CTL plants. Despite higher CTL investment costs and concerns about potential GHG regulations, the increase in coal use for CTL plants in the *AEO2009* reference case is greater than in the *AEO2008* reference case, because higher liquids prices increase the economic attractiveness of the technology.

The *AEO2009* reference case includes greater use of renewable energy than the *AEO2008* reference case. Total consumption of marketed renewable fuels—including wood, municipal waste, and biomass in the end-use sectors; hydroelectricity, geothermal, municipal waste, biomass, solar, and wind for generation in the electric power sector; ethanol for gasoline blending and biomass-based diesel in the transportation sector, of which 3.4 quadrillion Btu is included with liquids fuel consumption in 2030—grows by 3.3 percent per year in the reference case.

Although the situation is uncertain, the current state of the industry and EIA's present view of the projected rates of technology development and market penetration of cellulosic biofuel technologies suggest that available quantities of cellulosic biofuels will be insufficient to meet the new RFS targets for cellulosic biofuels before 2022, triggering both waivers and a modification of applicable volumes, as provided in Section 211(o) of the Clean Air Act as amended by EISA2007. The modification of volumes reduces the overall target in 2022 from 36 billion credits to 29.8 billion credits in the *AEO2009* reference case.

On a volumetric basis, ethanol use in the *AEO2009* reference case grows from 6.5 billion gallons in 2007 to 29.6 billion gallons in 2030—about 20 percent of total gasoline consumption by volume and about 24 percent more than in the *AEO2008* reference case. Ethanol use for gasoline blending grows to 12.2 billion gallons and E85 consumption to 17.5 billion gallons in 2030. The ethanol supply is produced from both corn and cellulose feedstocks, with corn accounting for 15.0 billion gallons and cellulose 12.6 billion gallons of ethanol production in 2030 (including both domestic and imported production). Both are eligible for RFS credits.[3]

Other biofuels are produced domestically and imported, including some produced from corn that are ineligible for RFS credits. Biodiesel use increases to 1.9 billion gallons in 2030, or about 2.3 percent of total diesel consumption by volume. In addition, consumption of biomass-to-liquids (BTL) diesel grows to 3.6 billion gallons in 2030, or 4.8 percent of total diesel consumption by volume.

Excluding hydroelectricity, renewable energy consumption in the electric power sector grows from 1.0 quadrillion Btu in 2007 to 3.4 quadrillion Btu in 2030. The projected consumption of nonhydroelectric renewable energy in the *AEO2009* reference case is a result predominantly of State RPS programs that require specific and generally increasing shares of electricity sales to be supplied by renewable resources, such as wind, solar, geothermal, and in some States biomass or hydropower. Rising fossil fuel prices also contribute to the growth in consumption of renewables in the later years of the projection. The largest source of growth in the *AEO2009* reference case is in biomass and wind. Both benefit from the higher fossil fuel prices and concerns about GHG regulations that dampen investment in carbon-intensive technologies in the *AEO2009* reference case, and neither benefits from any Federal or State subsidy beyond those in existing laws and regulations.

Energy Intensity

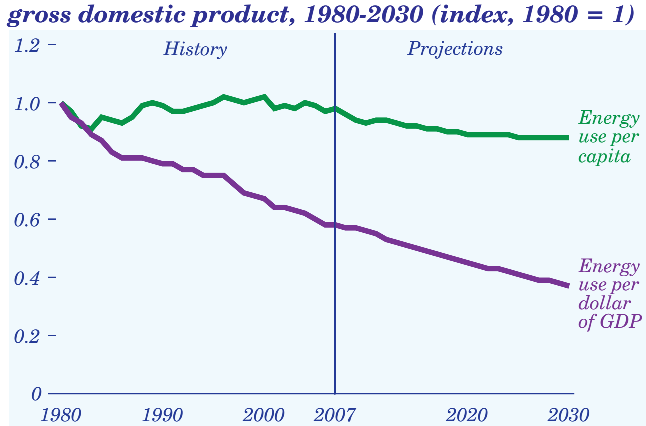
- The energy intensity of the U.S. economy declines steadily as the result of higher energy prices and the adoption of policies that promote improved energy efficiency in the *AEO2009* reference case.
- The reference case reflects observed historical relationships between energy prices and energy conservation. To the extent that consumer preferences change, the improvement in energy intensity or energy consumption per capita could be greater or smaller.

Energy intensity, measured as primary energy use (in thousand Btu) per dollar of GDP (in 2000 dollars), declines by more than one-third from 2007 to 2030 in the *AEO2009* reference case (Figure 4). Although energy use generally increases as the economy grows, higher energy prices, continuing improvement in energy efficiency, and a shift to less energy-intensive activities keep the rate of energy consumption growth lower than the rate of GDP growth.

Since 1992, the energy intensity of the U.S. economy has declined on average by 2.0 percent per year, in part because the share of industrial shipments accounted for by the energy-intensive industries has fallen from 24 percent in 1992 to 22 percent in 2007. In the *AEO2009* reference case, the energy-intensive industries' share of total industrial shipments continues to decline, to 18 percent in 2030.

Population is a key determinant of energy consumption, influencing demand for travel, housing, consumer goods, and services. Since 1990, the U.S. population has increased by 21 percent and energy consumption by a comparable 20 percent, with annual variations in energy use per capita resulting

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



[3] Under the provisions of EISA2007, only 15 billion gallons of ethanol produced directly from corn is eligible for RFS credits.

from variations in weather and economic factors. The age, income, and geographic distribution of the population also affect the growth of energy consumption. Aging of the population, a gradual shift from the North to the South, and rising per-capita income will influence future trends.

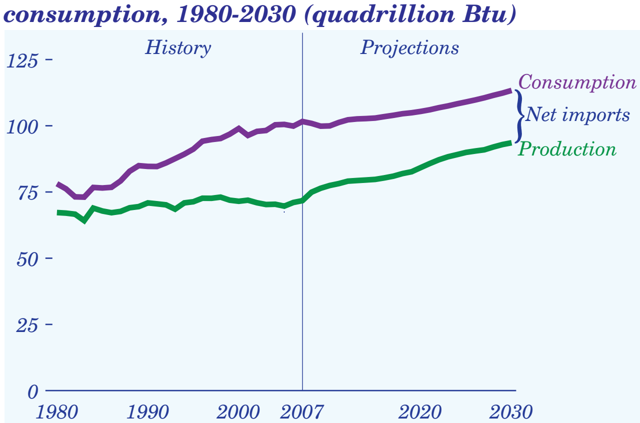
Overall, the U.S. population increases by 24 percent from 2007 to 2030 in the *AEO2009* reference case; over the same period, energy consumption increases by 11 percent. The result is a decrease in energy consumption per capita at an annual rate of 0.5 percent per year from 2007 to 2030, greater than the 0.2-percent yearly drop in the *AEO2008* reference case. The faster decline in energy consumption per capita results from the higher energy prices in the *AEO2009* reference case and revisions from the CAFE standards that were assumed in the *AEO2008* reference case.

With energy prices rising until recently, interest in energy conservation has increased. Although additional energy conservation is induced by higher energy prices in the *AEO2009* reference case, no further 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.

Energy Production and Imports

Net imports of energy meet a major but declining share of total U.S. energy demand in the *AEO2009* reference case (Figure 5). Increased use of biofuels, much of which is produced domestically, demand reductions resulting from new efficiency standards, rapid improvement in the efficiency of appliances, and higher energy prices act to moderate growth in

Figure 5. Total energy production and consumption, 1980-2030 (quadrillion Btu)



energy imports. Higher fuel prices also spur increased domestic energy production, further tempering growth in imports. The net import share of total U.S. energy consumption in 2030 is 17 percent, compared with 29 percent in 2007.

Liquids

- Consistent with the *AEO* assumption of adopting existing legislation and regulation, the *AEO2009* reference case reflects the removal of moratoria on offshore leasing and drilling in the Atlantic, Pacific, and Eastern Gulf of Mexico areas of the OCS, which results in production from those areas. It is likely that the particulars of lifting the moratoria will continue to be discussed in Congress and, as applicable, in State legislatures before any drilling occurs; however, some OCS areas already are included in the current 5-year leasing plan of the Mineral Management Service.
- Net imports of liquids meet a large but declining share of total U.S. liquids demand. Increased use of biofuels, reduced demand for liquids as a result of tighter CAFE standards, and higher energy prices act to moderate the growth in liquids demand. Higher fuel prices also contribute to the projected increase in domestic liquids production. As a result, U.S. dependence on imported liquids, measured as a share of U.S. liquids use, is expected to continue declining over the next 25 years, from 58 percent in 2007 to less than 40 percent in 2025, before increasing to 41 percent in 2030.
- Higher world oil prices drive the initiation of U.S. oil shale production in the *AEO2009* reference case. The long-term potential for oil shale production is one of the more uncertain areas of the projection, considering the relatively high costs of, and needed improvements in, extraction technologies as well as the potential for changes in controlling legislation.

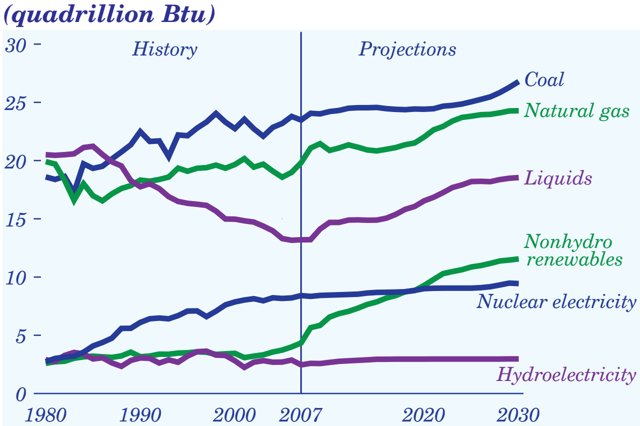
In general, U.S. crude oil production in the *AEO2009* reference case projection is higher than in the *AEO2008* reference case, consistent with the projected expansion of enhanced oil recovery (EOR) operations and higher crude oil prices. U.S. crude oil production increases from 5.1 million barrels per day in 2007 to a peak of 7.4 million barrels per day in 2030, with production increases from the deep waters of the Gulf of Mexico, Pacific and Atlantic OCS, and onshore EOR projects.

Total domestic liquids supply, including crude oil, natural gas plant liquids, refinery processing gain, and other refinery inputs (including ethanol, biodiesel, BTL, and liquids from coal) increase through 2030 in the *AEO2009* reference case, while net imports of crude oil and other liquids decline from 12.1 million barrels per day in 2007 to 8.8 million barrels per day in 2030. Total domestic liquids supply grows from 8.7 million barrels per day in 2007 to 12.8 million barrels per day in 2030 (Figure 6).

Natural Gas

- Total production levels are relatively stable from 2007 through 2016 at about 20.4 trillion cubic feet. After 2016 they begin to rise, to 23.7 trillion cubic feet in 2030—4.2 trillion cubic feet more than projected in the *AEO2008* reference case.
- Higher natural gas prices and a reevaluation of the resource base result in higher unconventional natural gas production in the *AEO2009* reference case than in the *AEO2008* reference case. In 2030, production of “tight gas” is about 28 percent higher and production of gas shale is 85 percent higher in *AEO2009* than in *AEO2008*.
- The recent expiration of moratoria on drilling in the Atlantic, Pacific, and Eastern Gulf of Mexico OCS areas is reflected in the *AEO2009* reference case and contributes to increased offshore natural gas production in the later years of the projection.
- Net pipeline imports are lower in the *AEO2009* reference case relative to the *AEO2008* reference case, in part because of a decrease in imports of liquefied natural gas (LNG) by Mexico and Canada that were projected to be re-exported to the United States in the *AEO2008* reference case and were reported as pipeline imports. In addition, declining production in Canada, due in part to lower profitability for unconventional production than in the United States, is expected to reduce the availability of natural gas supplies for export to the United States.
- Prospects for future LNG imports are significantly lower in the *AEO2009* reference case than in the *AEO2008* reference case. While LNG imports increase in the first decade of the projection as world liquefaction capacity increases at a rapid pace, supplies tighten in the longer term, when rising world oil prices lead to an increase in global demand for LNG. The future direction of the global LNG market is one of the key uncertainties in the *AEO2009* reference case.

Figure 6. Energy production by fuel, 1980-2030 (quadrillion Btu)



Total domestic production of natural gas (including supplemental natural gas supplies) is significantly higher in the *AEO2009* reference case than in the *AEO2008* reference case. Although exploration and production costs are higher, the higher prices in the *AEO2009* reference case support the higher level of production.

AEO2009 expects the Alaska natural gas pipeline to be completed in 2020, which is the same as in the *AEO2008* reference case. Project planning appears to be progressing on schedule, and the economics continue to be favorable. Once the pipeline is in service, Alaska’s total natural gas production in the *AEO2009* reference case increases to 2.0 trillion cubic feet in 2021 (from 0.4 trillion cubic feet in 2007) and remains at that level through 2030.

Total net imports of LNG to the United States in the *AEO2009* reference case are significantly lower than in the *AEO2008* reference case due to a reevaluation of U.S. competitiveness for supplies on the world market. U.S. imports of LNG increase as world liquefaction capacity expands, peaking at 1.5 trillion cubic feet in 2018; thereafter, they decline to 0.8 trillion cubic feet in 2030, as growth in world demand outpaces growth in liquefaction capacity. With the decline in LNG imports, the utilization of U.S. regasification capacity falls from 36 percent in 2007 to 16 percent in 2030.

With many new international players entering LNG markets, the competition for available supplies is expected to be strong, and the amounts available to the U.S. market may vary considerably from year to year. The *AEO2009* reference case has been updated to reflect current market dynamics, which could change considerably as worldwide LNG markets evolve.

Coal

- Although coal remains the most important fuel for U.S. electricity generation, slower growth in electricity demand and increasing concern about GHG emissions affect coal markets by slowing the growth of demand for coal in the *AEO2009* reference case compared with the *AEO2008* reference case. Consequently, western coal production, typically the source of marginal supply, does not grow as much as in previous *AEO*s.

As domestic coal use grows in the *AEO2009* reference case, U.S. coal production increases at an average rate of 0.6 percent per year, from 23.5 quadrillion Btu (1,147 million short tons) in 2007 to 26.8 quadrillion Btu (1,336 million short tons) in 2030—6 percent less than in the *AEO2008* reference case. Production from mines west of the Mississippi River provides the largest share of the incremental coal production. On a Btu basis, 52 percent of domestic coal production originates from States west of the Mississippi River in 2030, up from 50 percent in 2007.

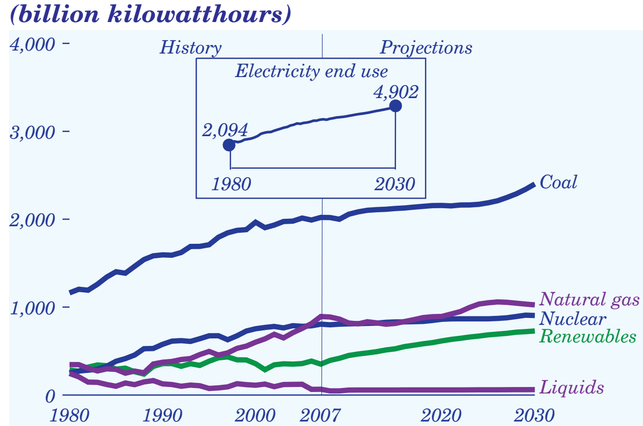
Typically, trends in U.S. coal production are linked to its use for electricity generation, which currently accounts for 92 percent of total coal consumption. Coal consumption in the electric power sector in the *AEO2009* reference case, at 24.1 quadrillion Btu in 2030, is less than in the *AEO2008* reference case (27.6 quadrillion Btu in 2030). Slower growth in overall electricity demand and reduced investment in new coal-fired generating capacity, combined with more generation from natural gas and renewable energy, underlie the reduced outlook for coal consumption in the electricity sector.

Another emerging market for coal is CTL plants. Despite higher plant costs and concerns about GHG regulations, the higher oil prices in this year's reference case make new CTL plants attractive. Coal use in CTL plants grows from 0.4 quadrillion Btu (30 million short tons) in 2020 to 1.1 quadrillion Btu (70 million short tons) in 2030.

Electricity Generation

- Total electricity consumption, including both purchases from electric power producers and on-site generation, grows from 3,903 billion kilowatthours in 2007 to 4,902 billion kilowatthours in 2030, increasing at an average annual rate of 1.0 percent in the *AEO2009* reference case. The growth rate in the *AEO2009* projection is slightly lower than in the *AEO2008* reference case (1.1 percent per year).
- Even though the mix of investments in new power plants relies less on coal than in recent *AEO*s, coal remains the dominant fuel for electricity generation because of continued reliance on existing coal-fired plants and the addition of some new ones in the absence of an explicit policy to reduce GHG emissions (Figure 7).
- Natural gas plays a larger role than in recent *AEO*s because it is less carbon intensive than coal, and because new natural-gas-fired plants are much cheaper than new renewable or nuclear plants. Compared with the *AEO2008* reference case, electricity generation from natural gas in 2030 is 38 percent higher in the *AEO2009* reference case. The key factor in the increase is dampened growth in coal-fired generation as concerns about GHG emissions and the possible impact of future policies reduce the number of new coal plants added.
- Generation from renewable resources increases in response to requirements in more than one-half of the States for minimum renewable generation shares. Renewable generation in the *AEO2009* reference case is significantly higher than in the *AEO2008* reference case, with the share of generation coming from renewable fuels growing from 8.5 percent in 2007 to 14.1 percent in 2030. In the *AEO2009* reference case, Federal subsidies for renewable generation are assumed to expire as enacted. Their extension would have a large impact on renewable generation.

Figure 7. Electricity generation by fuel, 1980-2030 (billion kilowatthours)

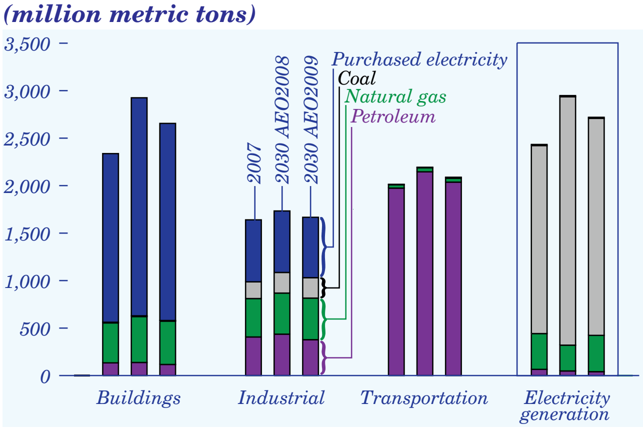


- The *AEO2009* reference case does not reflect the December 2008 reinstatement of the Clean Air Interstate Rule (CAIR) by the U.S. Court of Appeals, vacating its ruling in the summer of 2008 that overturned CAIR. Although the earlier ruling is reflected in *AEO2009*, it is assumed that electricity generators will continue to retrofit existing capacity with emission control equipment to comply with the revised National Ambient Air Quality Standards (NAAQS). Also, it is assumed that plants not equipped with scrubbers will be required ultimately to use low-sulfur coal in order to comply with the NAAQS.

A total of 46 gigawatts of coal-fired generating capacity is added from 2007 to 2030 in the *AEO2009* reference case, less than one-half the 103 gigawatts added in the *AEO2008* reference case. Concerns about GHG emissions significantly slow the expansion of coal-fired capacity in the *AEO2009* reference case, even under current laws and policies. Nuclear generating capacity in the *AEO2009* reference case increases from 100.5 gigawatts in 2007 to 112.2 gigawatts in 2030. The increase includes 12.7 gigawatts of capacity at newly built nuclear power plants and 3.4 gigawatts from uprates of existing plants, partially offset by 4.4 gigawatts of retirements.

Electricity generation from nuclear power plants grows from 806 billion kilowatthours in 2007 to 905 billion kilowatthours in 2030 in the *AEO2009* reference case, accounting for about 18 percent of total generation in 2030—about the same share as in 2007. Additional nuclear capacity is built in some of the alternative *AEO2009* cases, particularly those with higher demand for electricity, higher fossil fuel prices, or an explicit cap on GHG emissions.

Figure 8. U.S. energy-related carbon dioxide emissions by sector and fuel, 2007 and 2030 (million metric tons)



Energy-Related Carbon Dioxide Emissions

- Total energy-related CO_2 emissions in 2030 are 6,410 million metric tons in the *AEO2009* reference case, as compared with 6,851 million metric tons in the *AEO2008* reference case—a decline of 6.4 percent or 441 million metric tons.
- Energy-related CO_2 emissions grow by 0.3 percent per year from 2007 to 2030 in the *AEO2009* reference case, and emissions per capita fall by 0.6 percent per year, as demand for electricity and transportation fuels moderates in the face of higher energy prices, efficiency standards, State RPS requirements, and recently increased Federal CAFE standards.

Energy-related CO_2 emissions reflect the quantities of fossil fuels consumed and, because of their varying carbon content, the mix of coal, petroleum, and natural gas. Given the high carbon content of coal and its use currently to generate more than one-half of U.S. electricity, prospects for CO_2 emissions depend in part on growth in electricity demand. Electricity sales growth in the *AEO2009* reference case slows as a result of a variety of regulatory and socioeconomic factors, including appliance and building efficiency standards, higher energy prices, housing patterns, and economic activity. With slower electricity growth and increased use of renewables for electricity generation influenced by RPS laws in many States, electricity-related CO_2 emissions grow by just 0.5 percent per year from 2007 to 2030 (Figure 8). CO_2 emissions from transportation activity also slow in comparison with the recent past, as Federal CAFE standards increase the efficiency of the vehicle fleet, and higher fuel prices moderate the growth in travel.

Taken together, all these factors tend to slow the growth of the absolute level of primary energy consumption and promote a lower carbon fuel mix. As a result, energy-related emissions of CO_2 grow by 7 percent from 2007 to 2030—lower than the 11-percent increase in total energy use. Over the same period, the economy becomes less carbon-intensive as CO_2 emissions grow by about one-tenth of the increase in GDP, and emissions per capita decline by 14 percent.

Table 1. Total energy supply and disposition in the *AEO2009* and *AEO2008* reference cases, 2007-2030

Energy and economic factors	2007	2010		2020		2030	
		AEO2009	*AEO2008*	*AEO2009*	*AEO2008*	*AEO2009*	*AEO2008*
Primary energy production (quadrillion Btu)							
Petroleum	13.14	14.69	15.03	16.54	15.71	18.54	14.15
Dry natural gas	19.84	20.87	19.85	22.02	20.24	24.28	20.00
Coal	23.50	24.21	23.97	24.41	25.20	26.79	28.63
Nuclear power	8.41	8.45	8.31	9.00	9.05	9.44	9.57
Hydropower	2.46	2.67	2.92	2.95	3.00	2.97	3.00
Biomass	3.23	4.20	4.05	6.49	6.42	8.28	8.12
Other renewable energy	0.97	1.54	1.51	1.73	2.00	2.15	2.45
Other	0.97	0.83	0.54	1.05	0.58	1.13	0.64
Total	**72.52**	**77.45**	**76.17**	**84.19**	**82.21**	**93.58**	**86.56**
Net imports (quadrillion Btu)							
Petroleum	26.03	21.08	23.93	19.04	24.03	18.44	26.52
Natural gas	3.90	2.54	3.96	1.93	3.66	0.73	3.28
Coal/other (- indicates export)	-0.52	-1.16	-0.84	-0.11	1.06	0.26	1.86
Total	**29.41**	**22.46**	**27.04**	**20.86**	**28.75**	**19.43**	**31.66**
Consumption (quadrillion Btu)							
Liquid fuels	40.75	38.10	40.46	38.97	42.24	41.56	43.99
Natural gas	23.70	23.09	23.93	24.03	24.01	25.08	23.39
Coal	22.74	22.91	23.03	23.98	25.87	26.41	29.90
Nuclear power	8.41	8.45	8.31	9.00	9.05	9.44	9.57
Hydropower	2.46	2.67	2.92	2.95	3.00	2.97	3.00
Biomass	2.65	2.98	3.01	4.55	4.50	5.52	5.51
Other renewable energy	0.97	1.54	1.51	1.73	2.00	2.15	2.45
Net electricity imports	0.23	0.21	0.18	0.20	0.17	0.23	0.20
Total	**101.92**	**99.95**	**103.34**	**105.41**	**110.85**	**113.35**	**118.01**
Liquid fuels (million barrels per day)							
Domestic crude oil production	5.07	5.61	5.93	6.46	6.23	7.38	5.59
Other domestic production	3.59	4.06	3.70	4.72	4.45	5.39	4.85
Net imports	12.11	9.92	11.39	8.92	11.36	8.79	12.41
Consumption	20.65	19.79	20.99	20.23	21.96	21.65	22.80
Natural gas (trillion cubic feet)							
Production	19.36	20.36	19.36	21.48	19.73	23.68	19.50
Net imports	3.79	2.47	3.85	1.86	3.55	0.69	3.18
Consumption	23.05	22.46	23.25	23.38	23.33	24.40	22.72
Coal (million short tons)							
Production	1,147	1,177	1,166	1,209	1,270	1,336	1,455
Net imports	-25	-48	-34	-3	46	9	78
Consumption	1,129	1,140	1,145	1,218	1,327	1,358	1,545
Prices (2007 dollars)							
Imported low-sulfur, light crude oil (dollars per barrel)	72.33	77.97	75.97	115.64	61.26	130.50	72.29
Imported crude oil (dollars per barrel)	63.83	71.97	66.88	110.34	52.89	123.81	60.19
Domestic natural gas at wellhead (dollars per thousand cubic feet)	6.39	5.92	6.50	6.75	5.58	8.39	6.81
Domestic coal at minemouth (dollars per short ton)	25.82	29.40	26.84	27.94	23.10	28.94	23.93
Average electricity price (cents per kilowatthour)	9.1	9.0	9.4	9.4	8.8	10.5	9.1
Economic indicators							
Real gross domestic product (billion 2000 dollars)	11,524	11,793	12,453	15,511	15,984	20,112	20,219
GDP chain-type price index (index, 2000=1.000)	1.198	1.262	1.260	1.547	1.520	1.737	1.871
Real disposable personal income (billion 2000 dollars)	8,644	9,039	9,472	12,024	12,654	15,442	16,246
Value of manufacturing shipments (billion 2000 dollars)	5,750	5,256	5,997	6,752	7,113	8,451	7,997
Primary energy intensity (thousand Btu per 2000 dollar of GDP)	**8.84**	**8.47**	**8.30**	**6.80**	**6.93**	**5.64**	**5.84**
Energy-related carbon dioxide emissions (million metric tons)	**5,991**	**5,819**	**6,011**	**5,993**	**6,384**	**6,410**	**6,851**

Notes: Quantities are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, 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. Coal consumption includes waste coal consumed in the electric power and industrial sectors, which is not included in the tonnage of coal production.

Sources: AEO2009 National Energy Modeling System, run AEO2009.D112408B; and AEO2008 National Energy Modeling System, run AEO2008.D030208F.